

Northern Utilities, Inc.

New Hampshire Division

2020 / 2021 WINTER & SUMMER SEASON PROPOSED COST OF GAS ADJUSTMENT

WINTER RATES TO BE EFFECTIVE NOVEMBER 1, 2020

SUMMER RATES TO BE EFFECTIVE MAY 1, 2021

FILED SEPTEMBER 17, 2020

Northern Utilities, Inc.
New Hampshire Division
2020 / 2021 Annual Cost of Gas Filing
Winter and Summer Periods

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Winter Season

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Northern Utilities, Inc.
New Hampshire Division
2020 / 2021 Annual Cost of Gas Filing
Winter and Summer Periods

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Northern Utilities, Inc.
New Hampshire Division

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Northern Utilities, Inc.
New Hampshire Division

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New Hampshire Division

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New Hampshire Division

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N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Third Revised Page 40
Superseding Second Revised Page 40

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2020 - April 30, 2021

(Col 1)	(Col 2)	(Col 3)
<u>ANTICIPATED DIRECT COST OF GAS</u>		
Purchased Gas:		
Demand Costs:	\$4,596,721	
Supply Costs:	\$8,233,230	
Storage & Peaking Gas:		
Demand, Capacity:	\$11,702,910	
Commodity Costs:	\$2,618,320	
Interruptible Included Above	\$0	
Inventory Finance Charge	\$1,266	
Capacity Release, & Asset Management	(\$3,272,870)	
Re-entry Rate & Conversion Rate Revenues	\$ (5,000)	
Total Anticipated Direct Cost of Gas		<u>\$23,874,576</u>
<u>ANTICIPATED INDIRECT COST OF GAS</u>		
Adjustments:		
Prior Period Under/(Over) Collection	\$614,082	
Interest	(\$44,016)	
Refunds	\$0	
<u>Interruptible Margins</u>	<u>\$0</u>	
Total Adjustments		\$570,066
Working Capital:		
Total Anticipated Direct Cost of Gas	\$23,874,576	
Working Capital Percentage	<u>0.0892%</u>	
Working Capital Allowance	\$ 21,301	
Plus: Working Capital Reconciliation (Acct 173)	<u>(\$35,910)</u>	
Total Working Capital Allowance		(\$14,609)
Bad Debt:		
Bad Debt Allowance	\$156,687	
Plus: Bad Debt Reconciliation (Acct 173)	(\$4,239)	
Total Bad Debt Allowance		\$152,448
Local Production and Storage Capacity		\$476,106
Miscellaneous Overhead-81.23% Allocated to WinterSeason		<u>\$471,532</u>
Total Anticipated Indirect Cost of Gas		\$1,655,544
Total Cost of Gas		<u>\$25,530,120</u>

Issued: September 17, 2020

Issued By: Robert B. Hevert
Senior Vice President

Effective Date: November 1, 2020

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N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Third Revised Page No. 41
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Anticipated Cost of Gas

New Hampshire Division

Period Covered: May 1, 2021 - October 31, 2021

(Col 1)	(Col 2)	(Col 3)
<u>ANTICIPATED DIRECT COST OF GAS</u>		
Purchased Gas:		
Demand Costs:	\$842,503	
Supply Costs:	\$2,140,506	
Storage & Peaking Gas:		
Demand, Capacity:	\$332,957	
Commodity Costs:	\$25,153	
Interruptible Included Above	\$0	
Inventory Finance Charge	\$0	
Capacity Release & Asset Management	\$0	
Re-entry Rate and Conversion Rate Revenues	\$0	
Total Anticipated Direct Cost of Gas		<u>\$3,341,118</u>
<u>ANTICIPATED INDIRECT COST OF GAS</u>		
Adjustments:		
Prior Period Under/(Over) Collection	\$141,851	
Interest	(\$43,640)	
Refunds	\$0	
<u>Interruptible Margins</u>	<u>\$0</u>	
Total Adjustments		\$98,211
Working Capital:		
Total Anticipated Direct Cost of Gas	\$3,341,119	
Working Capital Percentage	<u>0.0892%</u>	
Working Capital Allowance	\$2,981	
Plus: Working Capital Reconciliation (Acct 173)	<u>(\$8,295)</u>	
Total Working Capital Allowance		(\$5,314)
Bad Debt:		
Bad Debt Allowance	\$14,144	
Plus: Bad Debt Reconciliation (Acct 173)	(\$979)	
Total Bad Debt Allowance		\$13,166
Local Production and Storage Capacity		\$0
Miscellaneous Overhead-18.77% Allocated to the Summer Season		\$108,923
Total Anticipated Indirect Cost of Gas		\$214,984
Total Cost of Gas		<u>\$3,556,103</u>

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NORTHERN UTILITIES, INC.

Seventh Revised Page 42
Superseding Sixth Revised Page 42

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2020 - April 30, 2021

(Col 1)	(Col 2)	(Col 3)
Total Anticipated Direct Cost of Gas	\$23,874,576	
Projected Prorated Sales (11/01/20 - 04/30/21)	34,897,412	
Direct Cost of Gas Rate		\$0.6841 per therm
Demand Cost of Gas Rate	\$13,021,761	\$0.3731 per therm
Commodity Cost of Gas Rate	<u>\$10,851,549</u>	<u>\$0.3110</u> per therm
Total Direct Cost of Gas Rate	<u>\$23,874,576</u>	\$0.6841 per therm
Total Anticipated Indirect Cost of Gas	\$1,655,544	
Projected Prorated Sales (11/01/20 - 04/30/21)	34,897,412	
Indirect Cost of Gas		\$0.0474 per therm
TOTAL PERIOD AVERAGE COST OF GAS		\$0.7315 per therm

RESIDENTIAL COST OF GAS RATE -11/01/20	COGwr	\$0.7315 per therm
	Maximum (COG+25%)	\$0.9144

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/20	COGwl	\$0.6465 per therm
	Maximum (COG+25%)	\$0.8081

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	\$601,051
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF	<u>\$31,569</u>
C&I HLF TOTAL ADJUSTED DEMAND COSTS	\$632,620
C&I HLF PROJECTED PRORATED SALES (11/01/20 - 04/30/21)	2,277,711
DEMAND COST OF GAS RATE	\$0.2777

C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	\$733,070
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF	<u>(\$940)</u>
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	\$732,130
C&I HLF PROJECTED PRORATED SALES (11/01/20 - 04/30/21)	2,277,711
COMMODITY COST OF GAS RATE	\$0.3214

INDIRECT COST OF GAS **\$0.0474**

TOTAL C&I HLF COST OF GAS RATE **\$0.6465**

COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/20	COGwh	\$0.7437 per therm
	Maximum (COG+25%)	\$0.9296

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	\$5,855,245
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	<u>\$307,534</u>
C&I LLF TOTAL ADJUSTED DEMAND COSTS	\$6,162,780
C&I LLF PROJECTED PRORATED SALES (11/01/20 - 04/30/21)	15,933,486
DEMAND COST OF GAS RATE	\$0.3868

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	\$4,937,736
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	<u>(\$6,330)</u>
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	\$4,931,406
C&I LLF PROJECTED PRORATED SALES (11/01/20 - 04/30/21)	15,933,486
COMMODITY COST OF GAS RATE	\$0.3095

INDIRECT COST OF GAS **\$0.0474**

TOTAL C&I LLF COST OF GAS RATE **\$0.7437**

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NORTHERN UTILITIES, INC.

Eighth Revised Page No. 43
Superseding Seventh Revised Page No. 43

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: May 1, 2021 - October 31, 2021

(Col 1)	(Col 2)	(Col 3)
Total Anticipated Direct Cost of Gas	\$3,341,119	
Projected Prorated Sales (05/01/21 - 10/31/21)	8,061,210	
Direct Cost of Gas Rate		\$0.4146 per therm
Demand Cost of Gas Rate	\$1,175,460	\$0.1458 per therm
Commodity Cost of Gas Rate	<u>\$2,165,659</u>	<u>\$0.2687</u> per therm
Total Direct Cost of Gas Rate	\$3,341,119	\$0.4145 per therm
Total Anticipated Indirect Cost of Gas	\$214,984	
Projected Prorated Sales (05/01/21 - 10/31/21)	8,061,210	
Indirect Cost of Gas		\$0.0267 per therm
TOTAL PERIOD AVERAGE COST OF GAS		\$0.4412 per therm

RESIDENTIAL COST OF GAS RATE -05/01/21	COGwr	\$0.4412 per therm
	Maximum (COG+25%)	\$0.5515

COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/21	COGwl	\$0.3943 per therm
	Maximum (COG+25%)	\$0.4929

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	\$178,339
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF	<u>\$10,993</u>
C&I HLF TOTAL ADJUSTED DEMAND COSTS	\$189,332
C&I HLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)	1,912,209
DEMAND COST OF GAS RATE	\$0.0990
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	\$513,718
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF	<u>(\$69)</u>
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	\$513,650
C&I HLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)	1,912,209
COMMODITY COST OF GAS RATE	\$0.2686
INDIRECT COST OF GAS	\$0.0267
TOTAL C&I HLF COST OF GAS RATE	\$0.3943

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/21	COGwh	\$0.4733 per therm
	Maximum (COG+25%)	\$0.5916

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	\$452,907
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	<u>\$27,917</u>
C&I LLF TOTAL ADJUSTED DEMAND COSTS	\$480,823
C&I LLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)	2,701,981
DEMAND COST OF GAS RATE	\$0.1780
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	\$725,892
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	<u>(\$97)</u>
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	\$725,795
C&I LLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)	2,701,981
COMMODITY COST OF GAS RATE	\$0.2686
INDIRECT COST OF GAS	\$0.0267
TOTAL C&I LLF COST OF GAS RATE	\$0.4733

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N.H.P.U.C. No. 12 - Gas
Northern Utilities, Inc.

Fourth Revised Page 62
Superseding Third Revised Page 62

Local Delivery Adjustment Clause

Rate Schedule	GAPRA	EEC	LRR	ERC	ITMC	RCE	RPC	LDAC
Residential Heating	\$0.0044	\$0.0774	\$0.0220	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.1099
Residential Non-Heating	\$0.0044	\$0.0774	\$0.0220	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.1099
Small C&I	\$0.0044	\$0.0337	\$0.0030	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0472
Medium C&I	\$0.0044	\$0.0337	\$0.0030	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0472
Large C&I	\$0.0044	\$0.0337	\$0.0030	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0472
No Previous Sales Service								

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NHPUC No. 12 - Gas
NORTHERN UTILITIES, INC.

Ninth Revised Page 85
Superseding Eighth Page 85

**NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON RESIDENTIAL RATES**

Winter Season November 2020 - April 2021		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	<u>Tariff Rate R 5:</u>			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 50 therms	\$0.6920	\$0.8019	\$1.5334
	All usage over 50 therms	\$0.6920	\$0.8019	\$1.5334
	LDAC	\$0.1099		
<u>Gas Cost Adjustment:</u>				
Cost of Gas		\$0.7315		
Residential Heating Low Income	<u>Tariff Rate R 10:</u>			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 50 therms	\$0.6920	\$0.8019	\$1.5334
	All usage over 50 therms	\$0.6920	\$0.8019	\$1.5334
	LDAC	\$0.1099		
	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	\$0.7315		
	45% Low Income Discount	(\$9.99)	(\$9.99)	(\$9.99)
	45% Low Income Discount	(\$0.3114)	(\$0.3114)	(\$0.6406)
	45% Low Income Discount	(\$0.3114)	(\$0.3114)	(\$0.6406)
LDAC		\$0.0000		
<u>Gas Cost Adjustment:</u>				
45% Low Income Discount		(\$0.3292)		
Residential Non-Heating	<u>Tariff Rate R 6:</u>			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 10 therms	\$0.6470	\$0.7569	\$1.4884
	All usage over 10 therms	\$0.6470	\$0.7569	\$1.4884
	LDAC	\$0.1099		
<u>Gas Cost Adjustment:</u>				
Cost of Gas		\$0.7315		

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Tenth Revised Page 86
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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
SUMMER SEASON RESIDENTIAL RATES

Summer Season May 2021 - October 2021		Tariff Rates	Total Delivery Rates (Includes LDAC)	<u>Total Billed Rates</u> Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	<u>Tariff Rate R 5:</u>			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 50 therms	\$0.6099	\$0.7198	\$1.1610
	All usage over 50 therms	\$0.6099	\$0.7198	\$1.1610
	LDAC	\$0.1099		
	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	\$0.4412		
Residential Heating Low Income	<u>Tariff Rate R 10:</u>			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 50 therms	\$0.6099	\$0.7198	\$1.1610
	All usage over 50 therms	\$0.6099	\$0.7198	\$1.1610
	LDAC	\$0.1099		
	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	\$0.4412		
No Discount*	Monthly Customer Charge	\$0.00	\$0.00	\$0.00
No Discount*	First 50 therms	\$0.0000	\$0.0000	\$0.0000
No Discount*	All usage over 50 therms	\$0.0000	\$0.0000	\$0.0000
No Discount	LDAC	\$0.0000		
	<u>Gas Cost Adjustment:</u>			
No Discount*	Cost of Gas	\$0.0000		
Residential Non-Heating	<u>Tariff Rate R 6:</u>			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 10 therms	\$0.6470	\$0.7569	\$1.1981
	All usage over 10 therms	\$0.6470	\$0.7569	\$1.1981
	LDAC	\$0.1099		
	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	\$0.4412		

*: Discount applicable to winter months November through April only.

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NHPUC No. 12 - Gas
 NORTHERN UTILITIES, INC.

Eighth Revised Page 87
 Superseding Seventh Revised Page 87

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
 WINTER SEASON C&I RATES

Winter Season November 2020 - April 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter <u>Tariff Rate G 40:</u> Monthly Customer Charge First 75 therms All usage over 75 therms LDAC <u>Gas Cost Adjustment:</u> Cost of Gas	\$75.09 \$0.1865 \$0.1865 \$0.0472 \$0.7437	\$75.09 \$0.2337 \$0.2337 	\$75.09 \$0.9774 \$0.9774
C&I Low Annual/Low Winter <u>Tariff Rate G 50:</u> Monthly Customer Charge First 75 therms All usage over 75 therms LDAC <u>Gas Cost Adjustment:</u> Cost of Gas	\$75.09 \$0.1865 \$0.1865 \$0.0472 \$0.6465	\$75.09 \$0.2337 \$0.2337 	\$75.09 \$0.8802 \$0.8802
C&I Medium Annual/High Winter <u>Tariff Rate G 41:</u> Monthly Customer Charge All usage LDAC <u>Gas Cost Adjustment:</u> Cost of Gas	\$222.64 \$0.2425 \$0.0472 \$0.7437	\$222.64 \$0.2897 	\$222.64 \$1.0334
C&I Medium Annual/Low Winter <u>Tariff Rate G 51:</u> Monthly Customer Charge First 1,300 therms All usage over 1,300 therms LDAC <u>Gas Cost Adjustment:</u> Cost of Gas	\$222.64 \$0.1712 \$0.1399 \$0.0472 \$0.6465	\$222.64 \$0.2184 \$0.1871 	\$222.64 \$0.8649 \$0.8336
C&I High Annual/High Winter <u>Tariff Rate G 42:</u> Monthly Customer Charge All usage LDAC <u>Gas Cost Adjustment:</u> Cost of Gas	\$1,335.81 \$0.1984 \$0.0472 \$0.7437	\$1,335.81 \$0.2456 	\$1,335.81 \$0.9893
C&I High Annual/Low Winter <u>Tariff Rate G 52:</u> Monthly Customer Charge All usage LDAC <u>Gas Cost Adjustment:</u> Cost of Gas	\$1,335.81 \$0.1720 \$0.0472 \$0.6465	\$1,335.81 \$0.2192 	\$1,335.81 \$0.8657

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NORTHERN UTILITIES, INC.

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
SUMMER SEASON C&I RATES

Summer Season May 2021 - October 2021		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	<u>Tariff Rate G 40:</u> Monthly Customer Charge First 75 therms All usage over 75 therms LDAC Gas Cost Adjustment: Cost of Gas	\$75.09 \$0.1865 \$0.1865 \$0.0472 \$0.4733	\$75.09 \$0.2337 \$0.2337 \$0.0472 \$0.4733	\$75.09 \$0.7070 \$0.7070 \$0.0472 \$0.4733
C&I Low Annual/Low Winter	<u>Tariff Rate G 50:</u> Monthly Customer Charge First 75 therms All usage over 75 therms LDAC Gas Cost Adjustment: Cost of Gas	\$75.09 \$0.1865 \$0.1865 \$0.0472 \$0.3943	\$75.09 \$0.2337 \$0.2337 \$0.0472 \$0.3943	\$75.09 \$0.6280 \$0.6280 \$0.0472 \$0.3943
C&I Medium Annual/High Winter	<u>Tariff Rate G 41:</u> Monthly Customer Charge All usage LDAC Gas Cost Adjustment: Cost of Gas	\$222.64 \$0.1895 \$0.0472 \$0.4733	\$222.64 \$0.2367 \$0.0472 \$0.4733	\$222.64 \$0.7100 \$0.0472 \$0.4733
C&I Medium Annual/Low Winter	<u>Tariff Rate G 51:</u> Monthly Customer Charge First 1,000 therms All usage over 1,000 therms LDAC Gas Cost Adjustment: Cost of Gas	\$222.64 \$0.1337 \$0.1087 \$0.0472 \$0.3943	\$222.64 \$0.1809 \$0.1559 \$0.0472 \$0.3943	\$222.64 \$0.5752 \$0.5502 \$0.0472 \$0.3943
C&I High Annual/High Winter	<u>Tariff Rate G 42:</u> Monthly Customer Charge All usage LDAC Gas Cost Adjustment: Cost of Gas	\$1,335.81 \$0.1206 \$0.0472 \$0.4733	\$1,335.81 \$0.1678 \$0.0472 \$0.4733	\$1,335.81 \$0.6411 \$0.0472 \$0.4733
C&I High Annual/Low Winter	<u>Tariff Rate G 52:</u> Monthly Customer Charge All usage LDAC Gas Cost Adjustment: Cost of Gas	\$1,335.81 \$0.0792 \$0.0472 \$0.3943	\$1,335.81 \$0.1264 \$0.0472 \$0.3943	\$1,335.81 \$0.5207 \$0.0472 \$0.3943

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Title: Senior Vice President

NHPUC No. 12 – Gas
Northern Utilities, Inc.

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Superseding Second Revised Page 141

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **\$0.71 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **\$ 64.53 per MMBtu** per MDPQ per month for November 2020 through April 2021. Provided on Page 6 of Schedule 21-FXW.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Company Allowance Calculation: **1.30%** - Provided in Schedule 18-FXW

IV. Supplier Services and Associated Fees:

<u>SERVICE</u>	<u>PRICING</u>
Pool Administration (required) Non-Daily Metered Pools only	• \$0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• \$0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• \$1.50/customer/month billed @ marketer level
Customer Administration (required)	• \$10/customer/switch billed @ marketer level

V. Meter Read Charge: \$78.00 when customer phone line is not reporting daily data

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Senior Vice President

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2020 through October 31, 2021.

Commercial and Industrial

	<u>High Winter Use</u>	<u>Low Winter Use</u>
Pipeline:	23.23%	57.23%
Storage:	31.91%	17.78%
Peaking:	44.86%	24.99%

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Senior Vice President

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VII. DELIVERY SERVICE TERMS AND CONDITIONS (continued)

Appendix D

**Re-entry Surcharge and Conversion Surcharge
(continued)**

D. Information to be Filed with the Commission:

As part of the annual Cost of Gas filing, the Company shall file with the Commission a report showing the number of customers assessed the Re-entry Surcharge and the Conversion Surcharge and the amount of revenue received for each charge through the prior April 30. Pursuant to the Company's Cost of Gas Clause, the Company will apply such revenues as credits to the Company's New Hampshire Division Cost of Gas.

The following Re-entry Surcharge and Conversion Surcharge shall be applicable for the periods of November 1, 2020 through April 30, 2021 and May 1, 2021 through October 2021.

Effective Dates:	November 1, 2020 – April 30, 2021	May 1, 2021 – October 30, 2021
Re-entry Surcharge:	\$0.0012 per therm	\$0.0011 per therm
Conversion Surcharge, Low Load Factor (G-40, G-41, G-42):	\$0.0012 per therm	\$0.0011 per therm
Conversion Surcharge, High Load Factor (G-50, G-51, G-52):	\$0.0984 per therm	\$0.0011 per therm

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Title: Senior Vice President

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N.H.P.U.C No.12
NORTHERN UTILITIES, INC.

SecondThird Revised Page 40
Superseding FirstSecond Revised Page 40

Anticipated Cost of Gas

New Hampshire Division

Period Covered: November 1, 2019~~20~~ - October 31, 2020~~21~~

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	\$ ~~1,399,977~~	\$ 4,596,721
Supply Costs:	\$ ~~4,289,717~~	\$ 8,233,230
Storage & Peaking Gas:		
Demand, Capacity:	\$ ~~12,012,257~~	\$ 11,702,910
Commodity Costs:	\$ ~~9,816,975~~	\$ 2,618,320
Interruptible Included Above	\$ ~~—~~	\$ —
Inventory Finance Charge	\$ ~~2,734~~	\$ 1,266
Capacity Release	\$ ~~(6,067,829)~~	\$ (3,272,870)
Re-entry Rate & Conversion Rate Revenues	\$ ~~(10,000)~~	\$ (5,000)
Total Anticipated Direct Cost of Gas	\$ ~~21,453,831~~	\$ 23,874,576
ANTICIPATED INDIRECT COST OF GAS		
Adjustments:		
Prior Period Under/(Over) Collection	\$ ~~(1,406,949)~~	\$ 614,082
Interest	\$ ~~(29,113)~~	\$ (44,016)
Refunds	\$ ~~—~~	\$ —
Interruptible Margins	\$ ~~—~~	\$ —
Total Adjustments	\$ ~~(1,436,062)~~	\$ 570,066
Working Capital:		
Total Anticipated Direct Cost of Gas	\$ ~~21,453,831~~	\$ 23,874,576
Working Capital Percentage	~~0.2880%~~	0.0892%
Working Capital Allowance	\$ ~~61,778~~	\$ 21,301
Plus: Working Capital Reconciliation (Acct 173)	\$ ~~(35,633)~~	\$ (35,910)
Total Working Capital Allowance	\$ ~~26,145~~	\$ (14,609)
Bad Debt:		
Bad Debt Allowance	\$ ~~153,235~~	\$ 156,687
Plus: Bad Debt Reconciliation (Acct 173)	\$ ~~(2,792)~~	\$ (4,239)
Total Bad Debt Allowance	\$ ~~150,444~~	\$ 152,448
Local Production and Storage Capacity		
	\$ ~~476,106~~	\$ 476,106
Miscellaneous Overhead ~~80.55~~ 81.23% Allocated to Winter Season		
	\$ ~~467,545~~	\$ 471,532
Total Anticipated Indirect Cost of Gas		
	\$ ~~(315,822)~~	\$ 1,655,544
Total Cost of Gas		
	\$ ~~21,138,010~~	\$ 25,530,120

Issued: November 1, 2019 September 17, 2020
Effective Date: November 1, 2019~~20~~

Issued By: Robert B. Hevert
~~Christine Vaughan~~
Senior Vice President

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

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Superseding FirstSecond Revised Page 41

Anticipated Cost of Gas				
New Hampshire Division				
Period Covered: May 1, 202021 - October 31, 202021				
(Col 1)	(Col 2)	(Col 2)	(Col 3)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	\$374,176	\$842,503		
Supply Costs:	\$1,901,121	\$2,140,506		
Storage & Peaking Gas:				
Demand, Capacity:	\$351,629	\$332,957		
Commodity Costs:	\$15,556	\$25,153		
Interruptible Included Above	\$0	\$0		
Inventory Finance Charge	\$0	\$0		
Capacity Release & Asset Management	\$0	\$0		
Re-entry Rate & Conversion Rate Revenues	\$0	\$0		
Total Anticipated Direct Cost of Gas			\$2,642,482	\$3,341,118
ANTICIPATED INDIRECT COST OF GAS				
Adjustments:				
Prior Period Under/(Over) Collection	(\$339,771)	\$141,851		
Interest	(\$18,232)	(\$43,640)		
Refunds	\$0	\$0		
Interruptible Margins	\$0	\$0		
Total Adjustments			(\$358,003)	\$98,211
Working Capital:				
Total Anticipated Direct Cost of Gas	\$2,642,482	\$3,341,119		
Working Capital Percentage	0.2880%	0.089%		
Working Capital Allowance	\$7,609	\$2,981		
Plus: Working Capital Reconciliation (Acct 173)	(\$8,605)	(\$8,295)		
Total Working Capital Allowance			(\$996)	(\$5,314)
Bad Debt:				
Bad Debt Allowance	\$15,143	\$14,144		
Plus: Bad Debt Reconciliation (Acct 173)	(\$674)	(\$979)		
Total Bad Debt Allowance			\$14,470	\$13,166
Local Production and Storage Capacity			\$0	\$0
Miscellaneous Overhead-19.4518.77% Allocated to the Summer Season			\$112,910	\$108,923
Total Anticipated Indirect Cost of Gas			(\$231,620)	\$214,984
Total Cost of Gas			\$2,410,862	\$3,556,103

Issued: November 1, 2019September 17, 2020

Effective Date: May 1, 20202021

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Christine VaughanRobert B. Hevert

Senior Vice President

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Sixth-~~Seventh~~ Revised Page 42
Superseding Fifth ~~Sixth~~ Revised Page 42

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2019~~20~~ - April 30, 2020~~21~~

(Col 1)	(Col 2)	(Col 3)		
Total Anticipated Direct Cost of Gas	\$21,453,834	\$23,874,576		
Projected Prorated Sales (11/01/19 ~~20~~ - 04/30/20 ~~21~~)	<u>36,062,014</u>	<u>34,897,412</u>		
Direct Cost of Gas Rate			\$0.5949	\$0.6841 per therm
Demand Cost of Gas Rate	\$7,344,405	\$13,021,761	\$0.2037	\$0.3731 per therm
Commodity Cost of Gas Rate	\$14,106,692	\$10,851,549	\$0.3912	\$0.3110 per therm
Total Direct Cost of Gas Rate	\$21,451,097	\$23,874,576	\$0.5949	\$0.6841 per therm
Total Anticipated Indirect Cost of Gas	(\$315,822)	\$1,655,544		
Projected Prorated Sales (11/01/19 ~~20~~ - 04/30/20 ~~21~~)	<u>36,062,014</u>	<u>34,897,412</u>		
Indirect Cost of Gas			(\$0.0088)	\$0.0474 per therm
TOTAL PERIOD AVERAGE COST OF GAS			\$0.5861	\$0.7315 per therm
Period ending under collection to be recovered as determined on 11/20/2019	(\$739,666)			
Projected Sales (12/01/19 - 04/30/2020)	<u>31,485,060</u>			
Per unit change in Cost of Gas (12/01/19 - 04/30/20)	(\$0.0235)			

RESIDENTIAL COST OF GAS RATE - 12/01/19-11/01/20	COGwr	\$0.5861	\$0.7315	per therm
	Maximum (COG+25%)	\$0.7326	\$0.9144	

RESIDENTIAL COST OF GAS RATES - 11/01/2019
CHANGE IN PER UNIT COST
RESIDENTIAL COST OF GAS RATES - 12/01/2019

\$0.5861
(\$0.0236)
\$0.5626

COM/IND LOW WINTER USE COST OF GAS RATE - 12/01/19-11/01/20	COGwl	\$0.4716	\$0.6465	per therm
	Maximum (COG+25%)	\$0.5894	\$0.8081	

COM/IND LOW WINTER USE COST OF GAS RATES - 11/01/2019
CHANGE IN PER UNIT COST
COM/IND LOW WINTER USE COST OF GAS RATES - 12/01/2019

\$0.4950
(\$0.0236)
\$0.4715

C&I HLF DEMAND COSTS ALLOCATED PER SMBA
PLUS: RESIDENTIAL DEMAND REALLOCATION TO C&I HLF
C&I HLF TOTAL ADJUSTED DEMAND COSTS
C&I HLF PROJECTED PRORATED SALES (11/01/2020 - 04/30/2021)
DEMAND COST OF GAS RATE

\$601,051
\$31,569
\$632,620
2,277,711
\$0.2777

C&I HLF COMMODITY COSTS ALLOCATED PER SMBA
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF
C&I HLF TOTAL ADJUSTED COMMODITY COSTS
C&I HLF PROJECTED PRORATED SALES (11/01/2020 - 04/30/2021)
COMMODITY COST OF GAS RATE

\$733,070
(\$940)
\$732,130
2,277,711
\$0.3214

INDIRECT COST OF GAS

\$0.0474

TOTAL C&I HLF COST OF GAS RATE

\$0.6465

COM/IND HIGH WINTER USE COST OF GAS RATE - 12/01/19-11/01/20	COGwh	\$0.5847	\$0.7437	per therm
	Maximum (COG+25%)	\$0.7309	\$0.9296	

COM/IND HIGH WINTER USE COST OF GAS RATES - 11/01/2019
CHANGE IN PER UNIT COST
COM/IND HIGH WINTER USE COST OF GAS RATES - 12/01/2019

\$0.6082
(\$0.0235)
\$0.5847

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF
C&I LLF TOTAL ADJUSTED DEMAND COSTS
C&I LLF PROJECTED PRORATED SALES (11/01/2020 - 04/30/2021)
DEMAND COST OF GAS RATE

\$5,855,245
\$307,534
\$6,162,780
15,933,486
\$0.3868

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF
C&I LLF TOTAL ADJUSTED COMMODITY COSTS
C&I LLF PROJECTED PRORATED SALES (11/01/2020 - 04/30/2021)
COMMODITY COST OF GAS RATE

\$4,937,736
(\$6,330)
\$4,931,406
15,933,486
\$0.3095

INDIRECT COST OF GAS

\$0.0474

TOTAL C&I LLF COST OF GAS RATE

\$0.7437

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Issued By: Christine Vaughan-Robert B. Hevert
Senior Vice President

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

SeventhEighth Revised Page No. 43
Superseding SixthSeventh Page No. 43

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: May 1, 202021 - October 31, 202021

(Col 1)	(Col 2)	(Col 2)	(Col 3)	(Col 3)
Total Anticipated Direct Cost of Gas	\$2,642,482	\$3,341,119		
Projected Prorated Sales (05/01/2021- 10/31/2021)	8,708,804	8,061,210		
Direct Cost of Gas Rate			\$0.3034	\$0.4145 per therm
Demand Cost of Gas Rate	\$726,806	\$1,175,460	\$0.0833	\$0.1458 per therm
Commodity Cost of Gas Rate	\$1,916,677	\$2,165,659	\$0.2204	\$0.2687 per therm
Total Direct Cost of Gas Rate	\$2,642,482	\$3,341,119	\$0.3034	\$0.4145 per therm
Total Anticipated Indirect Cost of Gas	(\$234,620)	\$214,984		
Projected Prorated Sales (05/01/2021- 10/31/2021)	8,708,804	8,061,210		
Indirect Cost of Gas			(\$0.0266)	\$0.0267 per therm
TOTAL PERIOD AVERAGE COST OF GAS			\$0.2768	\$0.4412 per therm
Period ending over-collection to be recovered – per April Report	(\$341,893)			
Projected sales (05/01/20 – 10/31/20)	8,708,804			
Per-unit change in Cost-of-Gas (05/01/20 – 10/31/20)	(\$0.0393)			
Period ending over-collection to be recovered – per June Report	(\$427,393)			
Projected sales (07/01/20 – 10/31/20)	4,862,236			
Per-unit change in Cost-of-Gas (07/01/20 – 10/31/20)	(\$0.0879)			
Period ending under-collection to be recovered – per August Report	\$447,787			
Projected sales (09/01/20 – 10/31/20)	3,041,809			
Per-unit change in Cost-of-Gas (09/01/20 – 10/31/20)	\$0.1472			
RESIDENTIAL COST OF GAS RATE -05/01/2021	COGwr	\$0.2968	\$0.4412	per therm
	Maximum (COG+25%)	\$0.3460	\$0.5515	
INITIAL RESIDENTIAL COST-OF-GAS RATE – 05/01/20		\$0.2768		
CHANGE IN PER UNIT COST		(\$0.0393)		
REVISED RESIDENTIAL COST-OF-GAS RATE – 05/01/20		\$0.2375		
CHANGE IN PER UNIT COST		(\$0.0879)		
REVISED RESIDENTIAL COST-OF-GAS RATE – 07/01/20		\$0.1496		
CHANGE IN PER UNIT COST		\$0.1472		
REVISED RESIDENTIAL COST-OF-GAS RATE – 09/01/20		\$0.2968		
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2021	COGwl	\$0.2643	\$0.3943	per therm
	Maximum (COG+25%)	\$0.3964	\$0.4929	
INITIAL COM/IND LOW WINTER USE COST-OF-GAS RATE – 5/01/20		\$0.2443		
CHANGE IN PER UNIT COST		(\$0.0393)		
REVISED COM/IND LOW WINTER USE COST-OF-GAS RATE – 05/01/20		\$0.2050		
CHANGE IN PER UNIT COST		(\$0.0879)		
REVISED COM/IND LOW WINTER USE COST-OF-GAS RATE – 07/01/20		\$0.1171		
CHANGE IN PER UNIT COST		\$0.1472		
REVISED COM/IND LOW WINTER USE COST-OF-GAS RATE – 09/01/20		\$0.2643		
C&I HLF DEMAND COSTS ALLOCATED PER SMBA		\$178,339		
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF		\$10,993		
C&I HLF TOTAL ADJUSTED DEMAND COSTS		\$189,332		
C&I HLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)		1,912,209		
DEMAND COST OF GAS RATE		\$0.0990		
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA		\$513,718		
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF		(\$69)		
C&I HLF TOTAL ADJUSTED COMMODITY COSTS		\$513,650		
C&I HLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)		1,912,209		
COMMODITY COST OF GAS RATE		\$0.2686		
INDIRECT COST OF GAS		\$0.0267		
TOTAL C&I HLF COST OF GAS RATE		\$0.3943		
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2021	COGwh	\$0.3146	\$0.4733	per therm
	Maximum (COG+25%)	\$0.3996	\$0.5916	
INITIAL COM/IND HIGH WINTER USE COST-OF-GAS RATE – 05/01/20		\$0.3146		
CHANGE IN PER UNIT COST		(\$0.0393)		
REVISED COM/IND HIGH WINTER USE COST-OF-GAS RATE – 05/01/20		\$0.2753		
CHANGE IN PER UNIT COST		(\$0.0879)		
REVISED COM/IND HIGH WINTER USE COST-OF-GAS RATE – 07/01/20		\$0.1844		
CHANGE IN PER UNIT COST		\$0.1472		
REVISED COM/IND HIGH WINTER USE COST-OF-GAS RATE – 09/01/20		\$0.3346		
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA		\$452,907		
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF		\$27,917		
C&I LLF TOTAL ADJUSTED DEMAND COSTS		\$480,823		
C&I LLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)		2,701,981		
DEMAND COST OF GAS RATE		\$0.1780		
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA		\$725,892		
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF		(\$97)		
C&I LLF TOTAL ADJUSTED COMMODITY COSTS		\$725,795		
C&I LLF PROJECTED PRORATED SALES (05/01/21 - 10/31/21)		2,701,981		
COMMODITY COST OF GAS RATE		\$0.2686		
INDIRECT COST OF GAS		\$0.0267		
TOTAL C&I LLF COST OF GAS RATE		\$0.4733		

N.H.P.U.C. No. 12 - Gas
Northern Utilities, Inc.

~~Fourth~~ Third Revised Page 62
Superseding ~~Third~~ Second Revised Page 62

Local Delivery Adjustment Clause

Rate Schedule	RLIARA	GAPRA	EEC	EEC	LRR	LRR	ERC	ERC	ITMC	RCE	RPC	LDAC	LDAC
Residential Heating	\$0.0036	\$0.0044	\$0.0499	\$0.0774	\$0.0114	\$0.0220	\$0.0057	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0706	\$0.1099
Residential Non-Heating	\$0.0036	\$0.0044	\$0.0499	\$0.0774	\$0.0114	\$0.0220	\$0.0057	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0706	\$0.1099
Small C&I	\$0.0036	\$0.0044	\$0.0247	\$0.0337	\$0.0019	\$0.0030	\$0.0057	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0359	\$0.0472
Medium C&I	\$0.0036	\$0.0044	\$0.0247	\$0.0337	\$0.0019	\$0.0030	\$0.0057	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0359	\$0.0472
Large C&I	\$0.0036	\$0.0044	\$0.0247	\$0.0337	\$0.0019	\$0.0030	\$0.0057	\$0.0061	\$0.0000	\$0.0000	\$0.0000	\$0.0359	\$0.0472
No Previous Sales Service													

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Title: Senior Vice President

NHPUC No. 12 - Gas
NORTHERN UTILITIES, INC.

~~Eighth~~ ~~Ninth~~ Revised Page 85
Superseding ~~Seventh~~ ~~Eighth~~ Page 85

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON RESIDENTIAL RATES

Winter Season November 2019 ~~20~~ - April 2020 ~~21~~		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	Tariff Rate R 5:			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 50 therms	\$0.6920	~~\$0.7626~~ <u>\$0.8019</u>	~~\$1.3252~~ <u>\$1.5334</u>
	All usage over 50 therms	\$0.6920	~~\$0.7626~~ <u>\$0.8019</u>	~~\$1.3252~~ <u>\$1.5334</u>
	LDAC	~~\$0.0706~~ <u>\$0.1099</u>		
Gas Cost Adjustment:				
Cost of Gas		~~\$0.5626~~ <u>\$0.7315</u>		
Residential Heating Low income	Tariff Rate R 10:			
	Monthly Customer Charge	~~\$8.8800~~ <u>\$22.20</u>	~~\$8.8800~~	~~\$8.8800~~
	First 50 therms	~~\$0.2768~~ <u>\$0.6920</u>	~~\$0.3474~~ <u>\$0.8019</u>	~~\$0.9100~~ <u>\$1.5334</u>
	All usage over 50 therms	~~\$0.2768~~ <u>\$0.6920</u>	~~\$0.3474~~ <u>\$0.8019</u>	~~\$0.9100~~ <u>\$1.5334</u>
	LDAC	~~\$0.0706~~ <u>\$0.1099</u>		
	Gas Cost Adjustment:			
	Cost of Gas	~~\$0.5626~~ <u>\$0.7315</u>		
	<u>45% Low Income Discount</u>			
	<u>45% Low Income Discount</u>			
	<u>45% Low Income Discount</u>			
	<u>No Discount</u>			
	<u>45% Low Income Discount</u>			
	<u>Monthly Customer Charge</u>	<u>(\$9.99)</u>	<u>(\$9.99)</u>	<u>(\$9.99)</u>
	<u>First 50 therms</u>	<u>(\$0.3114)</u>	<u>(\$0.3114)</u>	<u>(\$0.6406)</u>
	<u>All usage over 50 therms</u>	<u>(\$0.3114)</u>	<u>(\$0.3114)</u>	<u>(\$0.6406)</u>
	LDAC	<u>\$0.0000</u>		
	Gas Cost Adjustment:			
	<u>Cost of Gas</u>	<u>(\$0.3292)</u>		
Residential Non-Heating	Tariff Rate R 6:			
	Monthly Customer Charge	\$22.20	\$22.20	\$22.20
	First 10 therms	\$0.6470	~~\$0.7176~~ <u>\$0.7569</u>	~~\$1.2802~~ <u>\$1.4884</u>
	All usage over 10 therms	\$0.6470	~~\$0.7176~~ <u>\$0.7569</u>	~~\$1.2802~~ <u>\$1.4884</u>
	LDAC	~~\$0.0706~~ <u>\$0.1099</u>		
Gas Cost Adjustment:				
Cost of Gas		~~\$0.5626~~ <u>\$0.7315</u>		

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NORTHERN UTILITIES, INC.

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
SUMMER-SEASON RESIDENTIAL RATES

Summer Season May 2020 ~~21~~ - October 2020 ~~21~~		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	Tariff Rate R 5: Monthly Customer Charge First 50 therms All usage over 50 therms LDAC Gas Cost Adjustment: Cost of Gas	\$22.20 \$0.6099 \$0.6099 \$0.0706 \$0.1099 \$0.2968 \$0.4412	\$22.20 \$0.6805 \$0.7198 \$0.6805 \$0.7198	\$22.20 \$0.9773 \$1.1610 \$0.9773 \$1.1610
Residential Heating Low income	Tariff Rate R 10: Monthly Customer Charge First 50 therms All usage over 50 therms LDAC Gas Cost Adjustment: Cost of Gas <u>No Discount*</u> Monthly Customer Charge <u>No Discount*</u> First 50 therms <u>No Discount*</u> All usage over 50 therms <u>No Discount</u> LDAC <u>No Discount*</u> Gas Cost Adjustment: Cost of Gas	\$8.8800 \$22.20 \$0.2440 \$0.6099 \$0.2440 \$0.6099 \$0.0706 \$0.1099 \$0.2968 \$0.4412 \$0.0000 \$0.0000 \$0.0000 \$0.0000 \$0.0000	\$8.88 \$0.3146 \$0.7198 \$0.3146 \$0.7198 \$0.0000 \$0.0000 \$0.0000	\$8.88 \$0.6114 \$1.1610 \$0.6114 \$1.1610 \$0.0000 \$0.0000 \$0.0000
Residential Non-Heating	Tariff Rate R 6: Monthly Customer Charge First 10 therms All usage over 10 therms LDAC Gas Cost Adjustment: Cost of Gas	\$22.20 \$0.6470 \$0.6470 \$0.0706 \$0.1099 \$0.2968 \$0.4412	\$22.20 \$0.7176 \$0.7569 \$0.7176 \$0.7569	\$22.20 \$1.0144 \$1.1981 \$1.0144 \$1.1981

*. Discount applicable to winter months November through April only.

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON C&I RATES

Winter Season November 201920 - April 202021		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	Tariff Rate G 40: Monthly Customer Charge First 75 therms All usage over 75 therms LDAC Gas Cost Adjustment: Cost of Gas	\$75.09 \$0.1865 \$0.1865 \$0.0369 \$0.0472 \$0.5847 \$0.7437	\$75.09 \$0.2224 \$0.2337 \$0.2224 \$0.2337	\$75.09 \$0.8074 \$0.9774 \$0.8074 \$0.9774
C&I Low Annual/Low Winter	Tariff Rate G 50: Monthly Customer Charge First 75 therms All usage over 75 therms LDAC Gas Cost Adjustment: Cost of Gas	\$75.09 \$0.1865 \$0.1865 \$0.0369 \$0.0472 \$0.4715 \$0.6465	\$75.09 \$0.2224 \$0.2337 \$0.2224 \$0.2337	\$75.09 \$0.6939 \$0.8802 \$0.6939 \$0.8802
C&I Medium Annual/High Winter	Tariff Rate G 41: Monthly Customer Charge All usage LDAC Gas Cost Adjustment: Cost of Gas	\$222.64 \$0.2425 \$0.0369 \$0.0472 \$0.5847 \$0.7437	\$222.64 \$0.2784 \$0.2897	\$222.64 \$0.8634 \$1.0334
C&I Medium Annual/Low Winter	Tariff Rate G 51: Monthly Customer Charge First 1,300 therms All usage over 1,300 therms LDAC Gas Cost Adjustment: Cost of Gas	\$222.64 \$0.1712 \$0.1399 \$0.0369 \$0.0472 \$0.4715 \$0.6465	\$222.64 \$0.2074 \$0.2184 \$0.1758 \$0.1871	\$222.64 \$0.6786 \$0.8649 \$0.6473 \$0.8336
C&I High Annual/High Winter	Tariff Rate G 42: Monthly Customer Charge All usage LDAC Gas Cost Adjustment: Cost of Gas	\$1,335.81 \$0.1984 \$0.0369 \$0.0472 \$0.5847 \$0.7437	\$1,335.81 \$0.2343 \$0.2456	\$1,335.81 \$0.8490 \$0.9893
C&I High Annual/Low Winter	Tariff Rate G 52: Monthly Customer Charge All usage LDAC Gas Cost Adjustment: Cost of Gas	\$1,335.81 \$0.1720 \$0.0369 \$0.0472 \$0.4715 \$0.6465	\$1,335.81 \$0.2079 \$0.2192	\$1,335.81 \$0.6794 \$0.8657

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
SUMMER SEASON C&I RATES

Summer Season May 2020 ~~21~~ - October 2020 ~~21~~		Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	<u>Tariff Rate G 40:</u>			
	Monthly Customer Charge	\$75.09	\$75.09	\$75.09
	First 75 therms	\$0.1865	~~\$0.2224~~ <u>\$0.2337</u>	~~\$0.5540~~ <u>\$0.7070</u>
	All usage over 75 therms	\$0.1865	~~\$0.2224~~ <u>\$0.2337</u>	~~\$0.5540~~ <u>\$0.7070</u>
	LDAC	~~\$0.0359~~ <u>\$0.0472</u>		
C&I Low Annual/Low Winter	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	~~\$0.3316~~ <u>\$0.4733</u>		
C&I Medium Annual/High Winter	<u>Tariff Rate G 50:</u>			
	Monthly Customer Charge	\$75.09	\$75.09	\$75.09
	First 75 therms	\$0.1865	~~\$0.2224~~ <u>\$0.2337</u>	~~\$0.4867~~ <u>\$0.6280</u>
	All usage over 75 therms	\$0.1865	~~\$0.2224~~ <u>\$0.2337</u>	~~\$0.4867~~ <u>\$0.6280</u>
	LDAC	~~\$0.0359~~ <u>\$0.0472</u>		
C&I Medium Annual/Low Winter	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	~~\$0.2643~~ <u>\$0.3943</u>		
C&I High Annual/High Winter	<u>Tariff Rate G 41:</u>			
	Monthly Customer Charge	\$222.64	\$222.64	\$222.64
	All usage	\$0.1895	~~\$0.2254~~ <u>\$0.2367</u>	~~\$0.5570~~ <u>\$0.7100</u>
	LDAC	~~\$0.0359~~ <u>\$0.0472</u>		
	<u>Gas Cost Adjustment:</u>			
C&I High Annual/Low Winter	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	~~\$0.3316~~ <u>\$0.4733</u>		
C&I Medium Annual/High Winter	<u>Tariff Rate G 51:</u>			
	Monthly Customer Charge	\$222.64	\$222.64	\$222.64
	First 1,000 therms	\$0.1337	~~\$0.1696~~ <u>\$0.1809</u>	~~\$0.4339~~ <u>\$0.5752</u>
	All usage over 1,000 therms	\$0.1087	~~\$0.1446~~ <u>\$0.1559</u>	~~\$0.4089~~ <u>\$0.5502</u>
	LDAC	~~\$0.0359~~ <u>\$0.0472</u>		
C&I Medium Annual/Low Winter	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	~~\$0.2643~~ <u>\$0.3943</u>		
C&I High Annual/High Winter	<u>Tariff Rate G 42:</u>			
	Monthly Customer Charge	\$1,335.81	\$1,335.81	\$1,335.81
	All usage	\$0.1206	~~\$0.1565~~ <u>\$0.1678</u>	~~\$0.4881~~ <u>\$0.6411</u>
	LDAC	~~\$0.0359~~ <u>\$0.0472</u>		
	<u>Gas Cost Adjustment:</u>			
C&I High Annual/Low Winter	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	~~\$0.3316~~ <u>\$0.4733</u>		
C&I Low Annual/High Winter	<u>Tariff Rate G 52:</u>			
	Monthly Customer Charge	\$1,335.81	\$1,335.81	\$1,335.81
	All usage	\$0.0792	~~\$0.1151~~ <u>\$0.1264</u>	~~\$0.3794~~ <u>\$0.5207</u>
	LDAC	~~\$0.0359~~ <u>\$0.0472</u>		
	<u>Gas Cost Adjustment:</u>			
C&I Low Annual/Low Winter	<u>Gas Cost Adjustment:</u>			
	Cost of Gas	~~\$0.2643~~ <u>\$0.3943</u>		

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: \$0.71 per MMBtu of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: \$ ~~65.41~~64.53 per MMBtu per MDPQ per month for November 2019 through April 2020. Provided on Page 6 of Schedule 21-FXW.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Company Allowance Calculation: 1.~~38~~30% - Provided in Schedule 18-FXW

IV. Supplier Services and Associated Fees:

<u>SERVICE</u>	<u>PRICING</u>
Pool Administration (required) Non-Daily Metered Pools only	• \$0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• \$0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• \$1.50/customer/month billed @ marketer level
Customer Administration (required)	• \$10/customer/switch billed @ marketer level

V. Meter Read Charge: \$78 when customer phone line is not reporting daily data.

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Issued by: ~~Christine~~
~~Vaughan~~ Robert. B.
Hevert

Effective: November 1, ~~2019~~ 2020

Senior Vice President

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, ~~2019~~ 2020 through October 31, ~~2020~~ 2021.

Commercial and Industrial

	<u>High Winter Use</u>	<u>Low Winter Use</u>
Pipeline:	~~9.35~~ <u>23.23</u> %	~~48.43~~ <u>57.23</u> %
Storage:	~~34.33~~ <u>31.91</u> %	~~19.53~~ <u>17.78</u> %
Peaking:	~~56.32~~ <u>44.86</u> %	~~32.04~~ <u>24.99</u> %

Issued: ~~November 1, 2019~~ September 17, 2020

Issued by: ~~Christine~~
~~Vaughan~~ Robert B.
Hevert

Effective: November 1, ~~2019~~ 2020

Senior Vice President

Authorized by NHPUC Order No. _____ in Docket No. DG19-__ __, dated _____.

VII. DELIVERY SERVICE TERMS AND CONDITIONS (continued)**Appendix D****Re-entry Surcharge and Conversion Surcharge
(continued)****D. Information to be Filed with the Commission:**

As part of the annual Cost of Gas filing, the Company shall file with the Commission a report showing the number of customers assessed the Re-entry Surcharge and the Conversion Surcharge and the amount of revenue received for each charge through the prior April 30. Pursuant to the Company's Cost of Gas Clause, the Company will apply such revenues as credits to the Company's New Hampshire Division Cost of Gas.

The following Re-entry Surcharge and Conversion Surcharge shall be applicable for the periods of November 1, ~~2019~~ 2020 through April 30, ~~2020~~ 2021 and May 1, ~~2020~~ 2021 through October ~~2020~~ 2021.

Effective Dates:	November 1, ~~2019~~ <u>2020</u> – April 30, ~~2020~~<u>2021</u>	May 1, ~~2020~~<u>2021</u> – October 30, ~~2020~~<u>2021</u>
Re-entry Surcharge:	\$0. ~~0409~~ <u>0012</u> per therm	\$0. ~~0406~~ <u>0011</u> per therm
Conversion Surcharge, Low Load Factor (G-40, G-41, G-42):	\$0. ~~1405~~ <u>0012</u> per therm	\$0. ~~0406~~ <u>0011</u> per therm
Conversion Surcharge, High Load Factor (G-50, G-51, G-52):	\$0. ~~2537~~ <u>0984</u> per therm	\$0. ~~0406~~ <u>0011</u> per therm

Issued: ~~November 1, 2019~~ September 17, 2020

Issued by: Christine
VaughanRobert B.
Hevert

Effective: November 1, ~~2019~~ 2020

Title: Senior Vice President

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NORTHERN UTILITIES, INC. - NEW HAMSHIRE DIVISION
2020 / 2021 Annual Cost of Gas Filing

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Wells Testimony		Pre-Filed Testimony
Demeris Testimony		Pre-Filed Testimony
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	Schedule 2-CAK	Comparison of Proposed Rates to Current Rates
	Schedule 3-SED	Typical Bill Analysis
Section 2 Cost of Gas Calculations		
	Schedule 4-CAK	Allocation of Demand Costs to ME & NH
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	Schedule 6-CAK	Forecast Firm Sales
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	Schedule 8-CAK	Allocation of Commodity Costs to ME & NH
	Schedule 9-CAK	NH Allocated Commodity Costs
	Schedule 10-CAK	Inventory Activity
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	Schedule 14-CAK	Bad Debt Calculation
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Section 3 Gas Supply Costs		
	Schedule 16-FXW	Metered Distribution Deliveries and Meter Counts
	Schedule 17-FXW	Sales Service Deliveries Forecast by Rate Class
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	Schedule 19-FXW	Capacity Path Diagrams and Details by Supply Source
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Schedule 27-CAK	Prior Year Re-entry Rate and Conversion Volumes & Revenues
Schedule 28-CAK	Short Term Debt Limit Calculation
Schedule 29-FXW	Supplier Prices
Schedule 30-FXW	Normal Year Sendout Volumes
Schedule 31-FXW	Design Year Sendout Volumes
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**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2020 / OCTOBER 2021 ANNUAL PERIOD
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-five years. Before joining
15 Unitil in January 2011, I was employed as an Analyst with Columbia Gas of
16 Massachusetts (“Columbia”) where I had worked since 1997 in supply planning. Prior to
17 working for Columbia, I was employed as an Analyst in the Rates and Regulatory Affairs
18 Department of Algonquin Gas Transmission Company (“Algonquin”) from 1993 to 1997.
19 Prior to working for Algonquin, I was employed as a Senior Associate/Energy Consultant

1 for 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 2019 / 2020 Annual Cost of Gas
6 (“COG”) proceeding, Docket No. DG 19-154 and the 2018 / 2019 Annual COG
7 proceeding, Docket No. DG 18-143. I have testified in numerous other Cost of Gas
8 proceedings as well.

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

10 A. This proceeding reflects the annual COG filing and will present both the 2020 / 2021
11 Winter Season and 2021 Summer Season COG rates as well as various ancillary rates. I,
12 Francis Wells, Manager of Gas Supply for Unitil Service, and Elena Demeris, Senior
13 Regulatory Analyst for Unitil Service are sharing the responsibility of supporting the
14 proposed New Hampshire Division 2020 / 2021 Annual COG and other proposed rate
15 adjustments in this proceeding.

16 Mr. Wells is sponsoring the customer demand forecast and the resulting forecasted gas
17 sendout and gas costs he developed for the Maine and New Hampshire Divisions. He is
18 also providing the Capacity Allocation Percentages, the Peaking Demand Rate
19 calculation and the Re-Entry Rate and Conversion Rate calculations.

20 Ms. Demeris is sponsoring the calculation of the 2020 / 2021 Local Distribution
21 Adjustment Clause (“LDAC”), and the typical customer bill impacts resulting from the
22 proposed 2020 / 2021 Winter Season and 2021 Summer Season COG rates.

My testimony presents and explains the New Hampshire Division's 2019 / 2020 Annual COG Reconciliation, the calculation of the 2020 / 2021 annual COG and the rates Northern proposes to charge customers for the November 1, 2020 to April 30, 2021 Winter Season, and for the May 1, 2021 to October 31, 2021 Summer Season. In addition, I will also discuss some of the proposed ancillary rates that are to be effective November 1, 2020 and May 1, 2021.

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

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

Schedule 1- CAK	Cost Overview & Calculation of the COG Rates
Schedule 2- CAK	Comparison of Proposed Residential Rates to 2019 / 2020 Rates
Schedule 4- CAK	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 5- CAK	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Schedule 6- CAK	Division Sales and Sendout Forecast
Schedule 7- CAK	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Schedule 8- CAK	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 9- CAK	New Hampshire Division Commodity Cost Analysis
Schedule 10- CAK	Northern Utilities Inventory Activity
Schedule 11- CAK	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 12-CAK	Calculation of High and Low Load Factor Rate Adjustments
Schedule 13- CAK	2019 - 2020 Annual Reconciliation
Schedule 14- CAK	Bad Debt Forecast
Schedule 15-CAK	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Schedule 26- CAK	Supplier Balancing Charge
Schedule 27- CAK	Prior Year Re-entry Rate and Conversion Rate Revenues

Schedule 28 -CAK	Short Term Debt Limit Calculation

Note: Schedules 3 and 16 through 25 and 29 through 39 are provided by Ms. Demeris and Mr. Wells.

II Summary

Q. Please Summarize Northern's proposed 2020 / 2021 Summer Period and Winter Period COG rates and describe how they compare to last year's rates.

A. Table 1 below provides Unitil's proposed 2020 / 2021 Winter Period COG rates and compares them to the average COG rates for the 2019 / 2020 Winter Period. As this table shows, Winter Period COG rates are higher than those in 2019 / 2020 by \$0.1650 for residential customers and higher by \$0.1711 and \$0.1551 per therm for High and Low Load Factor Commercial / Industrial customers, respectively.

Table 1

Winter Period Cost of Gas Rates

Class	2020 / 2021 Proposed Rate per therm	2019 / 2020 Average Rate per therm	Percent Change From 2019/2020 Winter Period
Residential Non-Heat (R-5, R-6 & R-10)	\$0.7315	\$0.5665	29.12%
C & I - High Load Factor (G-50, G-51 & G-52)	\$0.6465	\$0.4754	35.99%
C & I - Low Load Factor (G-40, G-41 & G-42)	\$0.7437	\$0.5886	26.35%

Table 2 below provides Unitil's proposed 2020 / 2021 Summer Period COG rates and compares them to the average COG rates for the 2019 / 2020 Summer Period. As this table shows, the proposed COG rates are \$0.2132 higher for Residential customers and \$0.1988 and \$0.2105 higher for High and Low Load Factor Commercial / Industrial customer, respectively.

Table 2

Summer Period Cost of Gas Rates

Class	2020 / 2021 Proposed Rate per therm	2019 / 2020 Average Rate per therm	Percent Change From 2019 / 2020 Summer Period
Residential Non-Heat (R-5, R-6 & R-10)	\$0.4412	\$0.2280	93.54%
C & I - High Load Factor (G-50, G-51 & G-52)	\$0.3943	\$0.1955	101.72%
C & I - Low Load Factor (G-40, G-41 & G-42)	\$0.4733	\$0.2628	80.12%

A summary of the calculation of these rates, and the components that make up these rates is provided in Schedule 1-CAK. A more detailed comparison of 2020 / 2021 residential COG rates to 2020 / 2021 residential rates is provided in Schedule 2-CAK. I will describe the reasons for the change in COG rates later in my testimony. Customer bill impacts resulting from the change in COG rates are discussed in the testimony of Ms. Demeris and are presented in Schedule 3-SED.

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 total Northern 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.

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

1 in a two-step process: (1) costs, by resource type¹, are allocated to months by application
2 of MPR allocation factors; and (2) the costs allocated to each month are then allocated to
3 the Maine and New Hampshire Divisions based on the relative shares of Design Year
4 demand² in that month. This MPR methodology was approved by the Commission
5 pursuant to settlements in Docket Nos. 2005-087 and 2005-273.

6 As I will explain in more detail below, I used the MPR methodology to allocate
7 Northern's projected total annual demand costs to the Maine and New Hampshire
8 Divisions for the 2020 / 2021 Winter Season (November 2020 through April 2021) and
9 for the 2021 Summer Season (May 2021 through October 2021).

10 **Q. Please give an overview of the process you followed to derive the MPR allocator**
11 **used to assign Northern's projected total demand costs for the 12-month period**
12 **November 2020 through October 2021 to the Maine and New Hampshire Divisions.**

13 A. I have prepared Schedule 4-CAK to explain how I calculated the MPR factors and how I
14 used these factors to allocate Northern's total demand costs for November 2020 through
15 October 2021 ("COG Period") to the Maine and New Hampshire Divisions. In this
16 attachment, I distinguish between two types of demand costs; Capacity-related and Off-
17 system Peaking demand costs. Capacity-related demand costs reflect the resource costs

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 2019 through April 2020, adjusted to reflect design weather conditions from November through April and normal weather conditions from May through October.

1 of Pipeline, Storage and On-system Peaking supplies, as well as credits for capacity
2 release and asset management agreements, for both Sales Service and capacity assigned
3 Delivery Service customers. Off-system Peaking demand costs reflect the costs
4 associated with Northern's Off-system Peaking resources used for Sales Service
5 customers only.

6 Schedule 4-CAK is arranged in the following six sections;

7 (1) Total Capacity-related demand costs, by type of resource (Pipeline, Storage,
8 On-system Peaking, and other capacity related costs and credits), are summarized
9 in Lines 1 through 14.

10 (2) Capacity-related demand costs for each resource type are allocated to each
11 month in the COG Period according to MPR allocators that were developed
12 specifically for each resource type, as shown on Lines 16 through 52, where the
13 MPR allocators are based on design year sendout volumes for each resource type.

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

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

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

4 6) Total Demand costs for each division are then calculated by applying the ratio
5 of each division's Capacity-related demand costs and Off-system Peaking demand
6 costs to Northern's total costs as shown in Lines 124 through 137. From these
7 calculations, the PR allocators are determined. As shown, for November 2020
8 through October 2021, the PR allocators are 59.12% for the Company's Maine
9 Division and 40.88% for the New Hampshire Division.

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

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

15 A. Northern no longer purchases Off-system Peaking supplies for capacity-assigned
16 Delivery Service customers in either its Maine or New Hampshire Divisions³.
17 Accordingly, these costs should not be included in the allocation of Capacity-related
18 demand costs because the associated dispatch of these resources includes capacity-
19 assigned (i.e. Sales Service plus capacity-assigned Delivery Service) load. A capacity

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

1 resource, like the Company's Off-system Peaking Supplies, that reflects only the cost
2 associated with Sales Service customers, should be allocated between divisions based on
3 the dispatch of Sales Service load only.

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

6 A. Lines 3 through 5 of Schedule 4-CAK show Northern's total projected demand costs for
7 Pipeline, Storage, and On-system Peaking resources⁴. Also included are estimates of
8 Northern's Capacity Release and Asset Management revenues, which I have summarized
9 in Lines 8 and 9 of Schedule 4-CAK.

10 The development of the MPR factors and the application of these factors to allocate
11 Pipeline, Storage and On-system Peaking demand costs to each month are shown on
12 Schedule 4-CAK, Lines 20 through 25, Lines 36 through 43 and Lines 47 through 52,
13 respectively. In addition, Lines 29 through 32 show the calculation of the Storage
14 Injection Fees, by month. Storage Injection Fees represent capacity costs that comprise
15 the portion of Northern's pipeline capacity that is used to transport gas to and from the
16 underground storage fields. If the Company expects to incur such fees, they are added to
17 the Storage demand costs, as shown on Line 42, and subtracted from the Pipeline demand
18 costs, as shown on Line 57. However, as indicated, for the 2020 / 2021 Winter Season,
19 storage injection fees are zero. This is because Northern is purchasing storage gas

⁴ The forecast of demand costs is provided in Schedule 20-FXW.

1 directly at the underground storage facility thereby eliminating the need for transportation
2 to the facility and the associated transfer of costs.

3 Northern's fixed capacity costs that have been allocated to each month are summarized
4 and consolidated on Lines 54 through 60. Lines 54, 55 and 56 repeat the Pipeline,
5 Storage, and On-system Peaking capacity costs from Lines 25, 43, and 52. Line 57
6 shows the credit to Pipeline capacity costs that is related to the Storage Injection Fees that
7 have been added to the Storage capacity costs⁵. In addition, 1/5 of total Capacity Release
8 revenues are allocated evenly to each month from November through March, as shown
9 on Line 58, and 1/6 of total Asset Management revenues are allocated evenly to each
10 month from November through April, as shown on Line 59.

11 **Q. How are the total Capacity-related Demand Costs and the Capacity Release and**
12 **Asset Management revenues, which have been allocated to each month according to**
13 **the process that you described above, allocated to the Maine and New Hampshire**
14 **Divisions?**

15 A. Northern's Total Capacity-related Demand Costs⁶ and Capacity Release and Asset
16 Management revenues allocated to each month are then allocated to the Maine and New
17 Hampshire Divisions according to the design year total firm sendout for both divisions,
18 which is shown in Lines 65 and 66 of Schedule 4-CAK; the calculated percentages are

⁵ As indicated, for the 2020 / 2021 Winter Season, the credit is zero due to purchases being made directly at the storage facility.

⁶ Costs reflect pipeline, storage and on-system peaking resources.

1 provided in Lines 70 and 71. In accordance with Commission-approved settlements⁷, the
2 design-year firm sendout quantities for the COG Period as shown on Lines 65 and 66 are
3 the sendout quantities required to serve the Maine and New Hampshire Divisions' firm
4 sales and transportation customers that are subject to the assigned-capacity requirements
5 under design winter conditions from May 2019 to April 2020.

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

8 A. Yes. Lines 101 through 106 of Schedule 4-CAK use the same process for allocating
9 resource costs to each month as that used in Lines 47 through 52. Also, Lines 109
10 through 123 use the same process for applying monthly costs to divisional sendout as
11 used in Lines 62 through 77. As shown in Lines 121 and 122, Off-system Peaking
12 demand costs are allocated to each division based on the design winter dispatch of Sales
13 Service customers only.

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

16 A. The combined PR allocators are based on the percentage of total Capacity-related and
17 Off-System Peaking PRs costs allocated to each division. Lines 125 and 130 of Schedule
18 4-CAK show the Capacity-related PR allocators while Lines 126 and 131 show the
19 corresponding values for Off-system peaking PR allocators. Lines 127 and 132 show the

⁷ These settlements were approved in Docket Nos. 2005-87 and 2005-273.

1 combined PR Allocators, 59.12% for Maine and 40.88% for New Hampshire, used to
2 assign costs between divisions.

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

4 **Q. Please explain how the projected annual demand-related costs that are allocated to**
5 **the New Hampshire Division are then assigned to be recovered in the 2020 / 2021**
6 **Winter Season and the 2021 Summer Season.**

7 A. Northern allocates costs between the seasons as well as among customer classes through
8 the Simplified Market Based Allocation (“SMBA”) method. I have prepared Schedule 5-
9 CAK to show detailed support for the allocation of New Hampshire Division Sales
10 Service demand costs to months, and then to seasons utilizing the SMBA method.

11 Lines 2 through 4 of Schedule 5-CAK summarize the Pipeline and Storage and On-
12 system Peaking demand costs that are allocated to the New Hampshire Division, as
13 determined in Schedule 4-CAK. Lines 12 through 22 of Schedule 5-CAK show the
14 calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs
15 allocated to the New Hampshire Division less the capacity assignment revenues from
16 New Hampshire Division transportation customers. The Winter and Summer Season
17 rates that will be charged to New Hampshire Division firm sales customers from
18 November 2020 through October 2021 will recover: (1) the Net Pipeline Demand costs

1 shown on Line 19; (2) the Net Storage costs shown on Line 20; and (3) the On-system
2 Peaking demand costs shown on Line 21 of Schedule 5-CAK.⁸

3 Lines 26 through 40 of Schedule 5-CAK show the calculation of pipeline demand costs
4 for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use
5 demand costs.⁹ The Base Use that is shown on Line 31 of Schedule 5-CAK is the
6 average projected daily use in July and August 2020¹⁰ for all firm sales classes. The Base
7 Pipeline Use Demand cost that is shown on Line 39 of Schedule 5-CAK is calculated by
8 multiplying Firm Sales Base Use, shown on Line 31, times the weighted average annual
9 cost of pipeline capacity, as shown on Line 35 of Schedule 5-CAK. Line 40 shows the
10 Remaining Pipeline Use Net Pipeline Demand costs for sales customers, which is the
11 difference between total net Pipeline and Product Demand costs and Base Pipeline Use
12 demand costs.

13 Lines 44 through 49 of Schedule 5-CAK show the calculation of the Proportional
14 Responsibility (“PR”) allocator that is used to allocate (a) Remaining Use Net Pipeline
15 Demand costs and (b) Storage and On-system Peaking costs related to Firm Sales
16 customers for twelve months, November 2020 through October 2021. Lines 51 through
17 55 show the calculation of the PR factor that is used to allocate (c) Capacity Release and
18 Asset Management revenues, (d) Interruptible margins and Re-entry Rate and Conversion

⁸ These direct demand costs are adjusted by CNG expenses (Line 75); Capacity Release and Asset Management revenues (Line 77); Interruptible margins (Line 78); and Re-Entry Rate and Conversion Rate Credits (Line 79).

⁹ 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.

¹⁰ Average Projected Daily demand by class in July and August is shown in Schedule 6-CAK, Line 48.

1 Rate revenues and (e) Off-system Peaking Supplies to the Winter Season months,
2 November 2020 through April 2021. These PR factors are summarized by type of
3 capacity cost at lines 60 through 65. Line 60 of Schedule 5-CAK shows that 1/12th of
4 the net annual Base Use pipeline demand costs is allocated to each month, and Lines 69
5 through 79 show the detailed allocation to months of all components that are included in
6 the Total Net Demand Costs, based on the “All Months” and “Peak Months Only”
7 allocation factors.

8 As shown on Line 79 of Schedule 5-CAK, \$13,021,761 of total direct demand costs are
9 allocated to the 2020 / 2021 Winter Season, and \$1,175,460 is allocated to the 2021
10 Summer Season.

11 **Q. Please explain the CNG expense listed on Line 75 of Attachment NUI-CAK-2.**

12 A. The expense listed on Line 75 is for compressed natural gas (CNG) service which was
13 required to maintain service to Northern’s customers during a one week pipeline outage in
14 June 2020. The pipeline outage was due to upstream construction involving the addition of
15 a new compressor to the Eliot Compressor Station as part of Portland Natural Gas
16 Transmission System’s (PNGTS) Portland Xpress Project (PXP). Northern’s distribution
17 system in Eliot is fed by a single pipeline interconnection. When the Company was
18 informed the pipeline would be taken out of service, a circumstance that was beyond the
19 Company’s control, the Company arranged for the CNG service in order to maintain
20 service. The total cost for the CNG service is \$286,008. Of this amount, the portion
21 allocated to the New Hampshire division, \$119,666, is based on the PR Allocator in effect at

1 the time of the outage (41.84%). The CNG expense is discussed in greater detail in Mr.
2 Wells' testimony.

3 **C. Allocation of New Hampshire Winter and Summer Season Demand Costs to**
4 **Customer Classes**

5 **Q. Please explain how the New Hampshire Division sales service demand-related costs**
6 **that were allocated to the Winter and Summer Seasons are allocated to each sales**
7 **rate class.**

8 A. The New Hampshire Division sales service Base Use demand-related costs for each
9 month are allocated to each sales service rate class based on that class's pro rata share of
10 total forecasted firm sendout to sales customers under normal weather conditions in that
11 month. The Remaining Use demand-related costs for each month are allocated to each
12 sales service rate class based on that class's pro rata share of total forecasted firm sales
13 design day, temperature-sensitive demand.

14 I have prepared Schedule 6-CAK to show the calculation of the factors that are used to
15 allocate New Hampshire Division sales service Winter and Summer Season Base Use
16 demand-related costs for each month to each sales service rate class. The firm sales
17 forecast, shown on Lines 1 to 16, and the firm sendout forecast by class, shown on Lines
18 18 to 33, are used to determine: daily Base Use, shown on Lines 35 to 48; Base Use
19 sendout, shown on Lines 49 to 64; and Remaining Use sendout, shown on Lines 66 to 80.
20 The Base and Remaining Use sendout values for each class are used to allocate the
21 seasonal demand costs to the New Hampshire Division firm sales classes.

I have prepared Schedule 7-CAK 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 5-CAK, Lines 69 through 79, and (b) the rate class allocators as shown Schedule 6-CAK, Lines 49 to 80. The Base Use Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Schedule 7-CAK. The Remaining Use Design Day allocators, which are used to allocate all other demand-related costs and credits to firm Sales Service rate classes, are shown on Lines 39 through 48.

The following table shows the location in Schedule 7-CAK of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Schedule 7-CAK
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 & CNG Expense	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.

1 A. Variable costs include commodity costs and variable pipeline and storage costs¹¹ for firm
2 sales. Mr. Wells prepared a forecast of Northern's variable gas costs by month, which is
3 provided in Schedule 23-FXW. These variable gas costs have been allocated between the
4 Maine and New Hampshire Divisions based on each Division's percentage of monthly
5 firm normal sendout. I have prepared Schedule 8-CAK to show the allocation of the
6 2020 / 2021 Winter and Summer Season variable gas costs between the Maine and New
7 Hampshire Divisions.

8 **Q. Please explain Schedule 8-CAK.**

9 A. Lines 1 through 10 of Schedule 8-CAK show the projected sendout volumes, by month
10 and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the
11 projected variable costs by month and by type of gas supply resource¹² that are shown on
12 Lines 18, 24 and 26 through 29 of Schedule 8-CAK. This Schedule also shows projected
13 Off-system Sales revenues on Line 30. The pipeline commodity costs shown on Lines 18
14 and 24 are based on projected NYMEX prices as of September 1, 2020. The total
15 variable gas costs for firm Sales Service, on Lines 32 and 45, are allocated to the Maine
16 and New Hampshire Divisions based on projected monthly firm sales sendout in each
17 division; the allocators are shown on Lines 49, 50, 54 and 55. Schedule 8-CAK also
18 shows the allocation of Commodity costs to the two Divisions, (Maine Division: Lines 60
19 through 67; New Hampshire Division: Lines 69 through 76). Finally, Schedule 8-CAK

¹¹ Variable costs include pipeline usage/commodity charges, pipeline fuel retention, storage commodity injection and withdrawal charges, and storage fuel retention.

¹² Due to the large variation in pipeline supply prices shown in Attachment Schedule 23-FXW, pipeline resources have been split into base use and remaining use in order to allocate commodity costs in a more equitable manner.

1 shows the inventory finance costs for underground storage and LNG resources (Lines 94
2 to 96), the allocation of these costs to the Maine and New Hampshire Divisions (Lines 99
3 to 101), and the allocation of New Hampshire Division's allocated share of annual
4 inventory finance costs to the Winter Season, using the firm sales remaining sendout
5 allocators (Lines 110 to 112).

6 I have prepared Schedule 9-CAK to summarize the New Hampshire Division variable gas
7 costs that were determined in Schedule 8-CAK. This attachment also shows the
8 calculation of base and remaining commodity costs.

9 **Q. Please explain how you calculated the inventory finance costs for underground**
10 **storage and LNG resources that are included in Schedule 8-CAK.**

11 A. The allocation of inventory finance charges to the Company's Maine and New
12 Hampshire Divisions are shown on Lines 99 and 100 of Schedule 8-CAK. These
13 inventory finance costs, as shown on Lines 94 and 95 were calculated based on
14 forecasted inventory activity calculations which are shown in Schedule 10-CAK.

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

17 A. I have prepared Schedule 11-CAK to show the allocation of New Hampshire Division
18 variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base
19 Sendout allocators by rate class. Lines 22 to 35 show the allocation of the monthly New

1 Hampshire Division Base Commodity costs¹³ to each rate class. Lines 37 to 56 show the
2 calculation of the Remaining Sendout allocators by rate class. Lines 57 to 70 show the
3 allocation of the monthly New Hampshire Division Remaining Commodity costs¹⁴ to
4 each rate class. A summary of all commodity costs allocated to the New Hampshire
5 Division's firm sales classes is shown on Lines 71 to 84.

6 **E. Adjustments**

7 **Q. Once direct demand and commodity costs are determined for the rate classes, are**
8 **any adjustments made?**

9 A. Yes. Since Residential COG rates are based on the average cost of gas (total seasonal
10 cost of gas divided by total seasonal demand), and the High and Low Load Factor
11 Commercial and Industrial ("C&I") COG rates are determined through the SMBA
12 method, an adjustment to C&I COG rates is required in order to properly recover all
13 costs. Schedule 12-CAK adjusts C&I COG rates in order to account for differences
14 between the average cost and SMBA methodologies. This adjustment is based on the
15 difference in total projected costs that would be assigned to Residential customers under
16 the two methodologies, and applies the difference to the C&I customer classes based on
17 their percentage of total allocated C&I demand and commodity costs.

18 **F. Refunds**

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

¹³ New Hampshire Division Base Commodity costs by month are shown in Schedule 9-CAK, Line 37.

¹⁴ New Hampshire Division Remaining Commodity costs by month are shown in Schedule 9-CAK, Line 38.

1 A. There are no refunds included in this filing.

2 **G. 2019 / 2020 Annual Reconciliation**

3 **Q. Please explain the 2019 / 2020 Annual COG Reconciliation.**

4 A. The 2019 / 2020 Annual COG Reconciliation is provided as Schedule 13-CAK. As Page
5 1 of this Schedule indicates, the projected October 31, 2019 annual ending balance is an
6 under-collection of \$755,934. As shown on Page 1 of this Schedule, the allocation of the
7 ending balance between seasons is based on the portion of projected sales that occur in
8 each season. Similar allocations are provided for Attachment A (Working Capital) and
9 Attachment B (Bad Debt) of this Annual Reconciliation.

10 **Q. Please explain the line item Fuel Tax Recovery that appears in the adjustment on**
11 **Form III, Schedule 2, and on Page 2 of Form III, Schedule 4 of Schedule 13-CAK**
12 **(Reconciliation).**

13 A. The line item Fuel Tax Recovery reflects the costs incurred to recover Northern's sales
14 taxes related to its Union Gas Storage contract. Because the Union facility is located in
15 Ontario, transactions under the Union Gas Storage contract are subject to Canadian tax
16 law. Although Northern is exempt from sales tax in Canada, it must initially pay the
17 sales tax and then submit a filing each quarter to the Canadian Revenue Agency ("CRA")
18 in order to certify that the gas purchased or sold by Northern is not for consumption in
19 Canada. Once the CRA makes this certification, the tax payments are then returned to
20 Northern. Northern utilizes its third party tax advisor, Grant Thornton, to assist the
21 Company in submitting the required filings to ensure that the Company qualifies for the

1 exemption and is reimbursed for the tax payments. Grant Thornton has provided tax
2 advisory services to the Company for many years and has extensive experience with
3 Canadian tax law. To date, Northern has recovered over \$525,000 in tax payments, which
4 far exceeds the amount of Fuel Tax Recovery expense, and no requested refunds or
5 exemptions have been disallowed.

6 **Q. Did Northern assign any of the tax payments to the cost of gas before those amounts**
7 **were refunded?**

8 A. No. The tax payments were never recorded as a cost of gas expense and, therefore, never
9 impacted cost of gas rates.

10 **Q. Why hasn't Northern included this item in prior cost of gas proceedings?**

11 A. Prior to the Union Gas contract, which became effective in April 2018, Northern
12 contracted for storage capacity from the Washington 10 facility. This facility was located
13 in Michigan and was not subject to Canadian tax law. For the Union Gas contract,
14 Northern submitted its initial filing in June of 2018. As is common with most initial
15 filings, the CRA conducted an audit of Northern's requested exemption. This audit
16 began in November 2018 and was concluded, with a finding that the Company was
17 exempt from Canadian sales tax, in April of 2019.

18 **Q. Why is Northern seeking to recover these costs through the COG?**

19 A. This expense is directly tied to the Union Storage contract. For costs recoverable under the COG,
20 Section IV.3 of the Company's tariff states that allowable expenses include "all costs of firm gas

1 supply including, but not limited to, commodity costs, taxes on commodity, demand charges,
2 local production and storage costs, and other gas supply expense incurred to procure and transport
3 supplies". Expenses incurred to secure the reimbursement of commodity tax payments fall under
4 this definition, and are appropriately included for recovery through the COG.

5 **Q. How is Northern assigning these costs to the New Hampshire and Maine divisions?**

6 A. Fuel Tax Recovery charges are allocated to each division based on the PR allocator in effect at
7 the time the invoices were received. I have provided a copy of the allocation of these costs in
8 Attachment F to Schedule 13-CAK.

9 **H. Miscellaneous Charges and Credits**

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

12 A. Northern is projecting a combined total of \$5,000 in revenues associated with the Re-
13 entry Rate and Conversion Rate. This amount is included in Schedule 1-CAK at Line 14.

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

15 The Working Capital Costs were based on a formula approved in Northern's 2017 base
16 rate proceeding, Docket No. DG 17-070. This formula derives the working capital
17 percentage by dividing the supply related net lag of 10.02 days by 365 days and then
18 multiplying the result by the prime interest rate. Based on the current prime rate of
19 3.25%, the Working Capital Percentage is 0.0892%. This percentage, when multiplied
20 by each season's forecasted Direct Cost of Gas, yields a 2020 / 2021 Winter Season

1 Working Capital Cost of \$21,301 and a 2021 Summer Season Working Capital Cost of
2 \$2,981. These amounts are included in Schedule 1-CAK at lines 29 and 138. ,

3 **Q. How did Northern develop its current projected Bad Debt expense for inclusion in**
4 **the 2020 / 2021 Winter Season and 2021 Summer Season COGs?**

5 A. To develop its bad debt projections, Northern forecasts 12 months of customer
6 write-offs for both supply and distribution service. This forecast is based on actual
7 experience and any recent unexpected increases or decreases in the number of customer
8 write-offs. As shown on Line 14 of Schedule 14-CAK, for the twelve months ended
9 December 31, 2021, Northern projects annual Bad Debt expense to be \$450,000. The
10 projected annual Bad Debt expense was then allocated to supply (38%) and distribution
11 (62%) services based on the actual Bad Debt experience of these components over the
12 12-months ended July 31, 2020. This is shown on Lines 7 and 5, respectively, of
13 Schedule CAK-14. The annual Bad Debt expense forecast allocated to supply, \$170,831,
14 as shown on Line 15, was then allocated further to the 2020 / 2021 Winter Season (92%)
15 and 2021 Summer Season (8%) based on the allocation of direct demand costs between
16 the Winter and Summer seasons. This breakout establishes the Winter Season Bad Debt
17 of \$156,687 (Line 16) and a Summer Season Bad Debt expense of \$14,144, (Line 17). I
18 have included these expenses at lines 36 and 144 in Schedule 1-CAK.

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

20 A. In addition to proactively providing customers with tools and information to manage their
21 accounts and avoid arrearages, the Company has a multi-step program in place for

1 maximizing the collection of receivables from customers with delinquent balances and
2 reducing bad debt. The goal of this program is to enable customers with delinquent
3 balances the ability to avoid disconnection and continue to receive gas service while
4 meeting their payment obligations. In this program, the Company employs a variety of
5 measures to maximize collections of receivables and reduce bad debt. Customer specific
6 measures include the following:

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

16
17 The Company also communicates regularly with its customers via bill messages, bill
18 inserts, newsletters, and its website, and shares tools and information that enable
19 customers to manage their accounts, including a budgeting tool, payment plan options,
20 and information regarding the discount program and financial assistance.

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

26 When a customer calls the Company in response to a disconnect notice or to otherwise
27 address a delinquency, we review several options with the customer to resolve the

1 delinquency, including full payment and sufficient partial payment coupled with a
2 payment plan for the balance. All payment plans are confirmed in writing and the
3 monthly payment plan amount due is clearly displayed along with the due date on each
4 invoice. The Company may also refer customers to “211” for contact information
5 regarding discounted rates, financial assistance and energy efficiency programs.

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

11 When a customer remains delinquent two days before the scheduled disconnection date,
12 the Company will make an outbound call to attempt to secure payment and discuss the
13 customer’s options. If an adequate payment is not received, an acceptable payment plan
14 is not established, or the Company does not determine that the customer is protected from
15 disconnection, the Company issues a disconnection work order to shut off the customer’s
16 service.^[1]

17 If, after an account is shut off for non-payment, the customer calls and makes a full or
18 otherwise sufficient payment, the Company will reinstate service to the customer,
19 establish a payment plan for any remaining balance and may assess a deposit to the
20 account. If the customer does not -address the unpaid balance after the disconnection, the

^[1] 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.

1 Company closes the account and mails a final bill to the customer. If the customer does
2 not make payment on the final bill, the Company makes two outbound calls to the
3 customer to request payment or establish a reasonable payment plan. It is only after the
4 Company receives no response to its proactive steps or if a customer does not follow
5 through with their payment plan, that the customer account is referred to a Collection
6 Agency and the receivables are classified as bad debt.

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

10 A. Northern's local production and storage costs were set at \$476,106 in the Company's
11 most recent base rate case proceeding, Docket No. DG 17-070, and are recovered solely
12 in the Winter Season. Also in the last base rate case proceeding, A&G expenses were set
13 at \$580,455. Of this amount, \$471,532 is recovered from sales customers in the Winter
14 Season and \$108,923 is recovered in the Summer Season. These amounts are included in
15 Schedule 1-CAK on lines 40, 42 and 150 respectively.

16 **I. Cost of Gas Factor**

17 **Q. Please explain the calculation of the proposed New Hampshire Division COG**
18 **Factors or Rates for the 2020 / 2021 Winter Season and the 2021 Summer Season.**

19 A. Schedule 1-CAK, which is similar to the Company's COG tariff Pages 40 through 43,
20 has been prepared to explain the calculation of the proposed 2020 / 2021 Winter and
21 2021 Summer COG Factors. Schedule 1-CAK shows the calculation of the Winter and

1 Summer Season COGs for each of Northern's three COG Rate Groups: (1) Residential
2 classes R-5, R-6 and R-10; (2) C&I Low Winter use classes G-50, G-51 and G-52; and
3 (3) C&I High Winter use classes G-40, G-41 and G-42.

4 As shown on Page 3 of Schedule 1-CAK, the 2020 / 2021 Winter Season projected
5 Average COG is \$0.7315 per therm (Line 66), which is the sum of the average Total
6 Direct COG, \$0.6841 per therm (Line 59) and the average Indirect COG, \$0.0474 per
7 therm (Line 63). As shown of Page 7 of Schedule 1-CAK, the 2021 Summer Season, the
8 projected Average COG is \$0.4412 per therm (Line 175), which is the sum of the average
9 Total Direct COG, \$0.4145 per therm (Line 168) and the average Indirect COG, \$0.0267
10 per therm (Line 172).

11 Also shown on Schedule 1-CAK are the proposed Residential COG Factors for the 2020 /
12 2021 Winter Period (Line 68) and the 2021 Summer Period (Line 177), the proposed C&I
13 Low Winter Use COG Factors for the 2020 / 2021 Winter Period (Line 72) and 2021
14 Summer Period (Line 181), and the proposed C&I High Winter Use COG Factors the
15 Winter 2020 / 2021 Winter Period (Line 92) and 2021 Summer Period (Line 201).

16 **Q. Please explain the calculation of the Working Capital allowances for the 2020 / 2021**
17 **Winter Season.**

18 The total Working Capital allowance, \$(14,609) shown on Line 33 of Schedule CAK-1 is
19 the sum of the current period working capital allowance (Line 29) plus the prior seasonal
20 allocation of Working Capital reconciliation balance (Line 31).

1 **Q. Please explain the calculation of the Bad Debt allowance for 2020 / 2021 Winter**
2 **Season.**

3 A. The Bad Debt allowance, \$152,448 (Line 38), is the sum of the current period bad debt
4 allowance (Line 36) plus the seasonal allocation of the Bad Debt reconciliation balance
5 (Line 37).

6 **Q. Please explain the calculation of the 2021 Summer Season Working Capital**
7 **allowances.**

8 The total Working Capital allowance, (\$5,314), as shown on Line 141 of Schedule 1-
9 CAK is the sum of the current period working capital allowance (Line 138) plus the prior
10 seasonal allocations of Working Capital reconciliation balance (Line 139).

11 **Q. Please explain the calculation of the Bad Debt allowance for 2021 Summer Season.**

12 A. The Bad Debt allowance, \$13,165 (Line 146), is the sum of the current period bad debt
13 allowances (Line 144), plus the seasonal allocations of the Bad Debt reconciliation
14 balance (Line 145).

15 **Q. Please explain the calculation of the Winter and Summer interest expense.**

16 A. Interest expense is calculated in Schedule 15-CAK (Line 100) and is based on the latest
17 prime rate and expected costs and revenues during the Winter and Summer seasons.

18 Winter and Summer period interest expense is also shown on Schedule 1-CAK, on Lines
19 21 and 130 respectively.

1 **J. Summary Analyses**

2 **Q. How does the proposed average 2020 / 2021 Winter Season Residential COG rate**
3 **compare to the average 2019 / 2020 Winter Season Residential COG rate?**

4 A. Schedule 2-CAK compares the proposed 2020 / 2021 Winter Season Residential COG
5 rate to the average 2019 / 2020 Winter Season Residential COG rate. As this Schedule
6 indicates, the Winter Season 2019 / 2020 COG rate was adjusted in December 2019 in
7 order to minimize variances between target and projected end of season balance.
8 Schedule 2-CAK also shows that the proposed 2020 / 2021 Winter Season COG rate,
9 \$0.7315 per therm, is about \$0.1650 per therm higher than the average 2019 / 2020
10 Winter Season COG rate, \$0.5665 per therm. This increase is due to a significant
11 increase in demand costs, lower projected sales, and a reconciliation under-collection
12 compared to a reconciliation over- collection in the prior year. These factors are
13 partially offset by lower commodity costs. The increase in demand costs is due to
14 significantly lower asset management revenues combined with two new pipeline
15 contracts (Atlantic Bridge and PXP¹⁵) beginning November 1, 2020 and higher demand
16 charges on TransCanada Pipelines ("TCPL"). Commodity costs are lower due to the new
17 pipeline contracts ability to access lower priced gas supplies. The change in costs and
18 projected sales for Residential customers is also applicable to C&I customers.

19 **Q. How does the proposed 2021 Summer Season Residential COG rate compare to the**
20 **filed 2020 Summer Season COG rate?**

¹⁵ These projects are discussed in detail in the testimony of Francis Wells.

1 A. Schedule 2-CAK also compares the proposed 2021 Summer Season Residential COG
2 rate to the average 2020 Summer Season Residential COG rate. As this Schedule
3 indicates, the proposed 2021 Summer Season average COG rate, \$0.4412 per therm, is
4 \$0.2132 per therm higher than the 2020 Summer Season Average COG. As with the
5 Winer COG rate, this increase is primarily due to higher demand costs, lower projected
6 demand and the reconciliation under-collection compared to the prior year's
7 reconciliation over-collection. This change in costs and projected sales for Residential
8 customers is also applicable to C&I customers.

9 **Q. Why is the variance in the Summer Season larger than the Winter Season?**

10 A. Seasonal variances can differ for a number of reasons. However, for the 2020-2021
11 annual COG period, changes in Northern's portfolio have a larger impact on the Summer
12 season than the Winter Season. This is because the Atlantic Bridge and PXP projects
13 have increased the average pipeline costs which is a key determinant of summer demand
14 costs. In addition, the Atlantic Bridge and PXP projects are expected to lower winter
15 season commodity costs due to their ability to access lower priced gas supplies. This will
16 help offset the higher demand costs in the winter but will have little or no impact on
17 summer commodity costs when lower priced supplies are more available.

18 **III. ANCILLARY CHARGES & SUPPORTING INFORMATION**

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

20 A. I have provided updates to four ancillary charges / schedules and supporting information
21 in various schedules in Section 4 of the filing. First, I have updated the Supplier

1 Balancing Charge to be effective November 1, 2020. The proposed charge remains
2 unchanged at \$0.71 per MMBtu. I have prepared Schedule 26-CAK to support the
3 updated Supplier Balancing Charge calculation. Second, I have updated the On-system
4 Peaking Demand charge to be effective November 1, 2020 through April 30, 2021. The
5 proposed charge is \$64.53 per Dth. Support for this charge is provided by Mr. Wells in
6 Schedule 21-FXW. Both the Supplier Balancing Charge and On-system Peaking
7 Demand Charge are included in Tariff Page No. 141, Appendix A.

8 Third, I have updated Tariff Page 156 which updates the capacity allocation percentages
9 for all non-exempt Delivery Service customers for the period November 1, 2020 through
10 October 31, 2021. The calculations supporting the capacity allocators are provided by
11 Mr. Wells in Schedule 22-FXW.

12 Lastly, I have updated the Re-entry Rates and Conversion Rates to be effective
13 November 1, 2020 through April 30, 2021, and May 1, 2021 through October 31, 2021.
14 For both High and Low Load Factor C&I customers the Re-entry Rate is \$0.0012 per
15 therm in the Winter Season and \$0.0011 per therm in the Summer Season. In the Winter
16 Season, the proposed Conversion Rate is \$0.0984 per therm for High Load Factor
17 customers and \$0.0012 per therm for Low Load Factor C&I customers. In the Summer
18 Season, the Conversion Rate is \$0.0011 per therm for both High and Low Load Factor
19 customers. These rates appear on Tariff Page No. 158, Appendix D. Support for these
20 rates is provided by Mr. Wells in Schedule 36-FXW.

21 **Q. Are there any additional schedules that are included in this filing?**

1 A. Yes, Schedules 27-CAK and 28-CAK have not been discussed in my testimony. Schedule
2 27-CAK provides the historical revenues from the Re-entry Rate and Conversion Rate
3 Surcharges that are applied to transportation customers returning to the Company's Sales
4 Service. Schedule 28-CAK determines Northern's short-term debt limit calculation for
5 the period November 2020 through October 2021.

6 **IV. FINAL MATTERS**

7 **Q. Will the Company propose to revise the 2020 / 2021 Winter Season COG rates if it**
8 **receives any new or updated information on gas supplier or transportation rates?**

9 A. If requested by Commission Staff, the Company will file a revised calculation of its 2020
10 / 2021 Winter and Summer Season COG rates to reflect updated gas and pipeline
11 transportation cost projections as well as any other cost information a few weeks prior to
12 the effective date of the Winter Season, November 1, 2020. In addition, the Company
13 will file proposed changes to the approved 2020 / 2021 Winter Season COG rates when
14 the projected end-of-season variance exceeds 2% of the target projected cost of gas. As
15 mentioned above, Schedule 15-CAK projects Northern's monthly COG over/under
16 collections, balances and interest. Northern will update this schedule each month with
17 actual costs and updated NYMEX prices in order to determine the variance between the
18 latest projected end-of-season balances and the target end-of-season balances established
19 in this COG filing. As indicated on Line 94 on that schedule, Northern projects a target

1 balance over collection of \$5,439,312¹⁶ on April 30, 2021. This target balance will be
2 updated in December to adjust for the actual balance effective November 1, 2020. If,
3 during the upcoming Winter Season, the Company's monthly projected April 30, 2021
4 ending balance varies from the target balance by 2% or more of total target projected gas
5 costs, then the Company will file to adjust the 2020 / 2021 Winter Season COG for the
6 subsequent month. These rates will take effect without further action by the Commission
7 for any decrease and for increases up to 25% of the initially-approved 2020 / 2021 Winter
8 Season COG rates.

9 Lastly, the Company will also file proposed changes to the approved 2021 Summer
10 Season COG when the projected annual variance exceeds 4% of the target projected gas
11 costs. If, during the upcoming Summer Season, the Company's updated projected
12 October 31, 2020 ending balance varies from the target Annual COG period balance by
13 4% or more of total Summer Period projected gas costs, and a rate change will help to
14 lower the annual reconciliation balance, it will then file to change the 2021 Summer COG
15 for the subsequent month. These rates will take effect without further action by the
16 Commission for any decrease and for increases up to 25% of the initially-approved 2021
17 Summer Period COG.

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

19 **A.** Yes it does.

¹⁶ This over-collection is projected to be near \$0 by October 31, 2021.

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**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2020-2021
COST OF GAS FILING**

**PREFILED TESTIMONY OF
FRANCIS X. WELLS**

1 **I. INTRODUCTION**

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

3 A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton,
4 NH.

5 **Q. What is your relationship with Northern Utilities, Inc.?**

6 A. I am employed by Unitil Service Corp. (the "Service Company") as Manager of Energy
7 Planning. The Service Company provides professional services to Northern Utilities, Inc.

8 **Q. Please briefly describe your educational and business experience.**

9 A. I earned my Bachelor of Arts Degree in both Economics and History from the
10 University of Maine in 1995. I joined the Service Company in September 1996 and
11 have worked primarily in the Energy Contracts department. My primary
12 responsibilities involve gas supply planning and acquisition.

13 **Q. Have you previously testified before the New Hampshire Public Utilities**
14 **Commission ("Commission")?**

15 A. Yes. I have testified as Northern's gas supply witness before the Commission in
16 Northern's Cost of Gas ("COG") proceedings.

17 **Q. Please summarize your prepared direct testimony in this proceeding.**

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1 A. The purpose of my testimony is to present and support Northern's gas supply cost
2 forecast, which was used for the calculation of the proposed COG.

3 The 2020-2021 fixed, annual demand cost estimates are 70% higher than the fixed,
4 annual demand cost estimates provided for the prior 2019-2020 Annual Period COG
5 filing. The major reasons for this increase include the projected beginning of service for
6 Portland XPress and Atlantic Bridge capacity and the decrease in projected Asset
7 Management Revenues.

8 Estimated 2020-2021 Winter Period average delivered commodity rates are 20% lower
9 than the average delivered commodity rates estimated for the 2019-2020 Winter Period
10 in last year's Annual COG filing. The major reason for this decrease is the replacement
11 of PNGTS and Maritimes Delivered Baseload supplies with lower priced supplies
12 accessed via the Portland XPress and Atlantic Bridge capacity contracts. The decrease
13 in commodity prices are partially offset by a 28% increase in NYMEX futures prices for
14 the upcoming 2020-2021 Winter Period compared to prices utilized in the 2019-2020
15 Annual COG initial filing. Estimated 2021 Summer Period average delivered commodity
16 rates are 22% higher than the 2020 Summer Period average delivered commodity rates
17 that were estimated in last year's Annual COG filing, reflecting 22% higher NYMEX
18 futures prices.

19 Northern projects combined sales service and delivery service distribution deliveries to
20 be 8,209,228 Dth in the New Hampshire Division for the 2020-2021 Annual Period,
21 which is 1.0% higher than the 2019-2020 Annual Period weather-normalized distribution
22 deliveries and 6.5% lower than the 2018-2019 Annual Period weather-normalized
23 distribution deliveries. The reduction in the forecast reflects the impacts of the COVID-
24 19 pandemic on the economy. The sales forecast reflects a gradual recovery to normal
25 use per customer levels at the beginning of 2023. Of the 8,209,228 Dth of projected

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1 distribution system deliveries, Northern projects that 4,295,862 Dth will be supplied by
2 the Company through Sales Service. In order to deliver 4,295,862 Dth of supply to
3 customer's retail meters, Northern projects a city-gate requirement of 4,352,444 Dth. In
4 addition, Northern expects its Company-Managed Sales obligation to equal 124,217 Dth
5 for the New Hampshire Division, bringing the total projected New Hampshire sendout
6 requirement to 4,476,661 Dth for the upcoming Winter Period. The details behind these
7 estimates are contained in Schedules 16-FXW and 17-FXW.

8 Northern's portfolio has 142,844 Dth maximum daily quantity of Pipeline, Storage and
9 Peaking Capacity (each of these Capacity terms as defined in the Company's New
10 Hampshire Division Delivery Service Terms and Conditions), assuming that the Atlantic
11 Bridge project is placed into service. I review the portfolio in more detail in the body of
12 my testimony.

13 I provide an update on the status of the Portland XPress ("PXP") and Atlantic Bridge
14 ("AB") projects, which the Company expects will be in service on or before November 1,
15 2020. In addition I discuss Northern's request to recover a one-time acquisition fee that
16 it paid to Emera Energy in order to take assignment of the Precedent Agreement for the
17 Atlantic Bridge project. Northern requests that Asset Management Revenue associated
18 with the AB capacity be offset by the one-time acquisition fee Northern paid to gain
19 assignment of the AB precedent agreement from Emera until such time as AMA revenue
20 or other non-core service revenues derived from use of the Atlantic Bridge capacity
21 exceed the one-time acquisition fee.

22 I project Northern's total company (including both the New Hampshire and Maine
23 Divisions) demand cost for the November 2020 through October 2021 gas year to be
24 \$45,258,751. (See Schedule 20-FXW). Mr. Chris Kahl, who is employed by Unitil
25 Service Corp. as a Senior Regulatory Analyst, presents the allocation of the total annual

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1 demand cost to Northern's New Hampshire Division and the allocation of annual
2 demand costs between the Winter and Summer COG rates. I also projected the
3 demand revenue from the New Hampshire Division's capacity assignment program to be
4 \$4,419,945. (See Schedule 21-FXW). I also discuss the updated Capacity Allocators
5 and Capacity Ratio pursuant to the New Hampshire Division capacity assignment
6 program, which are provided as Schedule 22-FXW.

7 I project that Northern's total company (including both the New Hampshire and Maine
8 Division) commodity cost to provide sales service during the 2020-2021 Winter Period
9 will be \$28,564,215 at an average rate equal to \$3.101 per Dth. (See Schedule 23-
10 FXW).

11 I provide the proposed Re-entry Rate, applicable to Capacity Assigned Delivery Service
12 customers who switch to Northern's Sales Service, and the proposed Conversion Rates,
13 applicable to Capacity Exempt Delivery Service customers who switch to Northern's
14 Sales Service. I also provide the supporting calculations for these proposed rates.
15 These calculations are provided in Schedule 36-FXW.

16 Finally, I discuss the unexpected CNG supply costs that were incurred by the Company
17 in June 2020 due to an outage of the Eliot Granite State meter that was necessitated
18 due to construction on the PNGTS system. This resulted in approximately \$286,000 in
19 gas supply cost. The Company seeks recovery of the portion of these costs allocated to
20 the New Hampshire Division through the COG.

21 **II. SALES AND SENDOUT FORECAST**

22 **Q. Please describe the Company's forecasts sales.**

23 **A.** The sales forecast has been updated in light of the pandemic and its effects on the
24 economy. Historically, for the residential, regular general, and large rate classes, the

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1 sales forecast is developed by independently forecasting meter growth, base usage per
2 meter, and a weather-driven usage per meter assuming 'normal' weather (average
3 degree days during over the last 20 years) for the forecast period. Also forecasted is the
4 Company's meter read cycle. In addition, Business Development personnel are
5 consulted for comments on significant usage changes for the Company's large
6 customers. The forecast seeks to limit subjectivity and typically relies on historical
7 trends. However, average usage per C&I customer has declined as a result of the
8 deterioration of the economic environment caused by the unprecedented COVID-19
9 crisis. Consequently, historical usage per customer levels are unlikely to be illustrative of
10 future sales over the short to medium terms. The sales forecast assumes that usage per
11 customer will return to pre-pandemic levels at the beginning of 2023. This timing
12 decision reflects an apparent consensus among macroeconomic forecasts reviewed by
13 the Company. The forecast assumes a recovery for usage per customer back to pre-
14 pandemic levels at a linear rate through the beginning of 2023.

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

18 A. I have prepared Table 1, below, which provides a summary of the company's forecast of
19 total billed distribution deliveries (Dth) for the upcoming 2020-2021 Annual Period.

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Table 1. 2020-2021 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years							
Month	2020-2021 Forecast ¹	2019-2020 Actual ²	2020-2021 minus 2019-2020	Percent Change	2018-2019 Actual ²	2020-2021 minus 2018-2019	Percent Change
Nov	659,578	696,660	-37,082	-5.3%	711,579	-52,001	-7.3%
Dec	946,024	949,247	-3,224	-0.3%	947,842	-1,819	-0.2%
Jan	1,139,404	1,190,037	-50,633	-4.3%	1,248,735	-109,331	-8.8%
Feb	1,223,700	1,278,231	-54,531	-4.3%	1,327,296	-103,596	-7.8%
Mar	1,100,828	1,047,338	53,490	5.1%	1,086,718	14,110	1.3%
Apr	774,735	750,676	24,059	3.2%	845,541	-70,806	-8.4%
May	570,317	519,041	51,276	9.9%	632,151	-61,834	-9.8%
Jun	397,160	382,043	15,118	4.0%	430,401	-33,241	-7.7%
Jul	346,583	333,729	12,854	3.9%	391,025	-44,442	-11.4%
Aug	347,374	324,955	22,419	6.9%	380,773	-33,399	-8.8%
Sep	356,180	335,134	21,046	6.3%	375,181	-19,002	-5.1%
Oct	425,676	402,137	23,539	5.9%	485,413	-59,737	-12.3%
Winter	5,844,268	5,912,189	-67,920	-1.1%	6,167,711	-323,442	-5.2%
Summer	2,443,290	2,297,039	146,251	6.4%	2,694,945	-251,655	-9.3%
Annual	8,287,558	8,209,228	78,331	1.0%	8,862,656	-575,097	-6.5%

Note 1: Forecast Data begins May 2020.

Note 2: Actual Data through April 2020 is weather normalized

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2020-2021 Annual Period in Schedule 16-FXW. Page 1 of Schedule 16-FXW provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2020-2021 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2019-2020 and 2018-2019 Annual Periods. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Schedule 16-FXW provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. How does the Company forecast Sales Service deliveries?

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1 A. To forecast Sales Service deliveries, Northern identified those customers utilizing
2 Delivery Service as of July 2020. The Company weather normalized monthly usage for
3 each customer and aggregated this data by rate class for both Capacity Assigned and
4 Capacity Exempt customers. This aggregated rate class forecast was adjusted down in
5 a manner consistent with the overall reduction in the forecast of distribution deliveries.
6 The forecast billed usage of current Delivery Service customers was subtracted from the
7 distribution deliveries of the entire system, provided in Schedule 16-FXW in order to
8 estimate Sales Service deliveries. Schedule 34-FXW provides an annual summary of
9 the C&I sales by rate class, breaking out Sales Service and Delivery Service from Total
10 Sales.

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

13 A. I have prepared Table 2, below, which provides a summary of the Company's forecast of
14 Total Deliveries, Sales Service Deliveries, Company Managed Deliveries and City-Gate
15 Receipts to meet the Sales Service Deliveries¹ for the upcoming Annual Period.

¹ When I use the term "City-Gate Receipts to meet the Sales Service Requirements", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

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Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary				
Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Company Managed Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-20	820,296	455,239	22,380	483,615
Dec-20	1,066,085	661,996	25,562	696,277
Jan-21	1,225,633	788,638	29,216	828,242
Feb-21	1,076,714	670,482	23,933	703,246
Mar-21	1,000,325	580,219	23,126	610,987
Apr-21	655,216	333,168	0	337,556
May-21	475,998	170,934	0	173,185
Jun-21	362,639	114,418	0	115,925
Jul-21	340,761	96,459	0	97,730
Aug-21	354,292	97,904	0	99,193
Sep-21	371,993	106,590	0	107,993
Oct-21	537,608	219,817	0	222,712
Winter	5,844,268	3,489,741	124,217	3,659,923
Summer	2,443,290	806,121	0	816,738
Annual	8,287,558	4,295,862	124,217	4,476,661

The detailed calculations can be found in Schedule 17-FXW. On Pages 1 and 2 of Schedule 17-FXW, I present calendar month and billed sales service deliveries by rate class. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the Maine Division.

On Page 3 of Schedule 17-FXW, I present my calculations of the city-gate receipts. First, I estimated Company Gas Allowance by multiplying the forecast Sales Service Deliveries and the Company Gas Allowance percentage. Company Gas Allowance includes both Company Use and Lost and Unaccounted For. The Company Gas Allowance Percentage was based on the recent history of actual data, which are presented in Schedule 18-FXW. Finally, I added Northern's projection of Company Managed Sales pursuant to the New Hampshire's Division's capacity assignment program.

Q. What are Company Managed Sales?

A. Company Managed Sales are a form of Capacity Assignment. Capacity Assignment is a means of transferring the demand cost responsibility for capacity contracts from

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1 Northern to the retail marketers on its system. Whenever a retail marketer enrolls a
2 customer, who is “capacity assigned,” the retail marketer assumes cost responsibility for
3 a pro-rated portion of the capacity contracts entered into by Northern, subject to the
4 capacity assignment provisions of each division. These capacity contracts can include
5 interstate pipeline contracts, underground storage contracts and on-site peaking
6 facilities. Such transfer may be achieved by releasing capacity directly to the retail
7 marketer (“Capacity Release”), who may then purchase their own supplies and utilize
8 the released contracts to deliver supplies to their customers. Pursuant to Northern’s
9 Delivery Service Terms and Conditions for its New Hampshire Division, all upstream
10 pipeline and underground storage capacity that delivers to Northern’s system is
11 assigned via Capacity Release except for upstream pipeline and storage capacity
12 resources that require the Bay State Exchange Agreement. These excepted pipeline
13 and storage resources are assigned via Company Managed Supply. On-system
14 peaking capacity, such as Northern’s Lewiston LNG plant, is also assigned via Company
15 Managed Supply. Under the Company Managed Supply form of capacity assignment,
16 Northern bills the retail marketer for a pro-rated portion of these capacity resources at
17 their respective actual costs and offers a city-gate delivered supply service. Such city-
18 gate supplies are priced in accordance with the capacity assignment provisions of each
19 division. Such arrangements are known as “Company Managed Sales.”

20 **Q. Please explain the process used to project Company Managed Sales for the New**
21 **Hampshire Division.**

22 **A.** Company Managed resources for the New Hampshire Division include pipeline
23 (specifically Iroquois Receipts and Algonquin Receipts capacity paths) and on-system
24 peaking resources (Lewiston LNG plant). The maximum daily volume of each Company
25 managed resource was estimated based on current capacity assigned transportation

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1 customer data. Northern allows marketers to nominate their peaking Company
2 managed resources on a daily basis. In addition, marketers are required to purchase
3 pipeline baseload supplies that are associated with the Company Managed pipeline
4 resources. The Company Managed Sales forecast assumes that marketers will utilize
5 all Pipeline and Peaking Company-managed supply available to them under the capacity
6 assignment program.

7 **III. NORTHERN'S GAS SUPPLY PORTFOLIO**

8 **Q. Please provide an overview of the gas supply portfolio that the Company uses to**
9 **supply its Sales Service customers and meet Company Managed Supply**
10 **obligations.**

11 **A.** I have prepared Table 3, below, which provides an overview of the sources of supply
12 available to Northern through its portfolio of contracts, including transportation contracts,
13 storage contracts, baseload and peaking supply contracts and an exchange agreement
14 with Bay State Gas Company.

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Table 3. Northern Capacity Summary (Dth/Day)

<u>Pipeline Capacity Paths</u>	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	40,586
<u>Storage Capacity Paths</u>	
Tennessee Firm Storage	2,644
Union Dawn Storage	39,863
Total Storage Capacity	42,507
<u>Peaking Capacity Paths</u>	
LNG - On-System	6,500
Peaking Contract 1	39,860
Additional Granite Capacity	13,391
Total Peaking Capacity	59,751
Total Design Day Capacity	142,844

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2020-2021 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above. This information can also be found on page 1 of Schedule 19-FXW.

Subsequent pages of Schedule 19-FXW include capacity path diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Capacity listed for each source of supply.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited ("TransCanada"), Union Pipelines Ltd. ("Union"), Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P.

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1 (“Iroquois”) and Texas Eastern Transmission System, L.P. (“Texas Eastern” or
2 “TETCO”). The gas supply portfolio also includes long-term storage contracts with
3 Union and Tennessee. Northern’s gas supply portfolio for 2020-2021 includes a single
4 multi-year peaking contract. This peaking supply arrangement was procured through a
5 Request-For-Proposals (“RFP”) and has a delivery period November through March for
6 4 years beginning November 2019. Northern also owns and operates a Liquefied
7 Natural Gas (“LNG”) facility in Lewiston, ME, which Northern relies on to produce 6,500
8 Dth per day with a storage capacity of approximately 12,000 Dth of LNG. Also through
9 an RFP Northern has procured an LNG Contract for up to 5,000 Dth per day with an
10 annual contract quantity of up to 125,000 Dth beginning November 2020 and ending
11 October 2021 in order to supply this facility. The gas supply portfolio includes an
12 exchange agreement with Bay State Gas Company (“BSG Exchange” or “Bay State
13 Exchange Agreement”), which is needed to bring the Iroquois Receipts, Leidy Hub
14 Supply and Transco Zone 6, non-NY capacity path supplies into Northern’s system, as
15 the delivery points on these capacity paths are on the Bay State Gas Company system.

16 The portfolio I used to project gas supply costs for the 2020-2021 winter season
17 presumes that the Portland XPress (“PXP”) and Atlantic Bridge (“AB”) projects are in
18 service by November 1, 2020. If the in-service date for either project is delayed,
19 Northern will replace these supplies with PNGTS or Maritimes delivered supplies, if
20 necessary.

21 The capacity path diagrams and capacity path details in Schedule 19-FXW show how
22 Northern has combined its transportation, storage and peaking supply contracts, along
23 with the BSG Exchange, in order to move natural gas supplies from the sources of
24 supply listed in Table 3 to Northern’s distribution system. Each of these contractual
25 arrangements represents a segment in one or more capacity paths. The capacity path

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1 diagrams show how each segment in the path is interconnected within the path. The
2 capacity path details provide basic contract information, such as product (transportation,
3 storage, peaking supply or exchange), vendor, contract ID number, contract rate
4 schedule, contract end date, contract maximum daily quantity ("MDQ"), contract
5 availability (year-round or winter-only), receipt and delivery points of the contract and
6 interconnecting pipelines with the contract delivery point.

7 **Q. Please describe the Company's process for procuring its gas supply commodity**
8 **supplies.**

9 A. Northern's practice is to secure most of its gas supply and asset management services
10 through an annual RFP for terms beginning April 1 and running through March 31 each
11 year. In March Northern completed its annual RFP for the delivery period of April 1,
12 2020 through March 31, 2021. Northern has entered into asset management
13 agreements for its Iroquois Receipts capacity path, Algonquin Receipts capacity path,
14 Niagara capacity path, its Tennessee Zone 0/L capacity path and its Union Dawn
15 Storage capacity path. Northern also entered into baseload supply agreements through
16 this RFP. Northern has also completed its RFP process for LNG supplies for the
17 upcoming winter. In the case of PXP and AB capacity, Northern will issue an asset
18 management RFP to secure gas supply for these capacity paths when the in-service
19 dates for the relevant facilities are finalized.

20 **Q. Please describe any changes in Northern's portfolio for the upcoming 2020-2021**
21 **Winter compared to the portfolio relied upon for the 2019-2020 Winter.**

22 A. Upon the applicable in-service dates, the PXP Dawn Hub capacity path will replace
23 PNGTS Delivered Baseload Supply purchases and that AB Ramapo capacity path will
24 replace Maritimes Delivered Baseload Supply purchases.

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1 **Q. Please provide an update on the PXP and AB projects.**

2 A. Northern expects PXP to be in-service on November 1, 2020 and that the capacity
3 contracts will begin, as planned.

4 Northern expects that all AB facilities will be constructed prior to November 1, 2020.

5 There was a possibility that the in-service date would be delayed due to a June 3, 2020

6 order remanding and vacating Algonquin's air permit from the Massachusetts

7 Department of Environmental Protection ("MA DEP") by the First Circuit Court of

8 Appeals, requiring the MA DEP to assess whether an electric motor was the Best

9 Available Control Technology ("BACT") for the compressor station located in Weymouth,

10 MA, which is needed in order to move gas from the Algonquin pipeline onto the

11 Maritimes pipeline. The MA DEP expects to complete its determination on the BACT

12 analysis on September 29, 2020. The process for any appeals to this determination

13 would be completed on January 19, 2021. Algonquin requested rehearing of the First

14 Circuit Court order, arguing that its permit should not be vacated during the pendency of

15 the MA DEP's process for considering whether an electric motor would be the BACT.

16 On August 31, Algonquin's rehearing request was granted by the First Circuit Court,

17 effectively reinstating the required air permit to place the Weymouth compressor station

18 into service and begin Atlantic Bridge service to Northern on October 1, 2020, assuming

19 completion of construction and commissioning activities, FERC approval to place the

20 Weymouth compressor into service and a favorable finding by the MA DEP on

21 September 29, 2020.

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IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Kahl to calculate the 2020-2021 Winter COG.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2020 through October 2021, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities
- New Hampshire Division Capacity Assignment program demand revenues
- Northern's commodity costs

The allocation of Northern's supply costs to the New Hampshire Division was performed by Mr. Kahl. The figures I present in my testimony relate to total company costs, inclusive of both the New Hampshire and Maine Divisions.

Q. Please provide Northern's demand cost forecast.

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

Table 4. Estimated Gas Supply Demand Costs November 1, 2020 through October 31, 2021			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	\$ 17,304,236	Att NUI-FXW-4, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	\$ 20,299,374	Att NUI-FXW-4, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	\$ 2,962,375	Att NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	\$ 1,658,003	Att NUI-FXW-4, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	\$ 11,109,167	Att NUI-FXW-4, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	\$ (8,074,404)	Att NUI-FXW-4, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	\$ 45,258,751	Sum Lines 1 through 6.

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1 I present the detailed calculations of this demand cost forecast in Schedule 20-FXW.
2 Page 1 of Schedule 20-FXW provides the summary data presented here in Table 4. On
3 page 2 of Schedule 20-FXW, I have calculated the annual demand cost forecast for
4 Northern's portfolio of transportation contracts. On page 3 of Schedule 20-FXW, I
5 designate each transportation contract as a pipeline, storage or peaking resource and
6 allocate transportation costs based upon these designations. Pages 4 and 5 of Schedule
7 20-FXW provide my calculations of demand costs for storage and peaking supply
8 contracts, respectively. On page 6 of Schedule 20-FXW, I forecast the capacity release
9 and asset management revenue the Company expects to receive. Please note that I
10 have not included an estimate of asset management revenue for PXP and AB capacity
11 paths. When in-service dates for these capacity contracts has been confirmed, Northern
12 will issue an Asset Management RFP for these resources and plans to update the
13 Company's COG Filing, as appropriate. Support for the transportation, storage and
14 supply demand rates used in Schedule 20-FXW are found in the Schedule 29-FXW,
15 Supplier Prices.

16 **Q. Please explain Northern's proposal to recover the one-time acquisition fee**
17 **associated with Northern's Atlantic Bridge capacity.**

18 A. Northern entered into the Atlantic Bridge Precedent Agreement by way of an assignment
19 and assumption agreement with the original contracting customer party, Emera. The
20 Atlantic Bridge project was fully subscribed at the time the capacity became available
21 and Northern negotiated a reasonable fee to secure the capacity. Northern requests
22 that Asset Management Revenue associated with the AB capacity be offset by the one-
23 time acquisition fee Northern paid to gain assignment of the AB precedent agreement
24 from Emera until such time as AMA revenue or other non-core service revenues derived
25 from use of the Atlantic Bridge capacity exceed the one-time acquisition fee. Northern

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notes that the Maine Public Utilities Commission determined that this fee was reasonable in light of the benefits to be gained from entering into the Atlantic Bridge agreement. 2016-00229, Northern Utilities, Inc. d/b/a Unitil, Order Part II at 27 (March 2, 2017).

Q. How does 2020-2021 Annual COG forecasted annual demand cost compare with the 2019-2020 Annual COG forecasted annual demand cost?

A. 2019-2020 Annual COG forecasted annual demand costs were equal to \$26,584,504. 2020-2021 Annual COG forecasted annual demand costs are equal to \$45,258,751, reflecting an increase in forecasted annual demand costs equal to \$18,674,247 or 70%.

This majority of the change in projected demand cost is explained by the following.

1. Increase in projected pipeline and storage demand contract costs by \$12,503,282. PXP is expected to increase annual demand costs by \$4,999,148. AB is expected to increase annual demand costs by \$6,212,299. \$1,305,786 of this figure is attributable to an increase in TransCanada tolls on the Union Dawn Storage capacity path. This increase in tolls will take place in January 1, 2021.

2. Decrease in projected Asset Management Agreement revenue credits by \$6,386,196. Lower AMA revenue reflects the results of Northern's annual request-for-proposals process, reflecting lower overall value obtained through asset management agreements. As discussed previously, the AMA revenue excludes any AMA revenue that the Company may obtain from PXP and AB capacity.

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

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed

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1 calculations of the demand revenues from capacity assignment in Schedule 21-FXW.

2 On page 1 of Schedule 21-FXW, I present a summary of the Company's forecast of New
3 Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of
4 Schedule 21-FXW, I present the Company's detailed calculations for each component of
5 capacity assignment, itemized on page 1 of Schedule 21-FXW. The 2020-2021
6 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to
7 be \$4,419,945. This represents a significant increase in this item from the 2019-2020
8 Annual COG Filing, in which the Company projected \$3,007,397 in Capacity Assignment
9 Demand Revenue. This increase in Capacity Assignment Demand Revenue is
10 attributable to the increase in overall demand costs, discussed earlier in my testimony.

11
12 **Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to**
13 **retail marketers for the period November 2020 through April 2021?**

14 A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 6 of
15 Schedule 21-FXW. The proposed Peaking Service Demand Charge is equal to \$64.53
16 per Dth, as shown in Schedule 21-FXW and presented in the proposed revised
17 Appendix A to the Delivery Service Terms and Conditions. Please note that the Peaking
18 Service Demand Charge applies only to capacity assignment pertaining to the on-
19 system LNG plant.

20 **Q. Please provide the Capacity Allocation Factors to be used for Capacity**
21 **Assignment under the current New Hampshire Division Delivery Service tariff for**
22 **effect November 1, 2020.**

23 A. The Capacity Allocation Factors are provided in the proposed updated Appendix C to the
24 New Hampshire Division's Delivery Service Terms and Conditions. My calculations are

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1 provided in Schedule 22-FXW. These Capacity Allocation Factors reflect a Capacity
2 Ratio equal to 1.056, which is equal to Total Design Day Capacity of 142,844 Dth
3 divided by the Total Design Day Planning Load (inclusive of both New Hampshire and
4 Maine) of 135,242 Dth. Both the Capacity Allocators and the Capacity Ratio calculations
5 assume that PXP and AB capacity are in service. If service is delayed for either or both
6 projects, the Company will need to revise the Capacity Allocators and the Capacity Ratio
7 to best assure equitable allocation of Capacity between Sales Service and Delivery
8 Service customers.

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

10 A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts
11 for sales service customers, which I calculated in Schedule 17-FXW, and the supply
12 sources available to Northern, which I presented in Schedule 19-FXW. I forecast supply
13 prices at each supply source, utilizing NYMEX natural gas contract price data and a
14 forecast of the adder to NYMEX for the price of supply at each supply source available
15 to Northern through its portfolio. To the extent that Northern's supply contract for a
16 particular supply source provides for a fixed adder to the NYMEX Last Day Settlement,
17 the contract prices are used to forecast the adder. If Northern's supply contract for a
18 particular supply source does not provide for a fixed adder to the NYMEX Last Day
19 Settlement, an estimate of the adder is based on the basis futures prices, through the
20 Intercontinental Exchange ("ICE"). I also forecast variable fuel retention factors and
21 rates for Northern's transportation and storage contracts. Then, I utilized the Sendout®
22 natural gas supply cost model to determine the optimal use of Northern's natural gas
23 supply resources to meet its projected city-gate requirements. The Company's supply
24 price forecast can be found on page 1 of Schedule 29-FXW.

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Q. Please present the Company's commodity cost forecast for the 2020-2021 Winter Period and the 2021 Summer Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter Period in Table 5, below.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes November 2020 through April 2021			
Supply Source	Winter Delivered City-Gate Costs	Winter Delivered City-Gate Volumes	Winter Delivered Cost per Dth
Base Pipeline Resources	\$ 8,258,046	2,635,323	\$ 3.134
Remaining Pipeline Resources	\$ 12,668,508	3,140,843	\$ 4.033
Storage Resources	\$ 5,242,569	2,885,522	\$ 1.817
Peaking Resources	\$ 1,332,538	307,647	\$ 4.331
Total Commodity Costs	\$ 27,501,662	8,969,336	\$ 3.066

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes May 2021 through October 2021			
Supply Source	Summer Delivered City- Gate Costs	Summer Delivered City- Gate Volumes	Summer Delivered Cost per Dth
Base Pipeline Resources	\$ 6,217,391	2,361,169	\$ 2.633
Remaining Pipeline Resources	\$ -	-	
Storage Resources	\$ -	-	
Peaking Resources	\$ 73,602	11,040	\$ 6.667
Total Commodity Costs	\$ 6,290,994	2,372,209	\$ 2.652

In summary, the 2020-2021 Winter Period net projected delivered commodity costs equal approximately \$27.5 million at an average delivered rate of \$3.066 per Dth, and the 2021 Summer Period net projected delivered commodity costs equal approximately \$6.3 million at an average delivered rate of \$2.652 per Dth. In support of this forecast, I prepared Schedule 23-FXW to show the monthly forecasted commodity cost by supply option. Page 1 of Schedule 23-FXW provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Schedule 23-FXW provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

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1
2 The detailed calculations of the delivered commodity cost are found in Schedule 24-
3 FXW. For each supply source, I have provided the detailed monthly calculations for
4 supply cost, fuel losses and variable transportation charges, which will be incurred by
5 Northern in order to deliver its supplies to Northern's city-gates for ultimate consumption
6 by our customers. Support of the supply prices and variable transportation charges
7 found in Schedule 24-FXW are found in the Schedule 29-FXW, Supplier Prices.
8

9 **Q. How do forecasted commodity costs for the 2020-2021 Winter Period (November**
10 **through April) presented here compare with the forecasted commodity costs**
11 **presented for the 2019-2020 Winter Period in last year's Annual COG filing?**

12 A. As show in Table 5, above, the 2020-2021 Winter Period forecasted commodity costs
13 are equal to \$27,501,662 at an average delivered rate of \$3.066 per Dth. The 2019-
14 2020 Winter Period forecasted commodity costs were equal to \$36,929,508 at an
15 average delivered rate of \$3.840 per Dth. Overall, 2020-2021 forecasted Winter Period
16 commodity costs are 26% lower than 2019-2020 forecasted Winter Period costs due
17 primarily to a 20% decrease in projected average unit cost. The 2020-2021 projected
18 delivered volume is 7% lower than was projected in 2019-2020. Projected NYMEX
19 prices are 28% higher heading into the 2020-2021 Winter Period (averaging \$3.15 per
20 Dth), compared to projected NYMEX prices heading into the 2019-2020 Winter Period
21 (averaging \$2.45 per Dth). The Company's unit cost forecast reflects these higher
22 NYMEX prices. Lower projected average unit cost is attributable to replacement of
23 PNGTS and Maritimes Delivered Supplies with lower cost supplies via PXP and AB
24 capacity paths, respectively.

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1 **Q. How do forecasted commodity costs for the 2021 Summer Period (May through**
2 **October) presented here compare with the forecasted commodity costs presented**
3 **for the 2020 Summer Period in last year's Annual COG filing?**

4 A. As show in Table 6, above, the 2021 Sumer Period forecasted commodity costs are
5 equal to \$6,290,994 at an average delivered rate of \$2.652 per Dth. The 2020 Summer
6 Period forecasted commodity costs were equal to \$5,384,034 at an average delivered
7 rate of \$2.170 per Dth. Overall, 2021 forecasted Summer Period commodity costs are
8 17% higher than 2020 forecasted Summer Period costs due primarily to a 22% increase
9 in projected average unit cost. The 2021 projected delivered volume is 4% lower than
10 was projected for 2020. The increase in Summer Period unit commodity costs reflects
11 an overall increase in NYMEX natural gas supply prices. Projected NYMEX prices for
12 the 2021 Summer Period are 22% higher (averaging \$2.82 per Dth), compared to
13 projected NYMEX prices for the 2020 Summer Period (averaging \$2.32 per Dth).

14 **Q. Please provide a summary of capacity utilization by supply source projected for**
15 **the upcoming year.**

16 A. Please refer to Schedules 30-FXW, 31-FXW and 32-FXW. Schedule 31-FXW provides
17 monthly supply volumes for Northern's normal year weather scenario. The data in
18 Schedule 30-FXW is also found in Schedule 23-FXW. Schedule 31-FXW provides
19 monthly supply volumes for Northern's design cold year weather scenario. Schedule 32-
20 FXW calculates the capacity utilization of all supply resources in both normal and design
21 cold weather scenarios.

22 **Q. Please provide Northern's Design Day Report for the upcoming Winter Period.**

23 A. Northern's Design Day Report is found in Schedule 33-FXW.

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1 **Q. Please provide Northern's 7-Day Cold Snap Analysis for the upcoming Winter**
2 **Period.**

3 A. Northern's 7-Day Cold Snap Analysis is found in Schedule 35-FXW.

4 **Q. Please provide the Company's monthly projections of storage inventory balances**
5 **for the period November 2020 through October 2021.**

6 A. Please refer to Schedule 10-CAK. These results are based upon the Company's
7 Sendout® analysis.

8

9 **V. PROPOSED RE-ENTRY AND CONVERSION SURCHARGES**

10 **Q. Please describe the Re-entry Surcharge and the Conversion Surcharge.**

11 A. The Re-entry Surcharge is applicable to all Capacity Assigned Delivery Service
12 customers, who switch from a retail marketer to Northern's Sales Service and the
13 Conversion Surcharge is applicable to all Capacity Exempt Delivery Service customers,
14 who switch from a retail marketer to Northern's Sales Service. I have prepared
15 proposed updated Re-entry and Conversion Surcharges to be applicable for the 2020-
16 2021 Annual Period. Customers electing to migrate and purchase their supply from
17 Northern shall be required to continue purchasing Northern's Sales Service until April 30
18 each year. After this time, such customers may elect to either switch to a retail marketer
19 or continue purchasing Sales Service from Northern under the normal cost of gas rates.

20 **Q. Please provide the proposed Re-entry Surcharge and the proposed Conversion**
21 **Surcharge.**

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1 A. Proposed Appendix D to the Delivery Service Terms and Conditions, provides the Re-
2 entry Surcharge and the Conversion Surcharge. The Re-entry Surcharge and
3 Conversion Surcharge will be applied as a surcharge in addition to the normal cost of
4 gas rates. These surcharges shall only be applicable to customers switching from
5 Delivery Service to Sales Service.

6 **Q. Please provide your calculations for the Re-entry Surcharge and the Conversion**
7 **Surcharges.**

8 A. Please refer to Schedule 36-FXW. Page 1 shows the calculations for the Re-entry
9 Surcharge for both the Winter Period and Summer Period. The Re-entry surcharge
10 reflects the removal of any prior period credits, such as an over-recovery due to
11 incumbent Sales Service Customers.

12 Page 2 shows the Conversion Surcharge calculations for the Winter Period. The
13 Conversion Surcharge reflects the removal of prior period credits due to incumbent
14 Sales Service customers plus the incremental cost to serve the customers, based on
15 estimated incremental commodity prices. Conversion customers will have a floor price
16 equal to the cost of gas rates applicable to Low Load Factor customers, removing prior
17 period credits. The Conversion Surcharge is equal to the Re-entry Surcharge during the
18 Summer Period.

19 Page 3 is the Incremental Commodity Price Worksheet. Pages 4 through 10 are the
20 Load Shape Price Factor Worksheet. Page 11 is the projected city-gate sendout
21 forecast of Delivery Service loads that are not currently subject to Capacity Assignment.

22

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1 **VI. COMPRESSED NATURAL GAS (“CNG”) SUPPLY EXPENSES**

2 **Q. Did Northern incur unexpected gas supply costs this past summer?**

3 A. Yes, Northern incurred gas supply costs of \$286,007.85 to provide compressed natural
4 gas (CNG) service to firm customers during a pipeline outage which took all pipeline
5 supply to the Eliot Granite State meter station out of service for one week in the middle
6 of June during the construction of PNGTS’ Portland Xpress Project (PXP). The PXP
7 construction involved adding a new compressor to the Eliot Compressor Station which
8 required the Joint Facilities pipeline to be purged out of service from Eliot to Newington
9 in order to complete the pipeline connections, resulting in the outage. The outage
10 resulted in unanticipated gas supply costs as the Company was required to procure
11 alternative supply on short notice to ensure uninterrupted firm service to customer
12 served on Northern’s Eliot distribution system.

13 **Q. How many customers does Northern serve in Eliot, Maine?**

14 A. Northern serves approximately 500 customers, including approximately 30 commercial
15 customers and the Portsmouth Naval Shipyard (PNSY) on its Eliot distribution system.
16 Prior to the outage, PNSY made arrangements to switch their Co-Generation plant to
17 alternate fuel. The Eliot meter station is not connected to the Granite main line, so
18 consequently the Eliot distribution system is a single-feed system and Northern had no
19 option but to arrange for a non-pipeline supply.

20 **Q. When did Northern first learn of the planned pipeline outage?**

21 A. Northern informally learned of the pending outage in early April, approximately 10 weeks
22 before the outage. The first pipeline notice was posted on April 14, 2020. An updated
23 notice modifying the outage dates was posted on April 24, 2020. The second posting

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provided an additional two weeks before the start of the Eliot outage, from June 1 to June 15, an adjustment made in response to a request from Unitil.

Q. What actions did Northern take when it learned of the pending outage?

A. Northern scheduled meetings with PNGTS and Maritimes Northeast Operating Company (MNOC), which operates and maintains the Joint Facilities, to better understand the work being done and options to mitigate impacts of both outages. These meetings were held weekly from mid-April to mid-June when the Eliot outage was ending. Northern engaged an outside engineer specializing in CNG decompression to assist with planning and design of CNG options that could serve customers in Eliot, identified and obtained temporary rights for a suitable property, and issued an RFP for CNG service. Northern received competitive offers to provide the CNG service in response to the RFP and awarded a contract to the lowest cost option. Northern worked to expeditiously secure the property for the CNG operation, obtain required permits and approvals, fabricate pipeline interconnections and present a thorough plan to the Maine PUC Safety Staff.

Q. Please describe the expenses incurred in connection with the above-described temporary CNG service that the Company has included for recovery in this Cost of Gas filing.

A. Expenses incurred by the Company in connection with the temporary CNG service are costs that are directly related to procuring and providing safe and reliable firm gas supply to customers. These costs include the CNG service itself, engineering support, temporary property rights, fabrication of the pipeline interconnection, weld inspection tests, and protective barriers for the site. These were all outside service expenses required and incurred to establish the CNG operation and maintain firm service to

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1 customers during the outage. Please see Schedule 39-FXW for a list of specific
2 charges.

3 **Q. How does the Company propose to recover these costs?**

4 A. As explained in the testimony of Mr. Kahl, the CNG expenses are proposed to be
5 recovered in the Company's demand charges, subject to allocation to both the New
6 Hampshire and Maine Divisions as well as to both the peak and off-peak seasons.

7 **Q. Is the Company aware of possible future pipeline outages that could similarly**
8 **require supplemental supply operations?**

9 A. Yes, in 2021 a new compressor will be added to the Westbrook Compressor Station as
10 part of PNGTS' Westbrook Xpress Project (WXP), which received its Certificate of Public
11 Convenience and Necessity from the Federal Energy Regulatory Commission on June
12 18, 2020. Also during 2021, a new interconnect will be constructed from the Joint
13 Facilities into Granite at South Berwick, Maine. PNGTS has not yet finalized
14 construction plans for these projects, so specific impacts are not yet known.

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

16 A. Yes it does.

**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2020/OCTOBER 2021 ANNUAL COST OF GAS
ADJUSTMENT FILING
PREFILED TESTIMONY OF
S. ELENA DEMERIS**

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is S. Elena Demeris. 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 that provides managerial, financial, regulatory and engineering services to Unitil Corporation’s principal subsidiaries Fitchburg Gas and Electric Light Company, d/b/a Unitil (“FG&E”), Granite State Gas Transmission, Inc. (“Granite”), Northern Utilities, Inc. d/b/a Unitil (“Northern”), and Unitil Energy Systems, Inc. (“UES”) (together “Unitil”). In this capacity I am responsible for preparing regulatory filings, pricing research, regulatory analysis, tariff administration, revenue requirements calculations, customer research, and other analytical services.

Q. Please summarize your professional and educational background.

A. In 1996, I graduated from the University of Massachusetts - Lowell with a Bachelor’s of Science Degree in Civil Engineering. In 2005, I earned a Master’s Degree in Business

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Administration and in 2006 a Master's Degree in Finance from Southern New Hampshire University. I joined Unitil in July 1998 in the regulatory/rate department.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to introduce and describe Northern's (or "the Company") proposed changes to its Local Delivery Adjustment Charges ("LDAC"). Northern is proposing changes to its LDAC for effect November 1, 2020 for the following components: Gas Assistance Program and Regulatory Assessment ("GAPRA"), formerly the Residential Low Income Assistance and Regulatory Assessment ("RLIARA") Costs Rate, Energy Efficiency Charge (EEC), Environmental Response Cost ("ERC") Rate, and Lost Revenue Rate ("LRR"). Northern is not proposing to change the following LDAC components: Interruptible Transportation Margin (ITM), Rate Case Expense (RCE) Factor and Reconciliation of Permanent Changes (RPC) in Distribution Rates. My testimony also discusses the impact the proposed cost of gas (COG) and LDAC rate changes have on customer bills during the 2020-2021 Winter and 2021 Summer Seasons.

Q. What are the Company's proposed LDAC surcharges?

A. The Company is submitting for approval a proposed LDAC of \$0.1099 per therm for the Residential Class and \$0.0472 per therm for the Commercial/Industrial (C&I) Class

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1 effective November 1, 2020 through October 31, 2021. The proposed rates are included
2 on the Fourth Revised Tariff Page 62, superseding the Third Revised Tariff Page 62.

3 **Q. Please describe the purpose of the GAPRA.**

4 A. The purpose of this rate is to allow the Company to recover revenue discounts associated
5 with customers participating in the Gas Assistance Program and Regulatory Assessment
6 (GAPRA), as well as the associated administrative costs of that program, pursuant to the
7 Commission's Order in Docket No. DG 05-076. The Commission's Order in Docket DG
8 20-013 renamed the RLIA effective November 1, 2020. The order also modified the
9 program to apply a 45% discount to both distribution and supply rates, excluding the
10 LDAC, and to apply the discounts during the winter period only. These changes are
11 reflected in Schedule 37. This rate also recovers the non-distribution (or COG) portion of
12 the annual NHPUC Regulatory Assessment (RA) to the Company. The GAPRA rate is
13 charged on all sales and delivery only services billed under the Company's rate
14 schedules.

15
16 **Q. Please describe the proposed change to the GAPRA rate.**

17 A. Northern is proposing to increase the GAPRA rate from \$0.0036 to \$0.0044 per therm
18 effective November 1, 2020.

19
20 **Q. Could you describe the derivation of the proposed GAPRA rate?**

21 A. The GAP rate is derived by estimating the Company's Gas Assistance Program and
22 Regulatory Assessment costs from November 1, 2020 through October 31, 2021, the

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1 Regulatory Assessment costs from July 1, 2020 through June 30, 2021, and the total
2 account ending balance as of October 31, 2020, based on actual data s through July, 2020
3 and estimated data from August 1, 2020 to October 31, 2020. The GAPRA costs are
4 estimated to be \$289,640 and are shown on Schedule 37 GAPRA, Page 1 of 3, Line 21.
5 Lines 1-7 explain the derivation of these costs. The estimated 2020 NHPUC Regulatory
6 Assessment collected in the LDAC, \$63,505, is shown on Schedule 37 GAP, Page 1 of 3,
7 Line 24, and is based on the NHPUC invoice dated August 19, 2020. Page 3 of 3 of the
8 schedule shows the assignment of the NHPUC annual Regulatory Assessment to
9 distribution and non-distribution costs. The \$368,964 assigned to distribution represents
10 the amount established in the Company's last base rate case proceeding in Docket No.
11 DG 17-070. The remainder, \$63,505, is assigned to the GAPRA and LDAC.
12 Lastly, the projected over-collection ending balance of the GAPRA is (\$33,560) as of
13 October 31, 2020, and is derived as shown on Schedule 37 GAP, Page 2 of 3. The total
14 amount of these three factors, \$319,585, is shown on Page 1 of 3, line 25, of Schedule 37
15 GAPRA, and is divided by estimated weather-normalized firm therm sales billed to
16 customers for the twelve-months ended October 31, 2021 to derive the proposed GAPRA
17 charge of \$0.0044 per therm.

18
19 **Q. What is the purpose of the EEC Rate?**

20 The purpose of the EEC rate is to recover from customers, excluding those with Special
21 Contracts, Energy Efficiency (EE) program costs and performance incentives.

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1 **Q. What are the changes being proposed to the EEC?**

2 A. The Company is proposing to increase the EEC rate for the Residential Customer Class
3 from \$0.0499 per therm to \$0.0774 per therm, and increase the charge for the C&I
4 Customer Class from \$0.0247 per therm to \$0.0337 per therm effective November 1,
5 2020.

6
7 **Q. Please describe the reason for these proposed changes to and the derivation of the**
8 **EEC rate.**

9 A. The proposed changes to the EEC rate are necessitated by the implementation of
10 Northern's 2021 EE program budgets. The budgets for the Residential and C&I
11 customer classes are provided in Schedule 37 EEC, Page 1 of 4. They include expected
12 monthly costs for the remainder of the 2020 rate year (August 2020 – October 2020,
13 proposed in Docket No. DE 20-092) and costs for 12 months of the 2021 rate year
14 (November 2020 – October 2021). The proposed changes to the EEC rate are impacted
15 by an expected under-collection in the November 1, 2020 beginning balance of the
16 Residential class and an expected over-collection in the November 1, 2020 beginning
17 balance of the C&I class. The derivation of the EEC rate is provided in Schedule 37
18 EEC, Page 2 of 4. As shown, it is derived by customer class and includes an annual
19 Reconciliation Adjustment of program costs, Performance Incentives and an adjustment
20 for Low-Income Discounts. Supporting information regarding the development of the
21 proposed EEC for the Residential Classes is provided in Schedule 37 EEC, Page 3 of 4,
22 and Page 4 of 4 provides the support for the proposed C&I Class.

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1 Please note the EEC Reconciliation Adjustments show actuals through July 2020 and
2 estimates through October 2021 to correspond with the EEC Reconciliation (Attachment
3 J3) filed by the Company on September 1, 2020 in the Docket No. DE 20-092, 2021 –
4 2023 Plan.

5
6 **Q. Please explain the purpose of the LRR?**

7 A. The purpose of the LRR is to recover lost distribution revenue related to the Company's
8 Energy Efficiency programs. This rate mechanism was established in accordance with
9 Order No. 25,932 in Docket No. DE 15-137 approving a Settlement Agreement which
10 provides for the implementation of a Lost Revenue Rate adjustment mechanism.

11
12 **Q. What are the changes being proposed to the LRR?**

13 A. The Company is proposing to increase the LRR rate for the Residential Customer Class
14 from \$0.0114 per therm to \$0.0220 per therm, and increase the charge for the C&I
15 Customer Class from \$0.0019 per therm to \$0.0030 per therm effective November 1,
16 2020.

17
18 **Q. Please explain the calculation of the proposed LRR?**

19 A. The calculation of the LRR is provided on Schedule 37-LRR. As shown on Page 1, the
20 LRR for the Residential and C&I Classes is derived by adding projected annual lost
21 distribution revenue over the period November 1, 2020 through October 31, 2021, the
22 expected October 31, 2020 reconciliation ending balance and the projected interest on

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1 monthly over/under collections, and dividing this total by forecast annual therm
2 throughput, by class. Page 2 provides the projected customer class monthly
3 reconciliation of costs and revenue for the period November 2019 through October 2021.
4 Beginning monthly balances are shown on Lines 2 and 21 for the Residential and C&I
5 classes, respectively, and ending monthly balances are shown on Lines 19 and 39,
6 respectively. Page 3 provides the calculation of estimated lost distribution revenue based
7 on estimated customer class therm savings as seen on Lines 4 and 8. Page 4 provides
8 further detail for the estimated savings that are used in the calculation of lost revenue on
9 Page 3. Page 5 provides the calculation of the Company's average distribution rates by
10 sector, excluding Customer Charges. These average distribution rates are derived by
11 taking seasonal averages of total volumetric revenue divided by total Winter and Summer
12 Season therms, by class. Please note the LRR reconciliations here correspond with the
13 LRR Reconciliation (Attachment J5) filed by the Company on September 1, 2020 in
14 Docket No. DE 20-092, 2021 – 2023 Plan.
15

16 **Q. Please explain the purpose of Northern's ERC.**

17 **A.** The purpose of the ERC is to recover expenditures associated with remediation of former
18 manufactured gas plants. The ERC is applied to all gas sales and delivery service billed
19 under the Company's sales and delivery service rate schedules. The costs submitted for
20 recovery through the ERC recovery mechanism are presented in the ERC Filing
21 submitted in this docket under separate cover. The environmental investigation and
22 remediation costs that underlie these expenses are the result of efforts by the Company to

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1 respond to its legal obligations at sites located in Exeter and Rochester, New Hampshire.

2 In total, the Company has incurred environmental remediation costs of \$77,165 from July
3 2019 through June 2020. A summary sheet and detailed backup spreadsheets supporting
4 2019-2020 costs are provided in the ERC Filing

5
6 **Q. Please describe the change to Northern's ERC rate that is proposed for effect**
7 **November 1, 2020.**

8 A. The current ERC rate is \$0.0057 per therm. Northern proposes to increase this rate to
9 \$0.0061 per therm.

10
11 **Q. Please explain the calculation of the proposed ERC rate.**

12 A. As stated above, during the period July 1, 2019 through June 30, 2020, ERC expenses
13 totaled \$77,165. Northern is allowed to recover one-seventh of the actual response costs
14 incurred by the Company in a twelve-month period ending June 30 of each year until
15 fully amortized over seven years, plus any insurance and third-party expenses for the
16 year, or \$421,540 (see table below). Due to the amortization of these costs, the ERC rate
17 in this filing includes the current year (\$77,165 divided by 7, or \$11,024) and six prior
18 years of unamortized amounts. Any insurance and third-party recoveries or other credits
19 for the year are used to reduce the unamortized balance. The total ERC costs to be
20 recovered, shown below and on Page 1, Line 13, of Schedule 38 - ERC (this schedule is
21 also Schedule 1 submitted by the Company in the Environmental Response Cost filing)
22 are comprised of the following:

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1/7 ERC costs incurred July 2019 – June 2020	\$11,024
1/7/ ERC costs incurred July 2018 – June 2019	\$29,051
1/7/ ERC costs incurred July 2017 – June 2018	\$40,449
1/7th ERC costs incurred July 2016 - June 2017	\$7,736
1/7th ERC costs incurred July 2015 - June 2016	\$ 311,412
1/7th ERC costs incurred July 2014 - June 2015	\$ 16,028
1/7th ERC costs incurred July 2013 - June 2014	\$ 5,840
Total	\$421,540

In addition, the ERC rate includes the prior period reconciliation of ERC costs. The October 31, 2020 ending balance is estimated to be an under collection of \$25,122, as shown on Schedule 37-ERC Page 2 of 2. Also included are the ending balances of the RPC and /RCE as proposed in DG 17-070. Given the above, total ERC costs to be recovered for the period of November 2020 through October 2021 are \$443,652. Dividing the recoverable ERC costs by projected total annual sales of 72,579,945 therms results in an ERC rate of \$0.0061 per therm. This calculation is illustrated in Schedule 37 ERC, Page 1 of 2.

Q. Does the proposed LDAC include a credit for Interruptible Transportation Margins?

A. No. The Company did not provide Interruptible Transportation service during the past year, has not provided this service for many years and does not expect to provide any in the upcoming year. Therefore, Northern has not credited any actual or expected interruptible margins back to customers.

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1

2 **Q. Have you prepared typical bill analyses showing the impacts of the proposed COG**
3 **and LDAC rate changes for effect on November 1, 20120for typical Residential**
4 **heating customers over the upcoming Winter Season?**

5 A. Yes, Schedule 3, pages 1 through 5 provides the analyses. It shows that a typical
6 Residential heating customer consuming 600 therms during the 2020/2021 Winter Season
7 will expect a bill of \$1,053.04. This is an increase of \$123.60, or 13.3% compared to the
8 2019/2020 Winter Season bill with the same consumption.

9

10 **Q. Have you prepared typical bill analyses showing the impacts of the proposed COG**
11 **and LDAC for effect on May 1, 2021 for typical Residential heating gas customers**
12 **over the next Summer Season?**

13 A. Yes, Schedule 3, pages 6 through 10 provides this analysis. It shows that a typical
14 residential heating customer consuming 132 therms during the 2021 Summer Season will
15 expect a bill of \$286.83. This is an increase of \$32.47, or 12.8% compared to the 2020
16 Summer Season bill with the same consumption.

17

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

19 A. Yes, it does.

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2020 - April 31, 2021

Column A	Column B	Column C
1 <u>ANTICIPATED DIRECT COST OF GAS</u>		
2 Purchased Gas for Sales Service:		
3 Demand Costs:	\$ 4,596,721	
4 Supply Costs:	\$ 8,233,230	
5		
6 Storage & Peaking Gas for Sales Service:		
7 Demand, Capacity:	\$ 11,702,910	
8 Commodity Costs:	\$ 2,618,320	
9		
10 Inventory Finance Charge	\$ 1,266	
11		
12 Capacity Release	\$ (3,272,870)	
13		
14 Re-entry Rate & Conversion Rate Revenues	\$ (5,000)	
15		
16 Total Anticipated Direct Cost of Gas		\$ 23,874,576
17		
18 <u>ANTICIPATED INDIRECT COST OF GAS</u>		
19 Adjustments:		
20 Prior Period Under/(Over) Collection	\$ 614,082	
21 Interest	\$ (44,016)	
22 Refunds	\$ -	
23 <u>Interruptible Margins</u>	\$ -	
24 Total Adjustments		\$ 570,066
25		
26 Working Capital:		
27 Total Anticipated Direct Cost of Gas	\$ 23,874,576	
28 Working Capital Allowance Percentage (10.02 [lag days]/365* prime rate)	<u>0.0892%</u>	
29 Working Capital Allowance	\$ 21,301	
30		
31 Plus: Working Capital Reconciliation (Acct 173)	<u>\$ (35,910)</u>	
32		
33 Total Working Capital Allowance		\$ (14,609)
34		
35 Bad Debt:		
36 Bad Debt Allowance	\$ 156,687	
37 Plus: Bad Debt Reconciliation (Acct 173)	<u>\$ (4,239)</u>	
38 Total Bad Debt Allowance		\$ 152,448
39		
40 Local Production and Storage Capacity		\$ 476,106
41		
42 Miscellaneous Overhead-81.23% Allocated to Winter Season		<u>\$ 471,532</u>
43		
44 Total Anticipated Indirect Cost of Gas		\$ 1,655,544
45		
46 Total Cost of Gas		<u>\$ 25,530,120</u>

(*) Prime Rate is 3.25%

**N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.**

Summary

Anticipated Cost of Gas

New Hampshire Division

Period Covered: November 1, 2020 - April 31, 2021

Column A	Column D
1 <u>ANTICIPATED DIRECT COST OF GAS</u>	
2 Purchased Gas for Sales Service:	
3 Demand Costs:	Schedule 5-CAK, LN 71 + Schedule 5-CAK, LN 75
4 Supply Costs:	Schedule 9-CAK, LN 15
5	
6 Storage & Peaking Gas for Sales Service:	
7 Demand, Capacity:	Schedule 5-CAK, LN 73 + Schedule 5-CAK, LN 74
8 Commodity Costs:	Schedule 9-CAK, LN 17 + Schedule 9-CAK, LN 18
9	
10 Inventory Finance Charge	Schedule 9-CAK, LN 19
11	
12 Capacity Release	-(Schedule 5-CAK, LN 77)
13	
14 Re-entry Rate & Conversion Rate Revenues	Schedule 5-CAK, LN 79
15	
16 Total Anticipated Direct Cost of Gas	Sum (LN 3 : LN 14)
17	
18 <u>ANTICIPATED INDIRECT COST OF GAS</u>	
19 Adjustments:	
20 Prior Period Under/(Over) Collection	Schedule 13-CAK, PG 1
21 Interest	Schedule 15-CAK, LN 115: Total
22 Refunds	
23 <u>Interruptible Margins</u>	-(Schedule 5-CAK, LN 78)
24 Total Adjustments	Sum (LN 20 : LN 23)
25	
26 Working Capital:	
27 Total Anticipated Direct Cost of Gas	LN 16
28 Working Capital Allowance Percentage (10.02 [lag days]/365* primTariff - NHPUC No. 12 , Section 6.1	
29 Working Capital Allowance	LN 27 * LN 28
30	
31 Plus: Working Capital Reconciliation (Acct 173)	Schedule 13-CAK, Attachment A
32	
33 Total Working Capital Allowance	Sum (LN 29 : LN 31)
34	
35 Bad Debt:	
36 Bad Debt Allowance	Schedule 14-CAK, LN 16
37 Plus: Bad Debt Reconciliation (Acct 173)	Schedule 13-CAK, Attachment B
38 Total Bad Debt Allowance	LN 36 + LN 37
39	
40 Local Production and Storage Capacity	Schedule 5-CAK, LN 84
41	
42 Miscellaneous Overhead-81.23% Allocated to Winter Season	Schedule 5-CAK, LN 83
43	
44 Total Anticipated Indirect Cost of Gas	Sum (LN 24 : LN 42)
45	
46 Total Cost of Gas	LN 44 + LN 16
(*) Prime Rate is 3.25%	

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48	CALCULATION OF FIRM SALES COST OF GAS RATE	
49	Period Covered: November 1, 2020 - April 31, 2021	
50		
51	Column A	Column D
52		
53	Total Anticipated Direct Cost of Gas	LN 16
54	Projected Prorated Sales (11/01/20 - 04/30/21)	Schedule 6-CAK, LN 11
55	Direct Cost of Gas Rate	LN 53 / LN 54
56		
57	Demand Cost of Gas Rate	Column B : SUM (LN 3 , LN 7 , LN 12) : COLUMN C: LN 5
58	Commodity Cost of Gas Rate	Column B : SUM (LN 4 , LN 8) : COLUMN C: LN 58 / LN 5
59	Total Direct Cost of Gas Rate	SUM (LN 57 : LN 58)
60		
61	Total Anticipated Indirect Cost of Gas	Column B : LN 44
62	Projected Prorated Sales (11/01/20 - 04/30/21)	Column B : LN 54
63	Indirect Cost of Gas	LN 61 / LN 62
64		
65		
66	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/20	LN 59 + LN 63
67		
68	RESIDENTIAL COST OF GAS RATE - 11/01/20	LN 66
69		LN 68 * 1.25
70		
71		
72	COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/20	LN 89
73		LN 72 * 1.25
74		
75	C&I HLF Demand Costs Allocated per SMBA	Schedule 7-CAK, LN 170
76	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 12-CAK, LN 16
77	C&I HLF Total Adjusted Demand Costs	Sum (LN 75 : LN 76)
78	C&I HLF Projected Prorated Sales (11/01/20 - 04/30/21)	Schedule 6-CAK, LN 14
79	Demand Cost of Gas Rate	LN 77 / LN 78
80		
81	C&I HLF Commodity Costs Allocated per SMBA	Schedule 11-CAK, LN 83
82	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 12-CAK, LN 26
83	C&I HLF Total Adjusted Commodity Costs	Sum (LN 81 : LN 82)
84	C&I HLF Projected Prorated Sales (11/01/20 - 05/30/21)	LN 78
85	Commodity Cost of Gas Rate	LN 83 / LN 84
86		
87	Indirect Cost of Gas	LN 63
88		
89	Total C&I HLF Cost of Gas Rate	Sum (LN 79, LN 85, LN 87)
90		
91		
92	COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/20	LN 109
93		LN 92 * 1.25
94		
95	C&I LLF Demand Costs Allocated per SMBA	Schedule 7-CAK, LN 171
96	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 12-CAK, LN 17
97	C&I LLF Total Adjusted Demand Costs	Sum (LN 95 : LN 96)
98	C&I LLF Projected Prorated Sales (11/01/20 - 04/30/21)	Schedule 6-CAK, LN 15
99	Demand Cost of Gas Rate	LN 97 / LN 98
100		
101	C&I LLF Commodity Costs Allocated per SMBA	Schedule 11-CAK, LN 84
102	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 12-CAK, LN 27
103	C&I LLF Total Adjusted Commodity Costs	Sum (LN 101 : LN 102)
104	C&I LLF Projected Prorated Sales (11/01/20 - 04/30/21)	LN 98
105	Commodity Cost of Gas Rate	LN 103 / LN 104
106		
107	Indirect Cost of Gas	LN 63
108		
109	Total C&I LLF Cost of Gas Rate	Sum (LN 99, LN 105, LN 107)

N.H.P.U.C No.12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

Summary Schedule

New Hampshire Division
Period Covered: May 1, 2021 - October 31, 2021

Column A	Column B	Column C
110 <u>ANTICIPATED DIRECT COST OF GAS</u>		
111 Purchased Gas:		
112 Demand Costs:	\$ 842,503	
113 Supply Costs:	\$ 2,140,506	
114		
115 Storage & Peaking Gas:		
116 Demand, Capacity:	\$ 332,957	
117 Commodity Costs:	\$ 25,153	
118		
119 Inventory Finance Charge	\$ -	
120		
121 Capacity Release	\$ -	
122		
123 Re-entry Rate & Conversion Rate Revenues	\$ -	
124		
125 Total Anticipated Direct Cost of Gas		\$ 3,341,119
126		
127 <u>ANTICIPATED INDIRECT COST OF GAS</u>		
128 Adjustments:		
129 Prior Period Under/(Over) Collection	\$ 141,851	
130 Interest	\$ (43,640)	
131 Refunds	\$ -	
132 Interruptible Margins	\$ -	
133 Total Adjustments		\$ 98,211
134		
135 Working Capital:		
136 Total Anticipated Direct Cost of Gas	\$ 3,341,119	
137 Working Capital Allowance Percentage (10.02 [lag days]/365* prime rate)	0.089%	
138 Working Capital Allowance	\$ 2,981	
139 Plus: Working Capital Reconciliation (Acct. 173)	\$ (8,295)	
140		
141 Total Working Capital Allowance		\$ (5,314)
142		
143 Bad Debt:		
144 Projected Bad Debt	\$ 14,144	
145 Plus: Bad Debt Reconciliation (Acct 173)	\$ (979)	
146 Total Bad Debt Expense		\$ 13,165
147		
148 Local Production and Storage Capacity		\$ -
149		
150 Miscellaneous Overhead-18.77% Allocated to Summer Season		\$ 108,923
151		
152 Total Anticipated Indirect Cost of Gas		\$ 214,984
153		
154 Total Cost of Gas		\$ 3,556,103
155		

(*) Prime Rate is 3.25%

N.H.P.U.C No.12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2021 - October 31, 2021

Column A	Column D
110 <u>ANTICIPATED DIRECT COST OF GAS</u>	
111 Purchased Gas:	
112 Demand Costs:	Schedule 5-CAK, LN 71 + Schedule 5-CAK, LN 75
113 Supply Costs:	Schedule 9-CAK, LN 15
114	
115 Storage & Peaking Gas:	
116 Demand, Capacity:	Schedule 5-CAK, LN 73
117 Commodity Costs:	Schedule 9-CAK, LN 17 + Schedule 9-CAK, LN 18
118	
119 Inventory Finance Charge	-(Schedule 9-CAK, LN 22)
120	
121 Capacity Release	-(Schedule 5-CAK, LN 77)
122	
123 Re-entry Rate & Conversion Rate Revenues	
124	
125 Total Anticipated Direct Cost of Gas	Sum (LN 112 : LN 123)
126	
127 <u>ANTICIPATED INDIRECT COST OF GAS</u>	
128 Adjustments:	
129 Prior Period Under/(Over) Collection	Schedule 13-CAK, PG 1
130 Interest	Schedule 15-CAK, LN 100: Total
131 Refunds	Company Analysis
132 Interruptible Margins	-(Schedule 5-CAK, LN 78)
133 Total Adjustments	Sum (LN 129 : LN 132)
134	
135 Working Capital:	
136 Total Anticipated Direct Cost of Gas	LN 125
137 Working Capital Allowance Percentage (10.02 [lag days]/365* primTariff - NHPUC No. 12 , Section 6.1	
138 Working Capital Allowance	LN 136 * LN 137
139 Plus: Working Capital Reconciliation (Acct. 173)	Schedule 13-CAK, Attachment A
140	
141 Total Working Capital Allowance	Sum (LN 138 : LN 139)
142	
143 Bad Debt:	
144 Projected Bad Debt	Schedule 14-CAK, LN 17
145 Plus: Bad Debt Reconciliation (Acct 173)	Schedule 13-CAK, Attachment B
146 Total Bad Debt Expense	Sum (LN 144 : LN 145)
147	
148 Local Production and Storage Capacity	Schedule 5-CAK, LN 84
149	
150 Miscellaneous Overhead-18.77% Allocated to Summer Season	Schedule 5-CAK, LN 83
151	
152 Total Anticipated Indirect Cost of Gas	Sum (LN 133 : LN 150)
153	
154 Total Cost of Gas	LN 152 + LN 125
155	

(*) Prime Rate is 3.25%

NORTHERN UTILITIES, INC.

156
157 CALCULATION OF FIRM SALES COST OF GAS RATE
158 Period Covered: May 1, 2021 - October 31, 2021
159

160 Column A	Column B	Column C
161		
162 Total Anticipated Direct Cost of Gas	\$ 3,341,119	
163 Projected Prorated Sales (05/01/21 - 10/31/21)	8,061,210	
164 Direct Cost of Gas Rate		\$ 0.4145 per therm
165		
166 Demand Cost of Gas Rate	\$ 1,175,460	\$ 0.1458 per therm
167 Commodity Cost of Gas Rate	\$ 2,165,659	\$ 0.2687 per therm
168 Total Direct Cost of Gas Rate	\$ 3,341,119	\$ 0.4145 per therm
169		
170 Total Anticipated Indirect Cost of Gas	\$ 214,984	
171 Projected Prorated Sales (05/01/21 - 10/31/21)	8,061,210	
172 Indirect Cost of Gas		\$ 0.0267 per therm
173		
174		
175 TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21		\$ 0.4412 per therm

176	RESIDENTIAL COST OF GAS RATE - 05/01/21	COGwr	\$ 0.4412 per therm
177			
178	Maximum (COG+25%)		\$ 0.5515

179	COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/21	COGwl	\$ 0.3943 per therm
180			
181	Maximum (COG+25%)		\$ 0.4929

182			
183			
184	C&I HLF Demand Costs Allocated per SMBA	\$ 178,339	
185	PLUS: Residential Demand Reallocation to C&I HLF	\$ 10,993	
186	C&I HLF Total Adjusted Demand Costs	\$ 189,332	
187	C&I HLF Projected Prorated Sales (05/01/21 - 10/31/21)	1,912,209	
188	Demand Cost of Gas Rate	\$ 0.0990	
189			
190	C&I HLF Commodity Costs Allocated per SMBA	\$ 513,718	
191	PLUS: Residential Commodity Reallocation to C&I HLF	\$ (69)	
192	C&I HLF Total Adjusted Commodity Costs	\$ 513,650	
193	C&I HLF Projected Prorated Sales (05/01/21 - 10/31/21)	1,912,209	
194	Commodity Cost of Gas Rate	\$ 0.2686	
195			
196	Indirect Cost of Gas	\$ 0.0267	
197			
198	Total C&I HLF Cost of Gas Rate	\$ 0.3943	

199	COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/21	COGwh	\$ 0.4733 per therm
200			
201	Maximum (COG+25%)		\$ 0.5916

202			
203			
204	C&I LLF Demand Costs Allocated per SMBA	\$ 452,907	
205	PLUS: Residential Demand Reallocation to C&I LLF	\$ 27,917	
206	C&I LLF Total Adjusted Demand Costs	\$ 480,823	
207	C&I LLF Projected Prorated Sales (05/01/21 - 10/31/21)	2,701,981	
208	Demand Cost of Gas Rate	\$ 0.1780	
209			
210	C&I LLF Commodity Costs Allocated per SMBA	\$ 725,892	
211	PLUS: Residential Commodity Reallocation to C&I LLF	\$ (97)	
212	C&I LLF Total Adjusted Commodity Costs	\$ 725,795	
213	C&I LLF Projected Prorated Sales (05/01/21 - 10/31/21)	2,701,981	
214	Commodity Cost of Gas Rate	\$ 0.2686	
215			
216	Indirect Cost of Gas	\$ 0.0267	
217			
218	Total C&I LLF Cost of Gas Rate	\$ 0.4733	

NORTHERN UTILITIES, INC.

156		
157	CALCULATION OF FIRM SALES COST OF GAS RATE	
158	Period Covered: May 1, 2021 - October 31, 2021	
159		
160	Column A	Column D
161		
162	Total Anticipated Direct Cost of Gas	LN 125
163	Projected Prorated Sales (05/01/21 - 10/31/21)	Schedule 6-CAK, LN 11
164	Direct Cost of Gas Rate	LN 162 / LN 163
165		
166	Demand Cost of Gas Rate	Column B : SUM (LN 112 , LN 116 , LN 121 , LN 123) : C
167	Commodity Cost of Gas Rate	Column B : SUM (LN 113 , LN 117 , LN 119) : COLUMN C
168	Total Direct Cost of Gas Rate	SUM (LN 166 : LN 167)
169		
170	Total Anticipated Indirect Cost of Gas	Column B : LN 152
171	Projected Prorated Sales (05/01/21 - 10/31/21)	Column B : LN 163
172	Indirect Cost of Gas	LN 170 / LN 171
173		
174		
175	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21	LN 168 + LN 172
176		
177	RESIDENTIAL COST OF GAS RATE - 05/01/21	LN 175
178		LN 177 * 1.25
179		
180		
181	COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/21	LN 198
182		LN 181 * 1.25
183		
184	C&I HLF Demand Costs Allocated per SMBA	Schedule 7-CAK, LN 170
185	PLUS: Residential Demand Reallocation to C&I HLF	Schedule 12-CAK, LN 16
186	C&I HLF Total Adjusted Demand Costs	Sum (LN 184 : LN 185)
187	C&I HLF Projected Prorated Sales (05/01/21 - 10/31/21)	Schedule 6-CAK, LN 14
188	Demand Cost of Gas Rate	LN 186 / LN 187
189		
190	C&I HLF Commodity Costs Allocated per SMBA	Schedule 11-CAK, LN 83
191	PLUS: Residential Commodity Reallocation to C&I HLF	Schedule 12-CAK, LN 26
192	C&I HLF Total Adjusted Commodity Costs	Sum (LN 190 : LN 191)
193	C&I HLF Projected Prorated Sales (05/01/21 - 10/31/21)	LN 187
194	Commodity Cost of Gas Rate	LN 192 / LN 193
195		
196	Indirect Cost of Gas	LN 172
197		
198	Total C&I HLF Cost of Gas Rate	Sum (LN 188, LN 194, LN 196)
199		
200		
201	COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/21	LN 218
202		LN 201 * 1.25
203		
204	C&I LLF Demand Costs Allocated per SMBA	Schedule 7-CAK, LN 171
205	PLUS: Residential Demand Reallocation to C&I LLF	Schedule 12-CAK, LN 17
206	C&I LLF Total Adjusted Demand Costs	Sum (LN 204 : LN 205)
207	C&I LLF Projected Prorated Sales (05/01/21 - 10/31/21)	Schedule 6-CAK, LN 15
208	Demand Cost of Gas Rate	LN 206 / LN 207
209		
210	C&I LLF Commodity Costs Allocated per SMBA	Schedule 11-CAK, LN 84
211	PLUS: Residential Commodity Reallocation to C&I LLF	Schedule 12-CAK, LN 27
212	C&I LLF Total Adjusted Commodity Costs	Sum (LN 210 : LN 211)
213	C&I LLF Projected Prorated Sales (05/01/21 - 10/31/21)	LN 207
214	Commodity Cost of Gas Rate	LN 212 / LN 213
215		
216	Indirect Cost of Gas	LN 172
217		
218	Total C&I LLF Cost of Gas Rate	Sum (LN 208, LN 214, LN 216)

NORTHERN UTILITIES, INC.

**N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.**

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2020 - October 31, 2021

	Column A	Column B	Column C
219	<u>ANTICIPATED DIRECT COST OF GAS</u>		
220	Purchased Gas for Sales Service:		
221	Demand Costs:	\$ 5,439,224	
222	Supply Costs:	\$ 10,373,736	
223			
224	Storage & Peaking Gas for Sales Service:		
225	Demand, Capacity:	\$ 12,035,867	
226	Commodity Costs:	\$ 2,643,472	
227			
228	Inventory Finance Charge	\$ 1,266	
229			
230	Capacity Release	\$ (3,272,870)	
231			
232	Re-entry Rate & Conversion Rate Revenues	\$ (5,000)	
233			
234	Total Anticipated Direct Cost of Gas		\$ 27,215,695
235			
236	<u>ANTICIPATED INDIRECT COST OF GAS</u>		
237	Adjustments:		
238	Prior Period Under/(Over) Collection	\$ 755,933	
239	Interest	\$ (87,656)	
240	Refunds	\$ -	
241	<u>Interruptible Margins</u>	\$ -	
242	Total Adjustments		\$ 668,277
243			
244	Working Capital:		
245	Total Anticipated Direct Cost of Gas	\$ 27,215,695	
246	Working Capital Percentage	<u>0.0892%</u>	
247	Working Capital Allowance	\$ 24,282	
248			
249	Plus: Working Capital Reconciliation (Acct 173)	\$ (44,205)	
250			
251	Total Working Capital Allowance		\$ (19,923)
252			
253	Bad Debt:		
254	Bad Debt Allowance	\$ 170,831	
255	Plus: Bad Debt Reconciliation (Acct 173)	\$ (5,218)	
256	Total Bad Debt Allowance		\$ 165,613
257			
258	Local Production and Storage Capacity		\$ 476,106
259			
260	Miscellaneous Overhead		\$ 580,455
261			
262	Total Anticipated Indirect Cost of Gas		\$ 1,870,528
263			
264	Total Cost of Gas		<u>\$ 29,086,223</u>

NORTHERN UTILITIES, INC.

**N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.**

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2020 - October 31, 2021

Column A	Column D
219 <u>ANTICIPATED DIRECT COST OF GAS</u>	
220 Purchased Gas for Sales Service:	
221 Demand Costs:	LN 3 + LN 112
222 Supply Costs:	LN 4 + LN 113
223	
224 Storage & Peaking Gas for Sales Service:	
225 Demand, Capacity:	LN 7 + LN 116
226 Commodity Costs:	LN 8 + LN 117
227	
228 Inventory Finance Charge	LN 10 + LN 119
229	
230 Capacity Release	LN 12 + LN 121
231	
232 Re-entry Rate & Conversion Rate Revenues	LN 14 + LN 123
233	
234 Total Anticipated Direct Cost of Gas	LN 16 + LN 125
235	
236 <u>ANTICIPATED INDIRECT COST OF GAS</u>	
237 Adjustments:	
238 Prior Period Under/(Over) Collection	LN 20 + LN 129
239 Interest	LN 21 + LN 130
240 Refunds	LN 22 + LN 131
241 <u>Interruptible Margins</u>	LN 23 + LN 132
242 Total Adjustments	LN 24 + LN 133
243	
244 Working Capital:	
245 Total Anticipated Direct Cost of Gas	LN 27 + LN 136
246 Working Capital Percentage	LN 28 + LN 137
247 Working Capital Allowance	LN 29 + LN 138
248	
249 Plus: Working Capital Reconciliation (Acct 173)	LN 31 + LN 139
250	
251 Total Working Capital Allowance	LN 33 + LN 141
252	
253 Bad Debt:	
254 Bad Debt Allowance	LN 36 + LN 144
255 Plus: Bad Debt Reconciliation (Acct 173)	LN 37 + LN 145
256 Total Bad Debt Allowance	LN 38 + LN 146
257	
258 Local Production and Storage Capacity	LN 40 + LN 148
259	
260 Miscellaneous Overhead	LN 42 + LN 150
261	
262 Total Anticipated Indirect Cost of Gas	LN 44 + LN 152
263	
264 Total Cost of Gas	LN 46 + LN 154

Northern Utilities New Hampshire Division
Cost of Gas Rate Comparison - Residential Rate Classes
(rates per therm)

Proposed Rates	2019-2020 Actual Cost of Gas Rates						Average	Variance
November 2020 - April 2021	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	Winter 19-20	
\$0.7315	\$0.5861	\$0.5626	\$0.5626	\$0.5626	\$0.5626	\$0.5626	\$0.5665	\$0.1650
May 2021 - October 2021	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Average Summer 2020	
\$0.4412	\$0.2375	\$0.2375	\$0.1496	\$0.1496	\$0.2968	\$0.2968	\$0.2280	\$0.2132

Northern Utilities, Inc.
New Hampshire Division
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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
Typical Residential Heating Bill - 732 therms/year
Comparison of Winter 2020-2021 vs. Winter 2019-2020

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1																	
2	Typical Usage: therms (*)		55	97	126	139	106	76	600	46	22	15	13	13	23	132	732
3	Winter 2020 - 2021																
4	Customer Charge	units @	\$ 22.20						\$133.20								
5	First	50 units @	\$0.6920						\$207.60								
6	Over	50 units @	\$0.6920						\$207.51								
7	COG 1		\$40.21						\$40.21								
8	COG 2			\$70.79					\$70.79								
9	COG 3				\$92.18				\$92.18								
10	COG 4					\$101.87			\$101.87								
11	COG 5						\$77.85		\$77.85								
12	COG 6							\$55.90	\$55.90								
13	LDAC		\$0.1099	\$6.04	\$10.63	\$13.85	\$15.31	\$11.70	\$8.40	\$65.93							
14	Summer 2021																
15	Customer Charge	units @	\$ 22.20							\$ 22.20	\$22.20	\$22.20	\$22.20	\$ 22.20	\$22.20	\$133.20	
16	First	50 units @	\$0.6099							\$28.14	\$13.56	\$9.18	\$7.85	\$7.80	\$14.18	\$80.71	
17	Over	50 units @	\$0.6099							\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
20	COG 1		\$0.4412							\$20.35						\$20.35	
21	COG 2		\$0.4412								\$9.81					\$9.81	
22	COG 3		\$0.4412									\$6.64				\$6.64	
23	COG 4		\$0.4412										\$5.68			\$5.68	
24	COG 5		\$0.4412											\$5.65		\$5.65	
25	COG 6		\$0.4412												\$10.26	\$10.26	
26	Summer Period Weighted Avg. COG		\$0.4412														
27	LDAC		\$ 0.1099							\$5.07	\$2.44	\$1.65	\$1.41	\$1.41	\$2.55	\$14.54	
28	TOTAL			\$106.49	\$170.58	\$215.44	\$235.75	\$185.40	\$139.38	\$1,053.04	\$75.76	\$48.02	\$39.67	\$37.14	\$37.06	\$49.19	\$1,339.87
	Base Rate Change Winter	\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00								
		% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	COG Change Winter	\$ Change	\$7.99	\$16.34	\$21.28	\$23.52	\$17.98	\$12.91	\$100.03								
		% Change	8.30%	10.86%	11.25%	11.38%	11.01%	10.45%	10.76%								
	LDAC Change Winter	\$ Change	\$2.16	\$3.80	\$4.95	\$5.47	\$4.18	\$3.00	\$23.57								
		% Change	2.24%	2.53%	2.62%	2.65%	2.56%	2.43%	2.54%								
27																	
28	Typical Usage: therms		55	97	126	139	106	76	600	46	22	15	13	13	23	132	732
29	Winter 2019 - 2020																
30	Customer Charge	units @	\$ 22.20						\$133.20								
31	First	50 units @	\$0.6920						\$207.60								
32	Over	50 units @	\$0.6920						\$207.51								
33	COG 1		\$0.5861						\$32.22								
34	COG 2		\$0.5626	\$54.44					\$54.44								
35	COG 3		\$0.5626		\$70.90				\$70.90								
36	COG 4		\$0.5626			\$78.35			\$78.35								
37	COG 5		\$0.5626				\$59.88		\$59.88								
38	COG 6		\$0.5626					\$42.99	\$42.99								
39	Winter Period Weighted Avg. COG		\$0.5648														
40	LDAC	\$ 0.0706		\$3.88	\$6.83	\$8.90	\$9.83	\$7.51	\$5.40	\$42.35							
41	Summer 2020																
42	Customer Charge	units @	\$ 22.20							\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$133.20	
43	First	50 units @	\$0.6099							\$28.14	\$13.56	\$9.18	\$7.85	\$7.80	\$14.18	\$80.71	
44	Over	50 units @	\$0.6099							\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
45	COG 1		\$0.2375							\$10.96						\$10.96	
46	COG 2		\$0.2375								\$5.28					\$5.28	
47	COG 3		\$0.1496									\$2.25				\$2.25	
48	COG 4		\$0.1496										\$1.92			\$1.92	
49	COG 5		\$0.2968											\$3.80		\$3.80	
50	COG 6		\$0.2968												\$6.90	\$6.90	
51	Summer Period Weighted Avg. COG		\$0.2351														
52	LDAC	\$ 0.0706		\$3.26	\$1.57	\$1.06	\$0.91	\$0.90	\$1.64	\$9.34							
53	TOTAL			\$96.34	\$150.44	\$189.20	\$206.75	\$163.24	\$123.47	\$929.44	\$64.55	\$42.61	\$34.69	\$32.88	\$34.71	\$44.92	\$254.36
54	Change			\$10.15	\$20.15	\$26.24	\$28.99	\$22.16	\$15.91	\$123.60	\$11.21	\$5.40	\$4.98	\$4.26	\$2.35	\$4.27	\$32.47
55	% Chg			10.54%	13.39%	13.87%	14.02%	13.57%	12.89%	13.3%	17.37%	12.68%	14.35%	12.95%	6.77%	9.51%	12.77%

*-Note- Weighted by usage. Most recent 12 months actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
Typical G-40 Commercial & Industrial Bill - 2,039 therms/year
Comparison of Winter 2020-2021 vs. Winter 2019-2020

Northern Utilities, Inc.
New Hampshire Division
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			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1			150	272	377	404	302	202	1,708	125	54	33	30	32	57	331	2,039
2	Typical Usage: therms (*)																
3	Winter 2020 - 2021																
4	Customer Charge	units @ \$ 75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$450.54								
5	First	75 units @ \$0.1865	\$13.99	\$13.99	\$13.99	\$13.99	\$13.99	\$13.99	\$83.93								
6	Over	75 units @ \$0.1865	\$13.92	\$36.82	\$56.41	\$61.42	\$42.42	\$23.61	\$234.60								
7	COG 1	\$0.7437	\$111.29						\$111.29								
8	COG 2	\$0.7437		\$202.59					\$202.59								
9	COG 3	\$0.7437			\$280.72				\$280.72								
10	COG 4	\$0.7437				\$300.71			\$300.71								
11	COG 5	\$0.7437					\$224.93		\$224.93								
12	COG 6	\$0.7437						\$149.91	\$149.91								
13	LDAC	\$0.0472	\$7.06	\$12.86	\$17.82	\$19.09	\$14.28	\$9.51	\$80.61								
14	Summer 2021																
15	Customer Charge	units @ \$ 75.09								\$ 75.09	\$75.09	\$75.09	\$75.09	\$ 75.09	\$75.09		\$450.54
16	First	75 units @ \$0.1865								\$13.99	\$10.01	\$6.18	\$5.61	\$6.01	\$10.62		\$52.42
17	Over	75 units @ \$0.1865								\$9.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00		\$9.36
18	COG 1	\$0.4733								\$59.24							\$59.24
19	COG 2	\$0.4733									\$25.40						\$25.40
20	COG 3	\$0.4733										\$15.68					\$15.68
21	COG 4	\$0.4733											\$14.25				\$14.25
22	COG 5	\$0.4733												\$15.25			\$15.25
23	COG 6	\$0.4733													\$26.96		\$26.96
24	Summer Period Weighted Avg. COG	\$0.4733															
25	LDAC	\$ 0.0472								\$5.91	\$2.53	\$1.56	\$1.42	\$1.52	\$2.69		\$15.63
26	TOTAL		\$221.36	\$341.35	\$444.02	\$470.30	\$370.71	\$272.11	\$2,119.84	\$163.59	\$113.04	\$98.52	\$96.37	\$97.86	\$115.36	\$684.73	\$2,804.57
	Base Rate Change Winter	\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00								
	% Change		0%	0%	0%	0%	0%	0%	0%								
	COG Change Winter	\$ Change	\$20.28	\$43.31	\$60.02	\$64.29	\$48.09	\$32.05	\$268.04								
	% Change		10%	15%	16%	16%	15%	13%	15%								
	LDAC Change Winter	\$ Change	\$1.69	\$3.08	\$4.27	\$4.57	\$3.42	\$2.28	\$19.30								
	% Change		0.8%	1.0%	1.1%	1.1%	1.1%	1.0%	1.1%								
27			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
28	Typical Usage: therms		150	272	377	404	302	202	1,708	125	54	33	30	32	57	331	2,039
29	Winter 2019 - 2020																
30	Customer Charge	units @ \$ 75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$450.54								
31	First	75 units @ \$0.1865	\$13.99	\$13.99	\$13.99	\$13.99	\$13.99	\$13.99	\$83.93								
32	Over	75 units @ \$0.1865	\$13.92	\$36.82	\$56.41	\$61.42	\$42.42	\$23.61	\$234.60								
33	COG 1	\$0.6082	\$91.02						\$91.02								
34	COG 2	\$0.5847		\$159.28					\$159.28								
35	COG 3	\$0.5847			\$220.70				\$220.70								
36	COG 4	\$0.5847				\$236.42			\$236.42								
37	COG 5	\$0.5847					\$176.84		\$176.84								
38	COG 6	\$0.5847						\$117.86	\$117.86								
39	Winter Period Weighted Avg. COG	\$0.5868															
40	LDAC	\$ 0.0359	\$5.37	\$9.78	\$13.55	\$14.52	\$10.86	\$7.24	\$61.31								
41	Summer 2020																
42	Customer Charge	units @ \$ 75.09								\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09		\$450.54
43	First	75 units @ \$0.1865								\$13.99	\$10.01	\$6.18	\$5.61	\$6.01	\$10.62		\$52.42
44	Over	75 units @ \$0.1865								\$9.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00		\$9.36
45	COG 1	\$0.2723								\$34.08							\$34.08
46	COG 2	\$0.2723									\$14.61						\$14.61
47	COG 3	\$0.1844										\$6.11					\$6.11
48	COG 4	\$0.1844											\$5.55				\$5.55
49	COG 5	\$0.3316												\$10.68			\$10.68
50	COG 6	\$0.3316													\$18.89		\$18.89
51	Summer Period Weighted Avg. COG	\$0.2715															
52	LDAC	\$ 0.0359								\$4.49	\$1.93	\$1.19	\$1.08	\$1.16	\$2.04		\$11.89
53	TOTAL		\$199.39	\$294.95	\$379.74	\$401.44	\$319.20	\$237.78	\$1,832.50	\$137.01	\$101.64	\$88.57	\$87.33	\$92.94	\$106.64	\$614.14	\$2,446.64
54	Change		\$21.97	\$46.39	\$64.28	\$68.86	\$51.51	\$34.33	\$287.34	\$26.57	\$11.39	\$9.95	\$9.04	\$4.93	\$8.71	\$70.59	\$357.93
55	% Chg		11.02%	15.73%	16.93%	17.15%	16.14%	14.44%	15.68%	19.40%	11.21%	11.23%	10.35%	5.30%	8.17%	11.49%	14.63%

*-Note- Weighted by usage. Actual Weather Normalized.

Northern Utilities, Inc.
New Hampshire Division
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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
Typical G-41 Commercial & Industrial Bill - 20,286 therms/year
Comparison of Winter 2020-2021 vs. Winter 2019-2020

			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1			1,609	2,618	3,574	3,800	2,951	1,974	16,526	1,276	613	397	347	422	704	3,760	20,286
2	Typical Usage: therms (*)																
3	Winter 2020 - 2021																
4	Customer Charge	units @ \$ 222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84								
5	All	units @ \$0.2425	\$390.15	\$634.93	\$866.78	\$921.42	\$715.66	\$478.69	\$4,007.63								
6	COG 1	\$0.7437	\$1,196.53						\$1,196.53								
7	COG 2	\$0.7437		\$1,947.21					\$1,947.21								
8	COG 3	\$0.7437			\$2,658.23				\$2,658.23								
9	COG 4	\$0.7437				\$2,825.80			\$2,825.80								
10	COG 5	\$0.7437					\$2,194.80		\$2,194.80								
11	COG 6	\$0.7437						\$1,468.05	\$1,468.05								
12	LDAC	\$0.0472	\$75.94	\$123.58	\$168.71	\$179.34	\$139.30	\$93.17	\$780.04								
13	Summer 2021																
14	Customer Charge	units @ \$ 222.64								\$ 222.64	\$222.64	\$222.64	\$222.64	\$ 222.64	\$222.64	\$1,335.84	
15	All	units @ \$0.1895								\$241.86	\$116.18	\$75.24	\$65.84	\$80.04	\$133.38	\$712.54	
16	COG 1	\$0.4733								\$604.07						\$604.07	
17	COG 2	\$0.4733									\$290.18					\$290.18	
18	COG 3	\$0.4733										\$187.92				\$187.92	
19	COG 4	\$0.4733											\$164.45			\$164.45	
20	COG 5	\$0.4733												\$199.90		\$199.90	
21	COG 6	\$0.4733													\$333.14	\$333.14	
22	Summer Period Weighted Avg. COG	\$0.4733															
23	LDAC	\$ 0.0472								\$60.24	\$28.94	\$18.74	\$16.40	\$19.94	\$33.22	\$177.48	
24	TOTAL		\$1,885.26	\$2,928.37	\$3,916.35	\$4,149.20	\$3,272.40	\$2,262.56	\$18,414.13	\$1,128.82	\$657.94	\$504.54	\$469.33	\$522.51	\$722.38	\$4,005.53	\$22,419.66
	Base Rate Change Winter	\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00								
		% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	COG Change Winter	\$ Change	\$218.00	\$416.31	\$568.32	\$604.14	\$469.24	\$313.86	\$2,589.88								
		% Change	13.22%	16.77%	17.18%	17.25%	16.94%	16.29%	16.56%								
	LDAC Change Winter	\$ Change	\$18.18	\$29.59	\$40.39	\$42.94	\$33.35	\$22.31	\$186.75								
		% Change	1.102%	1.192%	1.221%	1.226%	1.204%	1.158%	1.194%								
25			Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26	Typical Usage: therms		1,609	2,618	3,574	3,800	2,951	1,974	16,526	1,276	613	397	347	422	704	3,760	20,286
27	Winter 2019 - 2020																
28	Customer Charge	units @ \$ 222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84								
29	All	units @ \$0.2425	\$390.15	\$634.93	\$866.78	\$921.42	\$715.66	\$478.69	\$4,007.63								
30	COG 1	\$0.6082	\$978.52						\$978.52								
31	COG 2	\$0.5847		\$1,530.91					\$1,530.91								
32	COG 3	\$0.5847			\$2,089.91				\$2,089.91								
33	COG 4	\$0.5847				\$2,221.66			\$2,221.66								
34	COG 5	\$0.5847					\$1,725.56		\$1,725.56								
35	COG 6	\$0.5847						\$1,154.19	\$1,154.19								
36	Winter Period Weighted Avg. COG	\$0.5870															
37	LDAC	\$ 0.0359	\$57.76	\$94.00	\$128.32	\$136.41	\$105.95	\$70.87	\$593.29								
38	Summer 2020																
39	Customer Charge	units @ \$ 222.64								\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84	
40	All	units @ \$0.1895								\$270.96	\$130.16	\$119.19	\$104.31	\$64.62	\$107.69	\$796.93	\$3,573.55
41	COG 1	\$0.2723								\$347.54						\$347.54	
42	COG 2	\$0.2723									\$166.95					\$166.95	
43	COG 3	\$0.1844										\$73.22				\$73.22	
44	COG 4	\$0.1844											\$64.07			\$64.07	
45	COG 5	\$0.3316												\$140.05		\$140.05	
46	COG 6	\$0.3316													\$233.40	\$233.40	
47	Summer Period Weighted Avg. COG	\$0.2727															
48	LDAC	\$ 0.0359								\$45.82	\$22.01	\$14.25	\$12.47	\$15.16	\$25.27	\$134.99	
49	TOTAL		\$1,649.08	\$2,482.48	\$3,307.64	\$3,502.12	\$2,769.81	\$1,926.39	\$15,637.51	\$857.86	\$527.78	\$385.35	\$365.03	\$457.89	\$614.69	\$3,208.60	\$18,846.11
50	Change		\$236.18	\$445.89	\$608.71	\$647.08	\$502.59	\$336.17	\$2,776.62	\$270.96	\$130.16	\$119.19	\$104.31	\$64.62	\$107.69	\$796.93	\$3,573.55
51	% Chg		14.32%	17.96%	18.40%	18.48%	18.15%	17.45%	17.76%	31.59%	24.66%	30.93%	28.57%	14.11%	17.52%	24.84%	18.96%

*-Note- Weighted by usage. Actual Weather Normalized.

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
Typical G-51 Commercial & Industrial Bill - 18,560 therms/year
Comparison of Winter 2020-2021 vs. Winter 2019-2020

		Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1	Typical Usage: therms (*)	1,509	1,802	2,123	2,164	1,959	1,145	10,702	1,488	1,251	1,329	1,194	1,072	1,524	7,858	18,560
3	Winter 2020 - 2021															
4	Customer Charge units @	\$ 222.64						\$1,335.84								
5	First 1,300 units @	\$0.1712						\$1,308.77								
6	Over 1,300 units @	\$0.1399						\$427.72								
7	COG 1	\$0.6465						\$975.75								
8	COG 2	\$0.6465	\$1,165.25					\$1,165.25								
9	COG 3	\$0.6465		\$1,372.66				\$1,372.66								
10	COG 4	\$0.6465			\$1,398.74			\$1,398.74								
11	COG 5	\$0.6465				\$1,266.40		\$1,266.40								
12	COG 6	\$0.6465					\$740.05	\$740.05								
13	LDAC	\$0.0472	\$71.24	\$85.07	\$100.22	\$102.12	\$92.46	\$54.03	\$505.13							
14	Summer 2021															
15	Customer Charge units @	\$ 222.64							\$ 222.64	\$222.64	\$222.64	\$222.64	\$ 222.64	\$222.64	\$1,335.84	
16	First 1,000 units @	\$0.1337							\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$802.20	
17	Over 1,000 units @	\$0.1087							\$53.01	\$27.25	\$35.76	\$21.09	\$7.84	\$56.99	\$201.93	
18	COG 1	\$0.3943							\$586.58						\$586.58	
19	COG 2	\$0.3943								\$493.14					\$493.14	
20	COG 3	\$0.3943									\$524.00				\$524.00	
21	COG 4	\$0.3943										\$470.80			\$470.80	
22	COG 5	\$0.3943											\$422.73		\$422.73	
23	COG 6	\$0.3943												\$601.02	\$601.02	
24	Summer Period Weighted Avg. COG	\$0.3943														
25	LDAC	\$ 0.0472							\$70.22	\$59.03	\$62.73	\$56.36	\$50.60	\$71.95	\$370.88	
26	TOTAL		\$1,521.46	\$1,765.80	\$2,033.24	\$2,066.88	\$1,896.23	\$1,212.70	\$10,496.31	\$1,066.14	\$935.76	\$978.83	\$904.58	\$837.51	\$1,086.30	\$16,305.44
	Base Rate Change Winter	\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00								
	% Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	COG Change Winter	\$ Change	\$228.66	\$315.42	\$371.56	\$378.62	\$342.80	\$200.32								
	% Change		17.92%	22.06%	22.69%	22.76%	22.39%	20.04%								
	LDAC Change Winter	\$ Change	\$17.05	\$20.37	\$23.99	\$24.45	\$22.14	\$12.94								
	% Change		1.34%	1.42%	1.47%	1.47%	1.45%	1.29%								
27																
28	Typical Usage: therms		1,509	1,802	2,123	2,164	1,959	1,145								
29	Winter 2019 - 2020															
30	Customer Charge units @	\$ 222.64						\$1,335.84								
31	First 1,300 units @	\$0.1712						\$1,308.77								
32	Over 1,300 units @	\$0.1399						\$427.72								
33	COG 1	\$0.4950						\$747.09								
34	COG 2	\$0.4715		\$849.83				\$849.83								
35	COG 3	\$0.4715			\$1,001.10			\$1,001.10								
36	COG 4	\$0.4715				\$1,020.12		\$1,020.12								
37	COG 5	\$0.4715					\$923.60	\$923.60								
38	COG 6	\$0.4715					\$539.73	\$539.73								
39	Winter Period Weighted Avg. COG	\$0.4748														
40	LDAC	\$ 0.0359	\$54.18	\$64.71	\$76.22	\$77.67	\$70.32	\$41.09	\$384.20							
41	Summer 2020															
42	Customer Charge units @	\$ 222.64							\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84	
43	First 1,000 units @	\$0.1337							\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$802.20	
44	Over 1,000 units @	\$0.1087							\$53.01	\$27.25	\$35.76	\$21.09	\$7.84	\$56.99	\$201.93	
45	COG 1	\$0.2050							\$304.97						\$304.97	
46	COG 2	\$0.2050								\$256.39					\$256.39	
47	COG 3	\$0.1171									\$155.62				\$155.62	
48	COG 4	\$0.1171										\$139.82			\$139.82	
49	COG 5	\$0.2643											\$283.36		\$283.36	
50	COG 6	\$0.2643												\$402.87	\$402.87	
51	Summer Period Weighted Avg. COG	\$0.1964														
52	LDAC	\$ 0.0359							\$53.41	\$44.90	\$47.71	\$42.86	\$38.49	\$54.72	\$282.09	
53	TOTAL		\$1,275.75	\$1,430.02	\$1,637.69	\$1,663.81	\$1,531.30	\$999.44	\$767.72	\$684.88	\$595.43	\$560.11	\$686.02	\$870.92	\$4,165.07	\$12,703.07
54	Change		\$245.71	\$335.79	\$395.55	\$403.07	\$364.93	\$213.26	\$298.42	\$250.89	\$383.40	\$344.47	\$151.49	\$215.38	\$1,644.05	\$3,602.36
55	% Chg		19.26%	23.48%	24.15%	24.23%	23.83%	21.34%	38.87%	36.63%	64.39%	61.50%	22.08%	24.73%	39.47%	28.36%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION
Impact of Rate Changes on Residential Heating Bills by Usage Level
Forecast Winter 2020-2021 vs. Actual Winter 2019-2020

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<u>Residential Heating</u>		
	<u>Winter 2019- 2020</u>	<u>Winter 2020- 2021</u>
Customer Charge	\$22.20	\$22.20
First 50 Therms	\$0.6920	\$0.6920
Over 50 therms	\$0.6920	\$0.6920
LDAC	\$0.0706	\$0.1099
CGA	\$0.5648	\$0.7315

Usage (Therms)	Winter 2019-2020	Winter 2020-2021	Total Bill		Base Rate		CGA		LDAC		
	Bill Amount	Bill Amount									
5	\$28.84	\$29.87	\$1.03	3.6%	\$0.00	0.0%	\$0.83	2.9%	\$0.20	0.7%	
10	\$35.47	\$37.53	\$2.06	5.8%	\$0.00	0.0%	\$1.67	4.7%	\$0.39	1.1%	
20	\$48.75	\$52.87	\$4.12	8.5%	\$0.00	0.0%	\$3.33	6.8%	\$0.79	1.6%	
25	\$55.38	\$60.54	\$5.15	9.3%	\$0.00	0.0%	\$4.17	7.5%	\$0.98	1.8%	
30	\$62.02	\$68.20	\$6.18	10.0%	\$0.00	0.0%	\$5.00	8.1%	\$1.18	1.9%	
45	\$81.93	\$91.20	\$9.27	11.3%	\$0.00	0.0%	\$7.50	9.2%	\$1.77	2.2%	
50	\$88.57	\$98.87	\$10.30	11.6%	\$0.00	0.0%	\$8.34	9.4%	\$1.97	2.2%	
75	\$121.75	\$137.21	\$15.45	12.7%	\$0.00	0.0%	\$12.51	10.3%	\$2.95	2.4%	
Monthly*	125	\$188.12	\$213.88	\$25.76	13.7%	\$0.00	0.0%	\$20.84	11.1%	\$4.91	2.6%
	150	\$221.30	\$252.21	\$30.91	14.0%	\$0.00	0.0%	\$25.01	11.3%	\$5.90	2.7%
	200	\$287.67	\$328.88	\$41.21	14.3%	\$0.00	0.0%	\$33.35	11.6%	\$7.86	2.7%

* Monthly amount for benchmarking purposes, does not represent the average monthly use of Northern's residential class.

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 132 therms/Summer

Comparison of Summer 2021 vs. Summer 2020

1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(*)			46	22	15	13	13	23	<u>132</u>
3	Summer 2021									
4	Customer Charge	units @	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$133.20
5	First	50 units @	\$0.6099	\$28.14	\$13.56	\$9.18	\$7.85	\$7.80	\$14.18	\$80.71
6	Over	50 units @	\$0.6099	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
7		COG 1	\$0.4412	\$20.35						\$20.35
8		COG 2	\$0.4412		\$9.81					\$9.81
9		COG 3	\$0.4412			\$6.64				\$6.64
10		COG 4	\$0.4412				\$5.68			\$5.68
11		COG 5	\$0.4412					\$5.65		\$5.65
12		COG 6	\$0.4412						\$10.26	\$10.26
13	Summer Period 2021 Avg. COG		\$0.4412 *							
14		LDAC	\$0.1099	\$5.07	\$2.44	\$1.65	\$1.41	\$1.41	\$2.55	\$14.54
15	TOTAL			\$75.76	\$48.02	\$39.67	\$37.14	\$37.06	\$49.19	\$286.83
Base Rate Change			\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
			% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
COG Change			\$ Change	\$9.40	\$4.53	\$4.39	\$3.75	\$1.85	\$3.36	\$27.27
			% Change	14.56%	10.63%	12.65%	11.41%	5.32%	7.47%	10.72%
LDAC Change			\$ Change	\$1.81	\$0.87	\$0.59	\$0.51	\$0.50	\$0.91	\$5.20
			% Change	2.81%	2.05%	1.70%	1.54%	1.45%	2.03%	2.04%
16				May	June	July	August	Sept	October	Summer
17	Typical Usage: therms			46	22	15	13	13	23	<u>132</u>
18	Summer 2020									
19	Customer Charge	units @	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$22.20	\$133.20
20	First	50 units @	\$0.6099	\$28.14	\$13.56	\$9.18	\$7.85	\$7.80	\$14.18	\$80.71
21	Over	50 units @	\$0.6099	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
22		COG 1	\$0.2375	\$10.96						\$10.96
23		COG 2	\$0.2375		\$5.28					\$5.28
24		COG 3	\$0.1496			\$2.25				\$2.25
25		COG 4	\$0.1496				\$1.92			\$1.92
26		COG 5	\$0.2968					\$3.80		\$3.80
27		COG 6	\$0.2968						\$6.90	\$6.90
28	Summer Period 2020 Avg. COG		\$0.2351 *							
29		LDAC	\$0.0706	\$3.26	\$1.57	\$1.06	\$0.91	\$0.90	\$1.64	\$9.34
30	TOTAL			\$64.55	\$42.61	\$34.69	\$32.88	\$34.71	\$44.92	\$254.36
31	Change			\$11.21	\$5.40	\$4.98	\$4.26	\$2.35	\$4.27	\$32.47
32	% Chg			17.37%	12.68%	14.35%	12.95%	6.77%	9.51%	12.77%

*-Note- Weighted by usage. Actual Weather Normalized.

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 331 therms/Summer

Comparison of Summer 2021 vs. Summer 2020

			May	June	July	August	Sept	October	Summer
1									
2	Typical Usage: therms(*)		125	54	33	30	32	57	<u>331</u>
3	Summer 2021								
4	Customer Charge	units @ \$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$450.54
5	First	75 units @ \$0.1865	\$13.99	\$10.01	\$6.18	\$5.61	\$6.01	\$10.62	\$52.42
6	Over	75 units @ \$0.1865	\$9.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$9.36
7		COG 1 \$0.4733	\$59.24						\$59.24
8		COG 2 \$0.4733		\$25.40					\$25.40
9		COG 3 \$0.4733			\$15.68				\$15.68
10		COG 4 \$0.4733				\$14.25			\$14.25
11		COG 5 \$0.4733					\$15.25		\$15.25
12		COG 6 \$0.4733						\$26.96	\$26.96
13	Summer Period 2021 Avg. COG	<u>\$0.4733</u> *							
14	LDAC	<u>\$0.0472</u>	\$5.91	\$2.53	\$1.56	\$1.42	\$1.52	\$2.69	\$15.63
15	TOTAL		\$163.59	\$113.04	\$98.52	\$96.37	\$97.86	\$115.36	\$684.73
	Base Rate Change	\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
		% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	COG Change	\$ Change	\$25.16	\$10.79	\$9.57	\$8.70	\$4.56	\$8.07	\$66.85
		% Change	18.36%	10.61%	10.81%	9.96%	4.91%	7.57%	10.89%
	LDAC Change	\$ Change	\$1.41	\$0.61	\$0.37	\$0.34	\$0.36	\$0.64	\$3.74
		% Change	1.03%	0.60%	0.42%	0.39%	0.39%	0.60%	0.61%
16									
17	Typical Usage: therms		125	54	33	30	32	57	<u>331</u>
18	Summer 2020								
19	Customer Charge	units @ \$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$75.09	\$450.54
20	First	75 units @ \$0.1865	\$13.99	\$10.01	\$6.18	\$5.61	\$6.01	\$10.62	\$52.42
21	Over	75 units @ \$0.1865	\$9.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$9.36
22		COG 1 \$0.2723	\$34.08						\$34.08
23		COG 2 \$0.2723		\$14.61					\$14.61
24		COG 3 \$0.1844			\$6.11				\$6.11
25		COG 4 \$0.1844				\$5.55			\$5.55
26		COG 5 \$0.3316					\$10.68		\$10.68
27		COG 6 \$0.3316						\$18.89	\$18.89
28	Summer Period 2020 Avg. COG	<u>\$0.2715</u> *							
29	LDAC	<u>\$0.0359</u>	\$4.49	\$1.93	\$1.19	\$1.08	\$1.16	\$2.04	\$11.89
30	TOTAL		\$137.01	\$101.64	\$88.57	\$87.33	\$92.94	\$106.64	\$614.14
31	Change		\$26.57	\$11.39	\$9.95	\$9.04	\$4.93	\$8.71	\$70.59
32	% Chg		19.40%	11.21%	11.23%	10.35%	5.30%	8.17%	11.49%

*-Note- Weighted by usage. Actual Weather Normalized.

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 3,760 therms/Summer

Comparison of Summer 2021 vs. Summer 2020

1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(1)			1,276	613	397	347	422	704	3,760
3	Summer 2021									
4	Customer Charge	units @	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84
5	All	units @	\$0.1895	\$241.86	\$116.18	\$75.24	\$65.84	\$80.04	\$133.38	\$712.54
6		COG 1	\$0.4733	\$604.07						\$604.07
7		COG 2	\$0.4733		\$290.18					\$290.18
8		COG 3	\$0.4733			\$187.92				\$187.92
9		COG 4	\$0.4733				\$164.45			\$164.45
10		COG 5	\$0.4733					\$199.90		\$199.90
11		COG 6	\$0.4733						\$333.14	\$333.14
12	Summer Period 2021 Avg. COG		\$0.4733 *							
13		LDAC	\$0.0472	\$60.24	\$28.94	\$18.74	\$16.40	\$19.94	\$33.22	\$177.48
14	TOTAL			\$1,128.82	\$657.94	\$504.54	\$469.33	\$522.51	\$722.38	\$4,005.53
	Base Rate Change	\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
		% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	COG Change	\$ Change	\$256.54	\$123.23	\$114.71	\$100.38	\$59.85	\$99.74	\$99.74	\$754.44
		% Change	29.90%	23.35%	29.77%	27.50%	13.07%	16.23%	16.23%	23.51%
	LDAC Change	\$ Change	\$14.42	\$6.93	\$4.49	\$3.93	\$4.77	\$7.95	\$7.95	\$42.49
		% Change	1.68%	1.31%	1.16%	1.08%	1.04%	1.29%	1.29%	1.32%
15				May	June	July	August	Sept	October	Summer
16	Typical Usage: therms			1,276	613	397	347	422	704	3,760
17	Summer 2020									
18	Customer Charge	units @	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84
19	All	units @	\$0.1895	\$241.86	\$116.18	\$75.24	\$65.84	\$80.04	\$133.38	\$712.54
20		COG 1	\$0.2723	\$347.54						\$347.54
21		COG 2	\$0.2723		\$166.95					\$166.95
22		COG 3	\$0.1844			\$73.22				\$73.22
23		COG 4	\$0.1844				\$64.07			\$64.07
24		COG 5	\$0.3316					\$140.05		\$140.05
25		COG 6	\$0.3316						\$233.40	\$233.40
26	Summer Period 2020 Avg. COG		\$0.2727 *							
27		LDAC	\$0.0359	\$45.82	\$22.01	\$14.25	\$12.47	\$15.16	\$25.27	\$134.99
28	TOTAL			\$857.86	\$527.78	\$385.35	\$365.03	\$457.89	\$614.69	\$3,208.60
29	Change			\$270.96	\$130.16	\$119.19	\$104.31	\$64.62	\$107.69	\$796.93
30	% Chg			31.59%	24.66%	30.93%	28.57%	14.11%	17.52%	24.84%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 7,858 therms/Summer

Comparison of Summer 2021 vs. Summer 2020

1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(1)			1,488	1,251	1,329	1,194	1,072	1,524	7,858
3	Summer 2021									
4	Customer Charge	units @	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84
5	First	1,000 units @	\$0.1337	\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$802.20
6	Over	1,000 units @	\$0.1087	\$53.01	\$27.25	\$35.76	\$21.09	\$7.84	\$56.99	\$201.93
7		COG 1	\$0.3943	\$586.58						\$586.58
8		COG 2	\$0.3943		\$493.14					\$493.14
9		COG 3	\$0.3943			\$524.00				\$524.00
10		COG 4	\$0.3943				\$470.80			\$470.80
11		COG 5	\$0.3943					\$422.73		\$422.73
12		COG 6	\$0.3943						\$601.02	\$601.02
13	Summer Period 2021 Avg. COG			\$0.3943	*					
14		LDAC	\$0.0472	\$70.22	\$59.03	\$62.73	\$56.36	\$50.60	\$71.95	\$370.88
15	TOTAL			\$1,066.14	\$935.76	\$978.83	\$904.58	\$837.51	\$1,086.30	\$5,809.12
Base Rate Change			\$ Change	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
			% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
COG Change			\$ Change	\$281.61	\$236.75	\$368.38	\$330.98	\$139.37	\$198.16	\$1,555.26
			% Change	36.68%	34.57%	61.87%	59.09%	20.32%	22.75%	37.34%
LDAC Change			\$ Change	\$16.81	\$14.13	\$15.02	\$13.49	\$12.11	\$17.22	\$88.79
			% Change	2.19%	2.06%	2.52%	2.41%	1.77%	1.98%	2.13%
16				May	June	July	August	Sept	October	Summer
17	Typical Usage: therms			1,488	1,251	1,329	1,194	1,072	1,524	7,858
18	Summer 2020									
19	Customer Charge	units @	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$222.64	\$1,335.84
20	First	1,000 units @	\$0.1337	\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$133.70	\$802.20
21	Over	1,000 units @	\$0.1087	\$53.01	\$27.25	\$35.76	\$21.09	\$7.84	\$56.99	\$201.93
22		COG 1	\$0.2050	\$304.97						\$304.97
23		COG 2	\$0.2050		\$256.39					\$256.39
24		COG 3	\$0.1171			\$155.62				\$155.62
25		COG 4	\$0.1171				\$139.82			\$139.82
26		COG 5	\$0.2643					\$283.36		\$283.36
27		COG 6	\$0.2643						\$402.87	\$402.87
28	Summer Period 2020 Avg. COG			\$0.1964	*					
29		LDAC	\$0.0359	\$53.41	\$44.90	\$47.71	\$42.86	\$38.49	\$54.72	\$282.09
30	TOTAL			\$767.72	\$684.88	\$595.43	\$560.11	\$686.02	\$870.92	\$4,165.07
31	Change			\$298.42	\$250.89	\$383.40	\$344.47	\$151.49	\$215.38	\$1,644.05
32	% Chg			38.87%	36.63%	64.39%	61.50%	22.08%	24.73%	39.47%

*-Note- Weighted by usage.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION
Impact of Rate Changes on Residential Heating Bills by Usage Level
Forecast Summer 2021 vs. Actual Summer 2020

Residential Heating		
	<u>Summer 2020</u>	<u>Summer 2021</u>
Customer Charge	\$22.20	\$22.20
First 50 Therms	\$0.6099	\$0.6099
Over 50 therms	\$0.6099	\$0.6099
LDAC	\$0.0706	\$0.1099
CGA	\$0.2351	\$0.4412

Usage (Therms)	Summer 2019 Bill Amount	Summer 2020 Bill Amount	Total Bill		Base Rate		COG		LDAC	
5	\$26.78	\$28.01	\$1.23	4.6%	\$0.00	0.0%	\$1.03	3.8%	\$0.20	0.7%
10	\$31.36	\$33.81	\$2.45	7.8%	\$0.00	0.0%	\$2.06	6.6%	\$0.39	1.2%
20	\$40.51	\$45.42	\$4.91	12.1%	\$0.00	0.0%	\$4.12	10.2%	\$0.79	2.0%
Monthly*	\$45.09	\$51.23	\$6.13	13.6%	\$0.00	0.0%	\$5.15	11.4%	\$0.98	2.2%
30	\$49.67	\$57.03	\$7.36	14.8%	\$0.00	0.0%	\$6.18	12.4%	\$1.18	2.4%
45	\$63.40	\$74.45	\$11.04	17.4%	\$0.00	0.0%	\$9.27	14.6%	\$1.77	2.8%
50	\$67.98	\$80.25	\$12.27	18.0%	\$0.00	0.0%	\$10.30	15.2%	\$1.97	2.9%
75	\$90.87	\$109.28	\$18.40	20.3%	\$0.00	0.0%	\$15.46	17.0%	\$2.95	3.2%
125	\$136.65	\$167.33	\$30.67	22.4%	\$0.00	0.0%	\$25.76	18.9%	\$4.91	3.6%
150	\$159.54	\$196.35	\$36.81	23.1%	\$0.00	0.0%	\$30.91	19.4%	\$5.90	3.7%
200	\$205.32	\$254.40	\$49.08	23.9%	\$0.00	0.0%	\$41.22	20.1%	\$7.86	3.8%

* Monthly amount for benchmarking purposes, does not represent the average monthly use of Northern's residential class.

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

Total Fixed Capacity Costs To Be Allocated

	NUI Total
Pipeline Demand	\$ 17,304,236
Storage Demand	\$ 23,261,749
On-system Peaking Demand	\$ 3,145,503
Subtotal Demand	\$ 43,711,488

Capacity Release (Credit)	\$ -
Asset Management (Credit)	\$ (8,074,404)
Total Net Demand Costs	\$ 35,637,084

Off-System Peaking Demand \$ 9,621,667 PR Allocation on Page 5

Total Demand Costs \$ 45,258,750

Proportional Responsibility (PR) Allocators

Allocation of Product and Pipeline Demand Costs (including Injections) to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Pipeline Sendout	1,224,769	1,252,887	1,252,886	1,246,859	1,497,106	1,116,363	730,195	489,319	423,088	442,673	508,970	866,778	11,051,893
Rank	5	2	3	4	1	6	8	10	12	11	9	7	
% Max Month	81.81%	83.69%	83.69%	83.28%	100.00%	74.57%	48.77%	32.68%	28.26%	29.57%	34.00%	57.90%	
PR	1.45%	0.00%	0.13%	0.37%	16.31%	2.78%	1.85%	0.31%	2.36%	0.12%	0.15%	1.30%	27.12%
CumPR	10.31%	10.81%	10.81%	10.68%	27.12%	8.86%	4.78%	2.79%	2.36%	2.47%	2.93%	6.08%	100.00%
Product and Pipeline Demand Costs	\$ 1,783,811	\$ 1,870,870	\$ 1,870,864	\$ 1,847,641	\$ 4,693,666	\$ 1,533,210	\$ 826,879	\$ 482,015	\$ 407,520	\$ 428,100	\$ 507,252	\$ 1,052,407	\$ 17,304,236

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Storage Injection Volume	-	-	-	-	-	-	-	-	-	-	-	-	-
Design Year Pipeline Sendout	1,224,769	1,252,887	1,252,886	1,246,859	1,497,106	1,116,363	730,195	489,319	423,088	442,673	508,970	866,778	11,051,893
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Storage	417,268	1,068,963	1,145,840	982,364	496,705	-	-	-	-	-	-	-	4,111,140
Rank	5	2	1	3	4	6	6	6	6	6	6	6	
% Max Month	36.42%	93.29%	100.00%	85.73%	43.35%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	7.28%	3.78%	6.71%	14.13%	1.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	33.63%
CumPR	7.28%	26.92%	33.63%	23.14%	9.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	\$ 1,694,195	\$ 6,262,846	\$ 7,823,525	\$ 5,383,824	\$ 2,097,360	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 23,261,749
Plus Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
TOTAL	\$ 1,694,195	\$ 6,262,846	\$ 7,823,525	\$ 5,383,824	\$ 2,097,360	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 23,261,749

Allocation of All Peaking Demand Costs Excluding Off-System Peaking

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	1,795	50,051	41,215	9,030	10,076	1,800	1,860	1,800	1,860	1,860	1,800	1,860	125,007
Rank	12	1	2	4	3	11	8	10	7	6	9	5	
% Max Month	3.59%	100.00%	82.34%	18.04%	20.13%	3.60%	3.72%	3.60%	3.72%	3.72%	3.60%	3.72%	
PR	0.30%	17.66%	31.11%	3.58%	0.70%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	53.35%
CumPR	0.30%	53.35%	35.70%	3.90%	4.59%	0.30%	0.31%	0.30%	0.31%	0.31%	0.30%	0.31%	100.00%
Peaking Demand Costs	\$ 9,401	\$ 1,678,273	\$ 1,122,925	\$ 122,556	\$ 144,459	\$ 9,429	\$ 9,901	\$ 9,429	\$ 9,901	\$ 9,901	\$ 9,429	\$ 9,901	\$ 3,145,503

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

Pipeline Demand	Schedule 20-FXW, PG 1, LN 1
Storage Demand	Schedule 20-FXW, PG 1, LN 2 & 3
<u>On-system Peaking Demand</u>	(Schedule 20-FXW, PG 1, LN 4 + 5) - LN 12
Subtotal Demand	Sum LN 3 : LN 5
Capacity Release (Credit)	Schedule FXW-20, PG 6
<u>Asset Management (Credit)</u>	Schedule FXW-20, PG 6
Total Net Demand Costs	Sum LN 6 : LN 9
Off-System Peaking Demand	Schedule FXW-20, PG 5
Total Demand Costs	LN 10 + LN 12

Proportional Responsibility (PR) Allocators

Allocation of Product and Pipeline Demand Costs (including Injections) to Months

Design Year Pipeline Sendout	Company Analysis
Rank	LN 20 Ranking
% Max Month	LN 20 / LN 20 MAX
PR	The difference between LN 22 for the month and LN 22 for next highest rank
CumPR	Cumulative Values, LN 23
Product and Pipeline Demand Costs	LN 24 * LN 3

Allocation of Storage Injection Fees to Months

Storage Injection Volume	Company Analysis
Design Year Pipeline Sendout	LN 20
% of Deliveries Injected	LN 29 / Sum (LN 29 : LN 30)
Injection Fees	LN 31 * LN 25

Allocation of Storage Demand Costs to Months

Design Year Storage	Company Analysis
Rank	LN 36 Ranking
% Max Month	LN 36 / LN 36 MAX
PR	The difference between LN 38 for the month and LN 38 for next highest rank
CumPR	Cumulative Values, LN 39
Storage Demand Costs	LN 40 * LN 4
Plus Injection Fees	LN 32
TOTAL	LN 41 + LN 42

Allocation of All Peaking Demand Costs Excluding Off-System Peaking

Design Year Peaking Volumes	Company Analysis
Rank	LN 47 Ranking
% Max Month	LN 47 / LN 47 MAX
PR	The difference between LN 49 for the month and LN 49 for next highest rank
CumPR	Cumulative Values, LN 50
Peaking Demand Costs	LN 51 * LN 5

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
Pipeline & Product Demand	\$ 1,783,811	\$ 1,870,870	\$ 1,870,864	\$ 1,847,641	\$ 4,693,666	\$ 1,533,210	\$ 826,879	\$ 482,015	\$ 407,520	\$ 428,100	\$ 507,252	\$ 1,052,407	\$ 17,304,236
Storage Incl Inj Fees	\$ 1,694,195	\$ 6,262,846	\$ 7,823,525	\$ 5,383,824	\$ 2,097,360	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 23,261,749
On-system Peaking	\$ 9,401	\$ 1,678,273	\$ 1,122,925	\$ 122,556	\$ 144,459	\$ 9,429	\$ 9,901	\$ 9,429	\$ 9,901	\$ 9,901	\$ 9,429	\$ 9,901	\$ 3,145,503
Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Less: Capacity Release	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Less: Asset Mgmt	\$ (1,345,734)	\$ (1,345,734)	\$ (1,345,734)	\$ (1,345,734)	\$ (1,345,734)	\$ (1,345,734)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (8,074,404)
Total Demand	\$ 2,141,673	\$ 8,466,255	\$ 9,471,580	\$ 6,008,286	\$ 5,589,751	\$ 196,906	\$ 836,780	\$ 491,444	\$ 417,421	\$ 438,000	\$ 516,681	\$ 1,062,308	\$ 35,637,084

Capacity Cost Allocator based on Design Year Firm Sendout

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
Therms													
Maine	970,397	1,432,432	1,623,320	1,399,774	1,200,683	695,176	428,509	285,862	241,624	257,015	290,717	515,450	9,340,959
New Hampshire	673,434	1,010,593	1,155,199	988,213	803,205	422,982	303,545	205,257	183,324	187,518	220,053	353,188	6,506,511
Total	1,643,831	2,443,026	2,778,519	2,387,987	2,003,887	1,118,157	732,055	491,119	424,948	444,533	510,770	868,638	15,847,470

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
Percentage of Total													
Maine	59.03%	58.63%	58.42%	58.62%	59.92%	62.17%	58.54%	58.21%	56.86%	57.82%	56.92%	59.34%	58.78%
New Hampshire	40.97%	41.37%	41.58%	41.38%	40.08%	37.83%	41.46%	41.79%	43.14%	42.18%	43.08%	40.66%	41.22%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Allocation of Demand Costs by Division

Maine	\$1,264,287	\$4,964,065	\$5,533,670	\$3,521,896	\$3,349,248	\$122,419	\$489,810	\$286,051	\$237,344	\$253,238	\$294,082	\$630,373	\$20,946,484
New Hampshire	\$877,386	\$3,502,190	\$3,937,910	\$2,486,391	\$2,240,502	\$74,486	\$346,970	\$205,393	\$180,077	\$184,762	\$222,600	\$431,935	\$14,690,600
Total	\$ 2,141,673	\$ 8,466,255	\$ 9,471,580	\$ 6,008,286	\$ 5,589,751	\$ 196,906	\$ 836,780	\$ 491,444	\$ 417,421	\$ 438,000	\$ 516,681	\$ 1,062,308	\$ 35,637,084

Detailed Allocation of Demand Costs by Division

Maine	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	
Pipeline & Product Demand	\$ 1,053,031	\$ 1,096,957	\$ 1,093,032	\$ 1,083,038	\$ 2,812,335	\$ 953,220	\$ 484,015	\$ 280,563	\$ 231,715	\$ 247,514	\$ 288,715	\$ 624,498	\$ 10,248,634	59.23%
Storage Incl Injection Fees	\$ 1,000,129	\$ 3,672,128	\$ 4,570,811	\$ 3,155,852	\$ 1,256,689	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 13,655,610	58.70%
On-system Peaking	\$ 5,549	\$ 984,031	\$ 656,057	\$ 71,839	\$ 86,556	\$ 5,862	\$ 5,795	\$ 5,488	\$ 5,629	\$ 5,724	\$ 5,367	\$ 5,875	\$ 1,843,774	58.62%
Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Capacity Release (Credit)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Asset Management (Credit)	\$ (794,423)	\$ (789,051)	\$ (786,231)	\$ (788,833)	\$ (806,332)	\$ (836,663)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (4,801,534)	59.47%
Total Allocated Demand	\$ 1,264,287	\$ 4,964,065	\$ 5,533,670	\$ 3,521,896	\$ 3,349,248	\$ 122,419	\$ 489,810	\$ 286,051	\$ 237,344	\$ 253,238	\$ 294,082	\$ 630,373	\$ 20,946,484	58.78%

New Hampshire	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	
Pipeline & Product Demand	\$ 730,780	\$ 773,913	\$ 777,832	\$ 764,604	\$ 1,881,331	\$ 579,990	\$ 342,864	\$ 201,452	\$ 175,806	\$ 180,586	\$ 218,537	\$ 427,909	\$ 7,055,602	40.77%
Storage Incl Injection Fees	\$ 694,067	\$ 2,590,717	\$ 3,252,713	\$ 2,227,971	\$ 840,671	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,606,139	41.30%
On-system Peaking	\$ 3,851	\$ 694,242	\$ 466,868	\$ 50,717	\$ 57,902	\$ 3,567	\$ 4,105	\$ 3,941	\$ 4,271	\$ 4,176	\$ 4,062	\$ 4,026	\$ 1,301,729	41.38%
Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Capacity Release	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Asset Management	\$ (551,311)	\$ (556,682)	\$ (559,503)	\$ (556,901)	\$ (539,402)	\$ (509,070)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (3,272,870)	40.53%
Total Allocated Demand	\$ 877,386	\$ 3,502,190	\$ 3,937,910	\$ 2,486,391	\$ 2,240,502	\$ 74,486	\$ 346,970	\$ 205,393	\$ 180,077	\$ 184,762	\$ 222,600	\$ 431,935	\$ 14,690,600	41.22%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

53		
54	Pipeline & Product Demand	LN 25
55	Storage	LN 43
56	Peaking	LN 52
57	Less: Injection Fees	-(LN 32)
58	Less: Capacity Release	-(LN 8 / 5)
59	Less: Asset Management	-(LN 9 / 6)
60	Total Demand	Sum (LN 54 : LN 59)
61		
62	Capacity Cost Allocator based on Design Year Firm Sendout	
63		
64	Therms	
65	Maine	Company Analysis
66	New Hampshire	Company Analysis
67	Total	LN 65 + LN 66
68		
69	Percentage of Total	
70	Maine	LN 65 / LN 67
71	New Hampshire	LN 66 / LN 67
72	Total	LN 70 + LN 71
73		
74	Allocation of Demand Costs by Division	
75	Maine	LN 60 * LN 70
76	New Hampshire	LN 60 * LN 71
77	Total	LN 75 + LN 76
78		
79	Detailed Allocation of Demand Costs by Division	
80	Maine	
81	Pipeline & Product Demand	LN 54 * LN 70
82	Storage	LN 55 * LN 70
83	Peaking	LN 56 * LN 70
84	Injection Fees	LN 57 * LN 70
85	Capacity Release (Credit)	LN 58 * LN 70
86	Asset Management (Credit)	LN 59 * LN 70
87	Total Allocated Demand	Sum (LN 81 : LN 86)
88		
89	New Hampshire	
90	Pipeline & Product Demand	LN 54 * LN 71
91	Storage	LN 55 * LN 71
92	Peaking	LN 56 * LN 71
93	Injection Fees	LN 57 * LN 71
94	Capacity Release	LN 58 * LN 71
95	Asset Management (Credit)	LN 59 * LN 71
96	Total Allocated Demand	Sum (LN 90 : LN 95)

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

97 **Off-System Peaking Demand Costs** \$ 9,621,667

98

99

Allocation of Off-system Peaking Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	-	71,125	338,579	149,734	-	-	-	-	-	-	-	-	559,438
Rank	4	3	1	2	4	4	4	4	4	4	4	4	
% Max Month	0.00%	21.01%	100.00%	44.22%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	7.00%	55.78%	11.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	74.39%
CumPR	0.00%	7.00%	74.39%	18.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Peaking Demand Costs	\$ -	\$ 673,742	\$ 7,157,244	\$ 1,790,682	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,621,667

107

Capacity Cost Allocator based on Design Year Sales

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
Therms													
Maine	788,728	1,172,256	1,329,620	1,139,227	980,037	561,673	338,637	220,772	185,065	196,409	219,374	398,451	7,530,248
New Hampshire	489,823	761,929	872,056	751,266	598,189	301,181	187,947	113,317	97,262	98,070	124,373	227,619	4,623,030
Total	1,278,551	1,934,184	2,201,676	1,890,493	1,578,225	862,854	526,584	334,089	282,327	294,479	343,746	626,070	12,153,278

114

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
Percentage of Total													
Maine	61.69%	60.61%	60.39%	60.26%	62.10%	65.09%	64.31%	66.08%	65.55%	66.70%	63.82%	63.64%	60.38%
New Hampshire	38.31%	39.39%	39.61%	39.74%	37.90%	34.91%	35.69%	33.92%	34.45%	33.30%	36.18%	36.36%	39.62%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

119

Allocation of Off-System Peaking Demand Costs by Division

Maine	\$0	\$408,336	\$4,322,350	\$1,079,080	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$5,809,767
New Hampshire	\$0	\$265,405	\$2,834,893	\$711,601	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$3,811,900
Total	\$ -	\$ 673,742	\$ 7,157,244	\$ 1,790,682	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,621,667

123

Total Weighted Average MPR Factor

Maine	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	
Total Pipeline, Storage & On-system	\$ 1,264,287	\$ 4,964,065	\$ 5,533,670	\$ 3,521,896	\$ 3,349,248	\$ 122,419	\$ 489,810	\$ 286,051	\$ 237,344	\$ 253,238	\$ 294,082	\$ 630,373	\$ 20,946,484	58.78%
Total Off-system Peaking	\$0	\$408,336	\$4,322,350	\$1,079,080	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$ 5,809,767	60.38%
Total Demand Cost Allocation	\$ 1,264,287	\$ 5,372,401	\$ 9,856,020	\$ 4,600,976	\$ 3,349,248	\$ 122,419	\$ 489,810	\$ 286,051	\$ 237,344	\$ 253,238	\$ 294,082	\$ 630,373	\$ 26,756,250	59.12%
New Hampshire	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	
Total Pipeline, Storage & On-system	\$ 877,386	\$ 3,502,190	\$ 3,937,910	\$ 2,486,391	\$ 2,240,502	\$ 74,486	\$ 346,970	\$ 205,393	\$ 180,077	\$ 184,762	\$ 222,600	\$ 431,935	\$ 14,690,600	41.22%
Total Off-system Peaking	\$0	\$265,405	\$2,834,893	\$711,601	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$ 3,811,900	39.62%
Total Demand Cost Allocation	\$ 877,386	\$ 3,767,595	\$ 6,772,803	\$ 3,197,992	\$ 2,240,502	\$ 74,486	\$ 346,970	\$ 205,393	\$ 180,077	\$ 184,762	\$ 222,600	\$ 431,935	\$ 18,502,500	40.88%
Total Northern	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	
Total Pipeline, Storage & On-system	\$ 2,141,673	\$ 8,466,255	\$ 9,471,580	\$ 6,008,286	\$ 5,589,751	\$ 196,906	\$ 836,780	\$ 491,444	\$ 417,421	\$ 438,000	\$ 516,681	\$ 1,062,308	\$ 35,637,084	
Total Off-system Peaking	\$ -	\$ 673,742	\$ 7,157,244	\$ 1,790,682	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,621,667	
Total Demand Cost Allocation	\$ 2,141,673	\$ 9,139,996	\$ 16,628,823	\$ 7,798,968	\$ 5,589,751	\$ 196,906	\$ 836,780	\$ 491,444	\$ 417,421	\$ 438,000	\$ 516,681	\$ 1,062,308	\$ 45,258,751	

97	Off-System Peaking Demand Costs	LN 12

98

99

Allocation of Off-system Peaking Demand Costs to Months

100		
101	Design Year Peaking Volumes	Company Analysis
102	Rank	LN 101 Ranking
103	% Max Month	LN 101 / LN 101 MAX
104	PR	The difference between LN 103 for the month and LN 103 for next highest rank
105	CumPR	Cumulative Values, LN 104
106	Peaking Demand Costs	LN 105 * LN 97

107

108

Capacity Cost Allocator based on Design Year Sales

109		
110	Therms	
111	Maine	Company Analysis
112	New Hampshire	Company Analysis
113	Total	LN 111 + LN 112

114

115	Percentage of Total	
116	Maine	LN 111 / LN 113
117	New Hampshire	LN 112 / LN 113
118	Total	LN 116 + LN 117

119

120	Allocation of Off-System Peaking Demand Costs by Division	
121	Maine	LN 106 * LN 116
122	New Hampshire	LN 106 * LN 117
123	Total	LN 121 + LN 122

Total Weighted Average MPR Factor

124	Maine	
125	Total Pipeline, Storage & On-system	LN 87
126	Total Off-system Peaking	LN 121
127	Total Demand Cost Allocation	LN 125 + LN 126

128

129	New Hampshire	
130	Total Pipeline, Storage & On-system	LN 96
131	Total Off-system Peaking	LN 122
132	Total Demand Cost Allocation	LN 130 + Ln 131

133

134	Total Northern	
135	Total Pipeline, Storage & On-system	LN 125 + LN 130
136	Total Off-system Peaking	LN 126 + LN 131
137	Total Demand Cost Allocation	LN 127 + LN 132

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH Division Total Annual Demand Cost Allocation

1	Resource	Costs
2	Pipeline & Product Demand	\$ 7,055,602
3	Storage	\$ 9,606,139
4	On-system Peaking	\$ 1,301,729
5	Total Gross Demand Cost	\$ 17,963,470
6		
7	Capacity Assignment Demand Revenue Estimate	\$ 4,419,945
8	NH Total Pipeline, Storage & Peaking Demand Cost	\$ 17,963,470
9	Capacity Assignment as % of Total Gross Demand Cost	24.61%
10		
11		Costs
12	Pipeline & Product Demand	\$ 1,736,044
13	Storage	\$ 2,363,608
14	On-system Peaking	\$ 320,293
15	Total Capacity Assignment Credit	\$ 4,419,945
16		
17	NH Net Annual Demand Cost (Less Capacity Assignment)	
18		Costs
19	Pipeline & Product Demand	\$ 5,319,558
20	Storage	\$ 7,242,531
21	On-system Peaking	\$ 981,436
22	Total Net Demand Cost (Less Capacity Assignment)	\$ 13,543,525

DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS

25		MMBtu/day
26	Pipeline MDQ	16,548
27	Less 24.61% NH Transp. Capacity Assignment	(4,072)
28	Net Pipeline MDQ	12,477
29		
30	Net Pipeline MDQ	12,477
31	Less: Firm Sales Base Use	3,176
32	Remaining Pipeline MDQ	9,300
33		
34		Unit Cost
35	Pipeline Unit Cost	\$426.36
36		
37		Costs
38	Pipeline & Product Demand	\$ 5,319,558
39	Less: Base Pipeline Use	\$ 1,354,234
40	Remaining Pipeline Use	\$ 3,965,324

1	Resource	
2	Pipeline & Product Demand	Schedule 4-CAK, LN 90 + Schedule 4-CAK, LN 93
3	Storage	Schedule 4-CAK, LN 91
4	On-system Peaking	Schedule 4-CAK, LN 92
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Schedule 21-FXW, Page 1
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11		
12	Pipeline & Product Demand	LN 2 * LN 9
13	Storage	LN 3 * LN 9
14	On-system Peaking	LN 4 * LN 9
15	Total Capacity Assignment Credit	Sum (LN 12 : LN 14)
16		
17	NH Net Annual Demand Cost (Less Capacity Assignment)	
18		
19	Pipeline & Product Demand	LN 2 - LN 12
20	Storage	LN 3 - LN 13
21	On-system Peaking	LN 4 - LN 14
22	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 15
23		
24	DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND (	
25		
26	Pipeline MDQ	Company Analysis
27	Less 24.61% NH Transp. Capacity Assignment	-(LN 26) * LN 9
28	Net Pipeline MDQ	Sum (LN 26 : LN 27)
29		
30	Net Pipeline MDQ	LN 28
31	Less: Firm Sales Base Use	Schedule 6-CAK, LN 48 / 10
32	Remaining Pipeline MDQ	LN 30 - LN 31
33		
34		
35	Pipeline Unit Cost	LN 19 / LN 30
36		
37		
38	Pipeline & Product Demand	LN 19
39	Less: Base Pipeline Use	LN 35 * LN 31
40	Remaining Pipeline Use	LN 38 - LN 39

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

41 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**

42 (Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)

44 All Months	Nov	Dec	Jan	Feb	Mar	Apr
45 Remaining Load for All Months	3,659,596	5,722,698	7,005,839	5,903,964	4,894,132	2,432,845
46 Rank	5	3	1	2	4	6
47 % Max Month	52.24%	81.68%	100.00%	84.27%	69.86%	34.73%
48 PR	3.50%	3.94%	15.73%	1.29%	4.41%	2.83%
49 CumPR	8.61%	16.96%	33.98%	18.26%	13.02%	5.11%

51 Peak Months Only	Nov	Dec	Jan	Feb	Mar	Apr
52 Remaining Load for Peak Months Only	3,659,596	5,722,698	7,005,839	5,903,964	4,894,132	2,432,845
53 Rank	5	3	1	2	4	6
54 % Max Month	52.24%	81.68%	100.00%	84.27%	69.86%	34.73%
55 PR	3.50%	3.94%	15.73%	1.29%	4.41%	5.79%
56 CumPR	9.29%	17.64%	34.66%	18.93%	13.70%	5.79%

57 **DEMAND COST PR ALLOCATORS**

59	Nov	Dec	Jan	Feb	Mar	Apr
60 Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
61 Pipeline - Remaining	8.61%	16.96%	33.98%	18.26%	13.02%	5.11%
62 Storage & Peaking	8.61%	16.96%	33.98%	18.26%	13.02%	5.11%
63 Capacity Release	9.29%	17.64%	34.66%	18.93%	13.70%	5.79%
64 Off-system Peaking	9.29%	17.64%	34.66%	18.93%	13.70%	5.79%
65 Interr. Margins & Off Sys Sales	9.29%	17.64%	34.66%	18.93%	13.70%	5.79%

66 **DEMAND COSTS ALLOCATED TO MONTHS**

68	Nov	Dec	Jan	Feb	Mar	Apr
69 Pipeline - Base	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853
70 Pipeline - Remaining	\$ 341,611	\$ 672,623	\$ 1,347,586	\$ 723,921	\$ 516,299	\$ 202,743
71 Total Pipeline	\$ 454,464	\$ 785,476	\$ 1,460,438	\$ 836,774	\$ 629,152	\$ 315,596
72						
73 Storage & On-system Peaking	\$ 708,492	\$ 1,395,000	\$ 2,794,854	\$ 1,501,392	\$ 1,070,790	\$ 420,482
74 Off-system Peaking	\$354,116	\$672,320	\$1,321,167	\$721,633	\$522,045	\$220,620
75 CNG Expense	\$ 10,309	\$ 20,298	\$ 40,667	\$ 21,847	\$ 15,581	\$ 6,118
76 Less Credits to Demand Cost						
77 Cap Rel Margins & Asset Mgt Credits	\$ 304,041	\$ 577,249	\$ 1,134,345	\$ 619,589	\$ 448,224	\$ 189,423
78 Interruptible Margins	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
79 Conversion Rate and Re-entry Rate Credits	\$ 464	\$ 882	\$ 1,733	\$ 947	\$ 685	\$ 289
80 Total Direct Demand Costs	\$ 1,222,876	\$ 2,294,963	\$ 4,481,049	\$ 2,461,110	\$ 1,788,659	\$ 773,104

81	
82 Indirect Demand Costs/(Credits)	
83 Miscellaneous Overhead	
84 Local Production & Storage	
85 Subtotal	

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

41 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /ALLOCATORS)**

42 (Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)

43		May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
44	All Months									
45	Remaining Load for All Months	747,254	206,402	0	7,319	127,084	1,242,537	31,949,670	29,619,074	2,330,596
46	Rank	8	9	12	11	10	7			
47	% Max Month	10.67%	2.95%	0.00%	0.10%	1.81%	17.74%			
48	PR	0.97%	0.13%	0.00%	0.01%	0.17%	1.01%	33.98%		
49	CumPR	1.27%	0.31%	0.00%	0.01%	0.18%	2.28%	100.00%	95.95%	4.05%

50		Annual	Winter	Summer
51	Peak Months Only			
52	Remaining Load for Peak Months Only	29,619,074	29,619,074	
53	Rank			
54	% Max Month			
55	PR	34.66%		
56	CumPR	100.00%	100.00%	0.00%

57 **DEMAND COST PR ALLOCATORS**

58		May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
59										
60	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
61	Pipeline - Remaining	1.27%	0.31%	0.00%	0.01%	0.18%	2.28%	100.00%	95.95%	4.05%
62	Storage & Peaking	1.27%	0.31%	0.00%	0.01%	0.18%	2.28%	100.00%	95.95%	4.05%
63	Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
64	Off-system Peaking	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

66 **DEMAND COSTS ALLOCATED TO MONTHS**

67		May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer	Winter	Summer
68												
69	Pipeline - Base	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 1,354,234	\$ 677,117	\$ 677,117	50.00%	50.00%
70	Pipeline - Remaining	\$ 50,409	\$ 12,144	\$ -	\$ 377	\$ 7,155	\$ 90,456	\$ 3,965,324	\$ 3,804,783	\$ 160,541	95.95%	4.05%
71	Total Pipeline	\$ 163,262	\$ 124,996	\$ 112,853	\$ 113,229	\$ 120,008	\$ 203,309	\$ 5,319,558	\$ 4,481,900	\$ 837,658	84.25%	15.75%
72												
73	Storage & On-system Peaking	\$ 104,547	\$ 25,185	\$ -	\$ 781	\$ 14,840	\$ 187,604	\$ 8,223,967	\$ 7,891,010	\$ 332,957	95.95%	4.05%
74	Off-system Peaking	\$0	\$0	\$0	\$0	\$0	\$0	\$ 3,811,900	\$ 3,811,900	\$ -	100.00%	0.00%
75	CNG Expense	\$ 1,521	\$ 366	\$ -	\$ 11	\$ 216	\$ 2,730	\$ 119,666	\$ 114,821	\$ 4,845		
76	Less Credits to Demand Cost											
77	Cap Rel Margins & Asset Mgt Credits	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$3,272,870	\$ 3,272,870	\$ -	100.00%	0.00%
78	Interruptible Margins	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
79	Conversion Rate and Re-entry Rate Credits	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,000	\$ 5,000	\$ -		
80	Total Direct Demand Costs	\$ 269,330	\$ 150,548	\$ 112,853	\$ 114,022	\$ 135,064	\$ 393,643	\$ 14,197,221	\$ 13,021,761	\$ 1,175,460	91.72%	8.28%

81												
82	Indirect Demand Costs/(Credits)											
83	Miscellaneous Overhead							\$ 580,455	\$ 471,532	\$ 108,923	81.23%	18.77%
84	Local Production & Storage							\$ 476,106	\$ 476,106	\$ -	100.00%	0.00%
85	Subtotal							\$ 1,056,561	\$ 947,638	\$ 108,923	89.69%	10.31%

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

41 **NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /ALLOCATORS)**

42 (Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)

43		
44	All Months	
45	Remaining Load for All Months	Schedule 6-CAK, LN 80
46	Rank	Rank LN 45
47	% Max Month	LN 45 / MAX Month LN 45
48	PR	The difference between LN 47 for the month and LN 47 for next highest rank
49	CumPR	Cumulative Values, LN 48

50		
51	Peak Months Only	
52	Remaining Load for Peak Months Only	LN 45
53	Rank	Rank LN 52
54	% Max Month	LN 52 / MAX Month LN 52
55	PR	The difference between LN 54 for the month and LN 54 for next highest rank
56	CumPR	Cumulative Values, LN 55

57		
58	DEMAND COST PR ALLOCATORS	
59		
60	Pipeline - Base	1/12
61	Pipeline - Remaining	LN 49
62	Storage & Peaking	LN 49
63	Capacity Release	LN 56
64	Off-system Peaking	LN 56
65	Interr. Margins & Off Sys Sales	LN 56

66		
67	DEMAND COSTS ALLOCATED TO MONTHS	
68		
69	Pipeline - Base	LN 39 * LN 60
70	Pipeline - Remaining	LN 40 * LN 61
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & On-system Peaking	LN 62 * (Sum LN 20 : LN 21)
74	Off-system Peaking	Schedule 4-CAK, LN 122,* LN 64
75	CNG Expense	
76	Less Credits to Demand Cost	
77	Cap Rel Margins & Asset Mgt Credits	Schedule 4-CAK, LN 95 * LN 63
78	Interruptible Margins	
79	Conversion Rate and Re-entry Rate Credits	Company Analysis
80	Total Direct Demand Costs	LN 71 + LN 73 + LN 74 - (Sum LN 76 : LN 79)

81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

**Northern Utilities - NEW HAMPSHIRE DIVISION
2020 - 2021 Period**

Forecasted Normal Sales By Class- Therms																
Calendar Month Firm Sales Volumes																
Line No.		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
1	Normal Winter															
2	Res Heat	2,155,744	3,134,826	3,734,531	3,175,010	2,747,578	1,577,689	714,418	478,211	403,153	409,190	445,492	918,725	19,894,567	16,525,377	3,369,189
3	Res General	20,981	30,510	36,347	30,902	26,741	15,355	16,503	11,047	9,313	9,453	10,291	21,223	238,668	160,837	77,830
4	Total Residential	2,176,725	3,165,337	3,770,878	3,205,911	2,774,319	1,593,044	730,922	489,258	412,466	418,643	455,783	939,948	20,133,234	16,686,215	3,447,020
5	G50 Low Annual-Low Winter	87,827	127,715	152,148	129,352	111,938	64,276	109,003	72,964	61,512	62,433	67,972	140,176	1,187,315	673,256	514,059
6	G40 Low Annual-High Winter	998,430	1,451,890	1,729,643	1,470,501	1,272,537	730,704	269,791	180,590	152,245	154,526	168,234	346,945	8,926,038	7,653,706	1,272,332
7	G51 Med Annual-Low Winter	142,064	206,586	246,107	209,234	181,066	103,970	192,270	128,700	108,500	110,125	119,894	247,255	1,995,772	1,089,028	906,744
8	G41 Med Annual-High Winter	899,058	1,307,386	1,557,494	1,324,144	1,145,883	657,978	261,437	174,998	147,531	149,741	163,025	336,201	8,124,875	6,891,943	1,232,933
9	G52 High Annual-Low Winter	67,238	97,775	116,480	99,029	85,697	49,208	104,200	69,748	58,801	59,682	64,976	133,999	1,006,833	515,427	491,406
10	G42 High Annual-High Winter	181,044	263,270	313,634	266,644	230,748	132,498	41,713	27,921	23,539	23,891	26,011	53,641	1,584,553	1,387,837	196,716
11	Total C&I	2,375,660	3,454,622	4,115,505	3,498,905	3,027,869	1,738,635	978,414	654,922	552,128	560,397	610,112	1,258,218	22,825,387	18,211,197	4,614,190
12	Total Sales	4,552,386	6,619,959	7,886,383	6,704,817	5,802,188	3,331,679	1,709,335	1,144,180	964,593	979,040	1,065,895	2,198,166	42,958,621	34,897,412	8,061,210
13																
14	Residential Heat & Non Heat	2,176,725	3,165,337	3,770,878	3,205,911	2,774,319	1,593,044	730,922	489,258	412,466	418,643	455,783	939,948	20,133,234	16,686,215	3,447,020
15	SALES HLF CLASSES	297,129	432,077	514,735	437,615	378,702	217,455	405,473	271,412	228,812	232,239	252,842	521,430	4,189,921	2,277,711	1,912,209
16	SALES LLF CLASSES	2,078,532	3,022,546	3,600,771	3,061,290	2,649,167	1,521,181	572,940	383,510	323,315	328,157	357,270	736,788	18,635,467	15,933,486	2,701,981
17	Total Firm Sales	4,552,386	6,619,959	7,886,383	6,704,817	5,802,188	3,331,679	1,709,335	1,144,180	964,593	979,040	1,065,895	2,198,166	42,958,621	34,897,412	8,061,210
18																
19	ESTIMATED SENDOUT BY CLASS - Therms															
20	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)															
21	Normal Winter															
22	Res Heat	2,184,200	3,176,206	3,783,827	3,216,920	2,783,846	1,598,514	723,848	484,523	408,474	414,592	451,372	930,852	20,157,175	16,743,512	3,413,663
23	Res General	21,258	30,913	36,827	31,309	27,094	15,558	16,721	11,193	9,436	9,577	10,427	21,503	241,818	162,960	78,858
24	G50 Low Annual-Low Winter	88,986	129,401	154,156	131,060	113,416	65,125	110,442	73,927	62,324	63,257	68,869	142,026	1,202,988	682,143	520,845
25	G40 Low Annual-High Winter	1,011,609	1,471,055	1,752,474	1,489,912	1,289,334	740,350	273,352	182,974	154,255	156,565	170,455	351,525	9,043,861	7,754,735	1,289,127
26	G51 Med Annual-Low Winter	143,940	209,313	249,355	211,996	183,456	105,343	194,808	130,399	109,932	111,578	121,477	250,519	2,022,116	1,103,403	918,713
27	G41 Med Annual-High Winter	910,925	1,324,643	1,578,053	1,341,623	1,161,009	666,664	264,888	177,308	149,478	151,717	165,177	340,639	8,232,124	6,982,916	1,249,207
28	G52 High Annual-Low Winter	68,125	99,066	118,018	100,336	86,828	49,858	105,575	70,669	59,577	60,469	65,834	135,767	1,020,123	522,231	497,892
29	G42 High Annual-High Winter	183,434	266,745	317,774	270,164	233,793	134,247	42,263	28,290	23,850	24,207	26,354	54,350	1,605,470	1,406,157	199,313
30	Subtotal															
31	Residential	2,205,458	3,207,119	3,820,654	3,248,229	2,810,940	1,614,072	740,570	495,716	417,910	424,169	461,799	952,356	20,398,993	16,906,473	3,492,520
32	SALES HLF CLASSES	301,051	437,780	521,529	443,392	383,701	220,325	410,826	274,995	231,833	235,305	256,180	528,312	4,245,227	2,307,777	1,937,450
33	SALES LLF CLASSES	2,105,968	3,062,443	3,648,301	3,101,699	2,684,136	1,541,260	580,503	388,572	327,583	332,489	361,986	746,514	18,881,455	16,143,808	2,737,647
34	Total Firm Sales	4,612,477	6,707,343	7,990,484	6,793,320	5,878,777	3,375,658	1,731,899	1,159,283	977,326	991,963	1,079,965	2,227,182	43,525,675	35,358,058	8,167,618

Northern Utilities - NEW HAMPSHIRE DIVISION
2020 - 2021 Period

Line No.	Forecasted Normal Sales By Class- Therms	
	Calendar Month Firm Sales Volumes	
	Firm Sales	
1	Res Heat	(Schedule 17-FXW, Page 1) * 10
2	Res General	(Schedule 17-FXW, Page 1) * 10
3	Total Residential	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	(Schedule 17-FXW, Page 1) * 10
5	G40 Low Annual-High Winter	(Schedule 17-FXW, Page 1) * 10
6	G51 Med Annual-Low Winter	(Schedule 17-FXW, Page 1) * 10
7	G41 Med Annual-High Winter	(Schedule 17-FXW, Page 1) * 10
8	G52 High Annual-Low Winter	(Schedule 17-FXW, Page 1) * 10
9	G42 High Annual-High Winter	(Schedule 17-FXW, Page 1) * 10
10	Total C&I	Sum LN 4 : LN 9
11	Total Sales	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	Total Firm Sales	Sum LN 13 : LN 15
17		
18	ESTIMATED SENDOUT BY CLASS - Therms	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	
20	Normal Winter	Unaccounted For)
21	Res Heat	LN 1 x Adj factor (Schedule 17-FXW, Page 3)
22	Res General	LN 2 x Adj factor (Schedule 17-FXW, Page 3)
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Schedule 17-FXW, Page 3)
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Schedule 17-FXW, Page 3)
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Schedule 17-FXW, Page 3)
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Schedule 17-FXW, Page 3)
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Schedule 17-FXW, Page 3)
28	G42 High Annual-High Winter	LN 9 x Adj factor (Schedule 17-FXW, Page 3)
29	Subtotal	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	Total Firm Sales	Sum LN 30 : LN 32

Sendout by Class - Allocation between Base & Remaining Sendout

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Northern Utilities - NEW HAMPSHIRE DIVISION

Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	DAILY BASE GAS ENTITLEMENT - Therms/day	
36	Res Heat	Avg (LN 21 Jul : LN 21 Aug) / 31 days
37	Res General	Avg (LN 22 Jul : LN 22 Aug) / 31 days
38	G50 Low Annual-Low Winter	Avg (LN 23 Jul : LN 23 Aug) / 31 days
39	G40 Low Annual-High Winter	Avg (LN 24 Jul : LN 24 Aug) / 31 days
40	G51 Med Annual-Low Winter	Avg (LN 25 Jul : LN 25 Aug) / 31 days
41	G41 Med Annual-High Winter	Avg (LN 26 Jul : LN 26 Aug) / 31 days
42	G52 High Annual-Low Winter	Avg (LN 27 Jul : LN 27 Aug) / 31 days
43	G42 High Annual-High Winter	Avg (LN 28 Jul : LN 28 Aug) / 31 days
44	Subtotal	
45	Residential	LN 36 + LN 37
46	SALES HLF CLASSES	LN 38 + LN 40 + LN 42
47	SALES LLF CLASSES	LN 39 + LN 41 + LN 43
48	Total Firm Sales	Sum LN 45 : LN 47
49	BASE SENDOUT BY CLASS - Therms	
50	Days per Month	
51		
52	Res Heat	MIN(LN 36 * LN 50, LN 21)
53	Res General	MIN(LN 37 * LN 50, LN 22)
54	G50 Low Annual-Low Winter	MIN(LN 38 * LN 50, LN 23)
55	G40 Low Annual-High Winter	MIN(LN 39 * LN 50, LN 24)
56	G51 Med Annual-Low Winter	MIN(LN 40 * LN 50, LN 25)
57	G41 Med Annual-High Winter	MIN(LN 41 * LN 50, LN 26)
58	G52 High Annual-Low Winter	MIN(LN 42 * LN 50, LN 27)
59	G42 High Annual-High Winter	MIN(LN 43 * LN 50, LN 28)
60	Subtotal	
61	Residential	LN 52 + LN 53
62	SALES HLF CLASSES	LN 54 + LN 56 + LN 58
63	SALES LLF CLASSES	LN 55 + LN 57 + LN 59
64	Total Firm Sales	Sum LN 61 : LN 63
65		
66	REMAINING SENDOUT BY CLASS - Therms	
67		
68	Res Heat	LN 21 - LN 52
69	Res General	LN 22 - LN 53
70	G50 Low Annual-Low Winter	LN 23 - LN 54
71	G40 Low Annual-High Winter	LN 24 - LN 55
72	G51 Med Annual-Low Winter	LN 25 - LN 56
73	G41 Med Annual-High Winter	LN 26 - LN 57
74	G52 High Annual-Low Winter	LN 27 - LN 58
75	G42 High Annual-High Winter	LN 28 - LN 59
76	Subtotal	
77	Residential	LN 68 + LN 69
78	SALES HLF CLASSES	LN 70 + LN 72 + LN 74
79	SALES LLF CLASSES	LN 71 + LN 73 + LN 75
80	Total Firm Sales	Sum LN 77 : LN 79

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

Base Capacity Costs

1	BASE SENDOUT BY CLASS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
2	Total Therms															
3	Res Heat	398,258	411,533	411,533	371,707	411,533	398,258	411,533	398,258	408,474	411,533	398,258	411,533	4,842,409	2,402,821	2,439,588
4	Res General	9,200	9,507	9,507	8,587	9,507	9,200	9,507	9,200	9,436	9,507	9,200	9,507	111,863	55,507	56,356
5	G50 Low Annual-Low Winter	60,765	62,790	62,790	56,714	62,790	60,765	62,790	60,765	62,324	62,790	60,765	62,790	738,838	366,614	372,224
6	G40 Low Annual-High Winter	150,397	155,410	155,410	140,371	155,410	150,397	155,410	150,397	154,255	155,410	150,397	155,410	1,828,675	907,395	921,280
7	G51 Med Annual-Low Winter	107,182	110,755	110,755	100,037	110,755	105,343	110,755	107,182	109,932	110,755	107,182	110,755	1,301,390	644,827	656,562
8	G41 Med Annual-High Winter	145,740	150,598	150,598	136,024	150,598	145,740	150,598	145,740	149,478	150,598	145,740	150,598	1,772,048	879,297	892,751
9	G52 High Annual-Low Winter	58,087	60,023	60,023	54,215	60,023	49,858	60,023	58,087	59,577	60,023	58,087	60,023	698,050	342,229	355,821
10	G42 High Annual-High Winter	23,253	24,028	24,028	21,703	24,028	23,253	24,028	23,253	23,850	24,028	23,253	24,028	282,733	140,293	142,440
11	Total Firm Sales	952,882	984,644	984,644	889,356	984,644	942,813	984,644	952,882	977,326	984,644	952,882	984,644	11,576,005	5,738,983	5,837,022
12																
13	% of Total															
14	Res Heat	41.80%	41.80%	41.80%	41.80%	41.80%	42.24%	41.80%	41.80%	41.80%	41.80%	41.80%	41.80%	41.80%		
15	Res General	0.97%	0.97%	0.97%	0.97%	0.97%	0.98%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%		
16	G50 Low Annual-Low Winter	6.38%	6.38%	6.38%	6.38%	6.38%	6.45%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%		
17	G40 Low Annual-High Winter	15.78%	15.78%	15.78%	15.78%	15.78%	15.95%	15.78%	15.78%	15.78%	15.78%	15.78%	15.78%	15.78%		
18	G51 Med Annual-Low Winter	11.25%	11.25%	11.25%	11.25%	11.25%	11.17%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%		
19	G41 Med Annual-High Winter	15.29%	15.29%	15.29%	15.29%	15.29%	15.46%	15.29%	15.29%	15.29%	15.29%	15.29%	15.29%	15.29%		
20	G52 High Annual-Low Winter	6.10%	6.10%	6.10%	6.10%	6.10%	5.29%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%		
21	G42 High Annual-High Winter	2.44%	2.44%	2.44%	2.44%	2.44%	2.47%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%		
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			
23																
24	PIPELINE BASE DEMAND COSTS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
25	TOTAL PIPELINE BASE DEMAND COST	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 112,853	\$ 1,354,234	\$ 677,117	\$ 677,117
26	Res Heat	\$ 47,167	\$ 47,167	\$ 47,167	\$ 47,167	\$ 47,167	\$ 47,671	\$ 47,167	\$ 47,167	\$ 47,167	\$ 47,167	\$ 47,167	\$ 47,167	\$ 566,507	\$ 283,505	\$ 283,002
27	Res General	\$ 1,090	\$ 1,090	\$ 1,090	\$ 1,090	\$ 1,090	\$ 1,101	\$ 1,090	\$ 1,090	\$ 1,090	\$ 1,090	\$ 1,090	\$ 1,090	\$ 13,087	\$ 6,549	\$ 6,538
28	G50 Low Annual-Low Winter	\$ 7,197	\$ 7,197	\$ 7,197	\$ 7,197	\$ 7,197	\$ 7,273	\$ 7,197	\$ 7,197	\$ 7,197	\$ 7,197	\$ 7,197	\$ 7,197	\$ 86,436	\$ 43,256	\$ 43,179
29	G40 Low Annual-High Winter	\$ 17,812	\$ 17,812	\$ 17,812	\$ 17,812	\$ 17,812	\$ 18,002	\$ 17,812	\$ 17,812	\$ 17,812	\$ 17,812	\$ 17,812	\$ 17,812	\$ 213,934	\$ 107,062	\$ 106,872
30	G51 Med Annual-Low Winter	\$ 12,694	\$ 12,694	\$ 12,694	\$ 12,694	\$ 12,694	\$ 12,609	\$ 12,694	\$ 12,694	\$ 12,694	\$ 12,694	\$ 12,694	\$ 12,694	\$ 152,243	\$ 76,079	\$ 76,164
31	G41 Med Annual-High Winter	\$ 17,260	\$ 17,260	\$ 17,260	\$ 17,260	\$ 17,260	\$ 17,445	\$ 17,260	\$ 17,260	\$ 17,260	\$ 17,260	\$ 17,260	\$ 17,260	\$ 207,310	\$ 103,747	\$ 103,563
32	G52 High Annual-Low Winter	\$ 6,879	\$ 6,879	\$ 6,879	\$ 6,879	\$ 6,879	\$ 5,968	\$ 6,879	\$ 6,879	\$ 6,879	\$ 6,879	\$ 6,879	\$ 6,879	\$ 81,642	\$ 40,365	\$ 41,277
33	G42 High Annual-High Winter	\$ 2,754	\$ 2,754	\$ 2,754	\$ 2,754	\$ 2,754	\$ 2,783	\$ 2,754	\$ 2,754	\$ 2,754	\$ 2,754	\$ 2,754	\$ 2,754	\$ 33,077	\$ 16,553	\$ 16,524
34																
35	Residential	\$ 48,257	\$ 48,257	\$ 48,257	\$ 48,257	\$ 48,257	\$ 48,772	\$ 48,257	\$ 48,257	\$ 48,257	\$ 48,257	\$ 48,257	\$ 48,257	\$ 579,594	\$ 290,055	\$ 289,539
36	SALES HLF CLASSES	\$ 26,770	\$ 26,770	\$ 26,770	\$ 26,770	\$ 26,770	\$ 25,851	\$ 26,770	\$ 26,770	\$ 26,770	\$ 26,770	\$ 26,770	\$ 26,770	\$ 320,320	\$ 159,700	\$ 160,620
37	SALES LLF CLASSES	\$ 37,826	\$ 37,826	\$ 37,826	\$ 37,826	\$ 37,826	\$ 38,230	\$ 37,826	\$ 37,826	\$ 37,826	\$ 37,826	\$ 37,826	\$ 37,826	\$ 454,320	\$ 227,362	\$ 226,958

**Northern Utilities - NEW HAMPSHIRE
Allocation of Demand Costs to Customers**

Base Capacity Costs

1	BASE SENDOUT BY CLASS	
2	Total Therms	
3	Res Heat	Schedule 6-CAK, LN 52
4	Res General	Schedule 6-CAK, LN 53
5	G50 Low Annual-Low Winter	Schedule 6-CAK, LN 54
6	G40 Low Annual-High Winter	Schedule 6-CAK, LN 55
7	G51 Med Annual-Low Winter	Schedule 6-CAK, LN 56
8	G41 Med Annual-High Winter	Schedule 6-CAK, LN 57
9	G52 High Annual-Low Winter	Schedule 6-CAK, LN 58
10	G42 High Annual-High Winter	Schedule 6-CAK, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12		
13	% of Total	
14	Res Heat	LN 3 / LN 11
15	Res General	LN 4 / LN 11
16	G50 Low Annual-Low Winter	LN 5 / LN 11
17	G40 Low Annual-High Winter	LN 6 / LN 11
18	G51 Med Annual-Low Winter	LN 7 / LN 11
19	G41 Med Annual-High Winter	LN 8 / LN 11
20	G52 High Annual-Low Winter	LN 9 / LN 11
21	G42 High Annual-High Winter	LN 10 / LN 11
22	Total Firm Sales	LN 11 / LN 11
23		
24	PIPELINE BASE DEMAND COSTS	
25	TOTAL PIPELINE BASE DEMAND COST	Schedule 5-CAK, LN 69
26	Res Heat	LN 25 * LN 14
27	Res General	LN 25 * LN 15
28	G50 Low Annual-Low Winter	LN 25 * LN 16
29	G40 Low Annual-High Winter	LN 25 * LN 17
30	G51 Med Annual-Low Winter	LN 25 * LN 18
31	G41 Med Annual-High Winter	LN 25 * LN 19
32	G52 High Annual-Low Winter	LN 25 * LN 20
33	G42 High Annual-High Winter	LN 25 * LN 21
34		
35	Residential	LN 26 + LN 27
36	SALES HLF CLASSES	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	LN 29 + LN 31 + LN 33
38		

Remaining Capacity Costs

	Column A	Column B	Column C	Column D
	Design Day Demand (MMBtu)	Avg Daily Base Use Load (MMBtu)	Remaining Design Day Demand (MMBtu)	% of Total Remaining Design Day Demand
Res Heat	23,486	1,327	22,158	50.39%
Res General	229	31	198	0.45%
G50 Low Annual-Low Winter	659	203	457	1.04%
G40 Low Annual-High Winter	10,113	501	9,612	21.86%
G51 Med Annual-Low Winter	1,108	357	751	1.71%
G41 Med Annual-High Winter	9,205	486	8,720	19.83%
G52 High Annual-Low Winter	559	194	365	0.83%
G42 High Annual-High Winter	1,795	78	1,717	3.90%
TOTAL	47,154	3,177	43,977	100.00%

REMAINING PIPELINE DEMAND

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
NH DIVISION TOTAL - REMAINING PIPELINE	\$ 341,611	\$ 672,623	\$ 1,347,586	\$ 723,921	\$ 516,299	\$ 202,743	\$ 50,409	\$ 12,144	\$ -	\$ 377	\$ 7,155	\$ 90,456	\$ 3,965,324	\$ 3,804,783	\$ 160,541
Res Heat	\$ 172,124	\$ 338,906	\$ 678,992	\$ 364,754	\$ 260,142	\$ 102,154	\$ 25,399	\$ 6,119	\$ -	\$ 190	\$ 3,605	\$ 45,577	\$ 1,997,960	\$ 1,917,070	\$ 80,890
Res General	\$ 1,535	\$ 3,022	\$ 6,054	\$ 3,252	\$ 2,320	\$ 911	\$ 226	\$ 55	\$ -	\$ 2	\$ 32	\$ 406	\$ 17,815	\$ 17,094	\$ 721
G50 Low Annual-Low Winter	\$ 3,547	\$ 6,984	\$ 13,992	\$ 7,516	\$ 5,361	\$ 2,105	\$ 523	\$ 126	\$ -	\$ 4	\$ 74	\$ 939	\$ 41,172	\$ 39,505	\$ 1,667
G40 Low Annual-High Winter	\$ 74,666	\$ 147,016	\$ 294,543	\$ 158,228	\$ 112,848	\$ 44,314	\$ 11,018	\$ 2,654	\$ -	\$ 82	\$ 1,564	\$ 19,771	\$ 866,704	\$ 831,615	\$ 35,090
G51 Med Annual-Low Winter	\$ 5,832	\$ 11,482	\$ 23,004	\$ 12,358	\$ 8,814	\$ 3,461	\$ 861	\$ 207	\$ -	\$ 6	\$ 122	\$ 1,544	\$ 67,691	\$ 64,950	\$ 2,741
G41 Med Annual-High Winter	\$ 67,733	\$ 133,365	\$ 267,194	\$ 143,536	\$ 102,370	\$ 40,199	\$ 9,995	\$ 2,408	\$ -	\$ 75	\$ 1,419	\$ 17,935	\$ 786,230	\$ 754,398	\$ 31,831
G52 High Annual-Low Winter	\$ 2,835	\$ 5,582	\$ 11,183	\$ 6,008	\$ 4,285	\$ 1,683	\$ 418	\$ 101	\$ -	\$ 3	\$ 59	\$ 751	\$ 32,907	\$ 31,575	\$ 1,332
G42 High Annual-High Winter	\$ 13,340	\$ 26,266	\$ 52,623	\$ 28,269	\$ 20,161	\$ 7,917	\$ 1,968	\$ 474	\$ -	\$ 15	\$ 279	\$ 3,532	\$ 154,844	\$ 148,575	\$ 6,269
TOTAL	\$ 341,611	\$ 672,623	\$ 1,347,586	\$ 723,921	\$ 516,299	\$ 202,743	\$ 50,409	\$ 12,144	\$ -	\$ 377	\$ 7,155	\$ 90,456	\$ 3,965,324	\$ 3,804,783	\$ 160,541
Residential	\$ 173,658	\$ 341,928	\$ 685,046	\$ 368,006	\$ 262,461	\$ 103,064	\$ 25,625	\$ 6,173	\$ -	\$ 191	\$ 3,637	\$ 45,984	\$ 2,015,776	\$ 1,934,165	\$ 81,611
SALES HLF CLASSES	\$ 12,213	\$ 24,048	\$ 48,179	\$ 25,882	\$ 18,459	\$ 7,249	\$ 1,802	\$ 434	\$ -	\$ 13	\$ 256	\$ 3,234	\$ 141,770	\$ 136,030	\$ 5,740
SALES LLF CLASSES	\$ 155,740	\$ 306,647	\$ 614,360	\$ 330,033	\$ 235,379	\$ 92,430	\$ 22,981	\$ 5,536	\$ -	\$ 172	\$ 3,262	\$ 41,239	\$ 1,807,778	\$ 1,734,588	\$ 73,190

STORAGE AND ON-SYSTEM PEAKING DEMAND

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
NH DIVISION TOTAL - PEAKING & STORAGE	\$ 708,492	\$ 1,395,000	\$ 2,794,854	\$ 1,501,392	\$ 1,070,790	\$ 420,482	\$ 104,547	\$ 25,185	\$ -	\$ 781	\$ 14,840	\$ 187,604	\$ 8,223,967	\$ 7,891,010	\$ 332,957
Res Heat	\$ 356,980	\$ 702,882	\$ 1,408,209	\$ 756,488	\$ 539,526	\$ 211,863	\$ 52,677	\$ 12,690	\$ -	\$ 394	\$ 7,477	\$ 94,526	\$ 4,143,712	\$ 3,975,949	\$ 167,763
Res General	\$ 3,183	\$ 6,267	\$ 12,557	\$ 6,745	\$ 4,811	\$ 1,889	\$ 470	\$ 113	\$ -	\$ 4	\$ 67	\$ 843	\$ 36,949	\$ 35,453	\$ 1,496
G50 Low Annual-Low Winter	\$ 7,356	\$ 14,484	\$ 29,019	\$ 15,589	\$ 11,118	\$ 4,366	\$ 1,086	\$ 261	\$ -	\$ 8	\$ 154	\$ 1,948	\$ 85,389	\$ 81,932	\$ 3,457
G40 Low Annual-High Winter	\$ 154,856	\$ 304,906	\$ 610,874	\$ 328,161	\$ 234,043	\$ 91,905	\$ 22,851	\$ 5,505	\$ -	\$ 171	\$ 3,244	\$ 41,005	\$ 1,797,520	\$ 1,724,745	\$ 72,775
G51 Med Annual-Low Winter	\$ 12,094	\$ 23,814	\$ 47,710	\$ 25,630	\$ 18,279	\$ 7,178	\$ 1,785	\$ 430	\$ -	\$ 13	\$ 253	\$ 3,203	\$ 140,388	\$ 134,705	\$ 5,684
G41 Med Annual-High Winter	\$ 140,477	\$ 276,596	\$ 554,153	\$ 297,690	\$ 212,312	\$ 83,372	\$ 20,729	\$ 4,994	\$ -	\$ 155	\$ 2,942	\$ 37,197	\$ 1,630,618	\$ 1,564,601	\$ 66,018
G52 High Annual-Low Winter	\$ 5,880	\$ 11,577	\$ 23,194	\$ 12,460	\$ 8,886	\$ 3,490	\$ 868	\$ 209	\$ -	\$ 6	\$ 123	\$ 1,557	\$ 68,249	\$ 65,486	\$ 2,763
G42 High Annual-High Winter	\$ 27,666	\$ 54,474	\$ 109,138	\$ 58,629	\$ 41,814	\$ 16,420	\$ 4,083	\$ 983	\$ -	\$ 30	\$ 579	\$ 7,326	\$ 321,142	\$ 308,140	\$ 13,002
TOTAL	\$ 708,492	\$ 1,395,000	\$ 2,794,854	\$ 1,501,392	\$ 1,070,790	\$ 420,482	\$ 104,547	\$ 25,185	\$ -	\$ 781	\$ 14,840	\$ 187,604	\$ 8,223,967	\$ 7,891,010	\$ 332,957
Residential	\$ 360,163	\$ 709,150	\$ 1,420,766	\$ 763,234	\$ 544,337	\$ 213,753	\$ 53,147	\$ 12,803	\$ -	\$ 397	\$ 7,544	\$ 95,369	\$ 4,180,661	\$ 4,011,402	\$ 169,259
SALES HLF CLASSES	\$ 25,330	\$ 49,875	\$ 99,923	\$ 53,678	\$ 38,283	\$ 15,033	\$ 3,738	\$ 900	\$ -	\$ 28	\$ 531	\$ 6,707	\$ 294,027	\$ 282,123	\$ 11,904
SALES LLF CLASSES	\$ 322,999	\$ 635,976	\$ 1,274,165	\$ 684,480	\$ 488,170	\$ 191,697	\$ 47,663	\$ 11,482	\$ -	\$ 356	\$ 6,765	\$ 85,528	\$ 3,749,280	\$ 3,597,486	\$ 151,794

Off-SYSTEM PEAKING DEMAND & CNG EXPENSE

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
NH DIVISION - OFF-SYSTEM PEAKING	\$ 364,425	\$ 692,618	\$ 1,361,835	\$ 743,480	\$ 537,625	\$ 226,738	\$ -	\$ 1,521	\$ 366	\$ -	\$ 11	\$ 216	\$ 3,928,836	\$ 3,926,721	\$ 2,115
Res Heat	\$ 183,618	\$ 348,981	\$ 686,171	\$ 374,608	\$ 270,887	\$ 114,244	\$ -	\$ 766	\$ 185	\$ -	\$ 6	\$ 109	\$ 1,979,576	\$ 1,978,510	\$ 1,066
Res General	\$ 1,637	\$ 3,112	\$ 6,118	\$ 3,340	\$ 2,415	\$ 1,019	\$ -	\$ 7	\$ 2	\$ -	\$ 0	\$ 1	\$ 17,651	\$ 17,642	\$ 10
G50 Low Annual-Low Winter	\$ 3,784	\$ 7,191	\$ 14,140	\$ 7,720	\$ 5,582	\$ 2,354	\$ -	\$ 16	\$ 4	\$ -	\$ 0	\$ 2	\$ 40,793	\$ 40,771	\$ 22
G40 Low Annual-High Winter	\$ 79,653	\$ 151,386	\$ 297,657	\$ 162,503	\$ 117,509	\$ 49,558	\$ -	\$ 333	\$ 80	\$ -	\$ 2	\$ 47	\$ 858,729	\$ 858,267	\$ 462
G51 Med Annual-Low Winter	\$ 6,221	\$ 11,823	\$ 23,247	\$ 12,692	\$ 9,178	\$ 3,871	\$ -	\$ 26	\$ 6	\$ -	\$ 0	\$ 4	\$ 67,068	\$ 67,032	\$ 36
G41 Med Annual-High Winter	\$ 72,257	\$ 137,330	\$ 270,020	\$ 147,414	\$ 106,598	\$ 44,957	\$ -	\$ 302	\$ 73	\$ -	\$ 2	\$ 43	\$ 778,995	\$ 778,576	\$ 419
G52 High Annual-Low Winter	\$ 3,024	\$ 5,748	\$ 11,302	\$ 6,170	\$ 4,462	\$ 1,882	\$ -	\$ 13	\$ 3	\$ -	\$ 0	\$ 2	\$ 32,605	\$ 32,587	\$ 18
G42 High Annual-High Winter	\$ 14,231	\$ 27,046	\$ 53,179	\$ 29,033	\$ 20,994	\$ 8,854	\$ -	\$ 59	\$ 14	\$ -	\$ 0	\$ 8	\$ 153,419	\$ 153,336	\$ 83
TOTAL	\$ 364,425	\$ 692,618	\$ 1,361,835	\$ 743,480	\$ 537,625	\$ 226,738	\$ -	\$ 1,521	\$ 366	\$ -	\$ 11	\$ 216	\$ 3,928,836	\$ 3,926,721	\$ 2,115
Residential	\$ 185,256	\$ 352,093	\$ 692,290	\$ 377,949	\$ 273,302	\$ 115,263	\$ -	\$ 773	\$ 186	\$ -	\$ 6	\$ 110	\$ 1,997,227	\$ 1,996,152	\$ 1,075
SALES HLF CLASSES	\$ 14,666	\$ 27,875	\$ 54,807	\$ 29,921	\$ 21,637	\$ 9,125	\$ -	\$ 61	\$ 15	\$ -	\$ 0	\$ 9	\$ 158,117	\$ 158,032	\$ 85
SALES LLF CLASSES	\$ 349,758	\$ 664,744	\$ 1,307,027	\$ 713,558	\$ 515,989	\$ 217,613	\$ -	\$ 1,460	\$ 352	\$ -	\$ 11	\$ 207	\$ 3,770,719	\$ 3,768,689	\$ 2,030

Remaining Capacity Costs

39		
40	Res Heat	Company Analysis
41	Res General	Company Analysis
42	G50 Low Annual-Low Winter	Company Analysis
43	G40 Low Annual-High Winter	Company Analysis
44	G51 Med Annual-Low Winter	Company Analysis
45	G41 Med Annual-High Winter	Company Analysis
46	G52 High Annual-Low Winter	Company Analysis
47	G42 High Annual-High Winter	Company Analysis
48	TOTAL	Sum LN 40 : LN 47
49		

REMAINING PIPELINE DEMAND

51		
52	NH DIVISION TOTAL - REMAINING PIPELINE DEMAND	Schedule 5-CAK, LN 70
53		
54	Res Heat	LN 40 Col D * LN 52
55	Res General	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	LN 47 Col D * LN 52
62	TOTAL	Sum LN 54 : LN 61
63		
64	Residential	LN 54 + LN 55
65	SALES HLF CLASSES	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	LN 57 + LN 59 + LN 61
67		

STORAGE AND ON-SYSTEM PEAKING DEMAND

69		
70	NH DIVISION TOTAL - PEAKING & STORAGE DEMAND	Schedule 5-CAK, LN 73
71		
72	Res Heat	LN 40 Col D * LN 70
73	Res General	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	LN 47 Col D * LN 70
80	TOTAL	Sum LN 72 : LN 79
81		
82	Residential	LN 72 + LN 73
83	SALES HLF CLASSES	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	LN 75 + LN 77 + LN 79
85		

Off-SYSTEM PEAKING DEMAND & CNG E

87		
88	NH DIVISION - OFF-SYSTEM PEAKING	Schedule 5-CAK, LN 74
89		
90	Res Heat	LN 40 Col D * LN 88
91	Res General	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	LN 47 Col D * LN 88
98	TOTAL	Sum LN 90 : LN 97
99		
100	Residential	LN 90 + LN 91
101	SALES HLF CLASSES	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	LN 93 + LN 95 + LN 97
103		
104		

105 **CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**

106		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
107	NH DIVISION - MONTHLY CAP. RELEASE	\$ (304,041)	\$ (577,249)	\$ (1,134,345)	\$ (619,589)	\$ (448,224)	\$ (189,423)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (3,272,870)	\$ (3,272,870)	\$ -
108																
109	Res Heat	\$ (153,194)	\$ (290,851)	\$ (571,549)	\$ (312,185)	\$ (225,841)	\$ (95,442)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,649,062)	\$ (1,649,062)	\$ -
110	Res General	\$ (1,366)	\$ (2,593)	\$ (5,096)	\$ (2,784)	\$ (2,014)	\$ (851)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (14,704)	\$ (14,704)	\$ -
111	G50 Low Annual-Low Winter	\$ (3,157)	\$ (5,994)	\$ (11,778)	\$ (6,433)	\$ (4,654)	\$ (1,967)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (33,982)	\$ (33,982)	\$ -
112	G40 Low Annual-High Winter	\$ (66,455)	\$ (126,170)	\$ (247,935)	\$ (135,424)	\$ (97,969)	\$ (41,402)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (715,354)	\$ (715,354)	\$ -
113	G51 Med Annual-Low Winter	\$ (5,190)	\$ (9,854)	\$ (19,364)	\$ (10,577)	\$ (7,651)	\$ (3,234)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (55,870)	\$ (55,870)	\$ -
114	G41 Med Annual-High Winter	\$ (60,284)	\$ (114,455)	\$ (224,914)	\$ (122,850)	\$ (88,872)	\$ (37,558)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (648,933)	\$ (648,933)	\$ -
115	G52 High Annual-Low Winter	\$ (2,523)	\$ (4,790)	\$ (9,414)	\$ (5,142)	\$ (3,720)	\$ (1,572)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (27,161)	\$ (27,161)	\$ -
116	G42 High Annual-High Winter	\$ (11,873)	\$ (22,541)	\$ (44,296)	\$ (24,195)	\$ (17,503)	\$ (7,397)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (127,804)	\$ (127,804)	\$ -
117	TOTAL	\$ (304,041)	\$ (577,249)	\$ (1,134,345)	\$ (619,589)	\$ (448,224)	\$ (189,423)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (3,272,870)	\$ (3,272,870)	\$ -
118																
119	Residential	\$ (154,560)	\$ (293,445)	\$ (576,645)	\$ (314,969)	\$ (227,855)	\$ (96,293)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,663,766)	\$ (1,663,766)	\$ -
120	SALES HLF CLASSES	\$ (10,870)	\$ (20,638)	\$ (40,556)	\$ (22,152)	\$ (16,025)	\$ (6,772)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (117,013)	\$ (117,013)	\$ -
121	SALES LLF CLASSES	\$ (138,611)	\$ (263,166)	\$ (517,144)	\$ (282,469)	\$ (204,344)	\$ (86,357)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,492,091)	\$ (1,492,091)	\$ -
122																

123 **MISCELLANEOUS CREDITS BY CLASS (Includes Re-entry Rate & Conversion Rate Revenues)**

124		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
125	NH DIVISION - MISCELLANEOUS CREDIT	\$ (464)	\$ (882)	\$ (1,733)	\$ (947)	\$ (685)	\$ (289)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (5,000)	\$ (5,000)	\$ -
126																
127	Res Heat	\$ (234)	\$ (444)	\$ (873)	\$ (477)	\$ (345)	\$ (146)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (2,519)	\$ (2,519)	\$ -
128	Res General	\$ (2)	\$ (4)	\$ (8)	\$ (4)	\$ (3)	\$ (1)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (22)	\$ (22)	\$ -
129	G50 Low Annual-Low Winter	\$ (5)	\$ (9)	\$ (18)	\$ (10)	\$ (7)	\$ (3)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (52)	\$ (52)	\$ -
130	G40 Low Annual-High Winter	\$ (102)	\$ (193)	\$ (379)	\$ (207)	\$ (150)	\$ (63)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,093)	\$ (1,093)	\$ -
131	G51 Med Annual-Low Winter	\$ (8)	\$ (15)	\$ (30)	\$ (16)	\$ (12)	\$ (5)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (85)	\$ (85)	\$ -
132	G41 Med Annual-High Winter	\$ (92)	\$ (175)	\$ (344)	\$ (188)	\$ (136)	\$ (57)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (991)	\$ (991)	\$ -
133	G52 High Annual-Low Winter	\$ (4)	\$ (7)	\$ (14)	\$ (8)	\$ (6)	\$ (2)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (41)	\$ (41)	\$ -
134	G42 High Annual-High Winter	\$ (18)	\$ (34)	\$ (68)	\$ (37)	\$ (27)	\$ (11)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (195)	\$ (195)	\$ -
135	TOTAL	\$ (464)	\$ (882)	\$ (1,733)	\$ (947)	\$ (685)	\$ (289)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (5,000)	\$ (5,000)	\$ -
136																
137	Residential	\$ (236)	\$ (448)	\$ (881)	\$ (481)	\$ (348)	\$ (147)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (2,542)	\$ (2,542)	\$ -
138	SALES HLF CLASSES	\$ (19)	\$ (35)	\$ (70)	\$ (38)	\$ (28)	\$ (12)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (201)	\$ (201)	\$ -
139	SALES LLF CLASSES	\$ (446)	\$ (846)	\$ (1,663)	\$ (908)	\$ (657)	\$ (278)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (4,799)	\$ (4,799)	\$ -
140																

141 **TOTAL NON-BASE CAPACITY COSTS**

142		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
143	Res Heat	\$ 559,294	\$ 1,099,474	\$ 2,200,951	\$ 1,183,188	\$ 844,368	\$ 332,673	\$ 78,076	\$ 19,575	\$ 185	\$ 583	\$ 11,088	\$ 140,212	\$ 6,469,667	\$ 6,219,948	\$ 249,719
144	Res General	\$ 4,987	\$ 9,804	\$ 19,625	\$ 10,550	\$ 7,529	\$ 2,966	\$ 696	\$ 175	\$ 2	\$ 5	\$ 99	\$ 1,250	\$ 57,689	\$ 55,462	\$ 2,227
145	G50 Low Annual-Low Winter	\$ 11,525	\$ 22,657	\$ 45,355	\$ 24,382	\$ 17,400	\$ 6,855	\$ 1,609	\$ 403	\$ 4	\$ 12	\$ 228	\$ 2,889	\$ 133,320	\$ 128,174	\$ 5,146
146	G40 Low Annual-High Winter	\$ 242,619	\$ 476,946	\$ 954,761	\$ 513,261	\$ 366,282	\$ 144,312	\$ 33,869	\$ 8,492	\$ 80	\$ 253	\$ 4,810	\$ 60,823	\$ 2,806,506	\$ 2,698,180	\$ 108,327
147	G51 Med Annual-Low Winter	\$ 18,949	\$ 37,250	\$ 74,568	\$ 40,086	\$ 28,607	\$ 11,271	\$ 2,645	\$ 663	\$ 6	\$ 20	\$ 376	\$ 4,750	\$ 219,191	\$ 210,731	\$ 8,460
148	G41 Med Annual-High Winter	\$ 220,091	\$ 432,661	\$ 866,110	\$ 465,604	\$ 332,273	\$ 130,912	\$ 30,724	\$ 7,703	\$ 73	\$ 230	\$ 4,363	\$ 55,176	\$ 2,545,919	\$ 2,447,651	\$ 98,268
149	G52 High Annual-Low Winter	\$ 9,212	\$ 18,109	\$ 36,251	\$ 19,488	\$ 13,907	\$ 5,479	\$ 1,286	\$ 322	\$ 3	\$ 10	\$ 183	\$ 2,309	\$ 106,559	\$ 102,446	\$ 4,113
150	G42 High Annual-High Winter	\$ 43,346	\$ 85,210	\$ 170,576	\$ 91,698	\$ 65,439	\$ 25,782	\$ 6,051	\$ 1,517	\$ 14	\$ 45	\$ 859	\$ 10,867	\$ 501,406	\$ 482,052	\$ 19,353
151	TOTAL	\$ 1,110,023	\$ 2,182,110	\$ 4,368,196	\$ 2,348,257	\$ 1,675,806	\$ 660,251	\$ 154,956	\$ 38,850	\$ 366	\$ 1,158	\$ 22,007	\$ 278,276	\$ 12,840,257	\$ 12,344,644	\$ 495,613
152																
153	Residential	\$ 564,281	\$ 1,109,278	\$ 2,220,576	\$ 1,193,738	\$ 851,897	\$ 335,639	\$ 78,772	\$ 19,750	\$ 186	\$ 588	\$ 11,187	\$ 141,462	\$ 6,527,356	\$ 6,275,410	\$ 251,945
154	SALES HLF CLASSES	\$ 39,686	\$ 78,016	\$ 156,173	\$ 83,956	\$ 59,914	\$ 23,606	\$ 5,540	\$ 1,389	\$ 13	\$ 41	\$ 787	\$ 9,949	\$ 459,070	\$ 441,351	\$ 17,719
155	SALES LLF CLASSES	\$ 506,056	\$ 994,817	\$ 1,991,446	\$ 1,070,563	\$ 763,995	\$ 301,006	\$ 70,644	\$ 17,712	\$ 167	\$ 528	\$ 10,033	\$ 126,865	\$ 5,853,831	\$ 5,627,883	\$ 225,948
156																

157 **TOTAL CAPACITY COSTS**

158		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	SUMMER
159	Res Heat	\$ 606,461	\$ 1,146,641	\$ 2,248,118	\$ 1,230,355	\$ 891,535	\$ 380,344	\$ 125,243	\$ 66,742	\$ 47,352	\$ 47,750	\$ 58,255	\$ 187,379	\$ 7,036,174	\$ 6,503,454	\$ 532,720
160	Res General	\$ 6,077	\$ 10,893	\$ 20,715	\$ 11,640	\$ 8,619	\$ 4,068	\$ 1,786	\$ 1,264	\$ 1,091	\$ 1,095	\$ 1,188	\$ 2,340	\$ 70,775	\$ 62,011	\$ 8,764
161	G50 Low Annual-Low Winter	\$ 18,722	\$ 29,853	\$ 52,551	\$ 31,578	\$ 24,596	\$ 14,129	\$ 8,805	\$ 7,600	\$ 7,200	\$ 7,209	\$ 7,425	\$ 10,086	\$ 219,755	\$ 171,430	\$ 48,325
162	G40 Low Annual-High Winter	\$ 260,431	\$ 494,758	\$ 972,573	\$ 531,073	\$ 384,094	\$ 162,314	\$ 51,681	\$ 26,304	\$ 17,892	\$ 18,065	\$ 22,622	\$ 78,635	\$ 3,020,441	\$ 2,805,242	\$ 215,199
163	G51 Med Annual-Low Winter	\$ 31,643	\$ 49,944	\$ 87,262	\$ 52,780	\$ 41,301	\$ 23,880	\$ 15,339	\$ 13,357	\$ 12,700	\$ 12,714	\$ 13,070	\$ 17,444	\$ 371,434	\$ 286,810	\$ 84,624
164	G41 Med Annual-High Winter	\$ 237,352	\$ 449,921	\$ 883,370	\$ 482,864	\$ 349,533	\$ 148,357	\$ 47,985	\$ 24,964	\$ 17,333	\$ 17,490	\$ 21,624	\$ 72,436	\$ 2,753,229	\$ 2,551,398	\$ 201,831
165	G52 High Annual-Low Winter	\$ 16,091	\$ 24,988	\$ 43,130	\$ 26,367	\$ 20,787	\$ 11,447	\$ 8,165	\$ 7,202	\$ 6,882	\$ 6,889	\$ 7,062	\$ 9,189	\$ 188,201	\$ 142,811	\$ 45,390
166	G42 High Annual-High Winter	\$ 46,100	\$ 87,964	\$ 173,330	\$ 94,452	\$ 68,193	\$ 28,566	\$ 8,805	\$ 4,271	\$ 2,768	\$ 2,799	\$ 3,613	\$ 13,620	\$ 534,482	\$ 498,605	\$ 35,877
167	TOTAL	\$ 1,222,876	\$ 2,294,963	\$ 4,481,049	\$ 2,461,110	\$ 1,788,659	\$ 773,104	\$ 267,809	\$ 151,703	\$ 113,219	\$ 114,010	\$ 134,859	\$ 391,129	\$ 14,194,491	\$ 13,021,761	\$ 1,172,730
168																
169	Residential	\$ 612,538	\$ 1,157,534	\$ 2,268,833	\$ 1,241,995	\$ 900,154	\$ 384,411	\$ 127,029	\$ 68,006	\$ 48,443	\$ 48,845	\$ 59,444	\$ 189,719	\$ 7,106,949	\$ 6,565,465	\$ 541,485
170	SALES HLF CLASSES	\$ 66,456	\$ 104,786	\$ 182,943	\$ 110,726	\$ 86,684	\$ 49,456	\$ 32,310	\$ 28,159	\$ 26,783	\$ 26,811	\$ 27,557	\$ 36,719	\$ 779,390	\$ 601,051	\$ 178,339
171	SALES LLF CLASSES	\$ 543,882	\$ 1,032,643	\$ 2,029,273	\$ 1,108,389	\$ 801,821	\$ 339,237	\$ 108,470	\$ 55,538	\$ 37,993	\$ 38,354	\$ 47,859	\$ 164,692	\$ 6,308,152	\$ 5,855,245	\$ 452,907
172																
173	% ALLOCATION BETWEEN SALES HLF AND LLF															
174	SALES HLF CLASSES															
175	SALES LLF CLASSES															

105	CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS	
106		
107	NH DIVISION - MONTHLY CAP. RELEASE	Schedule 5-CAK, LN 77
108		
109	Res Heat	LN 40 Col D * LN 107
110	Res General	LN 41 Col D * LN 107
111	G50 Low Annual-Low Winter	LN 42 Col D * LN 107
112	G40 Low Annual-High Winter	LN 43 Col D * LN 107
113	G51 Med Annual-Low Winter	LN 44 Col D * LN 107
114	G41 Med Annual-High Winter	LN 45 Col D * LN 107
115	G52 High Annual-Low Winter	LN 46 Col D * LN 107
116	G42 High Annual-High Winter	LN 47 Col D * LN 107
117	TOTAL	Sum LN 109 : LN 116
118		
119	Residential	LN 109 + LN 110
120	SALES HLF CLASSES	LN 111 + LN 113 + LN 115
121	SALES LLF CLASSES	LN 112 + LN 114 + LN 116
122		
123	MISCELLANEOUS CREDITS BY CLASS (Includes Re-entry Rate & Conversion Ra	
124		
125	NH DIVISION - MISCELLANEOUS CREDIT	Schedule 5-CAK, LN 78 + LN 79
126		
127	Res Heat	LN 40 Col D * LN 125
128	Res General	LN 41 Col D * LN 125
129	G50 Low Annual-Low Winter	LN 42 Col D * LN 125
130	G40 Low Annual-High Winter	LN 43 Col D * LN 125
131	G51 Med Annual-Low Winter	LN 44 Col D * LN 125
132	G41 Med Annual-High Winter	LN 45 Col D * LN 125
133	G52 High Annual-Low Winter	LN 46 Col D * LN 125
134	G42 High Annual-High Winter	LN 47 Col D * LN 125
135	TOTAL	Sum LN 127 : LN 134
136		
137	Residential	LN 127 + LN 128
138	SALES HLF CLASSES	LN 129 + LN 131 + LN 133
139	SALES LLF CLASSES	LN 130 + LN 132 + LN 134
140		
141	TOTAL NON-BASE CAPACITY COSTS	
142		
143	Res Heat	Sum of Ln 54, 72, 90, 109, 127
144	Res General	Sum of Ln 55, 73, 91, 110, 128
145	G50 Low Annual-Low Winter	Sum of Ln 56, 74, 92, 111, 129
146	G40 Low Annual-High Winter	Sum of Ln 57, 75, 93, 112, 130
147	G51 Med Annual-Low Winter	Sum of Ln 58, 76, 94, 113, 131
148	G41 Med Annual-High Winter	Sum of Ln 59, 77, 95, 114, 132
149	G52 High Annual-Low Winter	Sum of Ln 60, 78, 96, 115, 133
150	G42 High Annual-High Winter	Sum of Ln 61, 79, 97, 116, 134
151	TOTAL	Sum LN 143 : LN 150
152		
153	Residential	LN 143 + LN 144
154	SALES HLF CLASSES	LN 145 + LN 147 + LN 149
155	SALES LLF CLASSES	LN 146 + LN 148 + LN 150
156		
157	TOTAL CAPACITY COSTS	
158		
159	Res Heat	LN 143 + LN 26
160	Res General	LN 144 + LN 27
161	G50 Low Annual-Low Winter	LN 145 + LN 28
162	G40 Low Annual-High Winter	LN 146 + LN 29
163	G51 Med Annual-Low Winter	LN 147 + LN 30
164	G41 Med Annual-High Winter	LN 148 + LN 31
165	G52 High Annual-Low Winter	LN 149 + LN 32
166	G42 High Annual-High Winter	LN 150 + LN 33
167	TOTAL	Sum LN 159 : LN 166
168		
169	Residential	LN 159 + LN 160
170	SALES HLF CLASSES	LN 161 + LN 163 + LN 165
171	SALES LLF CLASSES	LN 162 + LN 164 + LN 166
172		
173	% ALLOCATION BETWEEN SALES HLF AND	
174	SALES HLF CLASSES	LN 170 / (LN170 + LN 171)
175	SALES LLF CLASSES	LN 171 / (LN 170 + LN 171)

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
Supply Volumes - MMBtu															
Total Baseload Pipeline	373,790	326,938	326,938	296,353	396,783	914,522	499,328	337,173	291,023	294,102	320,183	619,360	4,996,492	2,635,323	2,361,169
Total Remaining Pipeline	557,121	661,024	661,024	597,054	661,024	3,595	0	0	0	0	0	0	3,140,843	3,140,843	0
Total Storage	233,918	670,393	760,704	779,661	440,846	0	0	0	0	0	0	0	2,885,522	2,885,522	0
Total Peaking	1,794	25,246	241,465	35,494	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	318,687	307,647	11,040
Total Off-system Sales													0	0	
Subtotal	1,166,624	1,683,601	1,990,131	1,708,562	1,500,507	919,911	501,188	338,973	292,883	295,962	321,983	621,220	11,341,545	8,969,336	2,372,209
Less Interruptible - Maine	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Supply	1,166,624	1,683,601	1,990,131	1,708,562	1,500,507	919,911	501,188	338,973	292,883	295,962	321,983	621,220	11,341,545	8,969,336	2,372,209
Total Firm Pipeline Sendout	373,790	326,938	326,938	296,353	396,783	914,522	499,328	337,173	291,023	294,102	320,183	619,360	4,996,492	2,635,323	2,361,169
Variable Costs															
Base Pipeline Costs Modeled in Sendout™	\$ 1,083,860	\$ 1,099,844	\$ 1,146,675	\$ 1,033,098	\$ 1,329,637	\$ 2,564,932	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126	\$ 14,475,437	\$ 8,258,046	\$ 6,217,391
NYMEX Price Used for Forecast	\$2,324	\$2,485	\$2,588	\$2,556	\$2,473	\$2,277	\$2,261	\$2,297	\$2,336	\$2,345	\$2,329	\$2,354	\$2,354	\$2,354	\$2,354
NYMEX Price Used for Update	\$2,324	\$2,485	\$2,588	\$2,556	\$2,473	\$2,277	\$2,261	\$2,297	\$2,336	\$2,345	\$2,329	\$2,354	\$2,354	\$2,354	\$2,354
Increase/(Decrease) NYMEX Price	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Increase/(Decrease) in Pipeline Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Updated Pipeline Costs	\$ 1,083,860	\$ 1,099,844	\$ 1,146,675	\$ 1,033,098	\$ 1,329,637	\$ 2,564,932	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126	\$ 14,475,437	\$ 8,258,046	\$ 6,217,391
Remaining Pipeline Costs Modeled in Sendout™	\$ 1,726,682	\$ 2,590,803	\$ 3,157,895	\$ 2,794,434	\$ 2,387,373	\$ 11,321	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,668,508	\$ 12,668,508	\$ -
NYMEX Price Used for Forecast	\$2,324	\$2,485	\$2,588	\$2,556	\$2,473	\$2,277	\$2,261	\$2,297	\$2,336	\$2,345	\$2,329	\$2,354	\$2,354	\$2,354	\$2,354
NYMEX Price Used for Update	\$2,324	\$2,485	\$2,588	\$2,556	\$2,473	\$2,277	\$2,261	\$2,297	\$2,336	\$2,345	\$2,329	\$2,354	\$2,354	\$2,354	\$2,354
Increase/(Decrease) NYMEX Price	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Increase/(Decrease) in Pipeline Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Updated Pipeline Costs	\$ 1,726,682	\$ 2,590,803	\$ 3,157,895	\$ 2,794,434	\$ 2,387,373	\$ 11,321	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,668,508	\$ 12,668,508	\$ -
Subtotal	\$ 3,246,160	\$ 5,034,949	\$ 6,638,249	\$ 5,459,497	\$ 4,534,247	\$ 2,588,560	\$ 1,334,812	\$ 898,737	\$ 787,212	\$ 794,469	\$ 844,375	\$ 1,631,389	\$ 33,792,655	\$ 27,501,662	\$ 6,290,994
Interruptible Cost Estimate															
Variable Pipeline Costs	\$ 2,810,541	\$ 3,690,647	\$ 4,304,570	\$ 3,827,533	\$ 3,717,010	\$ 2,576,253	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126	\$ 27,143,945	\$ 20,926,554	\$ 6,217,391
Average Supply Cost (\$/MMBtu)	\$ 3.019	\$ 3.736	\$ 4.357	\$ 4.284	\$ 3.514	\$ 2.806	\$ 2.648	\$ 2.630	\$ 2.662	\$ 2.659	\$ 2.600	\$ 2.614	\$ -	\$ -	\$ -
Interruptible Cost - Maine	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Interruptible Cost - New Hampshire	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Firm Sales Baseload Pipeline	\$ 1,083,860	\$ 1,099,844	\$ 1,146,675	\$ 1,033,098	\$ 1,329,637	\$ 2,564,932	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126	\$ 14,475,437	\$ 8,258,046	\$ 6,217,391
Firm Sales Remaining Pipeline	\$ 1,726,682	\$ 2,590,803	\$ 3,157,895	\$ 2,794,434	\$ 2,387,373	\$ 11,321	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,668,508	\$ 12,668,508	\$ -
Total Storage	\$ 428,329	\$ 1,214,353	\$ 1,379,721	\$ 1,415,781	\$ 804,385	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,242,569	\$ 5,242,569	\$ -
Total Peaking	\$ 7,289	\$ 129,949	\$ 953,958	\$ 216,183	\$ 12,852	\$ 12,307	\$ 12,561	\$ 12,075	\$ 12,411	\$ 12,390	\$ 11,902	\$ 12,263	\$ 1,406,140	\$ 1,332,538	\$ 73,602
Off-system Sales	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Firm Sales Variable Costs	\$ 3,246,160	\$ 5,034,949	\$ 6,638,249	\$ 5,459,497	\$ 4,534,247	\$ 2,588,560	\$ 1,334,812	\$ 898,737	\$ 787,212	\$ 794,469	\$ 844,375	\$ 1,631,389	\$ 21,124,147	\$ 14,833,153	\$ 6,290,994

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Schedule 23-FXW, Page 2
3	Total Remaining Pipeline	Schedule 23-FXW, Page 2
4	Total Storage	Schedule 23-FXW, Page 2
5	Total Peaking	Schedule 23-FXW, Page 2
6	Total Off-system Sales	NA
7	Subtotal	SUM LN 2: LN 6
8	Less Interruptible - Maine	Company Analysis
9	Less Interruptible - New Hampshire	Company Analysis
10	Total Firm Supply	LN 7 - LN 8 - LN 9
11	Total Firm Pipeline Sendout	LN 2 + LN 3- LN 8 - LN 9
12	Variable Costs	
13	Pipeline Costs Modeled in Sendout™	Schedule 23-FXW, Page 1
14	NYMEX Price Used for Forecast	Schedule FXW-30, PG 1, LN 16
15	NYMEX Price Used for Update	Schedule FXW-30, PG 1, LN 16
16	Increase/(Decrease) NYMEX Price	LN 14 - LN 15
17	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 16
18	Total Updated Pipeline Costs	LN 13 + LN 17
19	Remaining Pipeline Costs Modeled in Sendout™	Schedule 23-FXW, Page 1
20	NYMEX Price Used for Forecast	Schedule FXW-30, PG 1, LN 16
21	NYMEX Price Used for Update	Schedule FXW-30, PG 1, LN 16
22	Increase/(Decrease) NYMEX Price	LN 20 - LN 21
23	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 22
24	Total Updated Pipeline Costs	LN 19 + LN 23
25		
26	Total Pipeline Baseload	LN 18
27	Total Remaining Pipeline	LN 24
28	Total Storage	Schedule 23-FXW, Page 1
29	Total Peaking	Schedule23-FXW, Page 1
30	Total Off-sytem Sales	NA
31		
32	Subtotal	Sum LN 19 : LN 22
33		
34	Interruptible Cost Estimate	Company Analysis
35	Variable Pipeline Costs Excl'd Hedges	LN 18 + LN 24
36	Average Supply Cost (\$/MMBtu)	LN 35 /(LN 2 + LN 3)
37	Interruptible Cost - Maine	LN 36 * LN 8
38	Interruptible Cost - New Hampshire	LN 36 * LN 9
39		
40	Firm Sales Pipeline Commodity	LN 26 - LN 37 - LN 38
41	Firm Sales Remaining Pipeline	LN 27 - LN 37 - LN 38
42	Total Storage	LN 28
43	Total Peaking	LN 29
44	Off-system Sales	LN 30
45	Total Firm Sales Variable Costs	SUM LN 40 : LN 44

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

46	Commodity Allocation Factors															
47	Firm Sales Sendout for Normal Winter, MMBtu															
48		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
49	Maine	705,389	1,012,886	1,191,105	1,029,250	912,646	582,355	328,003	223,048	195,153	196,769	213,990	398,508	6,989,104	5,433,632	1,555,472
50	New Hampshire	461,248	670,734	799,048	679,332	587,878	337,566	173,190	115,928	97,733	99,196	107,997	222,718	4,352,568	3,535,806	816,762
51	Total	1,166,637	1,683,621	1,990,153	1,708,582	1,500,524	919,921	501,193	338,977	292,885	295,966	321,987	621,226	11,341,671	8,969,438	2,372,233
52																
53	Percentage of Total															
54	Maine	60.46%	60.16%	59.85%	60.24%	60.82%	63.30%	65.44%	65.80%	66.63%	66.48%	66.46%	64.15%	61.62%	60.58%	65.57%
55	New Hampshire	39.54%	39.84%	40.15%	39.76%	39.18%	36.70%	34.56%	34.20%	33.37%	33.52%	33.54%	35.85%	38.38%	39.42%	34.43%
56	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
57																
58	Commodity Allocation by Jurisdiction															
59	Maine															
60	Firm Sales Baseload Pipeline	\$ 655,339	\$ 661,679	\$ 686,284	\$ 622,338	\$ 808,710	\$ 1,623,728	\$ 865,340	\$ 583,428	\$ 516,259	\$ 519,956	\$ 553,256	\$ 1,038,647	\$ 9,134,964	\$ 5,058,079	\$ 4,076,885
61	Firm Sales Remaining Pipeline	\$ 1,044,012	\$ 1,558,658	\$ 1,889,997	\$ 1,683,367	\$ 1,452,044	\$ 7,167	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,635,246	\$ 7,635,246	\$ -
62	Storage	\$ 258,983	\$ 730,569	\$ 825,762	\$ 852,866	\$ 489,242	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,157,422	\$ 3,157,422	\$ -
63	Peaking	\$ 4,407	\$ 78,179	\$ 570,943	\$ 130,229	\$ 7,817	\$ 7,791	\$ 8,220	\$ 7,946	\$ 8,270	\$ 8,237	\$ 7,910	\$ 7,867	\$ 847,815	\$ 799,365	\$ 48,450
64	Off-system Sales	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
65	Total Maine Commodity Costs	\$ 1,962,741	\$ 3,029,086	\$ 3,972,986	\$ 3,288,801	\$ 2,757,812	\$ 1,638,686	\$ 873,560	\$ 591,373	\$ 524,528	\$ 528,194	\$ 561,166	\$ 1,046,513	\$ 20,775,447	\$ 16,650,112	\$ 4,125,335
66	Maine Inventory Finance Costs	\$ 267	\$ 423	\$ 515	\$ 441	\$ 371	\$ 203	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,222	\$ 2,222	\$ -
67	Total Maine Variable Costs	\$ 1,963,008	\$ 3,029,509	\$ 3,973,502	\$ 3,289,242	\$ 2,758,183	\$ 1,638,889	\$ 873,560	\$ 591,373	\$ 524,528	\$ 528,194	\$ 561,166	\$ 1,046,513	\$ 20,777,669	\$ 16,652,334	\$ 4,125,335
68	New Hampshire															
69	Firm Sales Baseload Pipeline	\$ 428,520	\$ 438,165	\$ 460,391	\$ 410,760	\$ 520,928	\$ 941,204	\$ 456,911	\$ 303,234	\$ 258,542	\$ 262,123	\$ 279,217	\$ 580,479	\$ 5,340,473	\$ 3,199,967	\$ 2,140,506
70	Firm Sales Remaining Pipeline	\$ 682,670	\$ 1,032,145	\$ 1,267,898	\$ 1,111,067	\$ 935,329	\$ 4,154	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,033,263	\$ 5,033,263	\$ -
71	Storage	\$ 169,346	\$ 483,784	\$ 553,959	\$ 562,914	\$ 315,143	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,085,147	\$ 2,085,147	\$ -
72	Peaking	\$ 2,882	\$ 51,770	\$ 383,015	\$ 85,954	\$ 5,035	\$ 4,516	\$ 4,341	\$ 4,130	\$ 4,141	\$ 4,153	\$ 3,992	\$ 4,396	\$ 558,325	\$ 533,172	\$ 25,153
73	Off-system Sales	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
74	Total New Hampshire Commodity Costs	\$ 1,283,418	\$ 2,005,863	\$ 2,665,263	\$ 2,170,696	\$ 1,776,435	\$ 949,874	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875	\$ 13,017,208	\$ 10,851,549	\$ 2,165,659
75	New Hampshire Inventory Finance Costs	\$ 156	\$ 245	\$ 299	\$ 252	\$ 209	\$ 104	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,266	\$ 1,266	\$ -
76	Total New Hampshire Variable Costs	\$ 1,283,575	\$ 2,006,108	\$ 2,665,562	\$ 2,170,948	\$ 1,776,644	\$ 949,978	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875	\$ 13,018,474	\$ 10,852,815	\$ 2,165,659
77	Northern Utilities															
78	Firm Sales Baseload Pipeline	\$ 1,083,860	\$ 1,099,844	\$ 1,146,675	\$ 1,033,098	\$ 1,329,637	\$ 2,564,932	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126	\$ 14,475,437	\$ 8,258,046	\$ 6,217,391
79	Firm Sales Remaining Pipeline	\$ 1,726,682	\$ 2,590,803	\$ 3,157,895	\$ 2,794,434	\$ 2,387,373	\$ 11,321	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,668,508	\$ 12,668,508	\$ -
80	Storage	\$ 428,329	\$ 1,214,353	\$ 1,379,721	\$ 1,415,781	\$ 804,385	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,242,569	\$ 5,242,569	\$ -
81	Peaking	\$ 7,289	\$ 129,949	\$ 953,958	\$ 216,183	\$ 12,852	\$ 12,307	\$ 12,561	\$ 12,075	\$ 12,411	\$ 12,390	\$ 11,902	\$ 12,263	\$ 1,406,140	\$ 1,332,538	\$ 73,602
82	Off-system Sales	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
83	Total Northern Commodity Costs	\$ 3,246,160	\$ 5,034,949	\$ 6,638,249	\$ 5,459,497	\$ 4,534,247	\$ 2,588,560	\$ 1,334,812	\$ 898,737	\$ 787,212	\$ 794,469	\$ 844,375	\$ 1,631,389	\$ 33,792,655	\$ 27,501,662	\$ 6,290,994
84	Northern Inventory Finance Costs	\$ 424	\$ 668	\$ 815	\$ 694	\$ 580	\$ 307	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,488	\$ 3,488	\$ -
85	Total Northern Variable Costs	\$ 3,246,583	\$ 5,035,617	\$ 6,639,064	\$ 5,460,190	\$ 4,534,828	\$ 2,588,867	\$ 1,334,812	\$ 898,737	\$ 787,212	\$ 794,469	\$ 844,375	\$ 1,631,389	\$ 33,796,143	\$ 27,505,149	\$ 6,290,994
86																

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

46 **Commodity Allocation Factors**

47 Firm Sales Sendout for Normal Winter, MMBtu

48		
49	Maine	Company Analysis
50	New Hampshire	Schedule 17-FXW, LN 33 / 10
51	Total	LN 49 + LN 50

52 **Percentage of Total**

53		
54	Maine	LN 49 / LN 51
55	New Hampshire	LN 50 / LN 51
56	Total	LN 54 + LN 55

57 **Commodity Allocation by Jurisdiction**

58 **Maine**

59		
60	Firm Sales Pipeline Commodity	LN 40 * LN 54
61	Firm Sales Remaining Pipeline	LN 41 * LN 54
62	Storage	LN 42 * LN 54
63	Peaking	LN 43 * LN 54
64	Off-system Sales	LN 44 * LN 54
65	Total Maine Commodity Costs	SUM LN 60 : LN 64
66	Maine Inventory Finance Costs	LN 107
67	Total Maine Variable Costs	LN 55 + LN 56

68 **New Hampshire**

69	Firm Sales Pipeline Commodity Excl'd Hedge	LN 40 * LN 55
70	Firm Sales Remaining Pipeline	LN 41 * LN 55
71	Storage	LN 42 * LN 55
72	Peaking	LN 43 * LN 55
73	Off-system Sales	LN 44 * LN 55
74	Total New Hampshire Commodity Costs	SUM LN 69 : LN 73
75	New Hampshire Inventory Finance Costs	LN 112
76	Total New Hampshire Variable Costs	LN 74 + LN 75

77 **Northern Utilities**

78	Firm Sales Pipeline Commodity Excl'd Hedge	LN 60 + LN 69
79	Firm Sales Remaining Pipeline	LN 61 + LN 70
80	Storage	LN 62 + LN 71
81	Peaking	LN 63 + LN 72
82	Off-system Sales	LN 64 + LN 73
83	Total Northern Commodity Costs	LN 65 + LN 74
84	Northern Inventory Finance Costs	LN 66 + LN 75
85	Total Northern Variable Costs	LN 67 + LN 76

86

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

87 **Northern Utilities**
88 **Simplified Market Based Allocator (MBA) Calculations**
89 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**

91	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L	Col M	Col N	Col O	Col P
92																
93	Inventory Finance Charge	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
94	Storage	\$ 341	\$ 286	\$ 177	\$ 73	\$ 12	\$ -	\$ 59	\$ 173	\$ 230	\$ 287	\$ 398	\$ 506	\$ 2,543		\$ 1,653
95	Peaking	\$ 50	\$ 65	\$ 79	\$ 81	\$ 81	\$ 81	\$ 84	\$ 88	\$ 87	\$ 82	\$ 82	\$ 86	\$ 945		\$ 509
96	Total	\$ 392	\$ 351	\$ 255	\$ 153	\$ 93	\$ 81	\$ 143	\$ 261	\$ 317	\$ 370	\$ 480	\$ 592	\$ 3,488		\$ 2,162
97																
98	Inventory Finance Charge Allocation by Jurisdiction															
99	Maine	\$ 237	\$ 211	\$ 153	\$ 92	\$ 57	\$ 51	\$ 93	\$ 172	\$ 211	\$ 246	\$ 319	\$ 380	\$ 2,222		\$ 1,421
100	New Hampshire	\$ 155	\$ 140	\$ 103	\$ 61	\$ 36	\$ 30	\$ 49	\$ 89	\$ 106	\$ 124	\$ 161	\$ 212	\$ 1,266		\$ 741
101	Total	\$ 392	\$ 351	\$ 255	\$ 153	\$ 93	\$ 81	\$ 143	\$ 261	\$ 317	\$ 370	\$ 480	\$ 592	\$ 3,488		\$ 2,162
102																
103	Inventory Finance Charge Allocation by Month															
104	Maine															
105	Firm Sales Normal Remaining Sendout	515,750	816,925	995,144	852,252	716,685	392,716	0	0	0	0	0	0	0	4,289,472	0
106	Monthly % Sendout of Total Winter	12.02%	19.04%	23.20%	19.87%	16.71%	9.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
107	ME Allocated Inventory Finance Charge	\$ 267	\$ 423	\$ 515	\$ 441	\$ 371	\$ 203	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,222	\$ -
108																
109	New Hampshire															
110	Firm Sales Normal Remaining Sendout	365,960	572,270	700,584	590,396	489,413	243,285	0	0	0	0	0	0	0	2,961,907	0
111	Monthly % Sendout of Total Winter	12.36%	19.32%	23.65%	19.93%	16.52%	8.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
112	NH Allocated Inventory Finance Charge	\$ 156	\$ 245	\$ 299	\$ 252	\$ 209	\$ 104	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,266	\$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

87 **Northern Utilities**
88 **Simplified Market Based Allocator (MBA) Calculations**
89 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**
90
91
92

93	Inventory Finance Charge	
94	Storage	"Schedule 10-CAK - Carrying Costs"
95	Peaking	"Schedule 10-CAK - Carrying Costs"
96	Total	SUM LN 94 : LN 95

97		
98	Inventory Finance Charge Allocation by Jurisdiction	
99	Maine	LN 54 * LN 96
100	New Hampshire	LN 55 * LN 96
101	Total	SUM LN 99 : LN 100

102
103 **Inventory Finance Charge Allocation by Month**

104	Maine	
105	Firm Sales Remaining Sendout	Company Analysis
106	Monthly % Sendout of Total Winter	LN 105 / LN 105 COL O
107	ME Allocated Inventory Finance Charge	LN 106 * LN 99 COL N

108		
109	New Hampshire	
110	Firm Sales Remaining Sendout	NH Schedule 6-CAK, LN 80 / 10
111	Monthly % Sendout of Total Winter	LN 110 / LN 110 COL O
112	NH Allocated Inventory Finance Charge	LN 111 * LN 100 COL N

**Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS**

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
Supply Volumes - Therms															
1 New Hampshire Sales Pipeline Baseload	1,477,837	1,302,480	1,312,657	1,178,299	1,554,524	3,355,845	1,725,456	1,153,115	971,111	985,716	1,073,916	2,220,490	18,311,446	10,181,642	8,129,804
2 New Hampshire Sales Pipeline Remaining	2,202,664	2,633,441	2,654,018	2,373,887	2,589,772	13,192	0	0	0	0	0	0	12,466,975	12,466,975	0
3 New Hampshire Sales Storage	924,831	2,670,766	3,054,233	3,099,930	1,727,153	0	0	0	0	0	0	0	11,476,915	11,476,915	0
4 New Hampshire Sales Peaking	7,093	100,577	969,485	141,125	7,263	6,583	6,427	6,156	6,207	6,234	6,037	6,668	1,269,855	1,232,125	37,730
5 Total New Hampshire Firm Sales Sendout	4,612,425	6,707,264	7,990,394	6,793,242	5,878,711	3,375,620	1,731,883	1,159,271	977,318	991,950	1,079,953	2,227,158	43,525,190	35,357,657	8,167,534
6															
7 New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8															
9 Total Firm Sendout	4,612,425	6,707,264	7,990,394	6,793,242	5,878,711	3,375,620	1,731,883	1,159,271	977,318	991,950	1,079,953	2,227,158	43,525,190	35,357,657	8,167,534
10 Total Firm Sales	4,552,386	6,619,959	7,886,383	6,704,817	5,802,188	3,331,679	1,709,335	1,144,180	964,593	979,040	1,065,895	2,198,166	42,958,621	34,897,412	8,061,210
11 Difference (LAUF & Company Use)	60,039	87,305	104,010	88,426	76,524	43,941	22,548	15,091	12,725	12,911	14,058	28,993	566,569	460,245	106,324
12 Percent Difference	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%
13															
Variable Costs															
15 New Hampshire Sales Pipeline Baseload	\$ 428,520	\$ 438,165	\$ 460,391	\$ 410,760	\$ 520,928	\$ 941,204	\$ 456,911	\$ 303,234	\$ 258,542	\$ 262,123	\$ 279,217	\$ 580,479	\$ 5,340,473	\$ 3,199,967	\$ 2,140,506
16 New Hampshire Sales Pipeline Remaining	\$ 682,670	\$ 1,032,145	\$ 1,267,898	\$ 1,111,067	\$ 935,329	\$ 4,154	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,033,263	\$ 5,033,263	\$ -
17 New Hampshire Total Storage	\$ 169,346	\$ 483,784	\$ 553,959	\$ 562,914	\$ 315,143	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,085,147	\$ 2,085,147	\$ -
18 New Hampshire Total Peaking	\$ 2,882	\$ 51,770	\$ 383,015	\$ 85,954	\$ 5,035	\$ 4,516	\$ 4,341	\$ 4,130	\$ 4,141	\$ 4,153	\$ 3,992	\$ 4,396	\$ 558,325	\$ 533,172	\$ 25,153
19 New Hampshire Inventory Finance Charge	\$ 156	\$ 245	\$ 299	\$ 252	\$ 209	\$ 104	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,266	\$ 1,266	\$ -
20 Total New Hampshire Sales Variable Costs	\$ 1,283,575	\$ 2,006,108	\$ 2,665,562	\$ 2,170,948	\$ 1,776,644	\$ 949,978	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875	\$ 13,018,474	\$ 10,852,815	\$ 2,165,659
21															
22 New Hampshire Interruptible Commodity Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23 Total New Hampshire Commodity Costs	\$ 1,283,575	\$ 2,006,108	\$ 2,665,562	\$ 2,170,948	\$ 1,776,644	\$ 949,978	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875	\$ 13,018,474	\$ 10,852,815	\$ 2,165,659
24															
Supply Cost/Therm															
26 New Hampshire Sales Pipeline Baseload	\$ 0.290	\$ 0.336	\$ 0.351	\$ 0.349	\$ 0.335	\$ 0.280	\$ 0.265	\$ 0.263	\$ 0.266	\$ 0.266	\$ 0.260	\$ 0.261	\$ 0.292	\$ 0.314	\$ 0.263
27 New Hampshire Sales Pipeline Remaining	\$ 0.310	\$ 0.392	\$ 0.478	\$ 0.468	\$ 0.361	\$ 0.315	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.404	\$ 0.404	\$ -
28 New Hampshire Storage Excl Inventory Finance Costs	\$ 0.183	\$ 0.181	\$ 0.181	\$ 0.182	\$ 0.182	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.182	\$ 0.182	\$ -
29 New Hampshire Peaking Excl Inventory Finance Costs	\$ 0.406	\$ 0.515	\$ 0.395	\$ 0.609	\$ 0.693	\$ 0.686	\$ 0.675	\$ 0.671	\$ 0.667	\$ 0.666	\$ 0.661	\$ 0.659	\$ 0.440	\$ 0.433	\$ 0.667
30 New Hampshire Inventory Finance Costs per Dth Stor and Peak	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.016	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.000	\$ 0.000	\$ -
31 Weighted Average Cost per Dth Sendout	\$ 0.278	\$ 0.299	\$ 0.334	\$ 0.320	\$ 0.302	\$ 0.281	\$ 0.266	\$ 0.265	\$ 0.269	\$ 0.268	\$ 0.262	\$ 0.263	\$ 0.299	\$ 0.307	\$ 0.265
32															
33 New Hampshire Interruptible Cost / Therm	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
34															
Commodity Costs															
36 Base Commodity, therms	952,882	984,644	984,644	889,356	984,644	942,813	984,644	952,882	977,326	984,644	952,882	984,644	11,576,005	5,738,983	5,837,022
37 Base Commodity Cost	\$ 276,302	\$ 331,242	\$ 345,346	\$ 310,033	\$ 329,959	\$ 264,428	\$ 260,740	\$ 250,579	\$ 260,197	\$ 261,838	\$ 247,748	\$ 257,405	\$ 3,395,816	\$ 1,857,310	\$ 1,538,506
38 Remaining Commodity	\$ 1,007,273	\$ 1,674,866	\$ 2,320,216	\$ 1,860,915	\$ 1,446,686	\$ 685,550	\$ 200,512	\$ 56,785	\$ 2,487	\$ 4,438	\$ 35,461	\$ 327,470	\$ 9,622,658	\$ 8,995,505	\$ 627,152
39 Total Commodity	\$ 1,283,575	\$ 2,006,108	\$ 2,665,562	\$ 2,170,948	\$ 1,776,644	\$ 949,978	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875	\$ 13,018,474	\$ 10,852,815	\$ 2,165,659

**Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS**

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Schedule 8-CAK, LN 2 * LN 55 * 10
	New Hampshire Sales Pipeline Remaining	Schedule 8-CAK, LN 3 * LN 55 * 10
3	New Hampshire Sales Storage	Schedule 8-CAK, LN 4 * LN 55 * 10
4	New Hampshire Sales Peaking	Schedule 8-CAK, LN 5 * LN 55 * 10
5	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 4
6		
7	New Hampshire Interruptible Sendout (Pipeline)	Schedule 8-CAK, LN 9 * 10
8		
9	Total Firm Sendout	LN 5
10	Total Firm Sales	Schedule 6-CAK, LN 11
11	Difference (LAUF & Company Use)	LN 9 - LN 10
12	Percent Difference	LN 11 / LN 9
13		
14	Variable Costs	
15	New Hampshire Sales Pipeline Commodity	Schedule 8-CAK, LN 69
16	New Hampshire Sales Pipeline Remaining	Schedule 8-CAK, LN 70
17	New Hampshire Total Storage	Schedule 8-CAK, LN 71
18	New Hampshire Total Peaking	Schedule 8-CAK, LN 72
19	New Hampshire Inventory Finance Charge	Schedule 8-CAK, LN 75
20	Total New Hampshire Sales Variable Costs	Sum LN 15 : LN 19
21		
22	New Hampshire Interruptible Commodity Costs	Schedule 8-CAK, LN 38
23	Total New Hampshire Commodity Costs	LN 20 + LN 22
24		
25	Supply Cost/Therm	
26	New Hampshire Sales Pipeline Commodity	LN 15 / LN 1
	New Hampshire Sales Pipeline Remaining	LN 16 / LN 2
28	New Hampshire Storage Excl'd Inventory Finance Costs	LN 17 / LN 3
29	New Hampshire Peaking Excl'd Inventory Finance Costs	LN 18 / LN 4
30	New Hampshire Inventory Finance Costs per Dth Stor and Peak	LN 19 / Sum (LN 3 : LN 4)
31	Weighted Average Cost per Dth Sendout	LN 20 / LN 9
32		
33	New Hampshire Interruptible Cost / Therm	LN 22 / LN 7
34		
35	Commodity Costs	
36	Base Commodity, therms	Schedule 6-CAK, LN 64
37	Base Commodity Cost	Min (LN 26 * LN 36), LN 20
38	Remaining Commodity	LN 23 - LN 37
39	Total Commodity	LN 37 + LN 38

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Northern Utilities, Inc.
New Hampshire Division
Schedule 10
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**Northern Utilities, Inc.
Storage Inventory and Activity Costs**

Denotes Confidential Information

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding	Withdrawn Value plus Charges
Nov-19	210,095	-	-	210,095	314,932	\$ 1.50	NA	\$ -	\$ 1.50	\$ -	\$ 314,932	1.30%	\$ 341	\$ 314,932	\$ -
Dec-19	210,095	-	67,473	142,622	\$ 314,932	\$ 1.50	NA	\$ -	\$ 1.50	\$ 101,142	\$ 213,790	1.30%	\$ 286	\$ 213,790	\$ 101,142
Jan-20	142,622	-	67,473	75,149	\$ 213,790	\$ 1.50	NA	\$ -	\$ 1.50	\$ 101,142	\$ 112,648	1.30%	\$ 177	\$ 112,648	\$ 101,142
Feb-20	75,149	-	60,587	14,561	\$ 112,648	\$ 1.50	NA	\$ -	\$ 1.50	\$ 90,820	\$ 21,827	1.30%	\$ 73	\$ 21,827	\$ 90,820
Mar-20	14,561	-	14,561	-	\$ 21,827	\$ 1.50	NA	\$ -	\$ 1.50	\$ 21,827	\$ -	1.30%	\$ 12	\$ -	\$ 21,827
Apr-20	-	-	-	-	\$ -	NA	NA	\$ -	\$ -	\$ -	\$ -	1.30%	\$ -	\$ -	\$ -
May-20	-	42,775	-	42,775	\$ -	NA	\$ 2.53	\$ 108,013	\$ -	\$ -	\$ 108,013	1.30%	\$ 59	\$ 108,013	\$ -
Jun-20	42,775	41,395	-	84,171	\$ 108,013	\$ 2.53	\$ 2.52	\$ 104,203	\$ 2.52	\$ -	\$ 212,216	1.30%	\$ 173	\$ 212,216	\$ -
Jul-20	84,171	-	-	84,171	\$ 212,216	\$ 2.52	NA	\$ -	\$ 2.52	\$ -	\$ 212,216	1.30%	\$ 230	\$ 212,216	\$ -
Aug-20	84,171	41,754	-	125,924	\$ 212,216	\$ 2.52	\$ 2.54	\$ 106,096	\$ 2.53	\$ -	\$ 318,313	1.30%	\$ 287	\$ 318,312	\$ -
Sep-20	125,924	41,395	-	167,320	\$ 318,313	\$ 2.53	\$ 2.37	\$ 97,955	\$ 2.49	\$ -	\$ 416,268	1.30%	\$ 398	\$ 416,267	\$ -
Oct-20	167,320	42,775	-	210,095	\$ 416,268	\$ 2.49	\$ 2.39	\$ 102,260	\$ 2.47	\$ -	\$ 518,527	1.30%	\$ 506	\$ 518,526	\$ -

Union Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding	Withdrawn Value plus Charges
Nov-19	3,240,502	-	242,662	2,997,840	\$ 5,696,802	\$ 1.76	NA	\$ -	\$ 1.76	\$ 426,600	\$ 5,270,202			\$ 5,270,202	\$ 426,600
Dec-19	2,997,840	-	626,554	2,371,286	\$ 5,270,202	\$ 1.76	NA	\$ -	\$ 1.76	\$ 1,101,482	\$ 4,168,720			\$ 4,168,720	\$ 1,101,482
Jan-20	2,371,286	-	720,240	1,651,045	\$ 4,168,720	\$ 1.76	NA	\$ -	\$ 1.76	\$ 1,266,183	\$ 2,902,538			\$ 2,902,538	\$ 1,266,183
Feb-20	1,651,045	-	746,937	904,108	\$ 2,902,538	\$ 1.76	NA	\$ -	\$ 1.76	\$ 1,313,115	\$ 1,589,422			\$ 1,589,422	\$ 1,313,115
Mar-20	904,108	-	442,456	461,652	\$ 1,589,422	\$ 1.76	NA	\$ -	\$ 1.76	\$ 777,838	\$ 811,585			\$ 811,585	\$ 777,838
Apr-20	461,652	-	-	461,652	\$ 811,585	\$ 1.76	NA	\$ -	\$ 1.76		\$ 811,585			\$ 811,585	\$ -
May-20	461,652	748,903	-	1,210,556	\$ 811,585	\$ 2	\$ 2.62	\$ 1,959,757	\$ 2.29		\$ 2,771,342			\$ 2,771,342	\$ -
Jun-20	1,210,556	724,745	-	1,935,301	\$ 2,771,342	\$ 2.29	\$ 2.60	\$ 1,887,135	\$ 2.41		\$ 4,658,476			\$ 4,658,476	\$ -
Jul-20	1,935,301	340,007	-	2,275,308	\$ 4,658,476	\$ 2.41	\$ 2.63	\$ 894,258	\$ 2.44		\$ 5,552,735			\$ 5,552,735	\$ -
Aug-20	2,275,308	-	-	2,275,308	\$ 5,552,735	\$ 2.44	NA	\$ -	\$ 2.44		\$ 5,552,735			\$ 5,552,735	\$ -
Sep-20	2,275,308	-	-	2,275,308	\$ 5,552,735	\$ 2.44	NA	\$ -	\$ 2.44		\$ 5,552,735			\$ 5,552,735	\$ -
Oct-20	2,275,308	748,903	-	3,024,211	\$ 5,552,735	\$ 2.44	\$ -	\$ 1,944,847	\$ 2.48		\$ 7,497,581			\$ 7,497,581	\$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding	Withdrawn Value plus Charges
Nov-19	12,000	1,794	1,794	12,000											
Dec-19	12,000	22,761	22,761	12,000											
Jan-20	12,000	51,303	52,503	10,800											
Feb-20	10,800	33,254	33,254	10,800											
Mar-20	10,800	1,854	1,854	10,800											
Apr-20	10,800	1,794	1,794	10,800											
May-20	10,800	3,060	1,860	12,000											
Jun-20	12,000	1,800	1,800	12,000											
Jul-20	12,000	1,860	1,860	12,000											
Aug-20	12,000	660	1,860	10,800											
Sep-20	10,800	3,000	1,800	12,000											
Oct-20	12,000	1,860	1,860	12,000											

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

1	BASE SENDOUT BY CLASS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
2	Total Therms															
3	Res Heat	398,258	411,533	411,533	371,707	411,533	398,258	411,533	398,258	408,474	411,533	398,258	411,533	4,842,409	2,402,821	2,439,588
4	Res General	9,200	9,507	9,507	8,587	9,507	9,200	9,507	9,200	9,436	9,507	9,200	9,507	111,863	55,507	56,356
5	G50 Low Annual-Low Winter	60,765	62,790	62,790	56,714	62,790	60,765	62,790	60,765	62,324	62,790	60,765	62,790	738,838	366,614	372,224
6	G40 Low Annual-High Winter	150,397	155,410	155,410	140,371	155,410	150,397	155,410	150,397	154,255	155,410	150,397	155,410	1,828,675	907,395	921,280
7	G51 Med Annual-Low Winter	107,182	110,755	110,755	100,037	110,755	105,343	110,755	107,182	109,932	110,755	107,182	110,755	1,301,390	644,827	656,562
8	G41 Med Annual-High Winter	145,740	150,598	150,598	136,024	150,598	145,740	150,598	145,740	149,478	150,598	145,740	150,598	1,772,048	879,297	892,751
9	G52 High Annual-Low Winter	58,087	60,023	60,023	54,215	60,023	49,858	60,023	58,087	59,577	60,023	58,087	60,023	698,050	342,229	355,821
10	G42 High Annual-High Winter	23,253	24,028	24,028	21,703	24,028	23,253	24,028	23,253	23,850	24,028	23,253	24,028	282,733	140,293	142,440
11	Total Firm Sales	952,882	984,644	984,644	889,356	984,644	942,813	984,644	952,882	977,326	984,644	952,882	984,644	11,576,005	5,738,983	5,837,022
12	% of Total															
13	Res Heat	41.80%	41.80%	41.80%	41.80%	41.80%	42.24%	41.80%	41.80%	41.80%	41.80%	41.80%	41.80%	41.80%		
14	Res General	0.97%	0.97%	0.97%	0.97%	0.97%	0.98%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%		
15	G50 Low Annual-Low Winter	6.38%	6.38%	6.38%	6.38%	6.38%	6.45%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%		
16	G40 Low Annual-High Winter	15.78%	15.78%	15.78%	15.78%	15.78%	15.95%	15.78%	15.78%	15.78%	15.78%	15.78%	15.78%	15.78%		
17	G51 Med Annual-Low Winter	11.25%	11.25%	11.25%	11.25%	11.25%	11.17%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%		
18	G41 Med Annual-High Winter	15.29%	15.29%	15.29%	15.29%	15.29%	15.46%	15.29%	15.29%	15.29%	15.29%	15.29%	15.29%	15.29%		
19	G52 High Annual-Low Winter	6.10%	6.10%	6.10%	6.10%	6.10%	5.29%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%		
20	G42 High Annual-High Winter	2.44%	2.44%	2.44%	2.44%	2.44%	2.47%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%		
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		
22	BASE COMMODITY COSTS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
23	TOTAL BASE COMMODITY	\$ 276,302	\$ 331,242	\$ 345,346	\$ 310,033	\$ 329,959	\$ 264,428	\$ 260,740	\$ 250,579	\$ 260,197	\$ 261,838	\$ 247,748	\$ 257,405	\$ 3,395,816	\$ 1,857,310	\$ 1,538,506
24	Res Heat	\$ 115,481	\$ 138,443	\$ 144,338	\$ 129,579	\$ 137,906	\$ 111,698	\$ 108,976	\$ 104,730	\$ 108,750	\$ 109,435	\$ 103,547	\$ 107,583	\$ 1,420,464	\$ 777,444	\$ 643,020
25	Res General	\$ 2,668	\$ 3,198	\$ 3,334	\$ 2,993	\$ 3,186	\$ 2,580	\$ 2,517	\$ 2,419	\$ 2,512	\$ 2,528	\$ 2,392	\$ 2,485	\$ 32,814	\$ 17,959	\$ 14,854
26	G50 Low Annual-Low Winter	\$ 17,620	\$ 21,123	\$ 22,023	\$ 19,771	\$ 21,041	\$ 17,043	\$ 16,627	\$ 15,979	\$ 16,593	\$ 16,697	\$ 15,799	\$ 16,415	\$ 216,730	\$ 118,620	\$ 98,110
27	G40 Low Annual-High Winter	\$ 43,610	\$ 52,281	\$ 54,507	\$ 48,934	\$ 52,079	\$ 42,181	\$ 41,154	\$ 39,550	\$ 41,068	\$ 41,327	\$ 39,103	\$ 40,627	\$ 536,421	\$ 293,592	\$ 242,828
28	G51 Med Annual-Low Winter	\$ 31,079	\$ 37,259	\$ 38,845	\$ 34,873	\$ 37,115	\$ 29,545	\$ 29,329	\$ 28,186	\$ 29,268	\$ 29,452	\$ 27,867	\$ 28,954	\$ 381,771	\$ 208,716	\$ 173,055
29	G41 Med Annual-High Winter	\$ 42,259	\$ 50,662	\$ 52,819	\$ 47,418	\$ 50,466	\$ 40,875	\$ 39,879	\$ 38,325	\$ 39,796	\$ 40,047	\$ 37,892	\$ 39,369	\$ 519,810	\$ 284,501	\$ 235,309
30	G52 High Annual-Low Winter	\$ 16,843	\$ 20,192	\$ 21,052	\$ 18,899	\$ 20,114	\$ 13,983	\$ 15,895	\$ 15,275	\$ 15,861	\$ 15,961	\$ 15,103	\$ 15,691	\$ 204,871	\$ 111,084	\$ 93,786
31	G42 High Annual-High Winter	\$ 6,743	\$ 8,083	\$ 8,427	\$ 7,566	\$ 8,052	\$ 6,522	\$ 6,363	\$ 6,115	\$ 6,350	\$ 6,390	\$ 6,046	\$ 6,281	\$ 82,936	\$ 45,393	\$ 37,544
32																
33	Residential	\$ 118,148	\$ 141,641	\$ 147,672	\$ 132,572	\$ 141,092	\$ 114,278	\$ 111,494	\$ 107,149	\$ 111,262	\$ 111,963	\$ 105,939	\$ 110,068	\$ 1,453,278	\$ 795,404	\$ 657,874
34	SALES HLF CLASSES	\$ 65,542	\$ 78,574	\$ 81,920	\$ 73,543	\$ 78,270	\$ 60,571	\$ 61,850	\$ 59,440	\$ 61,722	\$ 62,111	\$ 58,769	\$ 61,059	\$ 803,371	\$ 438,421	\$ 364,951
35	SALES LLF CLASSES	\$ 92,612	\$ 111,027	\$ 115,754	\$ 103,918	\$ 110,597	\$ 89,578	\$ 87,396	\$ 83,990	\$ 87,214	\$ 87,764	\$ 83,041	\$ 86,278	\$ 1,139,167	\$ 623,485	\$ 515,681

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

1	BASE SENDOUT BY CLASS	
2	Total Therms	
3	Res Heat	Schedule 6-CAK, LN 52
4	Res General	Schedule 6-CAK, LN 53
5	G50 Low Annual-Low Winter	Schedule 6-CAK, LN 54
6	G40 Low Annual-High Winter	Schedule 6-CAK, LN 55
7	G51 Med Annual-Low Winter	Schedule 6-CAK, LN 56
8	G41 Med Annual-High Winter	Schedule 6-CAK, LN 57
9	G52 High Annual-Low Winter	Schedule 6-CAK, LN 58
10	G42 High Annual-High Winter	Schedule 6-CAK, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12	% of Total	
13	Res Heat	LN 3 / LN 11
14	Res General	LN 4 / LN 11
15	G50 Low Annual-Low Winter	LN 5 / LN 11
16	G40 Low Annual-High Winter	LN 6 / LN 11
17	G51 Med Annual-Low Winter	LN 7 / LN 11
18	G41 Med Annual-High Winter	LN 8 / LN 11
19	G52 High Annual-Low Winter	LN 9 / LN 11
20	G42 High Annual-High Winter	LN 10 / LN 11
21	Total Firm Sales	Sum LN 13 : LN 20
22	BASE COMMODITY COSTS	
23	TOTAL BASE COMMODITY	Schedule 9-CAK, LN 37
24	Res Heat	LN 23 * LN 13
25	Res General	LN 23 * LN 14
26	G50 Low Annual-Low Winter	LN 23 * LN 15
27	G40 Low Annual-High Winter	LN 23 * LN 16
28	G51 Med Annual-Low Winter	LN 23 * LN 17
29	G41 Med Annual-High Winter	LN 23 * LN 18
30	G52 High Annual-Low Winter	LN 23 * LN 19
31	G42 High Annual-High Winter	LN 23 * LN 20
32		
33	Residential	LN 24 + LN 25
34	SALES HLF CLASSES	LN 26 + LN 28 + LN 30
35	SALES LLF CLASSES	LN 27 + LN 29 + LN 31

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

REMAINING SENDOUT BY CLASS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
Total Therms															
Res Heat	1,785,942	2,764,673	3,372,294	2,845,213	2,372,313	1,200,257	312,316	86,266	-	3,059	53,115	519,320	15,314,766	14,340,691	974,074
Res General	12,058	21,407	27,320	22,723	17,588	6,358	7,215	1,993	-	71	1,227	11,997	129,955	107,454	22,502
G50 Low Annual-Low Winter	28,221	66,611	91,366	74,346	50,626	4,360	47,652	13,162	-	467	8,104	79,236	464,150	315,529	148,621
G40 Low Annual-High Winter	861,212	1,315,645	1,597,064	1,349,541	1,133,924	589,953	117,942	32,577	-	1,155	20,058	196,115	7,215,186	6,847,339	367,847
G51 Med Annual-Low Winter	36,757	98,558	138,600	111,959	72,701	-	84,053	23,217	-	823	14,295	139,764	720,727	458,576	262,151
G41 Med Annual-High Winter	765,185	1,174,045	1,427,455	1,205,599	1,010,411	520,924	114,290	31,568	-	1,119	19,437	190,042	6,460,076	6,103,620	356,456
G52 High Annual-Low Winter	10,038	39,043	57,994	46,121	26,805	-	45,552	12,582	-	446	7,747	75,744	322,073	180,002	142,072
G42 High Annual-High Winter	160,181	242,717	293,746	248,461	209,765	110,994	18,235	5,037	-	179	3,101	30,321	1,322,737	1,265,863	56,873
Total Firm Sales	3,659,596	5,722,698	7,005,839	5,903,964	4,894,132	2,432,845	747,254	206,402	-	7,319	127,084	1,242,537	31,949,670	29,619,074	2,330,596
% of Total															
Res Heat	48.80%	48.31%	48.14%	48.19%	48.47%	49.34%	41.80%	41.80%	41.80%	41.80%	41.80%	41.80%	41.80%		
Res General	0.33%	0.37%	0.39%	0.38%	0.36%	0.26%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%		
G50 Low Annual-Low Winter	0.77%	1.16%	1.30%	1.26%	1.03%	0.18%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%	6.38%		
G40 Low Annual-High Winter	23.53%	22.99%	22.80%	22.86%	23.17%	24.25%	15.78%	15.78%	15.78%	15.78%	15.78%	15.78%	15.78%		
G51 Med Annual-Low Winter	1.00%	1.72%	1.98%	1.90%	1.49%	0.00%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%		
G41 Med Annual-High Winter	20.91%	20.52%	20.38%	20.42%	20.65%	21.41%	15.29%	15.29%	15.29%	15.29%	15.29%	15.29%	15.29%		
G52 High Annual-Low Winter	0.27%	0.68%	0.83%	0.78%	0.55%	0.00%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%		
G42 High Annual-High Winter	4.38%	4.24%	4.19%	4.21%	4.29%	4.56%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%	2.44%		
Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		

REMAINING COMMODITY COSTS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
REMAINING COMMODITY	\$ 1,007,273	\$ 1,674,866	\$ 2,320,216	\$ 1,860,915	\$ 1,446,686	\$ 685,550	\$ 200,512	\$ 56,785	\$ 2,487	\$ 4,438	\$ 35,461	\$ 327,470	\$ 9,622,658	\$ 8,995,505	\$ 627,152
Res Heat	\$ 491,566	\$ 809,139	\$ 1,116,847	\$ 896,804	\$ 701,246	\$ 338,220	\$ 83,804	\$ 23,733	\$ 1,039	\$ 1,855	\$ 14,821	\$ 136,866	\$ 4,615,940	\$ 4,353,821	\$ 262,119
Res General	\$ 3,319	\$ 6,265	\$ 9,048	\$ 7,162	\$ 5,199	\$ 1,792	\$ 1,936	\$ 548	\$ 24	\$ 43	\$ 342	\$ 3,162	\$ 38,840	\$ 32,785	\$ 6,055
G50 Low Annual-Low Winter	\$ 7,768	\$ 19,495	\$ 30,259	\$ 23,434	\$ 14,965	\$ 1,229	\$ 12,787	\$ 3,621	\$ 159	\$ 283	\$ 2,261	\$ 20,883	\$ 137,142	\$ 97,148	\$ 39,993
G40 Low Annual-High Winter	\$ 237,041	\$ 385,051	\$ 528,921	\$ 425,372	\$ 335,183	\$ 166,242	\$ 31,648	\$ 8,963	\$ 393	\$ 700	\$ 5,597	\$ 51,686	\$ 2,176,797	\$ 2,077,811	\$ 98,986
G51 Med Annual-Low Winter	\$ 10,117	\$ 28,845	\$ 45,902	\$ 35,289	\$ 21,490	\$ -	\$ 22,554	\$ 6,387	\$ 280	\$ 499	\$ 3,989	\$ 36,835	\$ 212,187	\$ 141,644	\$ 70,544
G41 Med Annual-High Winter	\$ 210,611	\$ 343,609	\$ 472,749	\$ 380,002	\$ 298,673	\$ 146,791	\$ 30,668	\$ 8,685	\$ 380	\$ 679	\$ 5,424	\$ 50,085	\$ 1,948,355	\$ 1,852,435	\$ 95,921
G52 High Annual-Low Winter	\$ 2,763	\$ 11,427	\$ 19,207	\$ 14,537	\$ 7,923	\$ -	\$ 12,223	\$ 3,462	\$ 152	\$ 271	\$ 2,162	\$ 19,962	\$ 94,088	\$ 55,857	\$ 38,231
G42 High Annual-High Winter	\$ 44,088	\$ 71,036	\$ 97,284	\$ 78,314	\$ 62,006	\$ 31,277	\$ 4,893	\$ 1,386	\$ 61	\$ 108	\$ 865	\$ 7,991	\$ 399,309	\$ 384,005	\$ 15,304
Residential	\$ 494,885	\$ 815,404	\$ 1,125,895	\$ 903,966	\$ 706,445	\$ 340,011	\$ 85,740	\$ 24,282	\$ 1,063	\$ 1,898	\$ 15,163	\$ 140,028	\$ 4,654,780	\$ 4,386,606	\$ 268,174
SALES HLF CLASSES	\$ 20,648	\$ 59,767	\$ 95,368	\$ 73,260	\$ 44,378	\$ 1,229	\$ 47,564	\$ 13,470	\$ 590	\$ 1,053	\$ 8,412	\$ 77,680	\$ 443,417	\$ 294,649	\$ 148,768
SALES LLF CLASSES	\$ 491,741	\$ 799,695	\$ 1,098,953	\$ 883,688	\$ 695,862	\$ 344,310	\$ 67,208	\$ 19,033	\$ 834	\$ 1,487	\$ 11,886	\$ 109,762	\$ 4,524,461	\$ 4,314,250	\$ 210,211

Total Commodity Costs

TOTAL COMMODITY COSTS	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual	Winter	Summer
TOTAL COMMODITY	\$ 1,283,575	\$ 2,006,108	\$ 2,665,562	\$ 2,170,948	\$ 1,776,644	\$ 949,978	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875	\$ 13,018,474	\$ 10,852,815	\$ 2,165,659
Res Heat	\$ 607,046	\$ 947,582	\$ 1,261,185	\$ 1,026,383	\$ 839,152	\$ 449,918	\$ 192,780	\$ 128,463	\$ 109,789	\$ 111,290	\$ 118,368	\$ 244,449	\$ 6,036,404	\$ 5,131,265	\$ 905,139
Res General	\$ 5,987	\$ 9,463	\$ 12,382	\$ 10,156	\$ 8,385	\$ 4,372	\$ 4,453	\$ 2,968	\$ 2,536	\$ 2,571	\$ 2,734	\$ 5,647	\$ 71,653	\$ 50,744	\$ 20,909
G50 Low Annual-Low Winter	\$ 25,387	\$ 40,618	\$ 52,281	\$ 43,204	\$ 36,006	\$ 18,271	\$ 29,414	\$ 19,600	\$ 16,751	\$ 16,980	\$ 18,060	\$ 37,297	\$ 353,871	\$ 215,768	\$ 138,103
G40 Low Annual-High Winter	\$ 280,651	\$ 437,332	\$ 583,428	\$ 474,306	\$ 387,262	\$ 208,424	\$ 72,801	\$ 48,512	\$ 41,460	\$ 42,027	\$ 44,700	\$ 92,313	\$ 2,713,217	\$ 2,371,403	\$ 341,814
G51 Med Annual-Low Winter	\$ 41,196	\$ 66,104	\$ 84,747	\$ 70,163	\$ 58,605	\$ 29,545	\$ 51,883	\$ 34,573	\$ 29,547	\$ 29,951	\$ 31,856	\$ 65,788	\$ 593,958	\$ 350,360	\$ 243,598
G41 Med Annual-High Winter	\$ 252,870	\$ 394,271	\$ 525,569	\$ 427,420	\$ 349,139	\$ 187,666	\$ 70,547	\$ 47,010	\$ 40,177	\$ 40,726	\$ 43,316	\$ 89,455	\$ 2,468,165	\$ 2,136,935	\$ 331,230
G52 High Annual-Low Winter	\$ 19,606	\$ 31,619	\$ 40,259	\$ 33,437	\$ 28,038	\$ 13,983	\$ 28,118	\$ 18,737	\$ 16,013	\$ 16,232	\$ 17,264	\$ 35,654	\$ 298,959	\$ 166,942	\$ 132,017
G42 High Annual-High Winter	\$ 50,831	\$ 79,119	\$ 105,711	\$ 85,880	\$ 70,058	\$ 37,799	\$ 11,256	\$ 7,501	\$ 6,410	\$ 6,498	\$ 6,911	\$ 14,273	\$ 482,246	\$ 429,398	\$ 52,848
Residential	\$ 613,033	\$ 957,045	\$ 1,273,567	\$ 1,036,538	\$ 847,537	\$ 454,290	\$ 197,234	\$ 131,430	\$ 112,325	\$ 113,861	\$ 121,102	\$ 250,096	\$ 6,108,058	\$ 5,182,009	\$ 926,048
SALES HLF CLASSES	\$ 86,190	\$ 138,341	\$ 177,288	\$ 146,804	\$ 122,648	\$ 61,800	\$ 109,414	\$ 72,910	\$ 62,312	\$ 63,163	\$ 67,180	\$ 138,739	\$ 1,246,788	\$ 733,070	\$ 513,718
SALES LLF CLASSES	\$ 584,352	\$ 910,722	\$ 1,214,708	\$ 987,606	\$ 806,459	\$ 433,888	\$ 154,604	\$ 103,023	\$ 88,047	\$ 89,251	\$ 94,927	\$ 196,040	\$ 5,663,628	\$ 4,937,736	\$ 725,892
% ALLOCATION BETWEEN HLF & LLF															
HLF CLASSES%														12.93%	41.44%
LLF CLASSES %														87.07%	58.56%

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

36	REMAINING SENDOUT BY CLASS	
37	Total Therms	
38	Res Heat	Schedule 6-CAK, LN 68
39	Res General	Schedule 6-CAK, LN 69
40	G50 Low Annual-Low Winter	Schedule 6-CAK, LN 70
41	G40 Low Annual-High Winter	Schedule 6-CAK, LN 71
42	G51 Med Annual-Low Winter	Schedule 6-CAK, LN 72
43	G41 Med Annual-High Winter	Schedule 6-CAK, LN 73
44	G52 High Annual-Low Winter	Schedule 6-CAK, LN 74
45	G42 High Annual-High Winter	Schedule 6-CAK, LN 75
46	Total Firm Sales	Sum LN 38 : LN 45
47	% of Total	
48	Res Heat	LN 38 / LN 46
49	Res General	LN 39 / LN 46
50	G50 Low Annual-Low Winter	LN 40 / LN 46
51	G40 Low Annual-High Winter	LN 41 / LN 46
52	G51 Med Annual-Low Winter	LN 42 / LN 46
53	G41 Med Annual-High Winter	LN 43 / LN 46
54	G52 High Annual-Low Winter	LN 44 / LN 46
55	G42 High Annual-High Winter	LN 45 / LN 46
56	Total Firm Sales	Sum LN 62 : LN 69

57	REMAINING COMMODITY COSTS	
58	REMAINING COMMODITY	
59	Res Heat	Schedule 9-CAK, LN 38
60	Res General	LN 58 * LN 48
61	G50 Low Annual-Low Winter	LN 58 * LN 49
62	G40 Low Annual-High Winter	LN 58 * LN 50
63	G51 Med Annual-Low Winter	LN 58 * LN 51
64	G41 Med Annual-High Winter	LN 58 * LN 52
65	G52 High Annual-Low Winter	LN 58 * LN 53
66	G42 High Annual-High Winter	LN 58 * LN 54
67		LN 58 * LN 55
68	Residential	LN 59 + LN 60
69	SALES HLF CLASSES	LN 61 + LN 63 + LN 65
70	SALES LLF CLASSES	LN 62 + LN 64 + LN 66

Total Commodity Costs

71	TOTAL COMMODITY COSTS	
72	TOTAL COMMODITY	
73	Res Heat	Schedule 9-CAK, LN 39
74	Res General	LN 24 + LN 59
75	G50 Low Annual-Low Winter	LN 25 + LN 60
76	G40 Low Annual-High Winter	LN 26 + LN 61
77	G51 Med Annual-Low Winter	LN 27 + LN 62
78	G41 Med Annual-High Winter	LN 28 + LN 63
79	G52 High Annual-Low Winter	LN 29 + LN 64
80	G42 High Annual-High Winter	LN 30 + LN 65
81		LN 31 + LN 66
82	Residential	LN 73 + LN 74
83	SALES HLF CLASSES	LN 75 + LN 77 + LN 79
84	SALES LLF CLASSES	LN 76 + LN 78 + LN 80

Northern Utilities - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Demand and Commodity Cost Reallocation to HLF and LLF Customers

		Winter	Summer	Annual	
1	Demand	\$ 13,021,761	\$ 1,175,460	\$ 14,197,221	Schedule 5-CAK, LN 80
2	Commodity	\$ 10,852,815	\$ 2,165,659	\$ 13,018,474	Schedule 9-CAK, LN 39
3	Total	\$ 23,874,576	\$ 3,341,119	\$ 27,215,695	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	34,897,412	8,061,210	42,958,621	Schedule 6-CAK, LN 11
6	Forecasted Residential Sales (Therms)	16,686,215	3,447,020	20,133,234	Schedule 6-CAK, LN 3
7	Average Residential Rate:	Winter	Summer	Annual	
8	Average Demand Rate	\$0.3731	\$0.1458		LN 1 / LN 5
9	Average Commodity Rate	\$0.3110	\$0.2687		LN 2 / LN 5
10	Average Rate	\$0.6841	\$0.4145		LN 3 / LN 5
11					
12	Residential Reallocation:	Winter	Summer	Annual	
13	Demand Costs Allocated To Residential per SMBA	\$ 6,565,465	\$ 541,485	\$ 7,106,949	Schedule 7-CAK, LN 169
14	Demand Costs Allocated To Residential per Avg Res. Rate	\$ 6,226,361	\$ 502,575	\$ 6,728,937	LN 8 * LN 6
15	Demand Reallocation:	\$ 339,103	\$ 38,909	\$ 378,012	LN 13 - LN 14
16	HLF Allocation	\$ 31,569	\$ 10,993	\$ 42,562	LN 15 * LN 20
17	LLF Allocation	\$ 307,534	\$ 27,917	\$ 335,451	LN 15 * LN 21
18					
19	SMBA Capacity Cost Allocation (%)				
20	HLF	9.31%	28.25%		Schedule 7-CAK, LN 174
21	LLF	90.69%	71.75%		Schedule 7-CAK, LN 175
22					
23	Commodity Costs Allocated To Residential per SMBA	\$ 5,182,009	\$ 926,048	\$ 6,108,058	Schedule 11-CAK, LN 82
24	Commodity Costs Allocated To Residential per Avg Res. Rate	\$ 5,189,279	\$ 926,214	\$ 6,115,493	LN 9 * LN 6
25	Commodity Reallocation:	\$ (7,269)	\$ (166)	\$ (7,435)	LN 23 - LN 24
26	HLF Allocation	\$ (940)	\$ (69)	\$ (1,009)	LN 25 * LN 30
27	LLF Allocation	\$ (6,330)	\$ (97)	\$ (6,427)	LN 25 * LN 31
28					
29	SMBA Commodity Cost Allocation (%)				
30	HLF	12.93%	41.44%		Schedule 11-CAK, LN 87
31	LLF	87.07%	58.56%		Schedule 11-CAK, LN 88

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
SCHEDULE 1: SUMMARY OF ANNUAL BALANCE
August 2019 - October 2020

	AMOUNT	
Annual Beginning Balance	\$ (3,464,049)	FORM III SCHEDULE 2
Less: Reported Collections	\$ (21,019,661)	FORM III SCHEDULE 3
Add: Cost of Firm Gas Allowable	\$ 25,380,497	FORM III SCHEDULE 4
Add: Interest	\$ (140,854)	FORM III SCHEDULE 2
Annual Ending Balance	\$ 755,934	

Allocation of Reconciliation Balance to 2020 / 2021 Winter Season and 2021 Summer Season

Winter Season Sales (DTHs)	3,489,741	Schedule 6-CAK
Summer Season Sales(DTHs)	806,121	Schedule 6-CAK

Winter Season Sales Percentage	81.23%
Summer Season Sales Percentage	18.77%

Reconciliation Allocated to Winter Season \$ 614,082

Reconciliation Allocated to Summer Season \$ 141,851

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER, WINTER AND ANNUAL ACCOUNTS
August 2019 - October 2020
Acct 191

	<u>Aug-19</u>	<u>Sep-19</u>	<u>Oct-19</u>	<u>Nov-19</u>	<u>Dec-19</u>	<u>Jan-20</u>	<u>Feb-20</u>	<u>Mar-20</u>	<u>Apr-20</u>	<u>May-20</u>	<u>Jun-20</u>	<u>Jul-20</u>	-----Estimated-----			<u>Total</u>
	<u>Aug-20</u>	<u>Sep-20</u>	<u>Oct-20</u>													
Initial Account Beginning Balance	\$ (3,461,695)															
Adjustment (1)	\$ (2,354)															
Adjusted Beginning Balance	\$ (3,464,049)	\$ (3,215,882)	\$ (2,923,112)	\$ (2,723,393)	\$ (2,989,174)	\$ (2,517,994)	\$ (2,468,978)	\$ (2,618,103)	\$ (3,303,713)	\$ (3,378,341)	\$ (2,940,853)	\$ (2,158,585)	\$ (1,456,073)	\$ (657,097)	\$ 85,829	
Plus: Cost of Firm Gas (Schedule 4)	\$ 503,369	\$ 564,496	\$ 688,371	\$ 2,323,608	\$ 4,459,112	\$ 3,863,342	\$ 3,017,046	\$ 2,280,546	\$ 1,757,285	\$ 941,598	\$ 913,641	\$ 808,418	\$ 944,082	\$ 1,032,655	\$ 1,282,928	\$ 25,380,497
Less: Reported Collections (Schedule 3)	\$ (239,929)	\$ (257,690)	\$ (476,327)	\$ (2,576,921)	\$ (3,975,911)	\$ (3,804,475)	\$ (3,156,122)	\$ (2,954,460)	\$ (1,818,714)	\$ (491,628)	\$ (121,301)	\$ (101,018)	\$ (142,248)	\$ (288,956)	\$ (613,962)	\$ (21,019,661)
Annual Account Ending Balance	\$ (3,200,609)	\$ (2,909,076)	\$ (2,711,068)	\$ (2,976,705)	\$ (2,505,974)	\$ (2,459,127)	\$ (2,608,054)	\$ (3,292,016)	\$ (3,365,142)	\$ (2,928,371)	\$ (2,148,512)	\$ (1,451,185)	\$ (654,240)	\$ 86,601	\$ 754,795	
Month's Average Balance	\$ (3,332,329)	\$ (3,062,479)	\$ (2,817,090)	\$ (2,850,049)	\$ (2,747,574)	\$ (2,488,561)	\$ (2,538,516)	\$ (2,955,059)	\$ (3,334,427)	\$ (3,153,356)	\$ (2,544,682)	\$ (1,804,885)	\$ (1,055,157)	\$ (285,248)	\$ 420,312	
Interest Rate (Prime Rate)	5.50%	5.50%	5.25%	5.25%	5.25%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	\$ (15,273)	\$ (14,036)	\$ (12,325)	\$ (12,469)	\$ (12,021)	\$ (9,851)	\$ (10,048)	\$ (11,697)	\$ (13,199)	\$ (12,482)	\$ (10,073)	\$ (4,888)	\$ (2,858)	\$ (773)	\$ 1,138	\$ (140,854)
Annual Account Ending Balance w/int	<u>\$ (3,215,882)</u>	<u>\$ (2,923,112)</u>	<u>\$ (2,723,393)</u>	<u>\$ (2,989,174)</u>	<u>\$ (2,517,994)</u>	<u>\$ (2,468,978)</u>	<u>\$ (2,618,103)</u>	<u>\$ (3,303,713)</u>	<u>\$ (3,378,341)</u>	<u>\$ (2,940,853)</u>	<u>\$ (2,158,585)</u>	<u>\$ (1,456,073)</u>	<u>\$ (657,097)</u>	<u>\$ 85,829</u>	<u>\$ 755,934</u>	

(1)Reflects Fuel Tax Recovery Expense of \$7,567 plus ATV charges, plus interest of (\$9,921), not included in 2018-2019 reconciliation.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
August 2019 - October 2020

	<u>Aug-19</u>	<u>Sep-19</u>	<u>Oct-19</u>	<u>Nov-19</u>	<u>Dec-19</u>	<u>Jan-20</u>	<u>Feb-20</u>	<u>Mar-20</u>	<u>Apr-20</u>	<u>May-20</u>	<u>Jun-20</u>	<u>Jul-20</u>	----- Estimated ⁽¹⁾ -----	<u>Aug-20</u>	<u>Sep-20</u>	<u>Oct-20</u>	<u>Total</u>
Accrued Revenue	\$ (8,337)	\$ 20,647	\$ 56,363	\$ 1,192,976	\$ 576,774	\$ 57,927	\$ (603,756)	\$ (238,411)	\$ (305,768)	\$ (557,865)	\$ (187,584)	\$ (64,808)					
Billed Revenue	\$ 248,265	\$ 237,043	\$ 419,963	\$ 1,383,945	\$ 3,399,138	\$ 3,746,548	\$ 3,759,878	\$ 3,192,870	\$ 2,124,482	\$ 1,049,493	\$ 308,884	\$ 165,827					
Calendarized Revenue	<u>\$ 239,929</u>	<u>\$ 257,690</u>	<u>\$ 476,327</u>	<u>\$ 2,576,921</u>	<u>\$ 3,975,911</u>	<u>\$ 3,804,475</u>	<u>\$ 3,156,122</u>	<u>\$ 2,954,460</u>	<u>\$ 1,818,714</u>	<u>\$ 491,628</u>	<u>\$ 121,301</u>	<u>\$ 101,018</u>	<u>\$ 142,248</u>	<u>\$ 288,956</u>	<u>\$ 613,962</u>	<u>\$ 21,019,661</u>	

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS
August 2019 - October 2020

-----Estimated ⁽¹⁾-----

Commodity Costs	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Total
American Excavators	\$ -	\$ -	\$ -	\$ -	\$ (1,122)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -				
DTE Energy Trading	\$ 51,298	\$ 35,417	\$ 33,946	\$ 41,919	\$ 45,230	\$ 48,436	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -				
Emera Energy Services Corp.	\$ 162,425	\$ 154,484	\$ 179,909	\$ 302,973	\$ 397,799	\$ 484,075	\$ 328,399	\$ 225,308	\$ 187,931	\$ 570,088	\$ 428,898	\$ 98,409				\$ 3,520,697
Repsol	\$ -	\$ -	\$ -	\$ -	\$ 708,647	\$ 1,666,425	\$ 1,649,529	\$ 1,714,594	\$ 802,063	\$ -	\$ -	\$ -				\$ 6,541,258
Shell	\$ -	\$ 9,657	\$ 8,520	\$ 10,017	\$ 312,844	\$ 342,855	\$ 279,022	\$ 188,111	\$ 214,872	\$ 54,346	\$ 4,647	\$ 4,078				\$ 1,428,969
Southwestern	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 27,187	\$ 29,402	\$ 24,531				
Subtotal - Commodity	\$ 213,723	\$ 199,558	\$ 222,375	\$ 354,909	\$ 1,463,398	\$ 2,541,790	\$ 2,256,950	\$ 2,128,014	\$ 1,204,866	\$ 651,620	\$ 462,946	\$ 127,018				\$ 11,827,168
Transportation																
Granite	\$ 73	\$ 86	\$ 169	\$ 372	\$ 521	\$ 524	\$ 441	\$ 277	\$ 371	\$ (2,711)	\$ 103	\$ 60				\$ 284
Emera	\$ -	\$ -	\$ 190	\$ 215	\$ 335	\$ 360	\$ 394	\$ 389	\$ 155	\$ 490	\$ 221	\$ 107				\$ 2,857
Emera Energy Services	\$ -	\$ -	\$ -	\$ -	\$ 1,069	\$ 1,131	\$ 1,708	\$ 1,691	\$ 681							
Maritimes	\$ -	\$ 647	\$ 303	\$ 1,213	\$ 3,588	\$ 10,673	\$ 7,736	\$ -	\$ -	\$ 30,387	\$ 10,504	\$ 43				\$ 65,094
Tennessee	\$ 2,788	\$ 2,647	\$ 2,401	\$ 2,723	\$ 2,454	\$ 2,730	\$ 2,707	\$ 2,571	\$ 2,539	\$ 2,526	\$ 2,429	\$ 2,133				\$ 30,649
Subtotal - Commodity Transportation	\$ 2,861	\$ 3,380	\$ 3,062	\$ 4,524	\$ 7,967	\$ 15,417	\$ 12,987	\$ 4,928	\$ 3,745	\$ 30,692	\$ 13,257	\$ 2,343				\$ 105,163
Commodity Cost Estimates	\$ 202,617	\$ 225,079	\$ 359,561	\$ 1,473,647	\$ 2,557,717	\$ 2,304,354	\$ 2,160,209	\$ 1,208,937	\$ 679,019	\$ 339,930	\$ 168,987	\$ 124,887				\$ 11,804,944
Commodity Cost Reversals	\$ (216,511)	\$ (202,617)	\$ (225,079)	\$ (359,561)	\$ (1,473,647)	\$ (2,557,717)	\$ (2,304,354)	\$ (2,160,209)	\$ (1,208,937)	\$ (679,019)	\$ (339,930)	\$ (168,987)				\$ (11,896,568)
Subtotal - Estimates	\$ (13,894)	\$ 22,462	\$ 134,482	\$ 1,114,086	\$ 1,084,070	\$ (253,363)	\$ (144,145)	\$ (951,272)	\$ (529,918)	\$ (339,089)	\$ (170,943)	\$ (44,100)				\$ 24,339,788
Subtotal - Supply	\$ 202,690	\$ 225,399	\$ 359,919	\$ 1,473,519	\$ 2,555,435	\$ 2,303,845	\$ 2,125,792	\$ 1,181,670	\$ 678,693	\$ 343,223	\$ 305,260	\$ 85,261				\$ 11,840,707
Withdrawal - Underground Storage	\$ 701	\$ 9,246	\$ (11,577)	\$ 14,188	\$ 958,654	\$ 645,431	\$ 441,433	\$ 282,796	\$ 1,075	\$ (803)	\$ (3)	\$ (14)				\$ 2,341,126
ATV Reconciliation Charges	\$ (1,673)	\$ 4,800	\$ 10,401				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -				\$ 13,528
Off System Sales	\$ -	\$ -	\$ -	\$ (83)	\$ -	\$ -	\$ (49,725)	\$ (302,011)	\$ -	\$ -	\$ (6,006)	\$ -				\$ (357,825)
Net OBA Adjustment	\$ 15	\$ (59)	\$ (166)	\$ (894)	\$ 2,875	\$ (379)	\$ (1,127)	\$ 681	\$ (57)	\$ 496	\$ 2,984	\$ 204				\$ 4,572
Company Managed	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (159,275)	\$ (96,147)	\$ -	\$ (114,704)	\$ -	\$ -				\$ (370,126)
LNG Withdrawal / Boiloff	\$ 6,089	\$ 5,606	\$ 4,102	\$ 3,602	\$ 11,370	\$ 15,954	\$ 3,607	\$ 5,567	\$ 3,424	\$ 3,763	\$ 3,779	\$ 3,078				\$ 69,941
Supplier Balancing	\$ (6,750)	\$ 94	\$ (874)	\$ (12,836)	\$ (9,957)	\$ -	\$ 22,245	\$ 20,978	\$ (0)	\$ 1,193	\$ -	\$ (57,586)				\$ (43,494)
Inventory Finance Charge	\$ 342	\$ 331	\$ 416	\$ 430	\$ 448	\$ 348	\$ 210	\$ 77	\$ 35	\$ 36	\$ 43	\$ 53				\$ 2,768
Subtotal - Other Commodity	\$ (1,276)	\$ 20,018	\$ 2,302	\$ 4,406	\$ 963,390	\$ 661,353	\$ 257,368	\$ (88,060)	\$ 4,478	\$ (110,019)	\$ 797	\$ (54,266)				\$ 1,660,491
Sales for Resale Estimates	\$ -	\$ -	\$ (83)	\$ (72,317)	\$ (86,958)	\$ (145,872)	\$ (364,568)	\$ (52,147)	\$ -	\$ (6,006)	\$ -	\$ -				\$ (727,951)
Sales for Resale Reversals	\$ -	\$ -	\$ -	\$ 83	\$ 72,317	\$ 86,958	\$ 145,872	\$ 364,568	\$ 52,147	\$ -	\$ 6,006	\$ -				\$ 727,951
Subtotal - Estimates	\$ -	\$ -	\$ (83)	\$ (72,234)	\$ (14,642)	\$ (58,913)	\$ (218,696)	\$ 312,422	\$ 52,147	\$ (6,006)	\$ 6,006	\$ -				\$ (0)
Total Commodity Costs	\$ 201,414	\$ 245,417	\$ 362,138	\$ 1,405,691	\$ 3,504,183	\$ 2,906,284	\$ 2,164,464	\$ 1,406,032	\$ 735,318	\$ 227,198	\$ 312,063	\$ 30,995	\$ 184,082	\$ 272,655	\$ 522,928	\$ 14,480,862

(1) Monthly estimates provided in Table 2 of Northern's August 2020 Monthly Cost of Gas Report, submitted in DG 19-154 on August 21, 2020.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS
August 2019 - October 2020

Demand Costs	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	-----Estimated ⁽¹⁾ -----			Total
Pipeline Reservation																
Alberta Northeast	\$ 3,951	\$ 4,429	\$ 4,229	\$ 4,545	\$ 3,878	\$ 3,713	\$ 4,089	\$ 3,705	\$ 3,735	\$ 3,589	\$ 3,764	\$ 3,588				\$ 47,215
Algonquin	\$ 14,984	\$ 14,984	\$ 14,984	\$ 14,620	\$ 14,212	\$ 14,191	\$ 14,177	\$ 14,196	\$ 14,209	\$ 14,212	\$ 14,212	\$ 14,212				\$ 173,193
Emera	\$ 289,782	\$ 290,885	\$ 294,813	\$ 290,399	\$ 276,100	\$ 275,910	\$ 273,342	\$ 258,063	\$ 260,833	\$ 259,272	\$ 265,473	\$ 272,060				\$ 3,306,930
Granite State	\$ 165,766	\$ 165,766	\$ 165,766	\$ 225,679	\$ 225,679	\$ 225,679	\$ 225,679	\$ 225,679	\$ 225,679	\$ 144,287	\$ 144,287	\$ 144,287				\$ 2,284,235
Iroquois	\$ 15,686	\$ 15,698	\$ 15,698	\$ 15,698	\$ 14,890	\$ 14,890	\$ 14,890	\$ 14,890	\$ 14,890	\$ 14,890	\$ 14,390	\$ 14,390				\$ 180,404
Portland	\$ 322,027	\$ 322,027	\$ 322,027	\$ 322,027	\$ 305,455	\$ 305,455	\$ 305,455	\$ 305,455	\$ 305,455	\$ 305,455	\$ 305,455	\$ 305,455				\$ 3,731,748
Tennessee	\$ 158,898	\$ 158,898	\$ 158,898	\$ 158,898	\$ 137,938	\$ 137,938	\$ 137,938	\$ 137,938	\$ 137,938	\$ 137,938	\$ 137,938	\$ 137,938				\$ 1,739,096
Texas Eastern	\$ 3,593	\$ 3,663	\$ 3,663	\$ 3,663	\$ 3,474	\$ 3,486	\$ 3,486	\$ 3,466	\$ 3,466	\$ (3,320)	\$ 2,865	\$ 2,865				\$ 34,369
Total Pipeline Reservation	\$ 974,688	\$ 976,350	\$ 980,079	\$ 1,035,529	\$ 981,627	\$ 981,263	\$ 979,056	\$ 963,392	\$ 966,205	\$ 875,823	\$ 888,384	\$ 894,795				\$ 11,497,190
Product Demand																
Excelon	\$ -	\$ -	\$ -	\$ -	\$ 134,934	\$ 134,934	\$ 134,934	\$ 134,934	\$ 134,934	\$ -	\$ -	\$ -				\$ 674,670
Repsol	\$ -	\$ -	\$ -	\$ -	\$ 335,475	\$ 335,475	\$ 335,475	\$ 335,475	\$ 335,475	\$ 335,475	\$ 335,475	\$ 335,475				\$ 2,683,804
Total Product Demand	\$ -	\$ -	\$ -	\$ -	\$ 470,409	\$ 470,409	\$ 470,409	\$ 470,409	\$ 470,409	\$ 335,475	\$ 335,475	\$ 335,475				\$ 3,358,474
Storage Pipeline Transportation and Demand Reservation																
Emera	\$ 104,394	\$ 104,394	\$ 104,394	\$ 104,394	\$ 99,021	\$ 99,021	\$ 99,021	\$ 99,021	\$ 99,021	\$ 99,021	\$ 99,021	\$ 99,021				\$ 1,209,745
Tennessee	\$ 5,026	\$ 5,026	\$ 5,026	\$ 5,026	\$ 4,362	\$ 4,362	\$ 4,362	\$ 4,362	\$ 4,362	\$ 4,362	\$ 4,362	\$ 4,362				\$ 55,000
Total Storage & Demand Reservation	\$ 109,420	\$ 109,420	\$ 109,420	\$ 109,420	\$ 103,383	\$ 103,383	\$ 103,383	\$ 103,383	\$ 103,383	\$ 103,383	\$ 103,383	\$ 103,383				\$ 1,264,746
Demand Cost Estimates	\$ 1,339,212	\$ 1,336,006	\$ 1,337,245	\$ 1,742,188	\$ 1,746,046	\$ 1,747,272	\$ 1,742,921	\$ 1,730,240	\$ 1,592,764	\$ 1,593,883	\$ 1,601,745	\$ 1,602,865				\$ 19,112,392
Demand Cost Reversals	\$ (1,345,233)	\$ (1,339,212)	\$ (1,336,006)	\$ (1,337,245)	\$ (1,742,188)	\$ (1,746,046)	\$ (1,747,272)	\$ (1,742,921)	\$ (1,730,240)	\$ (1,592,764)	\$ (1,593,883)	\$ (1,601,745)				\$ (18,854,760)
Subtotal	\$ (6,021)	\$ (3,206)	\$ 1,239	\$ 404,943	\$ 3,858	\$ 1,226	\$ (4,351)	\$ (12,681)	\$ (137,476)	\$ 1,119	\$ 7,862	\$ 1,120				\$ 257,632
Capacity Release ⁽²⁾	\$ (790,626)	\$ (781,719)	\$ (782,739)	\$ (794,966)	\$ (756,594)	\$ (749,060)	\$ (853,186)	\$ (802,727)	\$ (755,612)	\$ (663,064)	\$ (754,897)	\$ (572,755)				\$ (9,057,944)
Other A&G Allowance	\$ 18,234	\$ 18,234	\$ 18,234	\$ 77,924	\$ 77,924	\$ 77,924	\$ 77,924	\$ 77,924	\$ 77,924	\$ 18,818	\$ 18,818	\$ 18,818				\$ 578,702
Local Production and Storage Allowance	\$ -	\$ -	\$ -	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ -	\$ -	\$ -				\$ 476,106
Conversion & Re-entry Fees	\$ -	\$ -	\$ -	\$ (125)	\$ (715)	\$ (313)	\$ (497)	\$ (469)	\$ (282)	\$ -	\$ (47)	\$ (43)				\$ (2,490)
Fuel Tax Recovery	\$ -	\$ -	\$ -	\$ 1,637	\$ -	\$ 845	\$ 492	\$ -	\$ -	\$ -	\$ -	\$ -				
Total Indirect Demand Costs	\$ (772,392)	\$ (763,485)	\$ (764,505)	\$ (636,178)	\$ (600,034)	\$ (591,252)	\$ (695,916)	\$ (645,921)	\$ (598,619)	\$ (644,245)	\$ (736,126)	\$ (553,980)				\$ (8,002,652)
Estimates - Cap Release & Comp Managed	\$ (12,753)	\$ (12,753)	\$ (12,753)	\$ (8,550)	\$ (12,866)	\$ (20,838)	\$ (20,838)	\$ (24,906)	\$ 193,159	\$ 236,002	\$ 238,602	\$ 235,231				\$ 776,737
Reversals - Cap Release & Comp Managed	\$ 9,014	\$ 12,753	\$ 12,753	\$ 12,753	\$ 8,550	\$ 12,866	\$ 20,838	\$ 20,838	\$ 24,906	\$ (193,159)	\$ (236,002)	\$ (238,602)				\$ (532,492)
Subtotal	\$ (3,739)	\$ -	\$ -	\$ 4,203	\$ (4,316)	\$ (7,971)	\$ (0)	\$ (4,068)	\$ 218,064	\$ 42,844	\$ 2,600	\$ (3,371)				\$ 244,245
Annual Demand Costs	\$ 301,955	\$ 319,079	\$ 326,233	\$ 917,917	\$ 954,928	\$ 957,058	\$ 852,582	\$ 874,515	\$ 1,021,967	\$ 714,399	\$ 601,578	\$ 777,423	\$ 760,000	\$ 760,000	\$ 760,000	\$ 10,899,635
Total Gas Costs	\$ 503,369	\$ 564,496	\$ 688,371	\$ 2,323,608	\$ 4,459,112	\$ 3,863,342	\$ 3,017,046	\$ 2,280,546	\$ 1,757,285	\$ 941,598	\$ 913,641	\$ 808,418	\$ 944,082	\$ 1,032,655	\$ 1,282,928	\$ 25,380,497

(1) Monthly estimates provided in Table 2 of Northern's August 2020 Monthly Cost of Gas Report, submitted in DG 19-154 on August 21, 2020.

(2) Includes Asset Management Agreement Revenue

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
August 2019 - October 2020

Indicates Confidential Data

Commodity Volumes:	<u>Aug-19</u>	<u>Sep-19</u>	<u>Oct-19</u>	<u>Nov-19</u>	<u>Dec-19</u>	<u>Jan-20</u>	<u>Feb-20</u>	<u>Mar-20</u>	<u>Apr-20</u>	<u>May-20</u>	<u>Jun-20</u>	<u>Jul-20</u>	<u>Aug-20</u>	<u>Sep-20</u>	<u>Oct-20</u>	<u>Total</u>
Amercian Excavators																
DTE Energy Trading																
Emera Energy Services Corp.																
Repsol																
Shell																
Southwestern																
Subtotal - Commodity Supply																
Granite																
Emera																
Emera Energy Services																
Maritimes																
Tennessee																
Subtotal - Commodity Transportation																
Commodity Volume Estimates																
Commodity Volume Reversals																
Subtotal - Estimates																
Subtotal - Supply																
Withdrawal - Underground Storage																
ATV Reconciliation Charges																
Off System Sales																
Net OBA Adjustment																
Company Managed																
LNG Withdrawal / Boiloff																
Supplier Balancing																
Inventory Finance Charge																
Subtotal - Other Commodity																
Sales for Resale Estimates																
Sales for Resale Reversals																
Subtotal - Estimates																
Total Commodity Volumes													102,888	104,952	212,494	

(1) Monthly estimates provided in Table 2 of Northern 's August 2020 Monthly Cost of Gas Report, submitted in DG 19-154 on August 21, 2020.

REDACTED

FORM III
Schedule 4
Page 4 of 4

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
August 2019 - October 2020

Indicates Confidential Data

Commodity Costs per Unit:	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Estimated ⁽¹⁾			Total			
													Aug-20	Sep-20	Oct-20				
DTE Energy Trading													\$	-	\$	-	\$	-	
Emera Energy Services Corp.																			
Repsol																			
Shell																			
Subtotal - Commodity Supply													\$	2.97	\$	2.96	\$	2.94	
Granite																			
Emera																			
Maritimes																			
Tennessee																			
Subtotal - Commodity Transportation													n/a		n/a		n/a		
Commodity Cost Estimates																			
Commodity Cost Reversals																			
Subtotal - Estimates													n/a		n/a		n/a		
Subtotal - Supply																			
Withdrawal - Underground Storage																			
ATV Reconciliation Charges																			
Off System Sales																			
Net OBA Adjustment																			
Company Managed																			
LNG Withdrawal / Boiloff																			
Supplier Balancing																			
Inventory Finance Charge																			
Subtotal - Other Commodity													n/a		n/a		n/a		
Off System Sales Estimates																			
Off System Sales Reversals																			
Subtotal - Estimates																			
Total Commodity Costs per unit													n/a		n/a		n/a		

(1) Monthly estimates provided in Table 2 of Northern 's August 2020 Monthly Cost of Gas Report, submitted in DG 19-154 on August 21, 2020.

FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2019-20 ANNUAL COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
August 2019 - July 2020

<i>New Hampshire</i>	<u>Aug-19</u>	<u>Sep-19</u>	<u>Oct-19</u>	<u>Nov-19</u>	<u>Dec-19</u>	<u>Jan-20</u>	<u>Feb-20</u>	<u>Mar-20</u>	<u>Apr-20</u>	<u>May-20</u>	<u>Jun-20</u>	<u>Jul-20</u>	<u>Total</u>
Throughput IN													
<i>BTU Factor</i>	1.028	1.028	1.029	1.029	1.046	1.044	1.043	1.038	1.034	1.03	1.03	1.028	
<i>GST Meter Throughput (MCF)</i>	360,759	379,250	510,562	876,507	1,005,765	1,006,889	976,058	791,711	615,328	422,342	331,534	319,992	7,596,697
<i>Salem Meter (MCF)</i>	13,855	15,452	23,593	53,919	69,400	70,252	64,973	47,723	35,941	19,185	12,555	12,385	439,233
<i>GST Meter Throughput (DTH)</i>	370,860	389,869	525,368	901,926	1,052,030	1,051,192	1,018,028	821,796	636,249	435,012	341,480	328,952	7,872,763
<i>Salem Meter (DTH)</i>	14,243	15,885	24,277	55,483	72,592	73,343	67,767	49,536	37,163	19,761	12,932	12,732	455,713
<i>LNG/Propane</i>													-
<i>Total Throughput</i>	385,103	405,754	549,645	957,408	1,124,623	1,124,535	1,085,795	871,332	673,412	454,773	354,412	341,684	8,328,476
Throughput OUT													
<i>Residential Gas</i>													
Charged	33,543	33,560	61,023	137,359	275,547	308,630	314,338	267,885	187,152	133,925	57,494	37,696	1,848,152
Uncharged Current	20,628	26,989	34,565	145,376	187,406	175,894	133,743	124,942	96,210	77,823	27,146	19,236	1,069,958
Uncharged Prior	(19,641)	(20,628)	(26,989)	(34,565)	(145,376)	(187,406)	(175,894)	(133,743)	(124,942)	(96,210)	(77,823)	(27,146)	(1,070,363)
Total Residential Gas	34,530	39,921	68,599	248,170	317,577	297,118	272,187	259,084	158,420	115,538	6,817	29,786	1,847,747
Interruptible				-	-	-	-	-	-	-	-	-	-
<i>Commercial/Industrial Gas</i>													
Charged	63,888	58,215	99,415	176,754	316,318	357,569	354,433	300,785	191,390	125,938	70,071	51,500	2,166,276
Uncharged Current	39,291	46,817	56,310	166,042	210,637	199,203	153,152	140,961	98,680	73,182	33,084	26,280	1,243,639
Uncharged Prior	(35,371)	(39,291)	(46,817)	(56,310)	(166,042)	(210,637)	(199,203)	(153,152)	(140,961)	(98,680)	(73,182)	(33,084)	(1,252,730)
Total C/I Gas	67,808	65,741	108,908	286,486	360,913	346,135	308,382	288,594	149,109	100,440	29,973	44,696	2,157,185
<i>Transportation</i>													
Charged	283,342	283,407	324,974	384,074	424,574	463,812	465,018	436,781	328,526	305,631	268,538	258,068	4,226,745
Uncharged Current	109,764	143,521	123,944	230,866	207,419	192,420	164,668	155,566	138,156	131,504	83,249	84,128	1,765,205
Uncharged Prior	(89,667)	(109,764)	(143,521)	(123,944)	(230,866)	(207,419)	(192,420)	(164,668)	(155,566)	(138,156)	(131,504)	(83,249)	(1,770,744)
Total Transportation	303,439	317,164	305,397	490,996	401,127	448,813	437,266	427,679	311,116	298,979	220,283	258,947	4,221,206
Company Use	140	100	89	84	240	294	289	257	180	141	60	64	1,938
Total Throughput OUT	405,917	422,926	482,993	#####	1,079,857	1,092,360	1,018,124	975,614	618,825	515,098	257,133	333,493	8,228,076
Total Throughput IN	385,103	405,754	549,645	957,408	1,124,623	1,124,535	1,085,795	871,332	673,412	454,773	354,412	341,684	8,328,476
Difference IN/OUT	(20,814)	(17,172)	66,653	(68,328)	44,766	32,175	67,671	(104,282)	54,587	(60,325)	97,279	8,191	100,400
%													1.21%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
August 2019 - October 2020

ANNUAL BALANCE SEASON - Acct 173

	<u>BEGINNING</u> <u>BALANCE</u>	<u>WORKING CAP</u> <u>ALLOWANCE (1)</u>	<u>WORKING CAP</u> <u>PERCENTAGE</u>	<u>WORKING CAP</u> <u>COLLECTIONS</u>	<u>WORKING CAP</u> <u>DEFERRED</u>	<u>ENDING</u> <u>BALANCE</u>	<u>AVE MONTHLY</u> <u>BALANCE</u>	<u>INTEREST</u> <u>RATE</u>	<u>INTEREST</u>	<u>ENDING BAL</u> <u>W/ INTEREST</u>
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	K = F + I + J
August 2019	\$ (44,680)									
Adjustment	\$ (14)									
August 2019	\$ (44,694)	760	0.1510%	(1,117)	(357)	(45,051)	(44,872)	5.50%	(206)	(45,257)
September	\$ (45,257)	852	0.1510%	(1,179)	(326)	(45,583)	(45,420)	5.50%	(208)	(45,791)
October	\$ (45,791)	992	0.1441%	(2,163)	(1,172)	(46,963)	(46,377)	5.25%	(203)	(47,165)
November	\$ (47,165)	3,346	0.1441%	(3,713)	(367)	(47,533)	(47,349)	5.25%	(207)	(47,740)
December	\$ (47,740)	6,426	0.1441%	(4,924)	1,501	(46,239)	(46,989)	5.25%	(206)	(46,444)
January 2020	\$ (46,444)	5,037	0.1304%	(4,735)	302	(46,142)	(46,293)	4.75%	(183)	(46,326)
February	\$ (46,326)	3,934	0.1304%	(3,938)	(4)	(46,330)	(46,328)	4.75%	(183)	(46,513)
March	\$ (46,513)	2,974	0.1304%	(3,686)	(712)	(47,225)	(46,869)	4.75%	(186)	(47,411)
April	\$ (47,411)	2,292	0.1304%	(2,266)	25	(47,385)	(47,398)	4.75%	(188)	(47,573)
May	\$ (47,573)	1,228	0.1304%	396	1,624	(45,949)	(46,761)	4.75%	(185)	(46,134)
June	\$ (46,134)	1,191	0.1304%	3	1,194	(44,940)	(45,537)	4.75%	(180)	(45,120)
July	\$ (45,120)	721	0.0892%	37	758	(44,363)	(44,741)	3.25%	(121)	(44,484)
Estimated August	\$ (44,484)	725	0.0892%	(500)	225	(44,259)	(44,371)	3.25%	(120)	(44,379)
Estimated September	\$ (44,379)	733	0.0892%	(500)	233	(44,146)	(44,262)	3.25%	(120)	(44,266)
Estimated October	\$ (44,266)	1,030	0.0892%	(850)	180	(44,085)	(44,176)	3.25%	(120)	(44,205)

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Schedule 4, Page 2, and multiplying by (10.02/365)* prime interest rate.

Winter Season Sales Percentage	81.23%
Summer Season Sales Percentage	18.77%
Reconciliation Allocated to Winter Season	\$ (35,910)
Reconciliation Allocated to Summer Season	\$ (8,295)

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
August 2019 - October 2020

ANNUAL BALANCE- Acct 173

	<u>BEGINNING BALANCE</u>	<u>ACUTAL BAD DEBT</u>	<u>BAD DEBT COLLECTIONS</u>	<u>DEFERRED BALANCE</u>	<u>ENDING BALANCE</u>	<u>AVE MO BALANCE</u>	<u>INTEREST RATE</u>	<u>INTEREST</u>	<u>END BAL W/ INTEREST</u>
	A	B	C	D = B + C	E = A + D	F = (A + E) / 2	G	H = (F * G) / 12	J = E + H + I
August 2019	(\$54,439)	22,785	(843)	21,942	(32,498)	(43,469)	5.50%	(199)	(32,697)
September	(\$32,697)	35,296	(889)	34,406	1,709	(15,494)	5.50%	(71)	1,638
October	\$1,638	32,853	(1,636)	31,218	32,856	17,247	5.25%	75	32,931
November	\$32,931	14,220	(17,732)	(3,512)	29,419	31,175	5.25%	136	29,556
December	\$29,556	7,458	(29,550)	(22,092)	7,464	18,510	5.25%	81	7,545
January 2020	\$7,545	24,377	(28,395)	(4,018)	3,527	5,536	4.75%	22	3,549
February	\$3,549	1,585	(23,616)	(22,031)	(18,483)	(7,467)	4.75%	(30)	(18,512)
March	(\$18,512)	1,221	(22,104)	(20,882)	(39,395)	(28,953)	4.75%	(115)	(39,509)
April	(\$39,509)	3,544	(13,600)	(10,056)	(49,565)	(44,537)	4.75%	(176)	(49,741)
May	(\$49,741)	6,444	(3,051)	3,393	(46,349)	(48,045)	4.75%	(190)	(46,539)
June	(\$46,539)	11,487	(876)	10,611	(35,928)	(41,233)	4.75%	(163)	(36,091)
July	(\$36,091)	12,480	(1,197)	11,282	(24,809)	(30,450)	3.25%	(82)	(24,891)
Estimated August	(\$24,891)	10,000	(850)	9,150	(15,741)	(20,316)	3.25%	(55)	(15,796)
Estimated September	(\$15,796)	10,000	(875)	9,125	(6,671)	(11,234)	3.25%	(30)	(6,702)
Estimated October	(\$6,702)	2,000	(500)	1,500	(5,202)	(5,952)	3.25%	(16)	(5,218)

Winter Season Sales Percentage 81.23%
Summer Season Sales Percentage 18.77%

Reconciliation Allocated to Winter Season \$ (4,239)
Reconciliation Allocated to Summer Season \$ (979)

Attachment C

**Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
May 2019 - October 2020**

		Beginning Balance	Firm Sales and Transportation (therms)	ERC Rate Recoveries /Passback	Current ERC Recoveries/ Passbacks	Ending Balance
May 2019	(act)	\$ 106,529	5,216,064	\$ 0.0058	\$ 30,252	\$ 76,277
June 2019	(act)	\$ 76,277	3,277,028	\$ 0.0058	\$ 19,019	\$ 57,259
July 2019	(act)	\$ 57,259	2,885,459	\$ 0.0058	\$ 16,750	\$ 40,509
August 2019	(act)	\$ 40,509	2,759,133	\$ 0.0058	\$ 16,016	\$ 24,493
September 2019	(act)	\$ 24,493	2,702,350	\$ 0.0058	\$ 15,689	\$ 8,804
October 2019	(act)	\$ 8,804	3,792,595	\$ 0.0058	\$ 22,002	\$ (13,198)
November 2019	(act)	\$ 422,377 ⁽¹⁾	5,944,629	\$ 0.0058 ⁽²⁾	\$ 34,075	\$ 388,302
December 2019	(act)	\$ 388,302	9,152,839	\$ 0.0057	\$ 52,173	\$ 336,129
January 2020	(act)	\$ 336,129	10,261,299	\$ 0.0057	\$ 58,492	\$ 277,637
February 2020	(act)	\$ 277,637	10,340,850	\$ 0.0057	\$ 58,945	\$ 218,692
March 2020	(act)	\$ 218,692	8,965,512	\$ 0.0057	\$ 51,106	\$ 167,586
April 2020	(act)	\$ 167,586	6,420,106	\$ 0.0057	\$ 36,598	\$ 130,988
May 2020	(act)	\$ 130,988	4,861,662	\$ 0.0057	\$ 27,710	\$ 103,278
June 2020	(act)	\$ 103,278	3,038,865	\$ 0.0057	\$ 17,331	\$ 85,947
July 2020	(act)	\$ 85,947	2,540,626	\$ 0.0057	\$ 14,489	\$ 71,458
August 2020	(est)	\$ 71,458	2,430,337	\$ 0.0057	\$ 13,853	\$ 57,605
September 2020	(est)	\$ 57,605	2,523,248	\$ 0.0057	\$ 14,383	\$ 43,223
October 2020	(est)	\$ 43,223	3,175,456	\$ 0.0057	\$ 18,100	\$ 25,122

(1) November Beginning Balance includes \$433,575 amortization from all prior years at 1/7 of annual costs.
(See Section 4.7 of Tariff.)

(2) November Current ERC Recoveries/Passbacks reflect an Average ERC Rate based on actual Firm Sales and Transportation (therms) at \$0.0057 and actual Firm Sales and Transportation (therms) at \$0.0058.

Attachment D

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIARA Reconciliation
May 2019 - October 2020

		<u>Beginning Balance</u>	<u>Program Costs</u>	<u>Regulatory Assessments</u>	<u>RLIARA Recoveries</u>	<u>Ending Balance</u>	<u>Average Monthly Balance</u>	<u>Interest Rate</u>	<u>Interest</u>	<u>Ending Balance w/Interest</u>
		A	B	C	D	E = A+B+C-D	F = (A+E)/2	G	H = F*(G/12)	I = E+H
May 2019	Actual	\$ (161,136)	\$ 27,022	\$ 11,421	\$ 22,952	\$ (145,645)	\$ (153,391)	5.50%	\$ (703)	\$ (146,348)
June 2019	Actual	\$ (146,348)	\$ 13,809	\$ 11,421	\$ 14,418	\$ (135,537)	\$ (140,943)	5.50%	\$ (646)	\$ (136,183)
July 2019	Actual	\$ (136,183)	\$ 11,937	\$ 11,421	\$ 12,693	\$ (125,519)	\$ (130,851)	5.50%	\$ (600)	\$ (126,119)
August 2019	Actual	\$ (126,119)	\$ 10,812	\$ (5,008)	\$ 12,139	\$ (132,454)	\$ (129,286)	5.50%	\$ (593) (1)	\$ (133,046)
September 2019	Actual	\$ (133,046)	\$ 10,740	\$ (21,436)	\$ 11,890	\$ (155,632)	\$ (144,339)	5.50%	\$ (662) (1)	\$ (156,294)
October 2019	Actual	\$ (156,294)	\$ 13,398	\$ (5,008)	\$ 16,641	\$ (164,544)	\$ (160,419)	5.25%	\$ (702)	\$ (165,246)
November 2019	Actual	\$ (165,246)	\$ 18,112	\$ 8,613	\$ 22,876	\$ (161,396)	\$ (163,321)	5.25%	\$ (715)	\$ (162,111)
December 2019	Actual	\$ (162,111)	\$ 37,740	\$ 14,434	\$ 32,952	\$ (142,889)	\$ (152,500)	5.25%	\$ (667)	\$ (143,556)
January 2020	Actual	\$ (143,556)	\$ 39,013	\$ 11,421	\$ 36,944	\$ (130,066)	\$ (136,811)	4.75%	\$ (542)	\$ (130,608)
February 2020	Actual	\$ (130,608)	\$ 50,483	\$ 605	\$ 37,230	\$ (116,749)	\$ (123,678)	4.75%	\$ (477)	\$ (117,225)
March 2020	Actual	\$ (117,225)	\$ 39,628	\$ 6,013	\$ 32,276	\$ (103,861)	\$ (110,543)	4.75%	\$ (438)	\$ (104,298)
April 2020	Actual	\$ (104,298)	\$ 35,052	\$ 6,013	\$ 23,113	\$ (86,346)	\$ (95,322)	4.75%	\$ (377)	\$ (86,723)
May 2020	Actual	\$ (86,723)	\$ 24,284	\$ 6,013	\$ 17,501	\$ (73,928)	\$ (80,326)	4.75%	\$ (318)	\$ (74,246)
June 2020	Actual	\$ (74,246)	\$ 18,438	\$ 6,013	\$ 10,934	\$ (60,729)	\$ (67,487)	4.75%	\$ (267)	\$ (60,996)
July 2020	Actual	\$ (60,996)	\$ 12,176	\$ 6,013	\$ 9,142	\$ (51,948)	\$ (56,472)	3.25%	\$ (153)	\$ (52,101)
August 2020	Est.	\$ (52,101)	\$ 10,190	\$ 5,292	\$ 8,749	\$ (45,368)	\$ (48,735)	3.25%	\$ (132)	\$ (45,500)
September 2020	Est.	\$ (45,500)	\$ 10,411	\$ 5,292	\$ 9,084	\$ (38,881)	\$ (42,191)	3.25%	\$ (114)	\$ (38,995)
October 2020	Est.	\$ (38,995)	\$ 11,673	\$ 5,292	\$ 11,432	\$ (33,462)	\$ (36,228)	3.25%	\$ (98)	\$ (33,560)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS

	<u>Aug-19</u>	<u>Sep-19</u>	<u>Oct-19</u>	<u>Nov-19</u>	<u>Dec-19</u>	<u>Jan-20</u>	<u>Feb-20</u>	<u>Mar-20</u>	<u>Apr-20</u>	<u>May-20</u>	<u>Jun-20</u>	<u>Jul-20</u>	<u>TOTAL</u>
Forecast Bill Month Sales	98,427	85,662	94,155	327,603	495,793	828,714	784,335	668,075	501,681	243,489	164,263	118,678	4,410,875
Actual Sales	97,431	91,774	160,439	314,112	591,865	666,199	668,771	568,670	378,541	259,863	127,565	89,196	4,014,428
Difference	(996)	6,112	66,283	(13,491)	96,072	(162,515)	(115,564)	(99,405)	(123,140)	16,374	(36,697)	(29,481)	(396,448)
Normal Bill Month Actual Sales	97,431	91,774	160,439	313,426	552,740	701,587	753,971	592,361	401,888	259,863	127,565	89,196	4,142,242
Actual Sales	97,431	91,774	160,439	314,112	591,865	666,199	668,771	568,670	378,541	259,863	127,565	89,196	4,014,428
Weather Variance	-	-	-	(686)	(39,125)	35,388	85,200	23,691	23,347	-	-	-	127,814
Total Variance Excluding Weather (excl weather effect)	(996)	6,112	66,283	(14,177)	56,947	(127,127)	(30,364)	(75,714)	(99,793)	16,374	(36,697)	(29,481)	(268,634)
Variance-difference due to meter count													1,237
-difference in load pattern													(397,685)
Total Sales Variance													(396,448)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
August 2019 - July 2020

	<u>NORMAL MMBtu</u>			<u>METERS</u>				
	2019-20 Forecast	2019-20 Actual	Difference	2019-20 Forecast	2019-20 Actual	Difference		
Res Heat	1,995,194	1,824,968	(170,225)	312,798	311,110	(1,688)		
Res General	23,534	23,185	(349)	15,037	15,558	521		
Total Res	2,018,728	1,848,153	(170,575)	327,835	326,668	(1,167)		
G-40	960,465	841,864	(118,601)	55,722	54,275	(1,447)		
G-50	170,442	126,569	(43,873)	8,860	9,023	163		
G-41	721,741	749,768	28,027	4,687	5,210	523		
G-51	239,930	225,480	(14,450)	1,908	1,831	(77)		
G-42	106,561	165,678	59,117	144	153	9		
G-52	193,009	56,915	(136,094)	39	30	(9)		
Total C & I	2,392,148	2,166,275	(225,873)	71,360	70,522	(838)		
Total Company	4,410,875	4,014,428	(396,448)	399,195	397,190	(2,005)		

	<u>NORMAL AVERAGE USE</u>			<u>Change in Sales Due to</u>		<u>Total Chg</u>	<u>%</u>
	2019-20 Forecast	2019-20 Actual	Difference	<u>Change In:</u>	<u>Meter Count Load Pattern</u>		
Res Heat	6.38	5.87	(0.51)	(10,765)	(159,460)	(170,225)	-8.53%
Res General	1.57	1.49	(0.07)	815	(1,164)	(349)	-1.48%
Total Res	7.94	7.36	(0.59)	(9,950)	(160,624)	(170,575)	-8.45%
G-40	17.24	15.51	(1.73)	(24,938)	(93,663)	(118,601)	-12.35%
G-50	19.24	14.03	(5.21)	3,136	(47,008)	(43,873)	-25.74%
G-41	154.00	143.91	(10.09)	80,604	(52,577)	28,027	3.88%
G-51	125.72	123.15	(2.58)	(9,734)	(4,716)	(14,450)	-6.02%
G-42	740.00	1,082.86	342.86	6,660	52,457	59,117	55.48%
G-52	4,948.96	1,897.18	(3,051.78)	(44,541)	(91,553)	(136,094)	-70.51%
Total C & I	33.52	30.72	(2.80)	11,187	(237,061)	(225,873)	-9.44%
Total Company	11.05	10.11	(0.94)	1,237	(397,685)	(396,448)	-8.99%

Attachment F
Page 1 of 1

Northern Utilities, Inc.
Grant-Thornton Expense for Fuel Tax Recovery

Invoice Date	Amount	PR Allocator		Cost Allocation	
		Maine	New Hampshire	Maine	New Hampshire
4/9/2019	\$10,977.28	55.89%	44.11%	\$6,135.20	\$4,842.08
6/10/2019	\$1,654.81	58.16%	41.84%	\$962.44	\$692.37
7/25/2019	\$1,933.64	58.16%	41.84%	\$1,124.61	\$809.03
7/25/2019	\$2,923.31	58.16%	41.84%	\$1,700.20	\$1,223.11
11/25/2019	\$3,913.44	58.16%	41.84%	\$2,276.06	\$1,637.38
1/16/2020	\$2,020.64	58.16%	41.84%	\$1,175.20	\$845.44
2/10/2020	\$1,174.72	58.16%	41.84%	\$683.22	\$491.50
Total	\$24,597.84			\$14,056.92	\$10,540.92

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	Actual Bad Debt Expense 12 Months Ended July 31, 2020				
2					
3	Total		\$	458,671	Company Analysis
4	Distribution		\$	284,549	Company Analysis
5	Distribution (%)			62.04%	LN 4 / LN 3
6	Non-Distribution		\$	174,123	Company Analysis
7	Non-Distribution(%)			37.96%	LN 6 / LN 3
8					
9	Winter Demand Cost %			91.72%	Schedule 7-CAK, LN 79
10	Summer Demand Cost %			8.28%	Schedule 7-CAK, LN 79
11					
12	Forecast Bad Debt Expense 12 Months Ended December 31, 2021				*
13					
14	Annual Total		\$	450,000	Company Forecast
15	Annual Non-Distribution		\$	170,831	LN 14 * LN 7
16	Winter Non-Distribution		\$	156,687	LN 15 * LN 9
17	Summer Non-Distribution		\$	14,144	LN 15 * LN 10

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

Sales Revenues	Oct-20	Winter						Summer					
		(Forecast) Nov-20	(Forecast) Dec-20	(Forecast) Jan-21	(Forecast) Feb-21	(Forecast) Mar-21	(Forecast) Apr-21	(Forecast) May-21	(Forecast) Jun-21	(Forecast) Jul-21	(Forecast) Aug-21	(Forecast) Sep-21	(Forecast) Oct-21
Volumes													
Residential Heat & Non Heat		2,176,725	3,165,337	3,770,878	3,205,911	2,774,319	1,593,044	730,922	489,258	412,466	418,643	455,783	939,948
Sales HLF Classes		297,129	432,077	514,735	437,615	378,702	217,455	405,473	271,412	228,812	232,239	252,842	521,430
Sales LLF Classes		2,078,532	3,022,546	3,600,771	3,061,290	2,649,167	1,521,181	572,940	383,510	323,315	328,157	357,270	736,788
Total		4,552,386	6,619,959	7,886,383	6,704,817	5,802,188	3,331,679	1,709,335	1,144,180	964,593	979,040	1,065,895	2,198,166
Rates													
Residential Heat & Non Heat CGA		\$0.7315	\$0.7315	\$0.7315	\$0.7315	\$0.7315	\$0.7315	\$0.4412	\$0.4412	\$0.4412	\$0.4412	\$0.4412	\$0.4412
Sales HLF Classes CGA		\$0.6465	\$0.6465	\$0.6465	\$0.6465	\$0.6465	\$0.6465	\$0.3943	\$0.3943	\$0.3943	\$0.3943	\$0.3943	\$0.3943
Sales LLF Classes CGA		\$0.7437	\$0.7437	\$0.7437	\$0.7437	\$0.7437	\$0.7437	\$0.4733	\$0.4733	\$0.4733	\$0.4733	\$0.4733	\$0.4733
Revenues													
Residential Heat & Non Heat		\$ (1,592,275)	\$ (2,315,444)	\$ (2,758,397)	\$ (2,345,124)	\$ (2,029,414)	\$ (1,165,312)	\$ (322,483)	\$ (215,861)	\$ (181,980)	\$ (184,705)	\$ (201,091)	\$ (414,705)
Sales HLF Classes		\$ (192,094)	\$ (279,338)	\$ (332,776)	\$ (282,918)	\$ (244,831)	\$ (140,584)	\$ (159,878)	\$ (107,018)	\$ (90,221)	\$ (91,572)	\$ (99,696)	\$ (205,600)
Sales LLF Classes		\$ (1,545,804)	\$ (2,247,867)	\$ (2,677,893)	\$ (2,276,681)	\$ (1,970,186)	\$ (1,131,302)	\$ (271,173)	\$ (181,515)	\$ (153,025)	\$ (155,317)	\$ (169,096)	\$ (348,722)
Total Sales		\$ (3,330,172)	\$ (4,842,649)	\$ (5,769,066)	\$ (4,904,724)	\$ (4,244,431)	\$ (2,437,198)	\$ (753,533)	\$ (504,394)	\$ (425,226)	\$ (431,594)	\$ (469,883)	\$ (969,027)

Gas Costs and Credits	Oct-20	Winter						Summer					
		Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	(Forecast) Jun-21	(Forecast) Jul-21	(Forecast) Aug-21	(Forecast) Sep-21	(Forecast) Oct-21
Demand Costs (net of Capacity Assignment)													
Pipeline		\$ 433,901	\$ 433,901	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176	\$ 445,176
Storage		\$ 565,543	\$ 565,543	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144	\$ 611,144
On-system Peaking		\$ 166,282	\$ 166,282	\$ 166,282	\$ 166,282	\$ 166,282	\$ 73,458	\$ 12,761	\$ 12,761	\$ 12,761	\$ 12,761	\$ 12,761	\$ 12,761
Off-System Peaking		\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658	\$ 317,658
Total Demand Costs		\$ 1,483,385	\$ 1,483,385	\$ 1,540,260	\$ 1,540,260	\$ 1,540,260	\$ 1,447,437	\$ 1,386,740	\$ 1,386,740	\$ 1,386,740	\$ 1,386,740	\$ 1,386,740	\$ 1,386,740
Asset Management and Capacity Release													
NUI AMA Revenue		\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)	\$ (672,867)
NUI Capacity Release								\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
NUI AMA Rev & Cap. Release Subtotal													
NH AMA Revenue		\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)
NH Capacity Release													
NH Total Asset Management and Capacity Release		\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)	\$ (272,739)
CNG Expenses		\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972	\$ 9,972
Re-entry Rate & Conversion Rate Revenue		\$ (1,000)	\$ (1,000)	\$ (1,000)	\$ (1,000)	\$ (1,000)		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Net Demand Costs		\$ 1,219,618	\$ 1,219,618	\$ 1,276,493	\$ 1,276,493	\$ 1,276,493	\$ 1,184,670	\$ 1,123,973	\$ 1,123,973	\$ 1,123,973	\$ 1,123,973	\$ 1,123,973	\$ 1,123,973
NUI Commodity Costs													
NUI Total Pipeline Volumes		930,912	987,962	987,962	893,407	1,057,807	918,117	499,328	337,173	291,023	294,102	320,183	619,360
Pipeline Costs Modeled in Sendout™		\$ 2,810,541	\$ 3,690,647	\$ 4,304,570	\$ 3,827,533	\$ 3,717,010	\$ 2,576,253	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126
NYMEX Price Used for Forecast		\$ 2,3240	\$ 2,4850	\$ 2,5880	\$ 2,5560	\$ 2,4730	\$ 2,2770	\$ 2,2610	\$ 2,2970	\$ 2,3360	\$ 2,3450	\$ 2,3290	\$ 2,3540
NYMEX Price Used for Update		\$ 2,3240	\$ 2,4850	\$ 2,5880	\$ 2,5560	\$ 2,4730	\$ 2,2770	\$ 2,2610	\$ 2,2970	\$ 2,3360	\$ 2,3450	\$ 2,3290	\$ 2,3540
Increase/(Decrease) NYMEX Price		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Increase/(Decrease) in Pipeline Costs		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Updated Pipeline Costs		\$ 2,810,541	\$ 3,690,647	\$ 4,304,570	\$ 3,827,533	\$ 3,717,010	\$ 2,576,253	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126
New Hampshire Allocated Percentage		39.54%	39.84%	40.15%	39.76%	39.18%	36.70%	34.56%	34.20%	33.37%	33.52%	33.54%	35.85%
NH Updated Pipeline Costs		\$ 1,111,190	\$ 1,470,310	\$ 1,728,289	\$ 1,521,827	\$ 1,456,256	\$ 945,358	\$ 456,911	\$ 303,234	\$ 258,542	\$ 262,123	\$ 279,217	\$ 580,479
NH Peaking Volumes													
NH Peaking Costs Modeled in Sendout													
Change in NYMEX Price													
Change in Peaking Costs													
NH Updated Peaking Costs													
NH Commodity Costs													
Pipeline		\$ 1,111,190	\$ 1,470,310	\$ 1,728,289	\$ 1,521,827	\$ 1,456,256	\$ 945,358	\$ 456,911	\$ 303,234	\$ 258,542	\$ 262,123	\$ 279,217	\$ 580,479
Storage		\$ 169,346	\$ 483,784	\$ 553,959	\$ 562,914	\$ 315,143	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Peaking		\$ 2,882	\$ 51,770	\$ 383,015	\$ 85,954	\$ 5,035	\$ 4,516	\$ 4,341	\$ 4,130	\$ 4,141	\$ 4,153	\$ 3,992	\$ 4,396
Total Commodity Costs		\$ 1,283,418	\$ 2,005,863	\$ 2,665,263	\$ 2,170,696	\$ 1,776,435	\$ 949,874	\$ 461,252	\$ 307,364	\$ 262,684	\$ 266,275	\$ 283,209	\$ 584,875
Inventory Finance Charge								\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Anticipated Direct Cost of Gas		\$ 2,503,036	\$ 3,225,481	\$ 3,941,756	\$ 3,447,189	\$ 3,052,928	\$ 2,134,543	\$ 1,585,224	\$ 1,431,337	\$ 1,386,657	\$ 1,390,248	\$ 1,407,182	\$ 1,708,848

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Ana

Sales Revenues				
Volumes	Winter	Summer	Prior Period	Total
Residential Heat & Non Heat				20,133,234
Sales HLF Classes				4,189,921
Sales LLF Classes				18,635,467
Total		8,061,210		42,958,621
Rates				
Residential Heat & Non Heat CGA				
Sales HLF Classes CGA				
Sales LLF Classes CGA				
Revenues				
Residential Heat & Non Heat				\$ (13,726,791)
Sales HLF Classes				\$ (2,226,524)
Sales LLF Classes				\$ (13,128,581)
Total Sales	\$ (25,528,240)	\$ (3,553,657)		\$ (29,081,896)
Gas Costs and Credits				
				Total
Demand Costs (net of Capacity Assignment)				
Pipeline	\$ 2,648,505	\$ 2,671,054		\$ 5,319,558
Storage	\$ 3,575,664	\$ 3,666,867		\$ 7,242,531
On-system Peaking	\$ 904,867	\$ 76,569		\$ 981,436
Off-System Peaking	\$ 1,905,950	\$ 1,905,950		\$ 3,811,900
Total Demand Costs	\$ 9,034,986	\$ 8,320,439		\$ 17,355,426
Asset Management and Capacity Release				
NUI AMA Revenue				\$ (8,074,404)
NUI Capacity Release				\$ -
NUI AMA Rev & Cap. Release Subtotal				\$ -
NH AMA Revenue				\$ (3,272,870)
NH Capacity Release				\$ -
NH Total Asset Management and Capacity Release		\$ -	\$ -	\$ (3,272,870)
CNG Expenses	\$ 59,833	\$ 59,833		\$ 119,666
Re-entry Rate & Conversion Rate Revenue	\$ (5,000)	\$ -		\$ (5,000)
Net Demand Costs	\$ 7,453,384	\$ 6,743,837		\$ 14,197,222
NUI Commodity Costs				
NUI Total Pipeline Volumes				8,137,336
Pipeline Costs Modeled in Sendout™				\$ 27,143,945
NYMEX Price Used for Forecast				
NYMEX Price Used for Update				
Increase/(Decrease) NYMEX Price				
Increase/(Decrease) in Pipeline Costs				
Updated Pipeline Costs				
New Hampshire Allocated Percentage				
NH Updated Pipeline Costs				\$ 10,373,736
NH Peaking Volumes				
NH Peaking Costs Modeled in Sendout				
Change in NYMEX Price				
Change in Peaking Costs				
NH Updated Peaking Costs				\$ -
NH Commodity Costs				
Pipeline				\$ 10,373,736
Storage				\$ 2,085,147
Peaking				\$ 558,325
Total Commodity Costs	\$ 10,851,549	\$ 2,165,659		\$ 13,017,208
Inventory Finance Charge				\$ -
Total Anticipated Direct Cost of Gas	\$ 18,304,934	\$ 8,909,496		\$ 27,214,430

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

	Oct-20	Winter						Summer					
		(Forecast) Nov-20	(Forecast) Dec-20	(Forecast) Jan-21	(Forecast) Feb-21	(Forecast) Mar-21	(Forecast) Apr-21	(Forecast) May-21	(Forecast) Jun-21	(Forecast) Jul-21	(Forecast) Aug-21	(Forecast) Sep-21	(Forecast) Oct-21
Working Capital													
Total Anticipated Direct Cost of Gas		\$ 2,660,976	\$ 3,383,421	\$ 4,099,696	\$ 3,605,129	\$ 3,210,868	\$ 2,292,483	\$ 1,603,378	\$ 1,449,490	\$ 1,404,811	\$ 1,408,402	\$ 1,425,336	\$ 1,727,002
Working Capital Percentage		0.0892%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%
Working Capital Allowance		\$ 2,374	\$ 3,018	\$ 3,657	\$ 3,216	\$ 2,864	\$ 2,045	\$ 1,430	\$ 1,293	\$ 1,253	\$ 1,256	\$ 1,271	\$ 1,540
Beginning Period Working Capital Balance		\$ (44,205)	\$ (41,948)	\$ (39,039)	\$ (35,483)	\$ (32,359)	\$ (29,579)	\$ (27,611)	\$ (26,254)	\$ (25,030)	\$ (23,843)	\$ (22,650)	\$ (21,438)
End of Period Working Capital Allowance		\$ (41,831)	\$ (38,930)	\$ (35,383)	\$ (32,268)	\$ (29,495)	\$ (27,534)	\$ (26,181)	\$ (24,961)	\$ (23,777)	\$ (22,587)	\$ (21,379)	\$ (19,898)
Interest		\$ (117)	\$ (110)	\$ (101)	\$ (92)	\$ (84)	\$ (77)	\$ (73)	\$ (69)	\$ (66)	\$ (63)	\$ (60)	\$ (56)
End of period with Interest	\$ (44,205)	\$ (41,948)	\$ (39,039)	\$ (35,483)	\$ (32,359)	\$ (29,579)	\$ (27,611)	\$ (26,254)	\$ (25,030)	\$ (23,843)	\$ (22,650)	\$ (21,438)	\$ (19,954)
Bad Debt													
Projected Bad Debt	\$ -	\$ 26,114.49	\$ 26,114.49	\$ 26,114.49	\$ 26,114.49	\$ 26,114.49	\$ 26,114.49	\$ 2,357.33	\$ 2,357.33	\$ 2,357.33	\$ 2,357.33	\$ 2,357.33	\$ 2,357.33
Beginning Period Bad Debt Balance		\$ (5,218)	\$ 20,918	\$ 47,125	\$ 73,402	\$ 99,751	\$ 126,171	\$ 152,662	\$ 155,436	\$ 158,218	\$ 161,007	\$ 163,803	\$ 166,608
End of Period Bad Debt Balance		\$ 20,897	\$ 47,033	\$ 73,239	\$ 99,517	\$ 125,865	\$ 152,285	\$ 155,020	\$ 157,794	\$ 160,575	\$ 163,364	\$ 166,161	\$ 168,965
Interest		\$ 21	\$ 92	\$ 163	\$ 234	\$ 306	\$ 377	\$ 417	\$ 424	\$ 432	\$ 439	\$ 447	\$ 454
End of Period Bad Debt Balance with Interest	\$ (5,218)	\$ 20,918	\$ 47,125	\$ 73,402	\$ 99,751	\$ 126,171	\$ 152,662	\$ 155,436	\$ 158,218	\$ 161,007	\$ 163,803	\$ 166,608	\$ 169,419
Local Production and Storage Capacity		\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Miscellaneous Overhead		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Gas Cost Other than Bad Debt and Working Capital Over/Under Collection		\$ 78,589	\$ 78,589	\$ 78,589	\$ 78,589	\$ 78,589	\$ 78,589	\$ 18,154	\$ 18,154	\$ 18,154	\$ 18,154	\$ 18,154	\$ 18,154
Beginning Balance Over/Under Collection	\$ 755,934	\$ 755,934	\$ 87,879	\$ (1,373,087)	\$ (3,048,437)	\$ (4,358,048)	\$ (5,404,814)	\$ (5,564,363)	\$ (4,728,437)	\$ (3,794,867)	\$ (2,824,234)	\$ (1,853,752)	\$ (902,026)
Net Costs - Revenues		\$ (669,196)	\$ (1,459,228)	\$ (1,669,371)	\$ (1,299,595)	\$ (1,033,563)	\$ (144,715)	\$ 849,845	\$ 945,097	\$ 979,585	\$ 976,808	\$ 955,453	\$ 757,975
Ending Balance before Interest		\$ 86,738	\$ (1,371,349)	\$ (3,042,458)	\$ (4,348,032)	\$ (5,391,611)	\$ (5,549,529)	\$ (4,714,518)	\$ (3,783,341)	\$ (2,815,282)	\$ (1,847,426)	\$ (898,299)	\$ (144,051)
Average Balance		\$ 421,336	\$ (641,735)	\$ (2,207,773)	\$ (3,698,235)	\$ (4,874,830)	\$ (5,477,171)	\$ (5,139,441)	\$ (4,255,889)	\$ (3,305,075)	\$ (2,335,830)	\$ (1,376,026)	\$ (523,038)
Interest Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Interest Expense		\$ 1,141	\$ (1,738)	\$ (5,979)	\$ (10,016)	\$ (13,203)	\$ (14,834)	\$ (13,919)	\$ (11,526)	\$ (8,951)	\$ (6,326)	\$ (3,727)	\$ (1,417)
Ending Balance Incl Interest Expense	\$ 755,934	\$ 87,879	\$ (1,373,087)	\$ (3,048,437)	\$ (4,358,048)	\$ (5,404,814)	\$ (5,564,363)	\$ (4,728,437)	\$ (3,794,867)	\$ (2,824,234)	\$ (1,853,752)	\$ (902,026)	\$ (145,467)
Total Over/Under Collection Ending Balance	\$ 706,511	\$ 66,849	\$ (1,365,002)	\$ (3,010,519)	\$ (4,290,657)	\$ (5,308,222)	\$ (5,439,312)	\$ (4,599,255)	\$ (3,661,680)	\$ (2,687,070)	\$ (1,712,599)	\$ (756,857)	\$ 3,998
Total Indirect Cost of Gas	\$ 706,511	\$ 187,474	\$ 185,317	\$ 181,794	\$ 177,396	\$ 173,937	\$ 171,565	\$ 8,366	\$ 10,633	\$ 13,179	\$ 15,818	\$ 18,443	\$ 21,033
Total Cost of Gas	\$ 706,511	\$ 2,690,510	\$ 3,410,798	\$ 4,123,550	\$ 3,624,585	\$ 3,226,866	\$ 2,306,108	\$ 1,593,590	\$ 1,441,969	\$ 1,399,835	\$ 1,406,066	\$ 1,425,625	\$ 1,729,881
Total Interest	\$ -	\$ 1,046	\$ (1,756)	\$ (5,917)	\$ (9,874)	\$ (12,981)	\$ (14,534)	\$ (13,576)	\$ (11,172)	\$ (8,586)	\$ (5,950)	\$ (3,340)	\$ (1,018)

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Anal

	Winter	Summer	Prior Period	Total
Working Capital				
Total Anticipated Direct Cost of Gas				\$ 28,270,991
Working Capital Percentage				
Working Capital Allowance	\$ 17,173	\$ 8,044	\$ (44,205)	\$ (18,987)
Beginning Period Working Capital Balance				
End of Period Working Capital Allowance				
Interest	\$ (580)	\$ (387)		\$ (966)
End of period with Interest				
Bad Debt				
Projected Bad Debt	\$ 156,687	\$ 14,144	\$ (5,218)	\$ 165,613
Beginning Period Bad Debt Balance				
End of Period Bad Debt Balance				
Interest	\$ 1,193	\$ 2,613		\$ 3,806
End of Period Bad Debt Balance with Interest				
Local Production and Storage Capacity				\$ 476,106
				\$ -
Miscellaneous Overhead				\$ 580,455
Gas Cost Other than Bad Debt and Working Capital Over/L				
Beginning Balance Over/Under Collection				\$ (33,008,253)
Net Costs - Revenues				\$ (810,906)
Ending Balance before Interest				\$ (33,819,159)
Average Balance				\$ (33,413,706)
Interest Rate				
Interest Expense				\$ (90,495)
Ending Balance Incl Interest Expense			\$ 755,934	
Total Over/Under Collection Ending Balance				
Total Indirect Cost of Gas	\$ 1,077,483	\$ 87,471	\$ 706,511	\$ 1,871,465
Total Cost of Gas	\$ 19,382,416	\$ 8,996,967	\$ 706,511	\$ 29,085,895
Total Interest	\$ (44,016)	\$ (43,640)		\$ (87,656)

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

Total Division Metered Deliveries (Dth)										
2020-2021	2020-2021 Compared to 2019-2020					2020-2021 Compared to 2018-2019				
Forecast	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2018-2019 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
1	2	3	4	5	6	7	8	9	10	11
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
659,578	696,660	-37,082	-5.3%	5,142	-42,223	711,579	-52,001	-7.3%	17,204	-69,205
946,024	949,247	-3,224	-0.3%	6,488	-9,712	947,842	-1,819	-0.2%	21,197	-23,016
1,139,404	1,190,037	-50,633	-4.3%	8,240	-58,873	1,248,735	-109,331	-8.8%	27,733	-137,064
1,223,700	1,278,231	-54,531	-4.3%	8,763	-63,294	1,327,296	-103,596	-7.8%	28,756	-132,351
1,100,828	1,047,338	53,490	5.1%	7,213	46,277	1,086,718	14,110	1.3%	23,190	-9,080
774,735	750,676	24,059	3.2%	5,099	18,960	845,541	-70,806	-8.4%	19,989	-90,796
570,317	519,041	51,276	9.9%	6,984	44,292	632,151	-61,834	-9.8%	12,702	-74,536
397,160	382,043	15,118	4.0%	5,288	9,830	430,401	-33,241	-7.7%	8,978	-42,219
346,583	333,729	12,854	3.9%	4,619	8,235	391,025	-44,442	-11.4%	8,162	-52,604
347,374	324,955	22,419	6.9%	4,528	17,890	380,773	-33,399	-8.8%	8,021	-41,420
356,180	335,134	21,046	6.3%	4,706	16,340	375,181	-19,002	-5.1%	7,976	-26,978
425,676	402,137	23,539	5.9%	5,655	17,884	485,413	-59,737	-12.3%	10,349	-70,086
5,844,268	5,912,189	-67,920	-1.1%	40,944	-108,864	6,167,711	-323,442	-5.2%	139,164	-462,606
2,443,290	2,297,039	146,251	6.4%	31,780	114,471	2,694,945	-251,655	-9.3%	56,354	-308,009
8,287,558	8,209,228	78,331	1.0%	72,724	5,606	8,862,656	-575,097	-6.5%	192,682	-767,779

Note 1 Company Forecast

Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data through April is weather normalized.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Pages 2 - 4; Sum of Column 7 of Billed Deliveries Table. Actual Data provided is weather normalized.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

Total Division Meter Counts						
2020-2021	Compared to 2019-2020			Compared to 2018-2019		
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
1	2	3	4	5	6	7
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
34,397	34,145	252	0.7%	33,585	812	2.4%
34,469	34,235	234	0.7%	33,715	754	2.2%
34,612	34,374	238	0.7%	33,860	752	2.2%
34,661	34,425	236	0.7%	33,926	735	2.2%
34,652	34,415	237	0.7%	33,928	724	2.1%
34,683	34,449	234	0.7%	33,882	801	2.4%
34,421	33,964	457	1.3%	33,743	678	2.0%
34,208	33,741	467	1.4%	33,509	699	2.1%
33,991	33,527	464	1.4%	33,296	695	2.1%
33,978	33,511	467	1.4%	33,277	701	2.1%
34,156	33,683	473	1.4%	33,445	711	2.1%
34,540	34,061	479	1.4%	33,819	721	2.1%
34,579	34,341	239	0.7%	33,816	763	2.3%
34,216	33,748	468	1.4%	33,515	701	2.1%
34,397	34,044	353	1.0%	33,665	732	2.2%

Note 1 Company Forecast

Note 2 Actual data through April. Forecast data beginning June. Page 2 - 4; Sum of Column 2 of Meter Counts table.

Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

Total Division Use Per Meter						
2020-2021	Compared to 2019-2020			Compared to 2018-2019		
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
1	2	3	4	5	6	7
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
19.18	20.40	-1.23	-6.0%	21.19	-2.01	-9.5%
27.45	27.73	-0.28	-1.0%	28.11	-0.67	-2.4%
32.92	34.62	-1.70	-4.9%	36.88	-3.96	-10.7%
35.30	37.13	-1.83	-4.9%	39.12	-3.82	-9.8%
31.77	30.43	1.34	4.4%	32.03	-0.26	-0.8%
22.34	21.79	0.55	2.5%	24.96	-2.62	-10.5%
16.57	15.28	1.29	8.4%	18.73	-2.17	-11.6%
11.61	11.32	0.29	2.5%	12.84	-1.23	-9.6%
10.20	9.95	0.24	2.4%	11.74	-1.55	-13.2%
10.22	9.70	0.53	5.4%	11.44	-1.22	-10.7%
10.43	9.95	0.48	4.8%	11.22	-0.79	-7.0%
12.32	11.81	0.52	4.4%	14.35	-2.03	-14.1%
169.01	172.16	-3.15	-1.8%	182.39	-13.34	-7.3%
71.41	68.06	3.34	4.9%	80.41	-8.99	-11.2%
240.94	241.13	-0.20	-0.1%	263.26	-22.32	-8.5%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

Residential Non-Heat Metered Deliveries (Dth)											
2020-2021	2020-2021 Compared to 2019-2020					2020-2021 Compared to 2018-2019					
Forecast	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2018-2019 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	
1	2	3	4	5	6	7	8	9	10	11	
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)	
Nov	1,818	1,715	103	6.0%	-33	136	1,877	-59	-3.1%	-68	9
Dec	2,774	2,553	221	8.7%	-50	271	2,640	134	5.1%	-117	251
Jan	3,284	3,044	240	7.9%	-59	299	3,160	124	3.9%	7	117
Feb	3,378	3,150	228	7.2%	-61	289	3,434	-56	-1.6%	38	-95
Mar	2,725	2,677	48	1.8%	-52	100	2,592	133	5.1%	37	96
Apr	2,104	2,217	-114	-5.1%	-42	-71	2,110	-6	-0.3%	7	-12
May	1,657	1,577	80	5.1%	-31	111	1,702	-44	-2.6%	-65	21
Jun	1,379	1,503	-124	-8.2%	-29	-95	1,393	-14	-1.0%	-54	40
Jul	1,212	1,326	-114	-8.6%	-26	-88	1,331	-120	-9.0%	-51	-69
Aug	1,167	1,187	-20	-1.7%	-23	3	1,200	-33	-2.7%	-46	13
Sep	1,199	1,268	-70	-5.5%	-25	-45	1,150	49	4.2%	-45	93
Oct	1,169	1,199	-31	-2.6%	-23	-8	1,393	-224	-16.1%	-53	-171
Winter	16,084	15,356	728	4.7%	-297	1,025	15,813	271	1.7%	-132	403
Summer	7,783	8,061	-278	-3.5%	-157	-121	8,169	-386	-4.7%	-313	-73
Annual	23,867	23,417	449	1.9%	-454	903	23,982	-115	-0.5%	-565	450

Note 1 Company Forecast

Note 2 Actual, weather normalized data through April. Forecast data beginning June.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Actual, weather normalized data through May. Forecast data beginning June.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

Total Division Meter Counts							
2020-2021	Compared to 2019-2020			Compared to 2018-2019			
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change	
1	2	3	4	5	6	7	
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	
	1,220	1,244	-24	-1.9%	1,266	-46	-3.6%
	1,210	1,234	-24	-1.9%	1,266	-56	-4.4%
	1,268	1,293	-25	-1.9%	1,265	3	0.2%
	1,266	1,291	-25	-1.9%	1,252	14	1.1%
	1,267	1,292	-25	-1.9%	1,249	18	1.4%
	1,280	1,305	-25	-1.9%	1,276	4	0.3%
	1,261	1,286	-25	-1.9%	1,311	-50	-3.8%
	1,265	1,290	-25	-1.9%	1,316	-51	-3.9%
	1,261	1,286	-25	-1.9%	1,311	-50	-3.8%
	1,261	1,286	-25	-1.9%	1,311	-50	-3.8%
	1,242	1,267	-25	-2.0%	1,292	-50	-3.9%
	1,213	1,237	-24	-1.9%	1,261	-48	-3.8%
	1,252	1,277	-25	-1.9%	1,262	-11	-0.8%
	1,251	1,275	-25	-1.9%	1,300	-50	-3.8%
	1,251	1,276	-25	-1.9%	1,281	-30	-2.4%

Note 1 Company Forecast

Note 2 Actual data through April. Forecast data beginning June.

Note 3 Actual Data.

Total Division Use Per Meter						
2020-2021	Compared to 2019-2020			Compared to 2018-2019		
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
1	2	3	4	5	6	7
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
1.49	1.38	0.11	8.1%	1.48	0.01	0.5%
2.29	2.07	0.22	10.8%	2.09	0.21	10.0%
2.59	2.35	0.24	10.0%	2.50	0.09	3.7%
2.67	2.44	0.23	9.4%	2.74	-0.07	-2.7%
2.15	2.07	0.08	3.8%	2.08	0.08	3.6%
1.64	1.70	-0.06	-3.3%	1.65	-0.01	-0.6%
1.31	1.23	0.09	7.2%	1.30	0.02	1.3%
1.09	1.17	-0.07	-6.4%	1.06	0.03	3.0%
0.96	1.03	-0.07	-6.8%	1.02	-0.05	-5.4%
0.93	0.92	0.00	0.2%	0.92	0.01	1.1%
0.97	1.00	-0.04	-3.6%	0.89	0.08	8.4%
0.96	0.97	-0.01	-0.6%	1.10	-0.14	-12.8%
12.85	12.03	0.82	6.8%	12.53	0.30	2.4%
6.22	6.32	-0.10	-1.5%	6.28	-0.06	-1.0%
19.08	18.35	0.72	3.9%	18.72	0.24	1.3%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

Residential Heat Metered Deliveries (Dth)										
2020-2021	2020-2021 Compared to 2019-2020					2020-2021 Compared to 2018-2019				
Forecast	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2018-2019 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
1	2	3	4	5	6	7	8	9	10	11
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	146,991	142,577	4,413	3.1%	1,705	2,708	146,507	484	0.3%	5,218
Dec	272,352	249,937	22,415	9.0%	2,810	19,605	250,171	22,181	8.9%	8,174
Jan	334,200	327,636	6,564	2.0%	3,735	2,829	342,961	-8,761	-2.6%	10,545
Feb	373,575	363,125	10,450	2.9%	4,105	6,345	386,780	-13,205	-3.4%	11,391
Mar	314,037	277,483	36,554	13.2%	3,147	33,408	281,420	32,617	11.6%	8,252
Apr	211,382	199,902	11,480	5.7%	2,240	9,240	199,888	11,495	5.8%	6,325
May	119,526	109,072	10,454	9.6%	2,035	8,420	117,979	1,547	1.3%	3,517
Jun	60,791	66,064	-5,273	-8.0%	1,263	-6,537	56,303	4,487	8.0%	1,733
Jul	38,534	40,546	-2,012	-5.0%	776	-2,787	37,841	693	1.8%	1,165
Aug	32,477	31,932	545	1.7%	614	-70	32,343	134	0.4%	1,003
Sep	36,047	36,499	-452	-1.2%	705	-1,157	32,410	3,638	11.2%	1,010
Oct	49,544	49,329	215	0.4%	953	-738	59,630	-10,086	-16.9%	1,859
Winter	1,652,538	1,560,661	91,877	5.9%	17,742	74,135	1,607,727	44,811	2.8%	50,749
Summer	336,919	333,442	3,477	1.0%	6,346	-2,869	336,506	413	0.1%	10,361
Annual	1,989,457	1,894,102	95,354	5.0%	24,088	71,267	1,944,233	45,224	2.3%	60,619

Note 1 Company Forecast

Note 2 Actual, weather normalized data through April. Forecast data beginning June.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Actual, weather normalized data through May. Forecast data beginning June.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

Total Division Meter Counts						
2020-2021	Compared to 2019-2020			Compared to 2018-2019		
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
1	2	3	4	5	6	7
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
26,228	25,918	310	1.2%	25,326	902	3.6%
26,264	25,972	292	1.1%	25,433	831	3.3%
26,349	26,052	297	1.1%	25,563	786	3.1%
26,391	26,096	295	1.1%	25,636	755	2.9%
26,399	26,103	296	1.1%	25,647	752	2.9%
26,442	26,149	293	1.1%	25,631	811	3.2%
26,321	25,839	482	1.9%	25,559	762	3.0%
26,219	25,727	492	1.9%	25,436	783	3.1%
26,054	25,565	489	1.9%	25,276	778	3.1%
26,062	25,570	492	1.9%	25,278	784	3.1%
26,232	25,735	497	1.9%	25,439	793	3.1%
26,489	25,987	502	1.9%	25,688	801	3.1%
26,346	26,048	297	1.1%	25,539	806	3.2%
26,230	25,737	492	1.9%	25,446	784	3.1%
26,288	25,893	395	1.5%	25,493	795	3.1%

Note 1 Company Forecast

Note 2 Actual data through April. Forecast data beginning June.

Note 3 Actual Data.

Total Division Use Per Meter							
2020-2021	Compared to 2019-2020			Compared to 2018-2019			
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change	
1	2	3	4	5	6	7	
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	
	5.60	5.50	0.10	1.9%	5.78	-0.18	-3.1%
	10.37	9.62	0.75	7.8%	9.84	0.53	5.4%
	12.68	12.58	0.11	0.9%	13.42	-0.73	-5.5%
	14.16	13.91	0.24	1.7%	15.09	-0.93	-6.2%
	11.90	10.63	1.27	11.9%	10.97	0.92	8.4%
	7.99	7.64	0.35	4.6%	7.80	0.20	2.5%
	4.54	4.22	0.32	7.6%	4.62	-0.07	-1.6%
	2.32	2.57	-0.25	-9.7%	2.21	0.11	4.7%
	1.48	1.59	-0.11	-6.7%	1.50	-0.02	-1.2%
	1.25	1.25	0.00	-0.2%	1.28	-0.03	-2.6%
	1.37	1.42	-0.04	-3.1%	1.27	0.10	7.9%
	1.87	1.90	-0.03	-1.5%	2.32	-0.45	-19.4%
	62.73	59.91	2.81	4.7%	62.95	-0.19	-0.3%
	12.85	12.96	-0.11	-0.9%	13.22	-0.37	-2.8%
	75.68	73.15	2.53	3.5%	76.27	-0.57	-0.7%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

Total Division C&I Metered Deliveries (Dth)											
2020-2021	2020-2021 Compared to 2019-2020					2020-2021 Compared to 2018-2019					
Forecast	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2018-2019 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	
1	2	3	4	5	6	7	8	9	10	11	
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)	
Nov	510,769	552,367	-41,598	-7.5%	-2,689	-38,909	563,195	-52,426	-9.3%	-3,544	-48,882
Dec	670,898	696,758	-25,860	-3.7%	-3,370	-22,490	695,032	-24,134	-3.5%	-2,080	-22,054
Jan	801,919	859,357	-57,437	-6.7%	-4,157	-53,281	902,614	-100,694	-11.2%	-4,749	-95,945
Feb	846,747	911,956	-65,209	-7.2%	-4,406	-60,804	937,081	-90,334	-9.6%	-4,527	-85,807
Mar	784,065	767,178	16,887	2.2%	-3,716	20,603	802,705	-18,640	-2.3%	-5,251	-13,389
Apr	561,249	548,556	12,692	2.3%	-2,666	15,359	643,544	-82,295	-12.8%	-1,292	-81,004
May	449,134	408,392	40,741	10.0%	0	40,741	512,471	-63,337	-12.4%	-2,535	-60,802
Jun	334,990	314,475	20,515	6.5%	0	20,515	372,705	-37,715	-10.1%	-1,820	-35,894
Jul	306,837	291,858	14,980	5.1%	0	14,980	351,853	-45,016	-12.8%	-1,731	-43,285
Aug	313,730	291,836	21,894	7.5%	0	21,894	347,230	-33,500	-9.6%	-1,713	-31,787
Sep	318,934	297,366	21,567	7.3%	45	21,523	341,622	-22,688	-6.6%	-1,628	-21,060
Oct	374,963	351,608	23,355	6.6%	51	23,304	424,390	-49,427	-11.6%	-1,977	-47,450
Winter	4,175,647	4,336,172	-160,525	-3.7%	-21,004	-139,521	4,544,171	-368,524	-8.1%	-21,163	-347,361
Summer	2,098,588	1,955,536	143,052	7.3%	96	142,956	2,350,270	-251,682	-10.7%	-11,401	-240,281
Annual	6,274,235	6,291,708	-17,473	-0.3%	-20,908	3,435	6,894,441	-620,206	-9.0%	-32,764	-587,442

Note 1 Company Forecast

Note 2 Actual, weather normalized data through April. Forecast data beginning June.

Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.

Note 4 Actual, weather normalized data through May. Forecast data beginning June.

Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

Total Division Meter Counts							
2020-2021	Compared to 2019-2020				Compared to 2018-2019		
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change	
1	2	3	4	5	6	7	
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	
Nov	6,949	6,983	-34	-0.5%	6,993	-44	-0.6%
Dec	6,995	7,029	-34	-0.5%	7,016	-21	-0.3%
Jan	6,995	7,029	-34	-0.5%	7,032	-37	-0.5%
Feb	7,004	7,038	-34	-0.5%	7,038	-34	-0.5%
Mar	6,986	7,020	-34	-0.5%	7,032	-46	-0.7%
Apr	6,961	6,995	-34	-0.5%	6,975	-14	-0.2%
May	6,839	6,839	0	0.0%	6,873	-34	-0.5%
Jun	6,724	6,724	0	0.0%	6,757	-33	-0.5%
Jul	6,676	6,676	0	0.0%	6,709	-33	-0.5%
Aug	6,655	6,655	0	0.0%	6,688	-33	-0.5%
Sep	6,682	6,681	1	0.0%	6,714	-32	-0.5%
Oct	6,838	6,837	1	0.0%	6,870	-32	-0.5%
Winter	6,982	7,016	-34	-0.5%	7,014	-33	-0.5%
Summer	6,736	6,735	0	0.0%	6,769	-33	-0.5%
Annual	6,859	6,876	-17	-0.2%	6,891	-33	-0.5%

Note 1 Company Forecast

Note 2 Actual data through April. Forecast data beginning June.

Note 3 Actual Data.

Total Division Use Per Meter							
2020-2021	Compared to 2019-2020				Compared to 2018-2019		
Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change	
1	2	3	4	5	6	7	
Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)	
Nov	73.50	79.10	-5.60	-7.1%	80.54	-7.03	-8.7%
Dec	95.91	99.13	-3.22	-3.2%	99.06	-3.15	-3.2%
Jan	114.64	122.26	-7.62	-6.2%	128.36	-13.72	-10.7%
Feb	120.89	129.58	-8.68	-6.7%	133.15	-12.25	-9.2%
Mar	112.23	109.28	2.95	2.7%	114.15	-1.92	-1.7%
Apr	80.63	78.42	2.21	2.8%	92.26	-11.64	-12.6%
May	65.67	59.72	5.96	10.0%	74.56	-8.89	-11.9%
Jun	49.82	46.77	3.05	6.5%	55.16	-5.34	-9.7%
Jul	45.96	43.72	2.24	5.1%	52.44	-6.48	-12.4%
Aug	47.14	43.85	3.29	7.5%	51.92	-4.78	-9.2%
Sep	47.73	44.51	3.22	7.2%	50.88	-3.15	-6.2%
Oct	54.84	51.43	3.41	6.6%	61.77	-6.94	-11.2%
Winter	598.09	618.07	-19.98	-3.2%	647.84	-49.71	-7.7%
Summer	311.56	290.34	21.22	7.3%	347.24	-35.58	-10.2%
Annual	914.79	915.09	-0.30	0.0%	1,000.44	-85.29	-8.5%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.

Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.

Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Calendar Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-20	2,098	215,574	99,843	8,783	89,906	14,206	18,104	6,724	0	455,239
Dec-20	3,051	313,483	145,189	12,772	130,739	20,659	26,327	9,778	0	661,996
Jan-21	3,635	373,453	172,964	15,215	155,749	24,611	31,363	11,648	0	788,638
Feb-21	3,090	317,501	147,050	12,935	132,414	20,923	26,664	9,903	0	670,482
Mar-21	2,674	274,758	127,254	11,194	114,588	18,107	23,075	8,570	0	580,219
Apr-21	1,536	157,769	73,070	6,428	65,798	10,397	13,250	4,921	0	333,168
May-21	1,650	71,442	26,979	10,900	26,144	19,227	4,171	10,420	0	170,934
Jun-21	1,105	47,821	18,059	7,296	17,500	12,870	2,792	6,975	0	114,418
Jul-21	931	40,315	15,225	6,151	14,753	10,850	2,354	5,880	0	96,459
Aug-21	945	40,919	15,453	6,243	14,974	11,012	2,389	5,968	0	97,904
Sep-21	1,029	44,549	16,823	6,797	16,302	11,989	2,601	6,498	0	106,590
Oct-21	2,122	91,873	34,695	14,018	33,620	24,725	5,364	13,400	0	219,817
Winter	16,084	1,652,538	765,371	67,326	689,194	108,903	138,784	51,543	0	3,489,741
Summer	7,783	336,919	127,233	51,406	123,293	90,674	19,672	49,141	0	806,121
Total	23,867	1,989,457	892,604	118,732	812,488	199,577	158,455	100,683	0	4,295,862

Forecast Calendar Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-20	2,098	215,574	113,485	10,471	158,166	31,709	61,225	144,103	83,464	820,296
Dec-20	3,051	313,483	167,388	14,907	230,291	42,988	83,594	128,194	82,189	1,066,085
Jan-21	3,635	373,453	197,294	17,365	263,260	46,514	99,779	139,118	85,215	1,225,633
Feb-21	3,090	317,501	168,206	14,864	226,359	40,712	86,319	137,096	82,567	1,076,714
Mar-21	2,674	274,758	149,203	13,419	210,207	39,178	79,952	139,901	91,033	1,000,325
Apr-21	1,536	157,769	85,432	8,912	123,004	34,793	59,223	129,656	54,891	655,216
May-21	1,650	71,442	32,738	12,350	57,049	34,028	30,398	142,207	94,136	475,998
Jun-21	1,105	47,821	20,376	8,710	32,240	26,674	21,487	115,968	88,256	362,639
Jul-21	931	40,315	16,505	7,487	24,006	22,623	18,475	121,550	88,869	340,761
Aug-21	945	40,919	16,768	7,671	24,994	24,120	18,155	128,967	91,752	354,292
Sep-21	1,029	44,549	19,390	8,366	32,507	27,155	22,475	123,875	92,648	371,993
Oct-21	2,122	91,873	41,122	15,620	68,266	39,244	37,442	147,375	94,543	537,608
Winter	16,084	1,652,538	881,008	79,937	1,211,287	235,893	470,093	818,068	479,360	5,844,268
Summer	7,783	336,919	146,899	60,205	239,062	173,844	148,433	779,942	550,204	2,443,290
Total	23,867	1,989,457	1,027,907	140,142	1,450,349	409,738	618,526	1,598,010	1,029,564	8,287,558

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-20	100%	100%	88%	84%	57%	45%	30%	5%	0%	55%
Dec-20	100%	100%	87%	86%	57%	48%	31%	8%	0%	62%
Jan-21	100%	100%	88%	88%	59%	53%	31%	8%	0%	64%
Feb-21	100%	100%	87%	87%	58%	51%	31%	7%	0%	62%
Mar-21	100%	100%	85%	83%	55%	46%	29%	6%	0%	58%
Apr-21	100%	100%	86%	72%	53%	30%	22%	4%	0%	51%
May-21	100%	100%	82%	88%	46%	57%	14%	7%	0%	36%
Jun-21	100%	100%	89%	84%	54%	48%	13%	6%	0%	32%
Jul-21	100%	100%	92%	82%	61%	48%	13%	5%	0%	28%
Aug-21	100%	100%	92%	81%	60%	46%	13%	5%	0%	28%
Sep-21	100%	100%	87%	81%	50%	44%	12%	5%	0%	29%
Oct-21	100%	100%	84%	90%	49%	63%	14%	9%	0%	41%
Winter	100%	100%	87%	84%	57%	46%	30%	6%	0%	60%
Summer	100%	100%	87%	85%	52%	52%	13%	6%	0%	33%
Total	100%	100%	87%	85%	56%	49%	26%	6%	0%	52%

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Bill Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-20	1,818	146,991	57,269	8,139	49,844	13,605	7,617	9,238	0	294,521
Dec-20	2,774	272,352	120,501	10,500	95,809	17,362	14,674	7,963	0	541,934
Jan-21	3,284	334,200	159,639	12,038	139,608	20,603	24,466	8,571	0	702,409
Feb-21	3,378	373,575	179,543	13,209	173,381	24,686	41,142	8,553	0	817,468
Mar-21	2,725	314,037	153,484	13,169	139,716	21,707	27,053	8,831	0	680,722
Apr-21	2,104	211,382	94,935	10,270	90,836	10,940	23,832	8,387	0	452,687
May-21	1,657	119,526	52,451	8,889	50,406	17,021	6,442	8,862	0	265,253
Jun-21	1,379	60,791	24,454	8,419	27,214	15,708	3,646	7,329	0	148,939
Jul-21	1,212	38,534	12,659	8,423	15,251	15,685	2,739	7,778	0	102,281
Aug-21	1,167	32,477	11,292	8,506	12,609	14,262	2,402	8,271	0	90,987
Sep-21	1,199	36,047	12,004	8,647	11,452	12,819	715	7,893	0	90,776
Oct-21	1,169	49,544	14,372	8,522	6,361	15,180	3,728	9,009	0	107,884
Nov-21	1,779	152,170	61,326	10,678	54,062	20,318	8,012	4,426	0	312,771
Dec-21	2,612	273,972	122,160	13,141	98,644	24,075	16,487	3,762	0	554,853
Jan-22	2,977	333,174	160,896	15,213	142,586	27,679	24,507	4,139	0	711,170
Feb-22	3,171	376,765	184,127	16,645	177,070	32,282	40,833	4,184	0	835,077
Mar-22	2,728	318,416	159,673	17,576	144,257	30,500	27,383	4,313	0	704,847
Apr-22	2,037	210,394	98,791	12,738	93,880	17,683	23,447	4,127	0	463,099
Winter	16,084	1,652,538	765,371	67,326	689,194	108,903	138,784	51,543	0	3,489,741
Summer	7,783	336,919	127,233	51,406	123,293	90,674	19,672	49,141	0	806,121
Total	23,867	1,989,457	892,604	118,732	812,488	199,577	158,455	100,683	0	4,295,862
Year 2 Winter	15,303	1,664,893	786,972	85,991	710,500	152,538	140,669	24,951	0	3,581,817

Forecast Bill Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-20	1,818	146,991	70,911	9,828	118,104	31,107	50,738	146,617	83,464	659,578
Dec-20	2,774	272,352	142,700	12,636	195,362	39,691	71,941	126,379	82,189	946,024
Jan-21	3,284	334,200	183,968	14,188	247,118	42,506	92,882	136,042	85,215	1,139,404
Feb-21	3,378	373,575	200,699	15,137	267,326	44,475	100,798	135,745	82,567	1,223,700
Mar-21	2,725	314,037	175,433	15,393	235,335	42,778	83,930	140,162	91,033	1,100,828
Apr-21	2,104	211,382	107,297	12,755	148,042	35,336	69,805	133,122	54,891	774,735
May-21	1,657	119,526	58,209	10,339	81,311	31,821	32,669	140,649	94,136	570,317
Jun-21	1,379	60,791	26,771	9,833	41,954	29,512	22,341	116,322	88,256	397,160
Jul-21	1,212	38,534	13,940	9,759	24,505	27,457	18,860	123,447	88,869	346,583
Aug-21	1,167	32,477	12,608	9,934	22,629	27,370	18,168	131,270	91,752	347,374
Sep-21	1,199	36,047	14,571	10,215	27,656	27,985	20,589	125,270	92,648	356,180
Oct-21	1,169	49,544	20,800	10,125	41,007	29,699	35,806	142,984	94,543	425,676
Nov-21	1,779	152,170	74,968	12,366	122,322	37,820	51,133	147,535	93,188	693,283
Dec-21	2,612	273,972	144,359	15,277	198,197	46,404	73,754	125,384	91,672	971,632
Jan-22	2,977	333,174	185,225	17,363	250,096	49,583	92,923	137,961	94,954	1,164,256
Feb-22	3,171	376,765	205,282	18,573	271,015	52,071	100,488	139,459	91,914	1,258,738
Mar-22	2,728	318,416	181,622	19,800	239,876	51,571	84,261	143,770	101,243	1,143,287
Apr-22	2,037	210,394	111,153	15,223	151,087	42,079	69,421	137,581	60,990	799,965
Winter	16,084	1,652,538	881,008	79,937	1,211,287	235,893	470,093	818,068	479,360	5,844,268
Summer	7,783	336,919	146,899	60,205	239,062	173,844	148,433	779,942	550,204	2,443,290
Total	23,867	1,989,457	1,027,907	140,142	1,450,349	409,738	618,526	1,598,010	1,029,564	8,287,558
Year 2 Winter	15,303	1,664,893	902,610	98,602	1,232,593	279,528	471,979	831,690	533,962	6,031,160

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-20	100%	100%	81%	83%	42%	44%	15%	6%	0%	45%
Dec-20	100%	100%	84%	83%	49%	44%	20%	6%	0%	57%
Jan-21	100%	100%	87%	85%	56%	48%	26%	6%	0%	62%
Feb-21	100%	100%	89%	87%	65%	56%	41%	6%	0%	67%
Mar-21	100%	100%	87%	86%	59%	51%	32%	6%	0%	62%
Apr-21	100%	100%	88%	81%	61%	31%	34%	6%	0%	58%
May-21	100%	100%	90%	86%	62%	53%	20%	6%	0%	47%
Jun-21	100%	100%	91%	86%	65%	53%	16%	6%	0%	38%
Jul-21	100%	100%	91%	86%	62%	57%	15%	6%	0%	30%
Aug-21	100%	100%	90%	86%	56%	52%	13%	6%	0%	26%
Sep-21	100%	100%	82%	85%	41%	46%	3%	6%	0%	25%
Oct-21	100%	100%	69%	84%	16%	51%	10%	6%	0%	25%
Nov-21	100%	100%	82%	86%	44%	54%	16%	3%	0%	45%
Dec-21	100%	100%	85%	86%	50%	52%	22%	3%	0%	57%
Jan-22	100%	100%	87%	88%	57%	56%	26%	3%	0%	61%
Feb-22	100%	100%	90%	90%	65%	62%	41%	3%	0%	66%
Mar-22	100%	100%	88%	89%	60%	59%	32%	3%	0%	62%
Apr-22	100%	100%	89%	84%	62%	42%	34%	3%	0%	58%
Winter	100%	100%	87%	84%	57%	46%	30%	6%	0%	60%
Summer	100%	100%	87%	85%	52%	52%	13%	6%	0%	33%
Total	100%	100%	87%	85%	56%	49%	26%	6%	0%	52%

Northern Utilities, Inc.
New Hampshire Division
Forecast Total Billed Meters

Month	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-20	1,220	26,228	5,059	815	727	278	34	33	3	34,397
Dec-20	1,210	26,264	5,097	819	732	278	34	32	3	34,469
Jan-21	1,268	26,349	5,097	818	733	278	34	32	3	34,612
Feb-21	1,266	26,391	5,104	820	732	278	35	32	3	34,661
Mar-21	1,267	26,399	5,085	822	731	278	35	32	3	34,652
Apr-21	1,280	26,442	5,055	829	729	278	35	32	3	34,683
May-21	1,261	26,321	4,989	835	668	281	30	33	3	34,421
Jun-21	1,265	26,219	4,880	830	667	281	30	33	3	34,208
Jul-21	1,261	26,054	4,834	828	666	282	30	33	3	33,991
Aug-21	1,261	26,062	4,817	826	664	282	30	33	3	33,978
Sep-21	1,242	26,232	4,822	826	678	290	30	33	3	34,156
Oct-21	1,213	26,489	4,938	822	728	281	33	33	3	34,540

Forecast Delivery Service Billed Meters

Month	Res Non-Heat	Res Heat	40	50	41	51	42	52	Special Contracts	Total Division
Nov-20			491	81	266	120	23	30	3	1,014
Dec-20			491	81	266	120	23	30	3	1,014
Jan-21			491	81	266	120	23	30	3	1,014
Feb-21			491	81	266	120	23	30	3	1,014
Mar-21			491	81	266	120	23	30	3	1,014
Apr-21			491	81	266	120	23	30	3	1,014
May-21			491	81	266	120	23	30	3	1,014
Jun-21			491	81	266	120	23	30	3	1,014
Jul-21			491	81	266	120	23	30	3	1,014
Aug-21			491	81	266	120	23	30	3	1,014
Sep-21			491	81	266	120	23	30	3	1,014
Oct-21			491	81	266	120	23	30	3	1,014

Forecast Sales Service Billed Meters

Month	Res Non-Heat	Res Heat	40	50	41	51	42	52	Special Contracts	Total Division
Nov-20	1,220	26,228	4,568	734	461	158	11	3	-	33,383
Dec-20	1,210	26,264	4,606	738	466	158	11	2	-	33,455
Jan-21	1,268	26,349	4,606	737	467	158	11	2	-	33,598
Feb-21	1,266	26,391	4,613	739	466	158	12	2	-	33,647
Mar-21	1,267	26,399	4,594	741	465	158	12	2	-	33,638
Apr-21	1,280	26,442	4,564	748	463	158	12	2	-	33,669
May-21	1,261	26,321	4,498	754	402	161	7	3	-	33,407
Jun-21	1,265	26,219	4,389	749	401	161	7	3	-	33,194
Jul-21	1,261	26,054	4,343	747	400	162	7	3	-	32,977
Aug-21	1,261	26,062	4,326	745	398	162	7	3	-	32,964
Sep-21	1,242	26,232	4,331	745	412	170	7	3	-	33,142
Oct-21	1,213	26,489	4,447	741	462	161	10	3	-	33,526

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern - New Hampshire City-Gate Sendout Requirement

Month	Sales Service Deliveries (Dth)	Company Gas Allowance (Percent)	Company Gas Allowance (LAUF and Company Use) (Dth)	Estimated Division Sales Service Sendout (Dth)	Estimated Company-Managed Sales	Total Estimated City-Gate Sendout Requirement
Nov-20	455,239	1.30%	5,996	461,235	22,380	483,615
Dec-20	661,996	1.30%	8,719	670,715	25,562	696,277
Jan-21	788,638	1.30%	10,388	799,026	29,216	828,242
Feb-21	670,482	1.30%	8,831	679,313	23,933	703,246
Mar-21	580,219	1.30%	7,642	587,861	23,126	610,987
Apr-21	333,168	1.30%	4,388	337,556	0	337,556
May-21	170,934	1.30%	2,251	173,185	0	173,185
Jun-21	114,418	1.30%	1,507	115,925	0	115,925
Jul-21	96,459	1.30%	1,271	97,730	0	97,730
Aug-21	97,904	1.30%	1,289	99,193	0	99,193
Sep-21	106,590	1.30%	1,403	107,993	0	107,993
Oct-21	219,817	1.30%	2,895	222,712	0	222,712
Winter	3,489,741	1.30%	45,965	3,535,706	124,217	3,659,923
Summer	806,121	1.30%	10,617	816,738	0	816,738
Annual	4,295,862	1.30%	56,582	4,352,444	124,217	4,476,661

Northern Utilities, Inc.
New Hampshire Division
Lost and Unaccounted For, Company Use and Therm Factor Data

Month	GSGT - NH City-Gates (MCF)	Therm Factor	Total - NH City-Gate (Dth)	Total System Billed Sales (Dth)	Company Use (Dth)	Lost and Unaccounted For (Dth)	Company Gas Allowance (Dth)
Jun-16	357,643	1.0279	367,636	388,601	46	(21,011)	(20,965)
Jul-16	333,740	1.0234	341,546	330,290	48	11,208	11,256
Aug-16	351,745	1.0268	361,183	362,108	77	(1,002)	(925)
Sep-16	344,260	1.0275	353,710	362,480	85	(8,855)	(8,770)
Oct-16	534,187	1.0277	548,995	450,915	76	98,004	98,080
Nov-16	727,721	1.0255	746,307	632,412	109	113,786	113,895
Dec-16	1,070,154	1.0296	1,101,863	914,020	180	187,663	187,843
Jan-17	1,072,453	1.0310	1,105,656	1,096,068	219	9,369	9,588
Feb-17	933,805	1.0393	970,504	1,031,216	218	(60,930)	(60,712)
Mar-17	1,096,739	1.0314	1,131,198	1,031,817	211	99,170	99,381
Apr-17	608,829	1.0277	625,669	834,527	162	(209,020)	(208,858)
May-17	505,254	1.0276	519,184	568,537	74	(49,427)	(49,353)
Jun-17	367,334	1.0280	377,630	385,480	56	(7,906)	(7,850)
Jul-17	339,837	1.0256	348,547	387,505	59	(39,017)	(38,958)
Aug-17	361,673	1.0280	371,789	366,063	62	5,664	5,726
Sep-17	357,543	1.0278	367,472	356,843	56	10,573	10,629
Oct-17	446,927	1.0284	459,625	427,725	32	31,868	31,900
Nov-17	794,934	1.0307	819,307	581,079	71	238,157	238,228
Dec-17	1,205,148	1.0339	1,245,942	1,003,583	209	242,150	242,359
Jan-18	1,274,596	1.0394	1,324,764	1,403,452	373	(79,061)	(78,688)
Feb-18	936,704	1.0340	968,580	1,110,066	270	(141,756)	(141,486)
Mar-18	999,035	1.0334	1,032,433	998,242	239	33,952	34,191
Apr-18	766,729	1.0318	791,111	889,668	211	(98,768)	(98,557)
May-18	443,025	1.0283	455,580	574,552	108	(119,080)	(118,972)
Jun-18	369,548	1.0292	380,339	409,352	40	(29,053)	(29,013)
Jul-18	351,086	1.0289	361,236	352,762	92	8,382	8,474
Aug-18	363,051	1.0284	373,373	369,837	131	3,405	3,536
Sep-18	378,195	1.0276	388,633	370,269	131	18,233	18,364
Oct-18	628,317	1.0303	647,361	485,554	100	161,707	161,807
Nov-18	923,290	1.0336	954,321	765,985	142	188,194	188,336
Dec-18	1,057,440	1.0382	1,097,877	1,067,650	207	30,020	30,227
Jan-19	1,259,492	1.0431	1,313,764	1,200,221	254	113,289	113,543
Feb-19	1,109,150	1.0375	1,150,732	1,229,927	257	(79,452)	(79,195)
Mar-19	1,008,861	1.0347	1,043,849	1,147,817	251	(104,219)	(103,968)
Apr-19	681,738	1.0309	702,824	843,446	173	(140,795)	(140,622)
May-19	545,305	1.0288	560,999	632,151	100	(71,252)	(71,152)
Jun-19	388,772	1.0290	400,027	430,401	58	(30,432)	(30,374)
Jul-19	365,810	1.0287	376,320	391,025	83	(14,788)	(14,705)
Aug-19	374,614	1.0280	385,103	380,773	140	4,190	4,330
Sep-19	394,298	1.0283	405,449	375,182	100	30,167	30,267
Oct-19	534,087	1.0295	549,837	485,412	89	64,336	64,425
Nov-19	930,426	1.0352	963,214	698,187	84	264,943	265,027
Dec-19	1,075,165	1.0460	1,124,591	1,016,439	240	107,912	108,152
Jan-20	1,077,141	1.0437	1,124,212	1,130,011	294	(6,093)	(5,799)
Feb-20	1,041,031	1.0434	1,086,254	1,133,789	289	(47,824)	(47,535)
Mar-20	839,434	1.0376	871,030	1,005,451	257	(134,678)	(134,421)
Apr-20	651,269	1.0343	673,594	707,068	180	(33,654)	(33,474)
May-20	441,527	1.0303	454,923	565,494	141	(110,712)	(110,571)
Total	33,019,063	1.0335	34,126,093	33,681,452	7,084	437,557	444,641
48-Month Average					0.02%	1.28%	1.30%

Northern Capacity Summary (Dth/Day)

Pipeline Capacity Paths

Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	40,586

Storage Capacity Paths

Tennessee Firm Storage	2,644
Union Dawn Storage	39,863
Total Storage Capacity	42,507

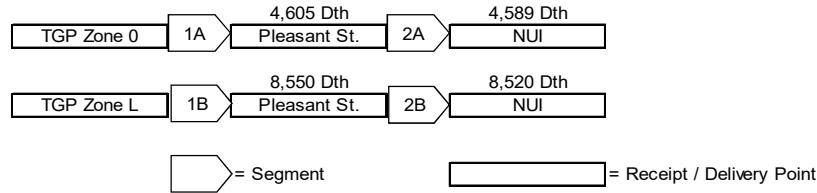
Peaking Capacity Paths

LNG - On-System	6,500
Peaking Contract 1	39,860
Additional Granite Capacity	13,391
Total Peaking Capacity	59,751

Total Design Day Capacity	142,844

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Zone 0 100 Leg, Zone L 500 and 800 Leg Pools

Capacity Path Diagram



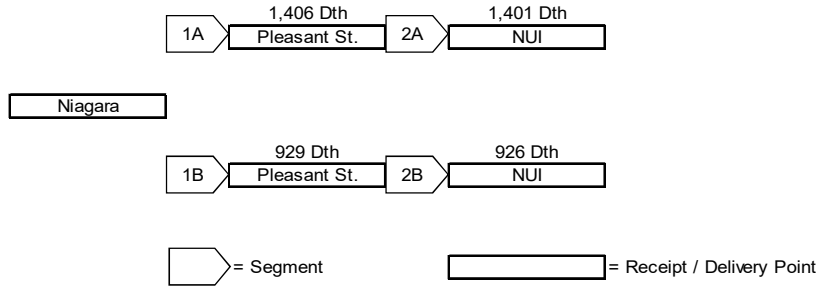
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A ¹	Transportation	Tennessee	5083	FT-A	10/31/2023	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B ¹	Transportation	Tennessee	5083	FT-A	10/31/2023	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

Note 1: Tennessee Contract No. 5083 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Niagara (Interconnection of TransCanada and Tennessee Pipelines)

Capacity Path Diagram

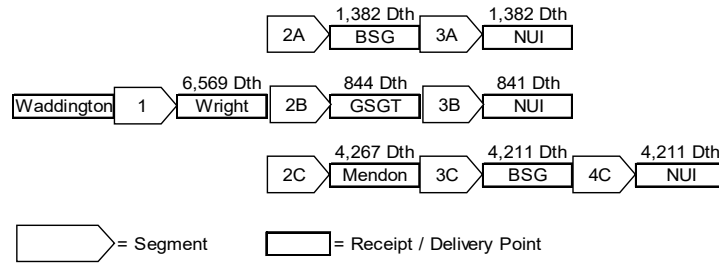


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2025	1,406	Dth	Year-Round	Niagara	Pleasant St.	Granite
2A	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	1,401	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2025	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						2,327	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Iroquois Receipts

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Iroquois	R181001	RTS-1	10/31/2023	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
2A	Transportation	Tennessee	95196	FT-A	10/31/2022	1,382	Dth	Year-Round	Wright	Bay State City Gate	
3A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
2B	Transportation	Tennessee	95196	FT-A	10/31/2022	844	Dth	Year-Round	Wright	Pleasant St.	Granite
3B	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	841	Dth	Year-Round	Granite	Northern City Gates	
2C	Transportation	Tennessee	41099	FT-A	10/31/2022	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
3C	Transportation	Algonquin	93200F	AFT-1	10/31/2021	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
4C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Capacity Path Diagram

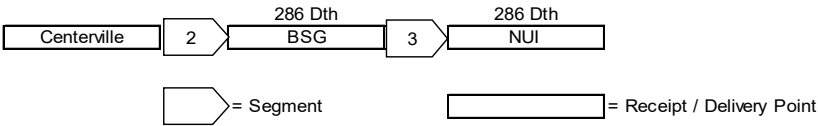


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Texas Eastern	800384	FT-1	10/31/2021	965	Dth	Year-Round	Leidy Storage	Lambertville, NJ	Algonquin
2	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2021	965	Dth	Year-Round	Lambertville, NJ	Bay State City Gate	
3	Exchange	Bay State Gas	NA	NA	Renewal Clause	965	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						965	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Capacity Path Diagram

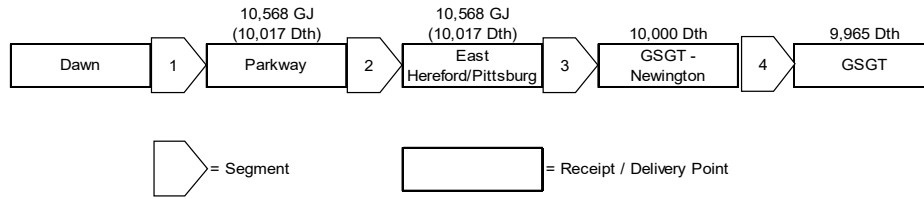


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2021	286	Dth	Year-Round	Centerville, NJ	Bay State City Gate	
2	Exchange	Bay State Gas	NA	NA	Renewal Clause	286	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						286	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: PXP Dawn Hub

Capacity Path Diagram

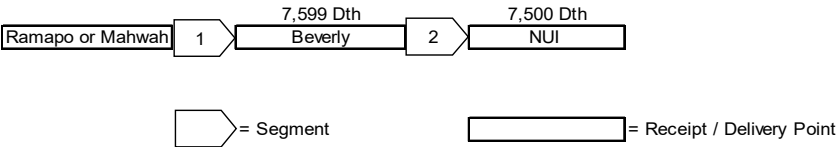


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Union	TBD	M12	10/31/2040	10,568	GJ	Year-Round	Dawn	Parkway	TransCanada
2	Transportation	TransCanada	TBD	FT	10/31/2040	10,568	GJ	Year-Round	Parkway	East Hereford	PNGTS
3	Transportation	PNGTS	TBD	FT	10/31/2040	10,000	Dth	Year-Round	Pittsburg, NH	Newington, NH	Granite
4	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	9,965	Dth	Year-Round	Newington, NH	Northern City Gates	
Total Path Deliverable						9,965	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Atlantic Bridge Ramapo

Capacity Path Diagram

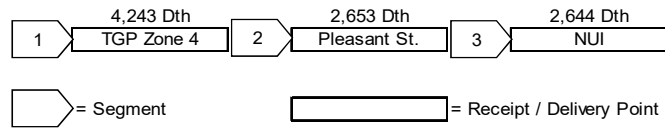


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	TBD	FT	10/31/2035	7,599	Dth	Year-Round	Ramapo or Mawhah	Beverly, MA	Maritimes
2	Transportation	Maritimes	TBD	FT	10/31/2025	7,500	Dth	Year-Round	Beverly, MA	Northern City Gates	
Total Path Deliverable						7,500	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Firm Storage - Market Area

Capacity Path Diagram



Capacity Path Detail

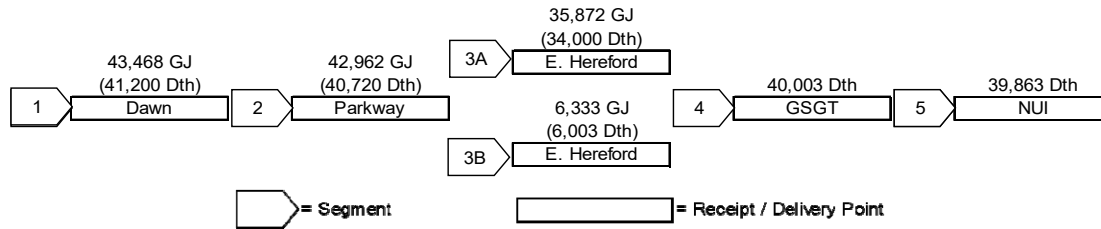
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1 ¹	Storage	Tennessee	5195	FS-MA	3/31/2025	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2 ²	Transportation	Tennessee	5265	FT-A	3/31/2025	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

Note 1: Tennessee Contract No. 5195 has a maximum storage quantity of 259,337 Dth.

Note 2: Tennessee Contract No. 5265 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Firm Storage could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Union Dawn Storage

Capacity Path Diagram

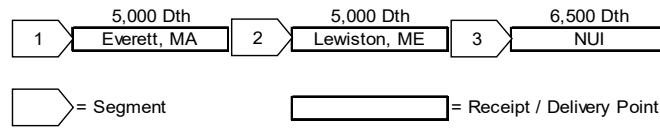


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Storage	Union	LST086	Firm Storage (MDWD)	3/31/2023	43,468	GJ	Year-Round	NA	Dawn	Union
1	Storage	Union	LST086	Firm Storage (MSB)	3/31/2023	4,220,224	GJ	Year-Round	NA	Dawn	
1	Storage	Union	LST086	Firm Storage (MDID)	3/31/2023	31,652	GJ	Year-Round	NA	Dawn	
2	Transportation	Union	M12256	M12	10/31/2033	42,962	GJ	Year-Round	Dawn	Parkway	TransCanada
3A	Transportation	TransCanada	57901	FT	3/31/2033	35,872	GJ	Year-Round	Parkway	East Hereford	PNGTS
3B	Transportation	TransCanada	57055	FT	10/31/2032	6,333	GJ	Year-Round	Parkway	East Hereford	PNGTS
4	Transportation	PNGTS	FTN-NUI-0001	FT	10/31/2033	40,003	Dth	Year-Round	Pittsburg, NH	Newington, NH	Granite
5	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	39,863	Dth	Year-Round	Newington, NH	Northern City Gates	
Total Path Deliverable						39,863	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Lewiston LNG Plant

Capacity Path Diagram



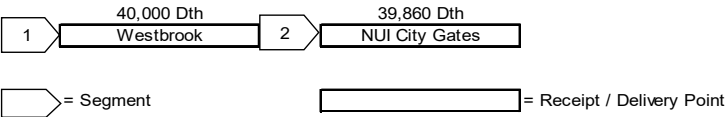
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1 ¹	LNG Contract	Confidential	NA	NA	10/31/2021	5,000	Dth	Year-Round	NA		NA
2	LNG Trucking Contract	Confidential			10/31/2021	5,000	Dth	Year-Round		Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	6,500	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						6,500	Dth				

Note 1: The LNG Contract allows Northern to nominate up to 5,000 Dth per day (5 trucks) with an annual maximum take equal to 125,000 Dth.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Contract 1

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1 ¹	Peaking Supply	Confidential	NA	NA	3/31/2024	40,000	Dth	Winter Only (Nov - Mar)	NA	Westbrook or Lewiston	Granite or Northern City Gates
2	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2021	39,860	Dth	Year-Round	Westbrook or Lewiston	Northern City Gates	
Total Path Deliverable						39,860	Dth				

Note 1: Peaking Contract 1 allows Northern to nominate up to 40,000 Dth per Day and up to 600,000 Dth from November through March with takes above 30,000 Dth per Day capped at 50,000 Dth. Contract volumes may also be delivered to NUI - Lewiston in which case no Granite capacity is utilized.

Northern Utilities, Inc. Estimated Gas Supply Demand Costs November 1, 2020 through October 31, 2021			
Line	Description	Estimate	Reference
1.	Pipeline Demand Costs	\$ 17,304,236	Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	\$ 20,299,374	Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	\$ 2,962,375	Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	\$ 1,658,003	Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	\$ 11,109,167	Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	\$ (8,074,404)	Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	\$ 45,258,751	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2020 through October 31, 2021

Capacity Path	Segment	Pipeline	Contract ID	Rate	Negotiated Rate	Maximum Daily Quantity (Dth)	Monthly Demand Rate (\$/MDQ)	Months Per Year	Reference (Sch 27-FXW, Page 2)	Monthly Demand	Annual Demand
Tennessee Zone 0/L Pools	1A	Tennessee	5083	FT-A	No	4,605	\$ 20.3504	12	Line 8	\$ 93,714	\$ 1,124,563
Tennessee Zone 0/L Pools	2A	Granite	19-100-FT-NN	FT-NN	No	4,589	\$ 4.4212	12	Line 3	\$ 20,289	\$ 243,467
Tennessee Zone 0/L Pools	1B	Tennessee	5083	FT-A	No	8,550	\$ 18.0643	12	Line 9	\$ 154,450	\$ 1,853,397
Tennessee Zone 0/L Pools	2B	Granite	19-100-FT-NN	FT-NN	No	8,520	\$ 4.4212	12	Line 3	\$ 37,669	\$ 452,023
Tennessee Niagara	1A	Tennessee	5292	FT-A	No	1,406	\$ 6.2725	12	Line 11	\$ 8,819	\$ 105,830
Tennessee Niagara	2A	Granite	19-100-FT-NN	FT-NN	No	1,401	\$ 4.4212	12	Line 3	\$ 6,194	\$ 74,329
Tennessee Niagara	1B	Tennessee	39735	FT-A	No	929	\$ 6.2725	12	Line 11	\$ 5,827	\$ 69,926
Tennessee Niagara	2B	Granite	19-100-FT-NN	FT-NN	No	926	\$ 4.4212	12	Line 3	\$ 4,094	\$ 49,128
Iroquois Receipts	1	Iroquois	181003	RTS-1	No	5,715	\$ 5.2357	12	Line 4	\$ 29,922	\$ 359,064
Iroquois Receipts	1	Iroquois	181003	RTS-1	No	854	\$ 5.2357	12	Line 4	\$ 4,471	\$ 53,655
Iroquois Receipts	2A	Tennessee	95196	FT-A	No	1,382	\$ 6.2725	12	Line 11	\$ 8,669	\$ 104,023
Iroquois Receipts	2B	Tennessee	95196	FT-A	No	844	\$ 6.2725	12	Line 11	\$ 5,294	\$ 63,528
Iroquois Receipts	3B	Granite	19-100-FT-NN	FT-NN	No	841	\$ 4.4212	12	Line 3	\$ 3,718	\$ 44,619
Iroquois Receipts	2C	Tennessee	41099	FT-A	No	4,267	\$ 6.2725	12	Line 11	\$ 26,765	\$ 321,177
Iroquois Receipts	3C	Algonquin	93002F	AFT-1	No	4,211	\$ 8.5927	12	Line 1	\$ 36,184	\$ 434,206
Leidy Hub	1	Texas Eastern	800384	FT-1	No	965	\$ 7.0960	12	Line 12	\$ 6,848	\$ 82,172
Leidy Hub	2	Algonquin	93201A1C	AFT-1	No	965	\$ 8.5927	12	Line 1	\$ 8,292	\$ 99,503
Transco Zone 6, non-NY	1	Algonquin	93201A1C	AFT-1	No	286	\$ 8.5927	12	Line 1	\$ 2,458	\$ 29,490
PXP Dawn Hub	1	Union		M12	No	10,017	\$ 2.8203	12	Line 14	\$ 28,251	\$ 339,011
PXP Dawn Hub	2	TransCanada		FT	No	10,017	\$ 12.9437	2	Line 13	\$ 129,657	\$ 259,314
PXP Dawn Hub	2	TransCanada		FT	No	10,017	\$ 16.6050	10	Line 13	\$ 166,332	\$ 1,663,323
PXP Dawn Hub	3	PNGTS		FT (PXP)	Yes	10,000	\$ 22.8125	12	Line 7	\$ 228,125	\$ 2,737,500
PXP Dawn Hub	4	Granite	19-100-FT-NN	FT-NN	No	9,965	\$ 4.4212	12	Line 3	\$ 44,057	\$ 528,687
Atlantic Bridge	1	Algonquin		AFT	Yes	7,599	\$ 54.9173	12	Line 2	\$ 417,317	\$ 5,007,799
Atlantic Bridge	2	Maritimes		MN365	Yes	7,500	\$ 13.3833	12	Line 5	\$ 100,375	\$ 1,204,500
Tennessee Firm Storage	2	Tennessee	5265	FT-A	No	2,653	\$ 7.1413	12	Line 10	\$ 18,946	\$ 227,350
Tennessee Firm Storage	3	Granite	19-100-FT-NN	FT-NN	No	2,644	\$ 4.4212	12	Line 3	\$ 11,690	\$ 140,276
Union Dawn Storage	2	Union	M12256	M12	No	40,720	\$ 2.8203	12	Line 14	\$ 114,843	\$ 1,378,111
Union Dawn Storage	3A	TransCanada	57901	FT	No	34,000	\$ 12.9437	2	Line 13	\$ 440,086	\$ 880,172
Union Dawn Storage	3A	TransCanada	57901	FT	No	34,000	\$ 16.6050	10	Line 13	\$ 564,570	\$ 5,645,700
Union Dawn Storage	3B	TransCanada	57055	FT	No	6,003	\$ 12.9437	2	Line 13	\$ 77,701	\$ 155,402
Union Dawn Storage	3B	TransCanada	57055	FT	No	6,003	\$ 16.6050	10	Line 13	\$ 99,680	\$ 996,798
Union Dawn Storage	4	PNGTS	208543	FT (C2C)	Yes	40,003	\$ 18.2500	12	Line 6	\$ 730,055	\$ 8,760,657
Union Dawn Storage	5	Granite	19-100-FT-NN	FT-NN	No	39,863	\$ 4.4212	12	Line 3	\$ 176,242	\$ 2,114,908
Peaking Capacity (Nov-Oct)	N/A	Granite	19-100-FT-NN	FT-NN	No	9,251	\$ 4.4212	12	Line 3	\$ 40,901	\$ 490,806
Peaking Capacity (Nov-Apr)	N/A	Granite	19-100-FT-NN	FT-NN	No	44,000	\$ 4.4212	6	Line 3	\$ 194,533	\$ 1,167,197
Total Annual Demand Costs											\$ 39,261,613

Northern Utilities, Inc.
Pipeline Contract Demand Cost Allocations
November 1, 2020 through October 31, 2021

Capacity Path	Segment	Pipeline	Contract ID	MDQ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Tennessee Zone 0/L Pools	1A	Tennessee	5083	4,605	4,605	-	-	\$ 1,124,563	\$ 1,124,563	\$ -	\$ -
Tennessee Zone 0/L Pools	2A	Granite	19-100-FT-NN	4,589	4,589	-	-	\$ 243,467	\$ 243,467	\$ -	\$ -
Tennessee Zone 0/L Pools	1B	Tennessee	5083	8,550	8,550	-	-	\$ 1,853,397	\$ 1,853,397	\$ -	\$ -
Tennessee Zone 0/L Pools	2B	Granite	19-100-FT-NN	8,520	8,520	-	-	\$ 452,023	\$ 452,023	\$ -	\$ -
Tennessee Niagara	1A	Tennessee	5292	1,406	1,406	-	-	\$ 105,830	\$ 105,830	\$ -	\$ -
Tennessee Niagara	2A	Granite	19-100-FT-NN	1,401	1,401	-	-	\$ 74,329	\$ 74,329	\$ -	\$ -
Tennessee Niagara	1B	Tennessee	39735	929	929	-	-	\$ 69,926	\$ 69,926	\$ -	\$ -
Tennessee Niagara	2B	Granite	19-100-FT-NN	926	926	-	-	\$ 49,128	\$ 49,128	\$ -	\$ -
Iroquois Receipts	1	Iroquois	181003	5,715	5,715	-	-	\$ 359,064	\$ 359,064	\$ -	\$ -
Iroquois Receipts	1	Iroquois	181003	854	854	-	-	\$ 53,655	\$ 53,655	\$ -	\$ -
Iroquois Receipts	2A	Tennessee	95196	1,382	1,382	-	-	\$ 104,023	\$ 104,023	\$ -	\$ -
Iroquois Receipts	2B	Tennessee	95196	844	844	-	-	\$ 63,528	\$ 63,528	\$ -	\$ -
Iroquois Receipts	3B	Granite	19-100-FT-NN	841	841	-	-	\$ 44,619	\$ 44,619	\$ -	\$ -
Iroquois Receipts	2C	Tennessee	41099	4,267	4,267	-	-	\$ 321,177	\$ 321,177	\$ -	\$ -
Iroquois Receipts	3C	Algonquin	93002F	4,211	4,211	-	-	\$ 434,206	\$ 434,206	\$ -	\$ -
Leidy Hub	1	Texas Eastern	800384	965	965	-	-	\$ 82,172	\$ 82,172	\$ -	\$ -
Leidy Hub	2	Algonquin	93201A1C	965	965	-	-	\$ 99,503	\$ 99,503	\$ -	\$ -
Transco Zone 6, non-NY	1	Algonquin	93201A1C	286	286	-	-	\$ 29,490	\$ 29,490	\$ -	\$ -
PXP Dawn Hub	1	Union	0	10,017	10,017	-	-	\$ 339,011	\$ 339,011	\$ -	\$ -
PXP Dawn Hub	2	TransCanada	0	10,017	10,017	-	-	\$ 259,314	\$ 259,314	\$ -	\$ -
PXP Dawn Hub	2	TransCanada	0	10,017	10,017	-	-	\$ 1,663,323	\$ 1,663,323	\$ -	\$ -
PXP Dawn Hub	3	PNGTS	0	10,000	10,000	-	-	\$ 2,737,500	\$ 2,737,500	\$ -	\$ -
PXP Dawn Hub	4	Granite	19-100-FT-NN	9,965	9,965	-	-	\$ 528,687	\$ 528,687	\$ -	\$ -
Atlantic Bridge	1	Algonquin	0	7,599	7,599	-	-	\$ 5,007,799	\$ 5,007,799	\$ -	\$ -
Atlantic Bridge	2	Maritimes	0	7,500	7,500	-	-	\$ 1,204,500	\$ 1,204,500	\$ -	\$ -
Tennessee Firm Storage	2	Tennessee	5265	2,653	-	2,653	-	\$ 227,350	\$ -	\$ 227,350	\$ -
Tennessee Firm Storage	3	Granite	19-100-FT-NN	2,644	-	2,644	-	\$ 140,276	\$ -	\$ 140,276	\$ -
Union Dawn Storage	2	Union	M12256	40,720	-	40,720	-	\$ 1,378,111	\$ -	\$ 1,378,111	\$ -
Union Dawn Storage	3A	TransCanada	57901	34,000	-	34,000	-	\$ 880,172	\$ -	\$ 880,172	\$ -
Union Dawn Storage	3A	TransCanada	57901	34,000	-	34,000	-	\$ 5,645,700	\$ -	\$ 5,645,700	\$ -
Union Dawn Storage	3B	TransCanada	57055	6,003	-	6,003	-	\$ 155,402	\$ -	\$ 155,402	\$ -
Union Dawn Storage	3B	TransCanada	57055	6,003	-	6,003	-	\$ 996,798	\$ -	\$ 996,798	\$ -
Union Dawn Storage	4	PNGTS	208543	40,003	-	40,003	-	\$ 8,760,657	\$ -	\$ 8,760,657	\$ -
Union Dawn Storage	5	Granite	19-100-FT-NN	39,863	-	39,863	-	\$ 2,114,908	\$ -	\$ 2,114,908	\$ -
Peaking Capacity (Nov-Oct)	N/A	Granite	19-100-FT-NN	9,251	-	-	26,216	\$ 490,806	\$ -	\$ -	\$ 490,806
Peaking Capacity (Nov-Apr)	N/A	Granite	19-100-FT-NN	44,000	-	-	30,000	\$ 1,167,197	\$ -	\$ -	\$ 1,167,197
Total Annual Demand Costs								\$ 39,261,613	\$ 17,304,236	\$ 20,299,374	\$ 1,658,003

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2020 through October 31, 2021

Vendor	Contract ID	Rate	Negotiated	MSQ (Dth)	MDWQ	Space Rate	Demand Rate	Months Per Year	Reference (Sch 27-FXW, Page 2)	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee Union	5195 LST086	FS-MA Storage	No Yes	259,337 4,000,000	4,243 41,200	\$ 0.0179 \$ 0.0592	\$ 1.3094	12 12	Line 1 Line 2	\$ 55,706 \$ 2,840,000	\$ 66,669	\$ 122,375 \$ 2,840,000

Total Annual Fixed Charges

\$ 2,962,375

MSQ = Maximum Space Quantity

MDWQ = Maximum Daily Withdrawal Quantity

REDACTED

Northern Utilities, Inc.
Peaking Contract Demand Cost Estimates
November 1, 2020 through October 31, 2021

Denotes Confidential Information

Resource	Supplier	Contract Quantity	Maximum Daily Quantity	Months per Year	Annual Fixed Charges
LNG Contract		125,000	5,000	5	
Peaking Contract 1		600,000	40,000	5	
Total Peaking Supply Contract Demand Costs					\$ 11,109,167

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Northern Utilities, Inc.
Asset Management and Capacity Release Revenue Projections
November 1, 2020 through October 31, 2021

Denotes Confidential Information	
Capacity Path	Projected Revenue
Tennessee Zone O/L Pools Tennessee Niagara Iroquois Receipts Leidy Hub & Transco Zone 6, non-NY Union Dawn Storage	
Total Asset Management	\$ (8,074,404)

Northern Utilities, Inc.
New Hampshire Division
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Northern Utilities, Inc. New Hampshire Division Retail Marketer Capacity Assignment Revenue Projections November 2020 through October 2021		
Item	Revenue	Reference
Pipeline Contract Capacity Assignment	\$ (3,942,611)	Page 2
Storage Contract Capacity Assignment	\$ (277,372)	Page 3
On-System Peaking Service Demand	\$ (235,657)	Page 4
Asset Management Revenue Assigned to Retail Suppliers	\$ 35,696	Page 5
Total Division Capacity Assignment Demand Revenue	\$ (4,419,945)	Sum of Items Above

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New Hampshire Division
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Northern Utilities, Inc. New Hampshire Division Pipeline Capacity Assignment Estimates November 2020 through October 2021														
Capacity Path	Segment	Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Peaking MDQ	Assigned Pipeline Credits	Assigned Storage Credits	Assigned Peaking Credits	ME Annual Cap Assign Credit
Tennessee Zone 0/L Pools	1A	Tennessee	5083	\$ 1,124,563	\$ -	\$ -	Y	(502)	-	-	\$ (122,591)	\$ -	\$ -	\$ (122,591)
Tennessee Zone 0/L Pools	2A	Granite	19-100-FT-NN	\$ 243,467	\$ -	\$ -	Y	(500)	-	-	\$ (26,527)	\$ -	\$ -	\$ (26,527)
Tennessee Zone 0/L Pools	1B	Tennessee	5083	\$ 1,853,397	\$ -	\$ -	Y	(932)	-	-	\$ (202,031)	\$ -	\$ -	\$ (202,031)
Tennessee Zone 0/L Pools	2B	Granite	19-100-FT-NN	\$ 452,023	\$ -	\$ -	Y	(929)	-	-	\$ (49,288)	\$ -	\$ -	\$ (49,288)
Tennessee Niagara	1A	Tennessee	5292	\$ 105,830	\$ -	\$ -	Y	(153)	-	-	\$ (11,516)	\$ -	\$ -	\$ (11,516)
Tennessee Niagara	2A	Granite	19-100-FT-NN	\$ 74,329	\$ -	\$ -	Y	(153)	-	-	\$ (8,117)	\$ -	\$ -	\$ (8,117)
Tennessee Niagara	1B	Tennessee	39735	\$ 69,926	\$ -	\$ -	Y	(101)	-	-	\$ (7,602)	\$ -	\$ -	\$ (7,602)
Tennessee Niagara	2B	Granite	19-100-FT-NN	\$ 49,128	\$ -	\$ -	Y	(101)	-	-	\$ (5,358)	\$ -	\$ -	\$ (5,358)
Iroquois Receipts	1	Iroquois	181003	\$ 359,064	\$ -	\$ -	Y	(623)	-	-	\$ (39,142)	\$ -	\$ -	\$ (39,142)
Iroquois Receipts	1	Iroquois	181003	\$ 53,655	\$ -	\$ -	Y	(93)	-	-	\$ (5,843)	\$ -	\$ -	\$ (5,843)
Iroquois Receipts	2A	Tennessee	95196	\$ 104,023	\$ -	\$ -	Y	(151)	-	-	\$ (11,366)	\$ -	\$ -	\$ (11,366)
Iroquois Receipts	2B	Tennessee	95196	\$ 63,528	\$ -	\$ -	Y	(92)	-	-	\$ (6,925)	\$ -	\$ -	\$ (6,925)
Iroquois Receipts	3B	Granite	19-100-FT-NN	\$ 44,619	\$ -	\$ -	Y	(92)	-	-	\$ (4,881)	\$ -	\$ -	\$ (4,881)
Iroquois Receipts	2C	Tennessee	41099	\$ 321,177	\$ -	\$ -	Y	(465)	-	-	\$ (35,001)	\$ -	\$ -	\$ (35,001)
Iroquois Receipts	3C	Algonquin	93002F	\$ 434,206	\$ -	\$ -	Y	(459)	-	-	\$ (47,329)	\$ -	\$ -	\$ (47,329)
Leidy Hub	1	Texas Eastern	800384	\$ 82,172	\$ -	\$ -	Y	(105)	-	-	\$ (8,941)	\$ -	\$ -	\$ (8,941)
Leidy Hub	2	Algonquin	93201A1C	\$ 99,503	\$ -	\$ -	Y	(105)	-	-	\$ (10,827)	\$ -	\$ -	\$ (10,827)
Transco Zone 6, non-NY	1	Algonquin	93201A1C	\$ 29,490	\$ -	\$ -	Y	(31)	-	-	\$ (3,196)	\$ -	\$ -	\$ (3,196)
PXP Dawn Hub	1	Union	0	\$ 339,011	\$ -	\$ -	Y	(1,092)	-	-	\$ (36,957)	\$ -	\$ -	\$ (36,957)
PXP Dawn Hub	2	TransCanada	0	\$ 259,314	\$ -	\$ -	Y	(1,092)	-	-	\$ (28,269)	\$ -	\$ -	\$ (28,269)
PXP Dawn Hub	2	TransCanada	0	\$ 1,663,323	\$ -	\$ -	Y	(1,092)	-	-	\$ (181,327)	\$ -	\$ -	\$ (181,327)
PXP Dawn Hub	3	PNGTS	0	\$ 2,737,500	\$ -	\$ -	Y	(1,090)	-	-	\$ (298,388)	\$ -	\$ -	\$ (298,388)
PXP Dawn Hub	4	Granite	19-100-FT-NN	\$ 528,687	\$ -	\$ -	Y	(1,086)	-	-	\$ (57,617)	\$ -	\$ -	\$ (57,617)
Atlantic Bridge	1	Algonquin	0	\$ 5,007,799	\$ -	\$ -	Y	(829)	-	-	\$ (546,317)	\$ -	\$ -	\$ (546,317)
Atlantic Bridge	2	Maritimes	0	\$ 1,204,500	\$ -	\$ -	Y	(818)	-	-	\$ (131,371)	\$ -	\$ -	\$ (131,371)
Tennessee Firm Storage	2	Tennessee	5265	\$ -	\$ 227,350	\$ -	Y	-	(248)	-	\$ -	\$ (21,253)	\$ -	\$ (21,253)
Tennessee Firm Storage	3	Granite	19-100-FT-NN	\$ -	\$ 140,276	\$ -	Y	-	(248)	-	\$ -	\$ (13,157)	\$ -	\$ (13,157)
Union Dawn Storage	2	Union	M12256	\$ -	\$ 1,378,111	\$ -	Y	-	(3,813)	-	\$ -	\$ (129,046)	\$ -	\$ (129,046)
Union Dawn Storage	3A	TransCanada	57901	\$ -	\$ 880,172	\$ -	Y	-	(3,183)	-	\$ -	\$ (82,400)	\$ -	\$ (82,400)
Union Dawn Storage	3A	TransCanada	57901	\$ -	\$ 5,645,700	\$ -	Y	-	(3,183)	-	\$ -	\$ (528,537)	\$ -	\$ (528,537)
Union Dawn Storage	3B	TransCanada	57055	\$ -	\$ 155,402	\$ -	Y	-	(562)	-	\$ -	\$ (14,549)	\$ -	\$ (14,549)
Union Dawn Storage	3B	TransCanada	57055	\$ -	\$ 996,798	\$ -	Y	-	(562)	-	\$ -	\$ (93,320)	\$ -	\$ (93,320)
Union Dawn Storage	4	PNGTS	208543	\$ -	\$ 8,760,657	\$ -	Y	-	(3,746)	-	\$ -	\$ (820,374)	\$ -	\$ (820,374)
Union Dawn Storage	5	Granite	19-100-FT-NN	\$ -	\$ 2,114,908	\$ -	Y	-	(3,732)	-	\$ -	\$ (197,999)	\$ -	\$ (197,999)
Peaking Capacity (Nov-Oct)	N/A	Granite	19-100-FT-NN	\$ -	\$ -	\$ 490,806	Y	-	-	(2,455)	\$ -	\$ -	\$ (45,962)	\$ (45,962)
Peaking Capacity (Nov-Apr)	N/A	Granite	19-100-FT-NN	\$ -	\$ -	\$ 1,167,197	Y	-	-	(2,809)	\$ -	\$ -	\$ (109,289)	\$ (109,289)
Total Capacity Assignment Credits											\$ (1,886,727)	\$ (1,900,634)	\$ (155,250)	\$ (3,942,611)

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New Hampshire Division
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Northern Utilities, Inc. New Hampshire Division Storage Contract Capacity Assignment Estimates November 2020 through October 2021								
Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned ME	Assigned MSQ	Assigned MDWQ	Annual Cap Assign Credit
Tennessee	5195	\$ 122,375	Y	N	9.36%	(24,282)	(397)	\$ (11,458)
Union	LST068	\$ 2,840,000	Y	N	9.36%	(374,527)	(3,858)	\$ (265,914)

Total Division Storage Capacity Assignment \$ (277,372)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

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New Hampshire Division
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Northern Utilities, Inc. New Hampshire Division On-System Peaking Demand Capacity Assignment Revenues November 2020 through October 2021			
Month	On-System Peaking Demand TCQ	Rate	Demand Revenue
Nov-20	609	\$ 64.53	\$ (39,276)
Dec-20	609	\$ 64.53	\$ (39,276)
Jan-21	609	\$ 64.53	\$ (39,276)
Feb-21	609	\$ 64.53	\$ (39,276)
Mar-21	609	\$ 64.53	\$ (39,276)
Apr-21	609	\$ 64.53	\$ (39,276)
Total Division Peaking Demand Revenue			\$ (235,657)

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New Hampshire Division
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Northern Utilities, Inc. - New Hampshire Division					
Asset Management and Capacity Release Revenue Assigned to Retail Suppliers					
November 2020 through October 2021					
Indicates Confidential Information					
Resources	Projected Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to Retail Marketers
Tennessee Zone 0/L Pools		No	Pipeline	10.90%	
Tennessee Niagara		No	Pipeline	10.90%	
Iroquois Receipts		Yes	Pipeline	10.90%	
Leidy Hub & Transco Zone 6, non-NY		Yes	Pipeline	10.90%	
PXP Dawn Hub		No	Pipeline	10.90%	
Atlantic Bridge		No	Pipeline	10.90%	
Union Dawn Storage		No	Storage	9.36%	
Total Asset Management	\$ (8,074,404)				\$ 35,696

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New Hampshire Division
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Northern Utilities, Inc. New Hampshire Division Peaking Capacity Assignment Demand Rate November 2020 through October 2021			
Indicates Confidential Information			
Line	Description	Northern	NH Division
2	Capacity Allocation Factor		40.88%
3	Peaking Plants	6,500	2,657
4	Total	6,500	2,657
5	LNG Demand Costs		
6	Peaking Plants Fixed Costs		\$ 420,658
7	Total On-System Peaking Fixed Costs		\$ 1,028,748
8	NH Division Peaking Service Demand Rate		\$ 64.53

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Northern Utilities
New Hampshire Division
Retail Supplier Capacity Assignment Estimates
November 2020 through October 2021

HLF Allocation	57.23%	17.78%	24.99%	100.00%
LLF Allocation	23.23%	31.91%	44.86%	100.00%
	Pipeline MDQ	Storage MDQ	Peaking MDQ	Total MDQ
HLF TCQ	1,974	613	862	3,450
LLF TCQ	2,450	3,366	4,731	10,547
Retail Supplier Total	4,425	3,980	5,595	14,000
Northern MDQ	40,586	42,507	59,751	142,844
Cap Assign/ Total MDQ	10.90%	9.36%	9.36%	9.80%

On System
Peaking
On System
Peaking Allocation

6,500
10.88%

Northern Utilities, Inc.
New Hampshire Division
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Northern Utilities - New Hampshire Division **Capacity Assignment Calculations 2020-2021** **Derivation of Class Assignments and Weightings**

Basic assumptions:

- 1 The MBA method allocates capacity costs based on design day demands in two pieces:
 - a The base use portion of the class design day demand based on base use
 - b The remaining portion of design day demand based on remaining design day demand
- 2 Base demand is composed solely of pipeline supplies
- 3 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

		Design Day Demand, Dt	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	229	241	0.4%	31	211
2	RATE B-Resi Htg	23,486	24,806	38.9%	1,327	23,478
3	RATE G-40	10,113	10,682	16.7%	501	10,180
4	RATE G-50	659	696	1.1%	203	494
5	RATE G-41	9,205	9,723	15.2%	486	9,237
6	RATE G-51	1,108	1,170	1.8%	357	813
7	RATE G-42	1,795	1,896	3.0%	78	1,819
8	RATE G-52	559	590	0.9%	194	397
9	Special Contract	1,600	1,690	2.6%	1,270	420
10	RATE T-40	1,580	1,669	2.6%	42	1,627
11	RATE T-50	95	100	0.2%	-	100
12	RATE T-41	6,884	7,271	11.4%	283	6,988
13	RATE T-51	1,202	1,270	2.0%	377	893
14	RATE T-42	1,522	1,608	2.5%	78	1,530
15	RATE T-52	369	390	0.6%	363	26
16	Total	60,406	63,801	100.0%	5,588	58,213
17						-
18	Residential Total	23,714	25,047	39.3%	1,358	23,689
19	LLF Total	31,099	32,848	51.5%	1,467	31,381
20	HLF Total	5,592	5,906	9.3%	2,763	3,143
21	Total	60,406	63,801	100.0%	5,588	58,213
22						
23						
24		Residential	Total C&I	LLF C&I	HLF C&I	Total
25	Residential Allocation	MDQ, Dt	MDQ, Dt	MDQ, Dt	MDQ, Dt	MDQ, Dt
26	Pipeline - Base	1,358	4,230	1,467	2,763	5,588
27	Pipeline - Remaining	5,758	6,781	6,164	617	12,540
28	Storage	7,453	11,532	10,482	1,050	18,986
29	Peaking	10,477	16,211	14,735	1,476	26,688
30	Total	25,047	38,754	32,848	5,906	63,801
31	Check - Should be 0	-	-	-	-	-
32						
33	Caapcity Allocations %s		LLF C&I	HLF C&I		
34						
35	Pipeline		23.23%	57.23%		
36	Storage		31.91%	17.78%		
37	Peaking		44.86%	24.99%		
38	Total		100.00%	100.00%		

Northern Utilities
New Hampshire Division Capacity Assignment Calculations

Northern Utilities, Inc.
New Hampshire Division
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	HLF	LLF	Total TCQ	Capacity Assignment	Pipeline MDQ	Storage MDQ	Peaking MDQ	Total MDQ
Retail Supplier Total	3,450	10,547	13,997	14,000	4,425	3,980	5,595	14,000
Northern -Total MDQ					18,128	18,986	26,688	63,801
NH Cap Assign/ Total MDQ		CHECK S/B 0 ->	0		24.41%	20.96%	20.96%	21.94%
HLF Capacity Allocator					57.23%	17.78%	24.99%	100.00%
LLF Capacity Allocator					23.23%	31.91%	44.86%	100.00%

			Northern Utilities, Inc. New Hampshire Division Schedule 20-154 Assigned Capacity Regulation Plan	
	Percentage Design Day	44.66%		
Pipeline Capacity Paths	Northern MDQ	NH Division MDQ	Pipeline Assigned %	Capacity Assigned
Tennessee Long-Haul	13,109	5,855	24.41%	1,429
Tennessee Niagara	2,327	1,039	24.45%	254
Iroquois Receipts	6,434	2,874	24.43%	702
Leidy Supply (Texas Eastern, Algonquin)	965	431	24.36%	105
Transco Zone 6, non-NY Supply (Algonquin)	286	128	24.22%	31
PXP Dawn Hub	9,965	4,451	24.40%	1,086
Atlantic Bridge Ramapo	7,500	3,350	24.42%	818
Total Pipeline Capacity	40,586	18,128	24.41%	4,425
Storage Capacity Paths	Northern MDQ	NH Division MDQ	Storage Assigned %	Capacity Assigned
Tennessee Firm Storage	2,644	1,181	20.96%	248
Dawn Hub Storage	39,863	17,805	20.96%	3,732
Total Storage Capacity	42,507	18,986	20.96%	3,980
Peaking Capacity Paths	Northern MDQ	NH Division MDQ	Peaking Assigned %	Capacity Assigned
LNG - On-System	6,500	2,903	20.96%	609
Granite - Not assigned as Storage or Pipeline Capacity	53,251	23,785	20.96%	4,986
Total Peaking Capacity	59,751	26,688	20.96%	5,595
Total Capacity	142,844	63,802	21.94%	14,000

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New Hampshire Division
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Northern Utilities, Inc.
New Hampshire Division
Design Day Forecast by Rate Class

2020-2021 Forecast Annual Sales (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	23,867	1,989,457	892,604	118,732	812,488	199,577	158,455	100,683	0	2,013,323	1,863,547	418,992	4,295,862
Capacity Assigned Delivery Service			133,740	19,071	602,619	194,589	150,019	142,453	436,449		886,378	792,562	1,678,941
Capacity Exempt Delivery Service			1,564	2,339	35,242	15,571	310,052	1,354,873	593,115		346,857	1,965,899	2,312,756
Total System	23,867	1,989,457	1,027,907	140,142	1,450,349	409,738	618,526	1,598,010	1,029,564	2,013,323	3,096,782	3,177,453	8,287,558

2020-2021 Forecast Annual Sendout (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	24,181	2,015,660	904,360	120,295	823,189	202,206	160,542	102,009		2,039,841	1,888,092	424,511	4,352,444
Capacity Assigned Delivery Service			135,501	19,322	610,556	197,152	151,995	144,329	442,197		898,052	803,001	1,701,053
Capacity Exempt Delivery Service			1,584	2,370	35,706	15,776	314,136	1,372,719	600,927		351,426	1,991,792	2,343,218
Total System	24,181	2,015,660	1,041,446	141,988	1,469,451	415,134	626,673	1,619,057	1,043,124	2,039,841	3,137,570	3,219,304	8,396,715

Prior Year WN Act	Total Division	Percent Change
	4,234,790	2.8%
	1,794,339	-5.2%
	2,543,188	-7.9%
	8,572,316	-2.0%

2020-2021 Forecast Load Factor (%)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	29.0%	23.5%	24.5%	50.0%	24.5%	50.0%	24.5%	50.0%		23.6%	24.5%	50.0%	25.3%
Capacity Assigned Delivery Service			23.5%	55.8%	24.3%	44.9%	27.4%	107.2%	75.7%		24.6%	67.4%	35.2%
Capacity Exempt Delivery Service			20.0%	100.0%	29.0%	45.0%	34.3%	82.9%	79.4%		33.5%	81.3%	67.0%
Total System	29.0%	23.5%	24.4%	51.2%	24.5%	47.3%	29.4%	81.2%	77.8%	23.6%	25.3%	71.7%	32.9%

Prior Year Actual	Total Division	Percent Change
	24.7%	2.5%
	37.3%	-5.7%
	71.0%	-5.7%
	33.6%	-2.0%

2020-2021 Design Day Sendout (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	229	23,486	10,113	659	9,205	1,108	1,795	559		23,714	21,114	2,326	47,154
Capacity Assigned Delivery Service			1,580	95	6,884	1,202	1,522	369	1,600		9,986	3,266	13,252
Capacity Exempt Delivery Service			22	6	337	96	2,512	4,538	2,074		2,871	6,715	9,586
Total System	229	23,486	11,714	760	16,426	2,406	5,830	5,466	3,675	23,714	33,971	12,307	69,992

Prior Year Design Day Actual	Total Division	Percent Change
	47,006	0.3%
	13,175	0.6%
	9,811	-2.3%
	69,992	0.0%

2020-2021 Baseload Sendout (Dth)
(Average Daily July and August Sendout)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	31	1,327	501	203	486	357	78	194		1,358	1,065	753	3,176
Capacity Assigned Delivery Service			42	0	283	377	78	363	1,270		402	2,010	2,412
Capacity Exempt Delivery Service			1	0	32	30	443	3,537	1,682		476	5,249	5,725
Total System	31	1,327	544	203	801	764	599	4,094	2,952	1,358	1,943	8,012	11,313

2020-2021 Planning Load Design Day Sendout (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	229	23,486	10,113	659	9,205	1,108	1,795	559		23,714	21,114	2,326	47,154
Capacity Assigned Delivery Service			1,580	95	6,884	1,202	1,522	369	1,600		9,986	3,266	13,252
Capacity Exempt Delivery Service			0	0	0	0	0	0	0		0	0	0
Total System	229	23,486	11,693	754	16,089	2,310	3,318	928	1,600	23,714	31,099	5,592	60,406

2020-2021 Planning Load Baseload Sendout (Dth)
(Average Daily July and August Sendout)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	31	1,327	501	203	486	357	78	194		1,358	1,065	753	3,176
Capacity Assigned Delivery Service			42	0	283	377	78	363	1,270		402	2,010	2,412
Capacity Exempt Delivery Service			0	0	0	0	0	0	0		0	0	0
Total System	31	1,327	543	203	768	734	155	557	1,270	1,358	1,467	2,763	5,588

REDACTED

Denotes Confidential Information

Northern Utilities, Inc. Commodity Cost by Supply Source (\$) November 2020 through October 2021																
Description	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Winter	Summer	Year	
Pipeline Supplies																
TGP Zone 4 300 Leg Supply																
Tennessee FS-MA Storage Path																
Dawn Supply																
Union Dawn Storage Path																
Leidy Hub																
Texas Eastern Zone M-3																
Transco Zone 6, non-NY																
Algonquin Receipts Pipeline Path																
Tennessee Niagara Pipeline Path																
PXP Dawn Pipeline Path																
Total Base Pipeline																
NH CM Pipeline (Leidy/M-3)																
ME CM Pipeline (Leidy/M-3)																
NH CM Pipeline (Transco)																
ME CM Pipeline (Transco)																
Net Base Pipeline	\$ 1,083,860	\$ 1,099,844	\$ 1,146,675	\$ 1,033,098	\$ 1,329,637	\$ 2,564,932	\$ 1,322,251	\$ 886,662	\$ 774,801	\$ 782,079	\$ 832,473	\$ 1,619,126	\$ 8,258,046	\$ 6,217,391	\$ 14,475,437	
Tennessee Zone 0																
Tennessee Zone L																
Tennessee Long-Haul Pipeline Path																
Iroquois Receipts Pipeline Path																
Atlantic Bridge Ramapo Pipeline Path																
Total Remaining Pipeline																
NH CM Pipeline (Iroq Rec)																
ME CM Pipeline (Iroq Rec)																
Net Remaining Pipeline	\$ 1,726,682	\$ 2,590,803	\$ 3,157,895	\$ 2,794,434	\$ 2,387,373	\$ 11,321	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,668,508	\$ -	\$ 12,668,508	
Underground Storage																
Tennessee Storage	\$ -	\$ 108,407	\$ 108,407	\$ 97,344	\$ 23,395	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 337,554	\$ -	\$ 337,554	
Tennessee FS-MA Storage Path	\$ -	\$ 108,407	\$ 108,407	\$ 97,344	\$ 23,395	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 337,554	\$ -	\$ 337,554	
Union Dawn Storage	\$ 428,329	\$ 1,105,945	\$ 1,271,314	\$ 1,318,437	\$ 780,990	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,905,015	\$ -	\$ 4,905,015	
Union Dawn Storage Path	\$ 428,329	\$ 1,105,945	\$ 1,271,314	\$ 1,318,437	\$ 780,990	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,905,015	\$ -	\$ 4,905,015	
Net Storage	\$ 428,329	\$ 1,214,353	\$ 1,379,721	\$ 1,415,781	\$ 804,385	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,242,569	\$ -	\$ 5,242,569	
Peaking Supplies																
Lewiston LNG																
Peaking Contract 1																
Off-System Peaking / Incremental Supply																
Total Peaking																
NH Peaking Service - (On System)																
ME Peaking Service - (On-System)																
Net Peaking	\$ 7,289	\$ 129,949	\$ 953,958	\$ 216,183	\$ 12,852	\$ 12,307	\$ 12,561	\$ 12,075	\$ 12,411	\$ 12,390	\$ 11,902	\$ 12,263	\$ 1,332,538	\$ 73,602	\$ 1,406,140	
Total NUI Commodity	\$ 3,373,616	\$ 5,240,327	\$ 6,961,810	\$ 5,711,470	\$ 4,688,432	\$ 2,588,560	\$ 1,334,812	\$ 898,737	\$ 787,212	\$ 794,469	\$ 844,375	\$ 1,631,389	\$ 28,564,215	\$ 6,290,994	\$ 34,855,209	
Company Managed Sales	\$ (127,456)	\$ (205,378)	\$ (323,561)	\$ (251,973)	\$ (154,185)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,062,553)	\$ -	\$ (1,062,553)	
Net Commodity Costs	\$ 3,246,160	\$ 5,034,949	\$ 6,638,249	\$ 5,459,497	\$ 4,534,247	\$ 2,588,560	\$ 1,334,812	\$ 898,737	\$ 787,212	\$ 794,469	\$ 844,375	\$ 1,631,389	\$ 27,501,662	\$ 6,290,994	\$ 33,792,655	

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2020 through October 2021

Description	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Winter	Summer	Year
Pipeline Supplies															
TGP Zone 4 300 Leg Supply	64,274	0	0	351	52,083	64,274	66,417	64,274	66,417	66,417	64,274	66,417	180,982	394,215	575,198
Tennessee FS-MA Storage Path	64,274	0	0	351	52,083	64,274	66,417	64,274	66,417	66,417	64,274	66,417	180,982	394,215	575,198
Dawn Supply	0	0	0	704	17,762	754,936	394,130	235,369	185,825	188,904	218,379	514,162	773,402	1,736,770	2,510,172
Union Dawn Storage Path	0	0	0	704	17,762	754,936	394,130	235,369	185,825	188,904	218,379	514,162	773,402	1,736,770	2,510,172
Leidy Hub	28,687	29,631	29,631	26,763	29,631	28,687	29,643	28,687	29,643	29,643	28,687	29,643	173,029	175,944	348,973
Texas Eastern Zone M-3	263	284	284	257	284	263	272	263	272	263	272	263	1,636	1,616	3,252
Transco Zone 6, non-NY	8,580	8,866	8,866	8,008	8,866	8,580	8,866	8,580	8,866	8,866	8,580	8,866	51,766	52,624	104,390
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	35,028	38,781	37,530	38,781	37,530	38,781	38,781	37,530	38,781	226,431	230,184	456,615
Tennessee Niagara Pipeline Path	55,067	56,902	56,902	51,395	56,902	6,740	0	0	0	0	0	0	283,909	0	283,909
PXP Dawn Pipeline Path	224,840	239,438	239,438	216,267	239,438	51,041	0	0	0	0	0	0	1,210,463	0	1,210,463
Total Base Pipeline	381,710	335,122	335,122	303,745	404,967	914,522	499,328	337,173	291,023	294,102	320,183	619,360	2,675,187	2,361,169	5,036,356
NH CM Pipeline (Leidy/M-3)	-3,150	-3,255	-3,255	-2,940	-3,255	0	0	0	0	0	0	0	-15,855	0	-15,855
ME CM Pipeline (Leidy/M-3)	-2,970	-3,069	-3,069	-2,772	-3,069	0	0	0	0	0	0	0	-14,949	0	-14,949
NH CM Pipeline (Transco)	-930	-961	-961	-868	-961	0	0	0	0	0	0	0	-4,681	0	-4,681
ME CM Pipeline (Transco)	-870	-899	-899	-812	-899	0	0	0	0	0	0	0	-4,379	0	-4,379
Net Base Pipeline	373,790	326,938	326,938	296,353	396,783	914,522	499,328	337,173	291,023	294,102	320,183	619,360	2,635,323	2,361,169	4,996,492
Tennessee Zone O	74,802	112,167	112,167	101,312	112,167	0	0	0	0	0	0	0	512,615	0	512,615
Tennessee Zone L	160,407	208,270	208,270	188,115	208,270	3,595	0	0	0	0	0	0	976,929	0	976,929
Tennessee Long-Haul Pipeline Path	235,209	320,438	320,438	289,427	320,438	3,595	0	0	0	0	0	0	1,489,544	0	1,489,544
Iroquois Receipts Pipeline Path	187,700	193,957	193,957	175,187	193,957	0	0	0	0	0	0	0	944,757	0	944,757
Atlantic Bridge Ramapo Pipeline Path	169,702	183,303	183,303	165,564	183,303	0	0	0	0	0	0	0	885,175	0	885,175
Total Remaining Pipeline	592,611	697,697	697,697	630,178	697,697	3,595	0	0	0	0	0	0	3,319,476	0	3,319,476
NH CM Pipeline (Iroq Rec)	-18,300	-18,910	-18,910	-17,080	-18,910	0	0	0	0	0	0	0	-92,110	0	-92,110
ME CM Pipeline (Iroq Rec)	-17,190	-17,763	-17,763	-16,044	-17,763	0	0	0	0	0	0	0	-86,523	0	-86,523
Net Remaining Pipeline	557,121	661,024	661,024	597,054	661,024	3,595	0	0	0	0	0	0	3,140,843	0	3,140,843
Underground Storage															
Tennessee Storage	0	66,417	66,417	59,639	14,333	0	0	0	0	0	0	0	206,805	0	206,805
Tennessee FS-MA Storage Path	0	66,417	66,417	59,639	14,333	0	0	0	0	0	0	0	206,805	0	206,805
Union Dawn Storage	233,918	603,977	694,287	720,022	426,513	0	0	0	0	0	0	0	2,678,717	0	2,678,717
Union Dawn Storage Path	233,918	603,977	694,287	720,022	426,513	0	0	0	0	0	0	0	2,678,717	0	2,678,717
Net Storage	233,918	670,393	760,704	779,661	440,846	0	0	0	0	0	0	0	2,885,522	0	2,885,522
Peaking Supplies															
Lewiston LNG	1,794	22,761	52,503	33,254	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040	125,000
Peaking Contract 1	0	7,425	201,313	8,415	0	0	0	0	0	0	0	0	217,152	0	217,152
Off-System Peaking / Incremental Supl	0	7,425	201,313	8,415	0	0	0	0	0	0	0	0	217,152	0	217,152
Total Peaking	1,794	30,186	253,815	41,669	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	331,112	11,040	342,152
NH Peaking Service - (On System)	0	-2,436	-6,090	-3,045	0	0	0	0	0	0	0	0	-11,571	0	-11,571
ME Peaking Service - (On-System)	0	-2,504	-6,260	-3,130	0	0	0	0	0	0	0	0	-11,894	0	-11,894
Net Peaking	1,794	25,246	241,465	35,494	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	307,647	11,040	318,687
Total NUI Commodity	1,210,034	1,733,398	2,047,338	1,755,253	1,545,364	919,911	501,188	338,973	292,883	295,962	321,983	621,220	9,211,298	2,372,209	11,583,507
Company Managed Sales	-43,410	-49,797	-57,207	-46,691	-44,857	0	0	0	0	0	0	0	-241,962	0	-241,962
Net Commodity Costs	1,166,624	1,683,601	1,990,131	1,708,562	1,500,507	919,911	501,188	338,973	292,883	295,962	321,983	621,220	8,969,336	2,372,209	11,341,545

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Denotes Confidential Information

Northern Utilities, Inc.
Average Delivered Commodity Cost by Supply Source (\$/Dth)
November 2020 through October 2021

Description	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Winter	Summer	Year
Pipeline Supplies															
TGP Zone 4 300 Leg Supply															
Tennessee FS-MA Storage Path															
Dawn Supply															
Union Dawn Storage Path															
Leidy Hub															
Texas Eastern Zone M-3															
Transco Zone 6, non-NY															
Algonquin Receipts Pipeline Path															
Tennessee Niagara Pipeline Path															
PXP Dawn Pipeline Path															
Total Base Pipeline															
NH CM Pipeline (Leidy/M-3)															
ME CM Pipeline (Leidy/M-3)															
NH CM Pipeline (Transco)															
ME CM Pipeline (Transco)															
Net Base Pipeline	\$ 2.900	\$ 3.364	\$ 3.507	\$ 3.486	\$ 3.351	\$ 2.805	\$ 2.648	\$ 2.630	\$ 2.662	\$ 2.659	\$ 2.600	\$ 2.614	\$ 3.134	\$ 2.633	\$ 2.897
Tennessee Zone 0															
Tennessee Zone L															
Tennessee Long-Haul Pipeline Path															
Iroquois Receipts Pipeline Path															
Atlantic Bridge Ramapo Pipeline Path															
Total Remaining Pipeline															
NH CM Pipeline (Iroq Rec)															
ME CM Pipeline (Iroq Rec)															
Net Remaining Pipeline	\$ 3.099	\$ 3.919	\$ 4.777	\$ 4.680	\$ 3.612	\$ 3.149							\$ 4.033	\$ 4.033	
Underground Storage															
Tennessee Storage		\$ 1.632	\$ 1.632	\$ 1.632	\$ 1.632								\$ 1.632		\$ 1.632
Tennessee FS-MA Storage Path		\$ 1.632	\$ 1.632	\$ 1.632	\$ 1.632								\$ 1.632		\$ 1.632
Union Dawn Storage	\$ 1.831	\$ 1.831	\$ 1.831	\$ 1.831	\$ 1.831								\$ 1.831		\$ 1.831
Union Dawn Storage Path	\$ 1.831	\$ 1.831	\$ 1.831	\$ 1.831	\$ 1.831								\$ 1.831		\$ 1.831
Net Storage	\$ 1.831	\$ 1.811	\$ 1.814	\$ 1.816	\$ 1.825								\$ 1.817	\$ 1.817	
Peaking Supplies															
Lewiston LNG															
Peaking Contract 1															
Off-System Peaking / Incremental Supply															
Total Peaking															
NH Peaking Service - (On System)															
ME Peaking Service - (On-System)															
Net Peaking	\$ 4.063	\$ 5.147	\$ 3.951	\$ 6.091	\$ 6.933	\$ 6.860	\$ 6.753	\$ 6.708	\$ 6.673	\$ 6.661	\$ 6.612	\$ 6.593	\$ 4.331	\$ 6.667	\$ 4.412
Total NUI Commodity	\$ 2.788	\$ 3.023	\$ 3.400	\$ 3.254	\$ 3.034	\$ 2.814	\$ 2.663	\$ 2.651	\$ 2.688	\$ 2.684	\$ 2.622	\$ 2.626	\$ 3.101	\$ 2.652	\$ 3.009
Company Managed Sales	\$ 2.936	\$ 4.124	\$ 5.656	\$ 5.397	\$ 3.437								\$ 4.391	\$	
Net Commodity Costs	\$ 2.783	\$ 2.991	\$ 3.336	\$ 3.195	\$ 3.022	\$ 2.814	\$ 2.663	\$ 2.651	\$ 2.688	\$ 2.684	\$ 2.622	\$ 2.626	\$ 3.066	\$ 2.652	\$ 2.980

REDACTED

Estimated Delivered City-Gate Commodity Costs and Volumes November 2020 through April 2021			
Denotes Confidential Information			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Union Dawn Storage Path		3,452,119	
Tennessee FS-MA Storage Path		387,788	
Algonquin Receipts Pipeline Path		226,431	
Tennessee Niagara Pipeline Path		283,909	
PXP Dawn Pipeline Path		1,210,463	
Peaking Contract 1		217,152	
Tennessee Long-Haul Pipeline Path		1,489,544	
Iroquois Receipts Pipeline Path		944,757	
Atlantic Bridge Ramapo Pipeline Path		885,175	
Lewiston LNG		113,960	
Total Delivered Commodity Cost	\$28,564,215	9,211,298	\$3.101

REDACTED

Estimated Delivered City-Gate Commodity Costs and Volumes May 2021 through October 2021			
Denotes Confidential Information			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Algonquin Receipts Pipeline Path		230,184	
Tennessee FS-MA Storage Path		394,215	
Union Dawn Storage Path		1,736,770	
Lewiston LNG		11,040	
Total Delivered Commodity Cost	\$6,290,994	2,372,209	\$2.652

Source of Supply: Tennessee Zone 0
 Delivered to Northern via Tennessee and Granite Pipelines

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 24	78,883	118,286	118,286	106,839	118,286	-	-	-	-	-	-	-	540,580	-
4	City Gate Delivered Volume	Line 36	74,802	112,167	112,167	101,312	112,167	-	-	-	-	-	-	-	512,615	-
5	Total Purchase Cost	Line 2 times Line 3														
6	Variable Transportation Costs	Sum Lines 28 and 38	\$ 21,994	\$ 32,980	\$ 32,980	\$ 29,788	\$ 32,980	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 150,722	\$ -
7	Total City Gate Delivered Costs	Sum Lines 4 and 5														
8	Average Delivered Price	Line 6 divided by Line 2														
9																
10	<u>Tennessee Zone 0 Supply Costs</u>															
11	Purchased Volumes	Sendout Optimization	78,883	118,286	118,286	106,839	118,286	-	-	-	-	-	-	-	540,580	-
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,231	-
13	NYMEX Cost	Line 9 times Line 10	\$ 228,839	\$ 386,322	\$ 399,215	\$ 355,453	\$ 376,741	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,746,571	\$ -
14	NYMEX Basis Price	Sch 27-FXW, Line 1 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1A															
21	Tennessee Gas Pipeline (Contract 5083)															
22	Receipt Point: Tennessee Zone 0															
23	Delivery Point: Pleasant St. (Interconnection with Granite)															
24	Received Volume	Line 11	78,883	118,286	118,286	106,839	118,286	-	-	-	-	-	-	-	540,580	-
25	Fuel Loss Rate	Sch 27-FXW, Line 36 of Page 2	4.84%	4.84%	4.84%	4.84%	4.84%	-	-	-	-	-	-	-	4.84%	-
26	Delivered Volume	Line 24 times (1 - Line 25)	75,065	112,561	112,561	101,668	112,561	-	-	-	-	-	-	-	514,416	-
27	Variable Transportation Rate	Sch 27-FXW, Line 22 of Page 2	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	-	-	-	-	-	-	-	\$ 0.2919	-
28	Variable Transportation Costs	Line 26 times Line 27	\$ 21,911	\$ 32,857	\$ 32,857	\$ 29,677	\$ 32,857	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 150,158	\$ -
29																
30	Transportation Segment 2A															
31	Granite State Gas Transmission (Contract 19-100-FT-NN)															
32	Receipt Point: Pleasant St.															
33	Delivery Point: Northern City Gates															
34	Received Volume	Line 26	75,065	112,561	112,561	101,668	112,561	-	-	-	-	-	-	-	514,416	-
35	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	-
36	City Gate Delivered Volume	Line 34 times (1 - Line 35)	74,802	112,167	112,167	101,312	112,167	-	-	-	-	-	-	-	512,615	-
37	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	-
38	Variable Transportation Costs	Line 36 times Line 37	\$ 82	\$ 123	\$ 123	\$ 111	\$ 123	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 564	\$ -

Source of Supply: Tennessee Zone L
Delivered to Northern via Tennessee and Granite Pipelines

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 24	168,045	218,188	218,188	197,073	218,188	3,766	-	-	-	-	-	-	1,023,447	-
4	City Gate Delivered Volume	Line 36	160,407	208,270	208,270	188,115	208,270	3,595	-	-	-	-	-	-	976,929	-
5	Total Purchase Cost	Line 2 times Line 3														
6	Variable Transportation Costs	Sum Lines 28 and 38	\$ 41,143	\$ 53,420	\$ 53,420	\$ 48,250	\$ 53,420	\$ 922	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 250,576	\$ -
7	Total City Gate Delivered Costs	Sum Lines 4 and 5														
8	Average Delivered Price	Line 6 divided by Line 2														
9																
10	<u>Tennessee Zone L Supply Costs</u>															
11	Purchased Volumes	Sendout Optimization	168,045	218,188	218,188	197,073	218,188	3,766	-	-	-	-	-	-	1,023,447	-
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,222	
13	NYMEX Cost	Line 9 times Line 10	\$ 487,499	\$ 712,601	\$ 736,383	\$ 655,661	\$ 694,928	\$ 10,632	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,297,705	\$ -
14	NYMEX Basis Price	Sch 27-FXW, Line 2 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1B															
21	Tennessee Gas Pipeline (Contract 5083)															
22	Receipt Point: Tennessee Zone L															
23	Delivery Point: Pleasant St. (Interconnection with Granite)															
24	Received Volume	Line 11	168,045	218,188	218,188	197,073	218,188	3,766	-	-	-	-	-	-	1,023,447	-
25	Fuel Loss Rate	Sch 27-FXW, Line 37 of Page 2	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%							4.21%	
26	Delivered Volume	Line 24 times (1 - Line 25)	160,971	209,002	209,002	188,776	209,002	3,608	-	-	-	-	-	-	980,360	-
27	Variable Transportation Rate	Sch 27-FXW, Line 23 of Page 2	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545							\$ 0.2545	
28	Variable Transportation Costs	Line 26 times Line 27	\$ 40,967	\$ 53,191	\$ 53,191	\$ 48,043	\$ 53,191	\$ 918	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 249,502	\$ -
29																
30	Transportation Segment 2B															
31	Granite State Gas Transmission (Contract 19-100-FT-NN)															
32	Receipt Point: Pleasant St.															
33	Delivery Point: Northern City Gates															
34	Received Volume	Line 26	160,971	209,002	209,002	188,776	209,002	3,608	-	-	-	-	-	-	980,360	-
35	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
36	City Gate Delivered Volume	Line 34 times (1 - Line 35)	160,407	208,270	208,270	188,115	208,270	3,595	-	-	-	-	-	-	976,929	-
37	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	
38	Variable Transportation Costs	Line 36 times Line 37	\$ 176	\$ 229	\$ 229	\$ 207	\$ 229	\$ 4	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,075	\$ -

Source of Supply: Niagara (Interconnect of TransCanada and Tennessee Pipelines)
Delivered to Northern via Tennessee and Granite Pipelines
Delivered to Northern via Tennessee and Bay State Exchange Agreement

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
4	Purchased Volumes	Line 9	55,728	57,586	57,586	52,013	57,586	6,821	-	-	-	-	-	-	287,319	-
5	City Gate Delivered Volume	Line 47	55,067	56,902	56,902	51,395	56,902	6,740	-	-	-	-	-	-	283,909	-
6	Total Purchase Cost	Line 15														
7	Variable Transportation Costs	Sum Lines 29, 39 and 49	\$ 4,200	\$ 4,340	\$ 4,340	\$ 3,920	\$ 4,340	\$ 514	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 21,652	\$ -
8	Total City Gate Delivered Costs	Sum Lines 3 and 4														
9	Average Delivered Price	Line 5 divided by Line 2														
10																
11	<u>Niagara Supply Costs</u>															
12	Purchased Volumes	Sendout Optimization	55,728	57,586	57,586	52,013	57,586	6,821	-	-	-	-	-	-	287,319	-
13	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,201	
14	NYMEX Cost	Line 9 times Line 10	\$ 161,667	\$ 188,075	\$ 194,352	\$ 173,047	\$ 183,411	\$ 19,256	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 919,807	\$ -
15	NYMEX Basis Price	Sch 27-FXW, Line 3 of Page 1														
16	NYMEX Basis Costs	Line 9 times Line 12														
17	Total Purchase Price	Line 10 plus Line 12														
18	Total Purchase Cost	Line 11 plus Line 13														
19																
20	<u>Transportation Fuel Losses and Variable Charges</u>															
21	Transportation Segment 1A															
22	Tennessee Gas Pipeline (Contract 5292)															
23	Receipt Point: Niagara															
24	Delivery Point: Pleasant St. (Interconnection with Granite)															
25	Received Volume	Line 9	33,552	34,670	34,670	31,315	34,670	4,474	-	-	-	-	-	-	173,351	-
26	Fuel Loss Rate	Sch 27-FXW, Line 39 of Page 2	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%							0.84%	
27	Delivered Volume	Line 25 times (1 - Line 26)	33,270	34,379	34,379	31,052	34,379	4,436	-	-	-	-	-	-	171,895	-
28	Variable Transportation Rate	Sch 27-FXW, Line 25 of Page 2	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749							\$ 0.0749	
29	Variable Transportation Costs	Line 27 times Line 28	\$ 2,492	\$ 2,575	\$ 2,575	\$ 2,326	\$ 2,575	\$ 332	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,875	\$ -
30																
31	Transportation Segment 1B															
32	Tennessee Gas Pipeline (Contract 39375)															
33	Receipt Point: Niagara															
34	Delivery Point: Pleasant St. (Interconnection with Granite)															
35	Received Volume	Line 9	22,176	22,915	22,915	20,698	22,915	2,347	-	-	-	-	-	-	113,968	-
36	Fuel Loss Rate	Sch 27-FXW, Line 39 of Page 2	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%							0.84%	
37	Delivered Volume	Line 35 times (1 - Line 36)	21,990	22,723	22,723	20,524	22,723	2,328	-	-	-	-	-	-	113,011	-
38	Variable Transportation Rate	Sch 27-FXW, Line 25 of Page 2	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749							\$ 0.0749	
39	Variable Transportation Costs	Line 37 times Line 38	\$ 1,647	\$ 1,702	\$ 1,702	\$ 1,537	\$ 1,702	\$ 174	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 8,465	\$ -
40																
41	Transportation Segment 2B															
42	Granite State Gas Transmission (Contract 19-100-FT-NN)															
43	Receipt Point: Pleasant St.															
44	Delivery Point: Northern City Gates															
45	Received Volume	Line 37	55,260	57,102	57,102	51,576	57,102	6,764	-	-	-	-	-	-	284,906	-
46	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
47	City Gate Delivered Volume	Line 45 times (1 - Line 46)	55,067	56,902	56,902	51,395	56,902	6,740	-	-	-	-	-	-	283,909	-
48	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	
49	Variable Transportation Costs	Line 47 times Line 48	\$ 61	\$ 63	\$ 63	\$ 57	\$ 63	\$ 7	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 312	\$ -

Source of Supply: Iroquois Receipts (Interconnect of TransCanada and Iroquois Pipelines)
Delivered to Northern via Iroquois, Tennessee and Granite Pipelines
Delivered to Northern via Iroquois, Tennessee, Algonquin Pipelines and Bay State Exchange Agreement

Denotes Confidential Information			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
Line	City Gate Delivered Costs	Reference														
4	Purchased Volumes	Line 9	190,531	196,935	196,935	177,877	196,935	-	-	-	-	-	-	-	959,214	-
5	City Gate Delivered Volume	Line 40	187,700	193,957	193,957	175,187	193,957	-	-	-	-	-	-	-	944,757	-
6	Total Purchase Cost	Line 15														
7	Variable Transportation Costs	Sum Lines 32, 42, 52, 62, 72 and 82	\$ 21,890	\$ 22,624	\$ 22,624	\$ 20,434	\$ 22,624	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 110,196	\$ -
8	Total City Gate Delivered Costs	Sum Lines 3 and 4														
9	Average Delivered Price	Line 5 divided by Line 2														
10																
11	Iroquois Receipts Supply Costs															
12	Purchased Volumes	Sendout Optimization	190,531	196,935	196,935	177,877	196,935	-	-	-	-	-	-	-	959,214	-
13	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,211	-
14	NYMEX Cost	Line 9 times Line 10	\$ 552,729	\$ 643,191	\$ 664,657	\$ 591,797	\$ 627,239	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,079,612	\$ -
15	NYMEX Basis Price	Sch 27-FXW, Line 4 of Page 1														
16	NYMEX Basis Costs	Line 9 times Line 12														
17	Total Purchase Price	Line 10 plus Line 12														
18	Total Purchase Cost	Line 11 plus Line 13														
19																
20	Transportation Fuel Losses and Variable Charges															
21	Transportation Segment 5															
22	Iroquois Pipeline (Contract R181001)															
23	Receipt Point: Waddington															
24	Delivery Point: Wright (Interconnection with Tennessee)															
25	Total Contract Received Volume	Sendout Optimization	190,531	196,935	196,935	177,877	196,935	-	-	-	-	-	-	-	959,214	-
26	Received Volume	Line 12	190,531	196,935	196,935	177,877	196,935	-	-	-	-	-	-	-	959,214	-
27	Percentage Allocated	Line 26 divided by Line 25	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%	-
28	Received Volume	Line 17	190,531	196,935	196,935	177,877	196,935	-	-	-	-	-	-	-	959,214	-
29	Fuel Loss Rate	Sch 27-FXW, Line 33 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%	-	-	-	-	-	-	-	0.00%	-
30	Delivered Volume	Line 28 times (1 - Line 29)	190,531	196,935	196,935	177,877	196,935	-	-	-	-	-	-	-	959,214	-
31	Variable Transportation Rate	Sch 27-FXW, Line 18 of Page 2	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045								\$ -	
32	Variable Transportation Costs	Line 30 times Line 31	\$ 857	\$ 886	\$ 886	\$ 800	\$ 886	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
33																
34	Transportation Segment 6A															
35	Tennessee Gas Pipeline (Contract 95196)															
36	Receipt Point: Wright															
37	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
38	Received Volume	Line 30	41,811	43,205	43,205	39,024	43,205	-	-	-	-	-	-	-	210,450	-
39	Fuel Loss Rate	Sch 27-FXW, Line 39 of Page 2	0.84%	0.84%	0.84%	0.84%	0.84%	-	-	-	-	-	-	-	0.84%	-
40	City Gate Delivered Volume	Line 38 times (1 - Line 39)	41,460	42,842	42,842	38,696	42,842	-	-	-	-	-	-	-	208,682	-
41	Variable Transportation Rate	Sch 27-FXW, Line 25 of Page 2	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749								\$ 0.0749	
42	Variable Transportation Costs	Line 40 times Line 41	\$ 3,105	\$ 3,209	\$ 3,209	\$ 2,898	\$ 3,209	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 15,630	\$ -
43																
44	Transportation Segment 6B															
45	Tennessee Gas Pipeline (Contract 95196)															
46	Receipt Point: Wright															
47	Delivery Point: Pleasant St. (Interconnection with Granite)															
48	Received Volume	Line 40	20,149	20,821	20,821	18,806	20,821	-	-	-	-	-	-	-	101,418	-
49	Fuel Loss Rate	Sch 27-FXW, Line 39 of Page 2	0.84%	0.84%	0.84%	0.84%	0.84%	-	-	-	-	-	-	-	0.84%	-
50	Delivered Volume	Line 48 times (1 - Line 49)	19,980	20,646	20,646	18,648	20,646	-	-	-	-	-	-	-	100,566	-
51	Variable Transportation Rate	Sch 27-FXW, Line 25 of Page 2	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749								\$ 0.0749	
52	Variable Transportation Costs	Line 50 times Line 51	\$ 1,497	\$ 1,546	\$ 1,546	\$ 1,397	\$ 1,546	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7,532	\$ -
53																
54	Transportation Segment 7B															
55	Granite State Gas Transmission (Contract 19-100-FT-NN)															
56	Receipt Point: Pleasant St.															
57	Delivery Point: Northern City Gates															
58	Received Volume	Line 50	19,980	20,646	20,646	18,648	20,646	-	-	-	-	-	-	-	100,566	-
59	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	-
60	City Gate Delivered Volume	Line 58 times (1 - Line 59)	19,910	20,574	20,574	18,583	20,574	-	-	-	-	-	-	-	100,214	-
61	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	-
62	Variable Transportation Costs	Line 60 times Line 61	\$ 22	\$ 23	\$ 23	\$ 20	\$ 23	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 110	\$ -
63																
64	Transportation Segment 6C															
65	Tennessee Gas Pipeline (Contract 41099)															
66	Receipt Point: Wright															
67	Delivery Point: Mendon (Interconnection with Algonquin)															
68	Received Volume	Line 30	128,570	132,909	132,909	120,047	132,909	-	-	-	-	-	-	-	647,346	-
69	Fuel Loss Rate	Sch 27-FXW, Line 39 of Page 2	0.84%	0.84%	0.84%	0.84%	0.84%	-	-	-	-	-	-	-	0.84%	-
70	Delivered Volume	Line 68 times (1 - Line 69)	127,490	131,793	131,793	119,039	131,793	-	-	-	-	-	-	-	641,908	-
71	Variable Transportation Rate	Sch 27-FXW, Line 25 of Page 2	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749								\$ 0.0749	
72	Variable Transportation Costs	Line 70 times Line 71	\$ 9,549	\$ 9,871	\$ 9,871	\$ 8,916	\$ 9,871	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 48,079	\$ -
73																
74	Transportation Segment 7C															
75	Algonquin Gas Transmission (Contract 93200F)															
76	Receipt Point: Mendon															
77	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
78	Received Volume	Line 70	127,490	131,793	131,793	119,039	131,793	-	-	-	-	-	-	-	641,908	-
79	Fuel Loss Rate	Sch 27-FXW, Line 30 of Page 2	0.91%	0.95%	0.95%	0.95%	0.95%	-	-	-	-	-	-	-	0.94%	-
80	City Gate Delivered Volume	Line 78 times (1 - Line 79)	126,330	130,541	130,541	117,908	130,541	-	-	-	-	-	-	-	635,861	-
81	Variable Transportation Rate	Sch 27-FXW, Line 15 of Page 2	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543								\$ 0.0543	
82	Variable Transportation Costs	Line 80 times Line 81	\$ 6,860	\$ 7,088	\$ 7,088	\$ 6,402	\$ 7,088	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,439	\$ -

Source of Supply: Leidy Hub
 Delivered to Northern via Algonquin Pipeline and Bay State Exchange

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 9	29,394	30,482	30,482	27,532	30,482	29,394	30,374	29,394	30,374	30,374	29,394	30,374	177,766	180,282
4	City Gate Delivered Volume	Sum Lines 39	28,687	29,631	29,631	26,763	29,631	28,687	29,643	28,687	29,643	29,643	28,687	29,643	173,029	175,944
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Sum Lines 41	\$ 2,858	\$ 2,952	\$ 2,952	\$ 2,666	\$ 2,952	\$ 2,858	\$ 2,953	\$ 2,858	\$ 2,953	\$ 2,953	\$ 2,858	\$ 2,953	\$ 17,238	\$ 17,526
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	<u>Leidy Hub Purchases</u>															
11	Purchased Volumes	Sendout Optimization	29,394	30,482	30,482	27,532	30,482	29,394	30,374	29,394	30,374	30,374	29,394	30,374	177,766	180,282
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,147	\$ 2,820
13	NYMEX Cost	Line 9 times Line 10	\$ 85,272	\$ 99,554	\$ 102,877	\$ 91,599	\$ 97,085	\$ 82,979	\$ 84,317	\$ 82,303	\$ 85,988	\$ 86,200	\$ 83,067	\$ 86,504	\$ 559,365	\$ 508,379
14	NYMEX Basis Price	Sch 27-FXW, Line 7 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1															
21	Algonquin Pipeline (Contract 93201A1C)															
22	Receipt Point: Algonquin Receipt Points															
23	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
24	Received Volume	Line 17	29,394	30,482	30,482	27,532	30,482	29,394	30,374	29,394	30,374	30,374	29,394	30,374	177,766	180,282
25	Fuel Loss Rate	Sch 27-FXW, Line 40 of Page 2	1.51%	1.86%	1.86%	1.86%	1.86%	1.51%	1.51%	1.51%	1.51%	1.51%	1.51%	1.51%	1.20%	1.20%
26	Delivered Volume	Line 24 times (1 - Line 25)	28,950	29,915	29,915	27,020	29,915	28,950	29,915	28,950	29,915	29,915	28,950	29,915	174,665	177,560
27	Variable Transportation Rate	Sch 27-FXW, Line 26 of Page 2	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449
28	Variable Transportation Costs	Line 26 times Line 27	\$ 1,300	\$ 1,343	\$ 1,343	\$ 1,213	\$ 1,343	\$ 1,300	\$ 1,343	\$ 1,300	\$ 1,343	\$ 1,343	\$ 1,300	\$ 1,343	\$ 7,842	\$ 7,972
29																
30	Transportation Segment 1															
31	Algonquin Pipeline (Contract 93201A1C)															
32	Receipt Point: Algonquin Receipt Points															
33	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
34	Total Contract Received Volume	Sendout Optimization	29,216	30,202	30,202	27,279	30,202	29,216	30,190	29,216	30,190	30,190	29,216	30,190	176,317	179,191
35	Received Volume	Line 16	28,950	29,915	29,915	27,020	29,915	28,950	29,915	28,950	29,915	29,915	28,950	29,915	174,665	177,560
36	Percentage Allocated	Line 35 divided by Line 34	99.09%	99.05%	99.05%	99.05%	99.05%	99.09%	99.09%	99.09%	99.09%	99.09%	99.09%	99.09%	99.06%	99.09%
37	Received Volume	Line 17	28,950	29,915	29,915	27,020	29,915	28,950	29,915	28,950	29,915	29,915	28,950	29,915	174,665	177,560
38	Fuel Loss Rate	Sch 27-FXW, Line 30 of Page 2	0.91%	0.95%	0.95%	0.95%	0.95%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	1.20%	1.20%
39	City Gate Delivered Volume	Line 37 times (1 - Line 38)	28,687	29,631	29,631	26,763	29,631	28,687	29,643	28,687	29,643	29,643	28,687	29,643	173,029	175,944
40	Variable Transportation Rate	Sch 27-FXW, Line 15 of Page 2	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543
41	Variable Transportation Costs	Line 39 times Line 40	\$ 1,558	\$ 1,609	\$ 1,609	\$ 1,453	\$ 1,609	\$ 1,558	\$ 1,610	\$ 1,558	\$ 1,610	\$ 1,610	\$ 1,558	\$ 1,610	\$ 9,395	\$ 9,554

Source of Supply: Texas Eastern Zone M-3
Delivered to Northern via Algonquin Pipeline and Bay State Exchange

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 9	266	287	287	259	287	266	275	266	275	275	266	275	1,652	1,631
4	City Gate Delivered Volume	Sum Lines 29	263	284	284	257	284	263	272	263	272	272	263	272	1,636	1,616
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Sum Lines 31	\$ 14	\$ 15	\$ 15	\$ 14	\$ 15	\$ 14	\$ 15	\$ 14	\$ 15	\$ 15	\$ 14	\$ 15	\$ 89	\$ 88
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	<u>Texas Eastern Zone M-3 Purchases</u>															
11	Purchased Volumes	Sendout Optimization	266	287	287	259	287	266	275	266	275	275	266	275	1,652	1,631
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,150	\$ 2,820
13	NYMEX Cost	Line 9 times Line 10	\$ 771	\$ 937	\$ 968	\$ 862	\$ 914	\$ 751	\$ 763	\$ 744	\$ 778	\$ 780	\$ 751	\$ 782	\$ 5,203	\$ 4,598
14	NYMEX Basis Price	Sch 27-FXW, Line 6 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1															
21	Algonquin Pipeline (Contract 93201A1C)															
22	Receipt Point: Algonquin Receipt Points															
23	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
24	Total Contract Received Volume	Sendout Optimization	29,216	30,202	30,202	27,279	30,202	29,216	30,190	29,216	30,190	30,190	29,216	30,190	176,317	179,191
25	Received Volume	Line 16	266	287	287	259	287	266	275	266	275	275	266	275	1,652	1,631
26	Percentage Allocated	Line 25 divided by Line 24	0.91%	0.95%	0.95%	0.95%	0.95%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.94%	0.91%
27	Received Volume	Line 17	266	287	287	259	287	266	275	266	275	275	266	275	1,652	1,631
28	Fuel Loss Rate	Sch 27-FXW, Line 30 of Page 2	0.91%	0.95%	0.95%	0.95%	0.95%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	1.20%	1.20%
29	City Gate Delivered Volume	Line 27 times (1 - Line 28)	263	284	284	257	284	263	272	263	272	272	263	272	1,636	1,616
30	Variable Transportation Rate	Sch 27-FXW, Line 15 of Page 2	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543
31	Variable Transportation Costs	Line 29 times Line 30	\$ 14	\$ 15	\$ 15	\$ 14	\$ 15	\$ 14	\$ 15	\$ 14	\$ 15	\$ 15	\$ 14	\$ 15	\$ 89	\$ 88

Source of Supply: Transco Zone 6 non-NY
Delivered to Northern via Algonquin Pipeline and Bay State Exchange

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 9	8,659	8,951	8,951	8,085	8,951	8,659	8,947	8,659	8,947	8,947	8,659	8,947	52,255	53,107
4	City Gate Delivered Volume	Sum Lines 26	8,580	8,866	8,866	8,008	8,866	8,580	8,866	8,580	8,866	8,866	8,580	8,866	51,766	52,624
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Sum Lines 28	\$ 466	\$ 481	\$ 481	\$ 435	\$ 481	\$ 466	\$ 481	\$ 466	\$ 481	\$ 481	\$ 466	\$ 481	\$ 2,811	\$ 2,857
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	<u>Tranco Zone 6, non-NY Purchases</u>															
11	Purchased Volumes	Sendout Optimization	8,659	8,951	8,951	8,085	8,951	8,659	8,947	8,659	8,947	8,947	8,659	8,947	52,255	53,107
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 3,146	\$ 2,820
13	NYMEX Cost	Line 9 times Line 10	\$ 25,119	\$ 29,234	\$ 30,210	\$ 26,898	\$ 28,509	\$ 24,444	\$ 24,838	\$ 24,245	\$ 25,330	\$ 25,393	\$ 24,470	\$ 25,482	\$ 164,414	\$ 149,758
14	NYMEX Basis Price	Sch 27-FXW, Line 5 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1															
21	Algonquin Pipeline (Contract 93201A1C)															
22	Receipt Point: Algonquin Receipt Points															
23	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
24	Received Volume	Line 17	8,659	8,951	8,951	8,085	8,951	8,659	8,947	8,659	8,947	8,947	8,659	8,947	52,255	53,107
25	Fuel Loss Rate	Sch 27-FXW, Line 30 of Page 2	0.91%	0.95%	0.95%	0.95%	0.95%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	1.20%	1.20%
26	City Gate Delivered Volume	Line 24 times (1 - Line 25)	8,580	8,866	8,866	8,008	8,866	8,580	8,866	8,580	8,866	8,866	8,580	8,866	51,766	52,624
27	Variable Transportation Rate	Sch 27-FXW, Line 15 of Page 2	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543
28	Variable Transportation Costs	Line 26 times Line 27	\$ 466	\$ 481	\$ 481	\$ 435	\$ 481	\$ 466	\$ 481	\$ 466	\$ 481	\$ 481	\$ 466	\$ 481	\$ 2,811	\$ 2,857

Source of Supply: Tennessee Zone 4
Delivered to Northern via Tennessee and Granite Pipelines

Denotes Confidential Information																
Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 9	65,297	-	-	356	52,912	65,297	67,473	65,297	67,473	67,473	65,297	67,473	183,861	400,486
4	City Gate Delivered Volume	Line 39	64,274	-	-	351	52,083	64,274	66,417	64,274	66,417	66,417	64,274	66,417	180,982	394,215
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Sum Lines 31 and 41	\$ 6,463	\$ -	\$ -	\$ 35	\$ 5,237	\$ 6,463	\$ 6,678	\$ 6,463	\$ 6,678	\$ 6,678	\$ 6,463	\$ 6,678	\$ 18,197	\$ 39,638
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	<u>Tennessee Zone 4 Supply Costs</u>															
11	Purchased Volumes	Sendout Optimization	65,297	-	-	356	52,912	65,297	67,473	65,297	67,473	67,473	65,297	67,473	183,861	400,486
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 2,956	\$ 2,820
13	NYMEX Cost	Line 9 times Line 10	\$ 189,425	\$ -	\$ -	\$ 1,185	\$ 168,524	\$ 184,332	\$ 187,306	\$ 182,831	\$ 191,017	\$ 191,489	\$ 184,528	\$ 192,164	\$ 543,467	\$ 1,129,333
14	NYMEX Basis Price	Sch 27-FXW, Line 8 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 2															
21	Tennessee Gas Pipeline (Contract 5265)															
22	Receipt Point: Tennessee FS-MA 300 Leg															
23	Delivery Point: Pleasant St. (Interconnection with Granite)															
24	Total Contract Received Volume	Sendout Optimization	65,297	67,473	67,473	60,944	67,473	65,297	67,473	65,297	67,473	67,473	65,297	67,473	393,956	
25	Received Volume	Line 16	65,297	-	-	356	52,912	65,297	67,473	65,297	67,473	67,473	65,297	67,473	183,861	
26	Percentage Allocated	Line 25 divided by Line 24	100.00%	0.00%	0.00%	0.58%	78.42%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	46.67%	100.00%
27	Received Volume	Line 11	65,297	-	-	356	52,912	65,297	67,473	65,297	67,473	67,473	65,297	67,473	183,861	400,486
28	Fuel Loss Rate	Sch 27-FXW, Line 38 of Page 2	1.22%			1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
29	Delivered Volume	Line 27 times (1 - Line 28)	64,500	-	-	352	52,266	64,500	66,650	64,500	66,650	66,650	64,500	66,650	181,618	395,600
30	Variable Transportation Rate	Sch 27-FXW, Line 24 of Page 2	\$ 0.0991		\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991
31	Variable Transportation Costs	Line 29 times Line 30	\$ 6,392	\$ -	\$ -	\$ 35	\$ 5,180	\$ 6,392	\$ 6,605	\$ 6,392	\$ 6,605	\$ 6,605	\$ 6,392	\$ 6,605	\$ 17,998	\$ 39,204
32																
33	Transportation Segment 3															
34	Granite State Gas Transmission (Contract 19-100-FT-NN)															
35	Receipt Point: Pleasant St.															
36	Delivery Point: Northern City Gates															
37	Received Volume	Line 29	64,500	-	-	352	52,266	64,500	66,650	64,500	66,650	66,650	64,500	66,650	181,618	395,600
38	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
39	City Gate Delivered Volume	Line 37 times (1 - Line 38)	64,274	-	-	351	52,083	64,274	66,417	64,274	66,417	66,417	64,274	66,417	180,982	394,215
40	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011
41	Variable Transportation Costs	Line 39 times Line 40	\$ 71	\$ -	\$ -	\$ 0	\$ 57	\$ 71	\$ 73	\$ 71	\$ 73	\$ 73	\$ 71	\$ 73	\$ 199	\$ 434

Source of Supply: Tennessee FS-MA Inventory
 Delivered to Northern via Tennessee and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
1	Gross Withdrawn Volume	Line 9	-	67,473	67,473	60,587	14,561	-	-	-	-	-	-	-	210,095	-
2	City Gate Delivered Volume	Line 38	-	66,417	66,417	59,639	14,333	-	-	-	-	-	-	-	206,805	-
3	Total Withdrawal Costs	Line 16	\$	-	\$ 101,729	\$ 101,729	\$ 91,348	\$ 21,954	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 316,760	\$ -
4	Variable Transportation Costs	Sum Lines 30 and 40	\$	-	\$ 6,678	\$ 6,678	\$ 5,997	\$ 1,441	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20,794	\$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	\$	-	\$ 108,407	\$ 108,407	\$ 97,344	\$ 23,395	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 337,554	\$ -
6	Average Delivered Price	Line 5 divided by Line 2		\$	1.632	\$ 1.632	\$ 1.632	\$ 1.632							\$ 1.632	
7																
8	<u>Tennessee FS-MA Withdrawn Inventory (Segment 1)</u>															
9	Gross Withdrawn Volume	Sendout Optimization	-	67,473	67,473	60,587	14,561	-	-	-	-	-	-	-	210,095	-
10	Withdrawal Rate	Sch 27-FXW, Line 1 of Page 3		\$	0.0087	\$ 0.0087	\$ 0.0087	\$ 0.0087							\$ 0.0087	
11	Withdrawal Charges	Line 9 times Line 10	\$	-	\$ 587	\$ 587	\$ 527	\$ 127	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,828	\$ -
12	Inventory Rate	FXW-8		\$	1.4990	\$ 1.4990	\$ 1.4990	\$ 1.4990							\$ 1.4990	
13	Withdrawn Inventory Value	Line 9 times Line 12	\$	-	\$ 101,142	\$ 101,142	\$ 90,820	\$ 21,827	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 314,932	\$ -
14	Withdrawal Fuel Losses	Sch 27-FXW, Line 1 of Page 3 times Line 9		-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14		-	67,473	67,473	60,587	14,561	-	-	-	-	-	-	210,095	-
16	Total Withdrawal Costs	Line 11 plus Line 13	\$	-	\$ 101,729	\$ 101,729	\$ 91,348	\$ 21,954	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 316,760	\$ -
17																
18	<u>Transportation Fuel Losses and Variable Charges</u>															
19	Transportation Segment 2															
20	Tennessee Gas Pipeline (Contract 5265)															
21	Receipt Point: Tennessee FS-MA Withdrawal Meter															
22	Delivery Point: Pleasant St. (Interconnection with Granite)															
23	Total Contract Received Volume	Sendout Optimization	65,297	67,473	67,473	60,944	67,473	65,297	67,473	65,297	67,473	67,473	65,297	67,473	393,956	400,486
24	Received Volume	Line 15	-	67,473	67,473	60,587	14,561	-	-	-	-	-	-	-	210,095	-
25	Percentage Allocated	Line 24 divided by Line 23	0.00%	100.00%	100.00%	99.42%	21.58%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	53.33%	0.00%
26	Received Volume	Line 24	-	67,473	67,473	60,587	14,561	-	-	-	-	-	-	-	210,095	-
27	Fuel Loss Rate	Sch 27-FXW, Line 38 of Page 2		1.22%	1.22%	1.22%	1.22%								1.22%	
28	Delivered Volume	Line 26 times (1 - Line 27)	-	66,650	66,650	59,848	14,384	-	-	-	-	-	-	-	207,532	-
29	Variable Transportation Rate	Sch 27-FXW, Line 24 of Page 2		\$	0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991							\$ 0.0991	
30	Variable Transportation Costs	Line 28 times Line 29	\$	-	\$ 6,605	\$ 6,605	\$ 5,931	\$ 1,425	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20,566	\$ -
31																
32	Transportation Segment 3															
33	Granite State Gas Transmission (Contract 19-100-FT-NN)															
34	Receipt Point: Pleasant St.															
35	Delivery Point: Northern City Gates															
36	Received Volume	Line 28	-	66,650	66,650	59,848	14,384	-	-	-	-	-	-	-	207,532	-
37	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	-	66,417	66,417	59,639	14,333	-	-	-	-	-	-	-	206,805	-
39	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$	0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	
40	Variable Transportation Costs	Line 38 times Line 39	\$	-	\$ 73	\$ 73	\$ 66	\$ 16	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 227	\$ -

Source of Supply: Union Dawn Storage Inventory
 Delivered to Northern via TransCanada, PNGTS and Granite Pipelines

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
1	Gross Withdrawn Volume	Line 9	242,662	626,554	720,240	746,937	442,456	-	-	-	-	-	-	-	2,778,850	-
2	City Gate Delivered Volume	Line 64	233,918	603,977	694,287	720,022	426,513	-	-	-	-	-	-	-	2,678,717	-
3	Total Withdrawal Costs	Line 16	\$ 427,814	\$ 1,104,614	\$ 1,269,784	\$ 1,316,850	\$ 780,050	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,899,112	\$ -
4	Variable Transportation Costs	Sum Lines 30, 43, 56 and 66	\$ 516	\$ 1,331	\$ 1,530	\$ 1,587	\$ 940	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,904	\$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	\$ 428,329	\$ 1,105,945	\$ 1,271,314	\$ 1,318,437	\$ 780,990	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,905,015	\$ -
6	Average Delivered Price	Line 5 divided by Line 2	\$ 1.831	\$ 1.831	\$ 1.831	\$ 1.831	\$ 1.831								\$ 1.831	
7																
8	<u>Union Dawn Storage Withdrawn Inventory (Segment 1)</u>															
9	Gross Withdrawn Volume	Sendout Optimization	242,662	626,554	720,240	746,937	442,456	-	-	-	-	-	-	-	2,778,850	-
10	Withdrawal Rate	Sch 27-FXW, Line 3 of Page 3	\$ 0.005	\$ 0.005	\$ 0.005	\$ 0.005	\$ 0.005								\$ 0.005	
11	Withdrawal Charges	Line 9 times Line 10	\$ 1,213	\$ 3,133	\$ 3,601	\$ 3,735	\$ 2,212	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 13,894	\$ -
12	Inventory Rate	FXW-8	\$ 1.758	\$ 1.758	\$ 1.758	\$ 1.758	\$ 1.758								\$ 1.758	
13	Withdrawn Inventory Value	Line 9 times Line 12	\$ 426,600	\$ 1,101,482	\$ 1,266,183	\$ 1,313,115	\$ 777,838	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,885,218	\$ -
14	Withdrawal Fuel Losses	Sch 27-FXW, Line 3 of Page 3 times Line 1	\$ 1,455,963	\$ 3,759,338	\$ 4,321,411	\$ 4,481,628	\$ 2,654,724	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 16,673,065	\$ -
15	Net Withdrawn Volume	Line 9 minus Line 14	241,206	622,794	715,919	742,455	439,801	-	-	-	-	-	-	-	2,762,177	-
16	Total Withdrawal Costs	Line 11 plus Line 13	\$ 427,814	\$ 1,104,614	\$ 1,269,784	\$ 1,316,850	\$ 780,050	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,899,112	\$ -
17																
18	Transportation Fuel Losses and Variable Charges															
19	Transportation Segment 3															
20	TransCanada Pipeline (Contract 33322)															
21	Receipt Point: Union Dawn															
22	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)															
23	Total Contract Received Volume	Sendout Optimization	241,206	622,794	715,919	743,181	458,117	774,542	404,366	241,481	190,651	193,810	224,050	527,515	3,555,760	1,781,873
24	Received Volume	Line 15	241,206	622,794	715,919	742,455	439,801	-	-	-	-	-	-	-	2,762,177	-
25	Percentage Allocated	Line 24 divided by Line 23	100.00%	100.00%	100.00%	99.90%	96.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.68%	0.00%
26	Received Volume	Line 24	241,206	622,794	715,919	742,455	439,801	-	-	-	-	-	-	-	2,762,177	-
27	Fuel Loss Rate	Sch 27-FXW, Line 42 of Page 2	1.10%	1.10%	1.10%	1.10%	1.10%								1.10%	
28	Delivered Volume	Line 26 times (1 - Line 27)	238,553	615,944	708,044	734,288	434,963	-	-	-	-	-	-	-	2,731,793	-
29	Variable Transportation Rate	Sch 27-FXW, Line 28 of Page 2	\$ -	\$ -	\$ -	\$ -	\$ -								\$ -	
30	Variable Transportation Costs	Line 28 times Line 29	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
31																
32	Transportation Segment 3															
33	TransCanada Pipeline (Contract 33322)															
34	Receipt Point: Union Dawn															
35	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)															
36	Total Contract Received Volume	Sendout Optimization	238,553	615,944	708,044	735,006	453,077	769,894	401,940	240,032	189,507	192,647	222,706	524,350	3,520,519	1,771,182
37	Received Volume	Line 28	238,553	615,944	708,044	734,288	434,963	-	-	-	-	-	-	-	2,731,793	-
38	Percentage Allocated	Line 37 divided by Line 36	100.00%	100.00%	100.00%	99.90%	96.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.60%	0.00%
39	Received Volume	Line 37	238,553	615,944	708,044	734,288	434,963	-	-	-	-	-	-	-	2,731,793	-
40	Fuel Loss Rate	Sch 27-FXW, Line 41 of Page 2	1.50%	1.50%	1.50%	1.50%	1.50%									
41	Delivered Volume	Line 39 times (1 - Line 40)	234,975	606,705	697,423	723,274	428,439	-	-	-	-	-	-	-	2,690,816	-
42	Variable Transportation Rate	Sch 27-FXW, Line 27 of Page 2	\$ -	\$ -	\$ -	\$ -	\$ -								\$ -	
43	Variable Transportation Costs	Line 41 times Line 42	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
44																
45	Transportation Segment 4															
46	PNGTS (Contract 1997-004)															
47	Receipt Point: Pittsburgh, NH (Interconnects with TransCanada at E. Hereford)															
48	Delivery Point: Granite (Westbrook, Newington, Eliot)															
49	Total Contract Received Volume	Sendout Optimization	234,975	606,705	697,423	723,981	446,281	758,346	395,910	236,432	186,665	189,758	219,365	516,485	3,467,711	1,744,614
50	Received Volume	Line 41	234,975	606,705	697,423	723,274	428,439	-	-	-	-	-	-	-	2,690,816	-
51	Percentage Allocated	Line 50 divided by Line 49	100.00%	100.00%	100.00%	99.90%	96.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.60%	0.00%
52	Total Contract Received Volume	Sendout Optimization	234,975	606,705	697,423	723,274	428,439	-	-	-	-	-	-	-	2,690,816	-
53	Fuel Loss Rate	Sch 27-FXW, Line 34 of Page 2	0.10%	0.10%	0.10%	0.10%	0.10%								0.10%	
54	Delivered Volume	Line 52 times (1 - Line 53)	234,740	606,098	696,726	722,551	428,011	-	-	-	-	-	-	-	2,688,125	-
55	Variable Transportation Rate	Sch 27-FXW, Line 21 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011								\$ 0.0011	
56	Variable Transportation Costs	Line 54 times Line 55	\$ 258	\$ 667	\$ 766	\$ 795	\$ 471	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,957	\$ -
57																
58	Transportation Segment 5															
59	Granite State Gas Transmission (Contract 19-100-FT-NN)															
60	Receipt Point: Westbrook, Newington, Eliot															
61	Delivery Point: Northern City Gates															
62	Received Volume	Line 54	234,740	606,098	696,726	722,551	428,011	-	-	-	-	-	-	-	2,688,125	-
63	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
64	City Gate Delivered Volume	Line 62 times (1 - Line 63)	233,918	603,977	694,287	720,022	426,513	-	-	-	-	-	-	-	2,678,717	-
65	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	
66	Variable Transportation Costs	Line 64 times Line 65	\$ 257	\$ 664	\$ 764	\$ 792	\$ 469	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,947	\$ -

Source of Supply: PNGTS (Westbrook, ME)
Delivered to Northern via Granite Pipeline

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter
3	Purchased Volumes	Line 9	-	-	-	726	18,316	774,542	404,366	241,481	190,651	193,810	224,050	527,515	793,583
4	City Gate Delivered Volume	Line 67	-	-	-	704	17,762	754,936	394,130	235,369	185,825	188,904	218,379	514,162	773,402
5	Total Purchase Cost	Line 15													
6	Variable Transportation Costs	Sum Lines 32, 46, 60 and 69													
7	Total City Gate Delivered Costs	Sum Lines 3 and 4													
8	Average Delivered Price	Line 5 divided by Line 2													
9															
10	<u>Portland Supply Costs</u>														
11	Purchased Volumes	Sendout Optimization	-	-	-	726	18,316	774,542	404,366	241,481	190,651	193,810	224,050	527,515	793,583
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2,901	\$ 3,266	\$ 3,375	\$ 3,327	\$ 3,185	\$ 2,823	\$ 2,776	\$ 2,800	\$ 2,831	\$ 2,838	\$ 2,826	\$ 2,848	\$ 2,832
13	NYMEX Cost	Line 9 times Line 10	\$ -	\$ -	\$ -	\$ 2,415	\$ 58,335	\$ 2,186,531	\$ 1,122,519	\$ 676,147	\$ 539,733	\$ 550,033	\$ 633,165	\$ 1,502,363	\$ 2,247,281
14	NYMEX Basis Price	Sch 27-FXW, Line 10 of Page 1													
15	NYMEX Basis Costs	Line 9 times Line 12													
16	Total Purchase Price	Line 10 plus Line 12													
17	Total Purchase Cost	Line 11 plus Line 13													
18															
19	<u>Transportation Fuel Losses and Variable Charges</u>														
20	Transportation Segment 2B														
21	Transportation Segment 3														
22	TransCanada Pipeline (Contract 33322)														
23	Receipt Point: Union Dawn														
24	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)														
25	Total Contract Received Volume	Sendout Optimization	241,206	622,794	715,919	743,181	458,117	774,542	404,366	241,481	190,651	193,810	224,050	527,515	3,555,760
26	Received Volume	Line 11	-	-	-	726	18,316	774,542	404,366	241,481	190,651	193,810	224,050	527,515	793,583
27	Percentage Allocated	Line 26 divided by Line 25	0.00%	0.00%	0.00%	0.10%	4.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	22.32%
28	Received Volume	Line 11	-	-	-	726	18,316	774,542	404,366	241,481	190,651	193,810	224,050	527,515	793,583
29	Fuel Loss Rate	Sch 27-FXW, Line 42 of Page 2				1.10%	1.10%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.61%
30	Delivered Volume	Line 28 times (1 - Line 29)	-	-	-	718	18,114	769,894	401,940	240,032	189,507	192,647	222,706	524,350	788,726
31	Variable Transportation Rate	Sch 27-FXW, Line 28 of Page 2				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
32	Variable Transportation Costs	Line 30 times Line 31	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
33															
34	Transportation Segment 2B														
35	Transportation Segment 3														
36	TransCanada Pipeline (Contract 33322)														
37	Receipt Point: Union Dawn														
38	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)														
39	Total Contract Received Volume	Sendout Optimization	238,553	615,944	708,044	735,006	453,077	769,894	401,940	240,032	189,507	192,647	222,706	524,350	3,520,519
40	Received Volume	Line 30	-	-	-	718	18,114	769,894	401,940	240,032	189,507	192,647	222,706	524,350	788,726
41	Percentage Allocated	Line 40 divided by Line 39	0.00%	0.00%	0.00%	0.10%	4.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	22.40%
42	Received Volume	Line 30	-	-	-	718	18,114	769,894	401,940	240,032	189,507	192,647	222,706	524,350	788,726
43	Fuel Loss Rate	Sch 27-FXW, Line 41 of Page 2				1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
44	Delivered Volume	Line 42 times (1 - Line 43)	-	-	-	707	17,842	758,346	395,910	236,432	186,665	189,758	219,365	516,485	776,895
45	Variable Transportation Rate	Sch 27-FXW, Line 27 of Page 2				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
46	Variable Transportation Costs	Line 44 times Line 45	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47															
48	Transportation Segment 2B														
49	Transportation Segment 3														
50	TransCanada Pipeline (Contract 33322)														
51	Receipt Point: Union Dawn														
52	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)														
53	Total Contract Received Volume	Sendout Optimization	234,975	606,705	697,423	723,981	446,281	758,346	395,910	236,432	186,665	189,758	219,365	516,485	3,467,711
54	Received Volume	Line 44	-	-	-	707	17,842	758,346	395,910	236,432	186,665	189,758	219,365	516,485	776,895
55	Percentage Allocated	Line 54 divided by Line 53	0.00%	0.00%	0.00%	0.10%	4.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	22.40%
56	Received Volume	Line 44	-	-	-	707	17,842	758,346	395,910	236,432	186,665	189,758	219,365	516,485	776,895
57	Fuel Loss Rate	Sch 27-FXW, Line 34 of Page 2				0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
58	Delivered Volume	Line 56 times (1 - Line 57)	-	-	-	706	17,825	757,588	395,515	236,195	186,478	189,568	219,146	515,968	776,119
59	Variable Transportation Rate	Sch 27-FXW, Line 21 of Page 2				\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011
60	Variable Transportation Costs	Line 58 times Line 59	\$ -	\$ -	\$ -	\$ 1	\$ 20	\$ 833	\$ 435	\$ 260	\$ 205	\$ 209	\$ 241	\$ 568	\$ 854
61															
62	Granite State Gas Transmission (Contract 19-100-FT-NN)														
63	Receipt Point: Westbrook, Newington, Eliot														
64	Delivery Point: Northern City Gates														
65	Received Volume	Line 58	-	-	-	706	17,825	757,588	395,515	236,195	186,478	189,568	219,146	515,968	776,119
66	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
67	City Gate Delivered Volume	Line 65 times (1 - Line 66)	-	-	-	704	17,762	754,936	394,130	235,369	185,825	188,904	218,379	514,162	773,402
68	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011
69	Variable Transportation Costs	Line 67 times Line 68	\$ -	\$ -	\$ -	\$ 1	\$ 20	\$ 830	\$ 434	\$ 259	\$ 204	\$ 208	\$ 241	\$ 568	\$ 851

Source of Supply: Atlantic Bridge Ramapo
Delivered to Northern via Algonquin Pipeline and Bay State Exchange

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
3	Purchased Volumes	Line 9	171,105	187,462	187,462	169,320	187,462	-	-	-	-	-	-	-	902,810	-
4	City Gate Delivered Volume	Sum Lines 39	169,702	183,303	183,303	165,564	183,303	-	-	-	-	-	-	-	885,175	-
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Sum Lines 41	\$ 35,547	\$ 42,722	\$ 42,722	\$ 38,588	\$ 42,722	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 202,301	\$ -
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	<u>Texas Eastern Zone M-3 Purchases</u>															
11	Purchased Volumes	Sendout Optimization	171,105	187,462	187,462	169,320	187,462	-	-	-	-	-	-	-	902,810	-
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2.901	\$ 3.266	\$ 3.375	\$ 3.327	\$ 3.185	\$ 2.823	\$ 2.776	\$ 2.800	\$ 2.831	\$ 2.838	\$ 2.826	\$ 2.848	\$ 3.214	-
13	NYMEX Cost	Line 9 times Line 10	\$ 496,376	\$ 612,250	\$ 632,683	\$ 563,329	\$ 597,066	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,901,703	\$ -
14	NYMEX Basis Price	Sch 27-FXW, Line 13 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1															
21	Algonquin Pipeline (Contract 93201A1C)															
22	Receipt Point: Algonquin Receipt Points															
23	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
24	Received Volume	Line 17	171,105	187,462	187,462	169,320	187,462	-	-	-	-	-	-	-	902,810	-
25	Fuel Loss Rate	#N/A	0.00%	1.41%	1.41%	1.41%	1.41%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1.20%	1.20%
26	Delivered Volume	Line 24 times (1 - Line 25)	171,105	184,819	184,819	166,933	184,819	-	-	-	-	-	-	-	892,493	-
27	Variable Transportation Rate	#N/A	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	\$ 0.2017	-
28	Variable Transportation Costs	Line 26 times Line 27	\$ 34,512	\$ 37,278	\$ 37,278	\$ 33,670	\$ 37,278	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 180,016	\$ -
29																
30	Transportation Segment 1															
31	Algonquin Pipeline (Contract 93201A1C)															
32	Receipt Point: Algonquin Receipt Points															
33	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
34	Total Contract Received Volume	Sendout Optimization	171,105	184,819	184,819	166,933	184,819	-	-	-	-	-	-	-	892,493	-
35	Received Volume	Line 16	171,105	184,819	184,819	166,933	184,819	-	-	-	-	-	-	-	892,493	-
36	Percentage Allocated	Line 35 divided by Line 34	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	-
37	Received Volume	Line 17	171,105	184,819	184,819	166,933	184,819	-	-	-	-	-	-	-	892,493	-
38	Fuel Loss Rate	#N/A	0.82%	0.82%	0.82%	0.82%	0.82%								1.20%	1.20%
39	City Gate Delivered Volume	Line 37 times (1 - Line 38)	169,702	183,303	183,303	165,564	183,303	-	-	-	-	-	-	-	885,175	-
40	Variable Transportation Rate	#N/A	\$ 0.0061	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297								\$ 0.0252	-
41	Variable Transportation Costs	Line 39 times Line 40	\$ 1,035	\$ 5,444	\$ 5,444	\$ 4,917	\$ 5,444	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 22,285	\$ -

Source of Supply: PXP Dawn Hub
Delivered to Northern via Granite Pipeline

Denotes Confidential Information			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
Line	City Gate Delivered Costs	Reference														
3	Purchased Volumes	Line 9	232,496	247,593	247,593	223,632	247,593	52,514	-	-	-	-	-	-	1,251,420	-
4	City Gate Delivered Volume	Line 67	224,840	239,438	239,438	216,267	239,438	51,041	-	-	-	-	-	-	1,210,463	-
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Sum Lines 32, 46, 60 and 69	\$ 496	\$ 528	\$ 528	\$ 477	\$ 528	\$ 112	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	2,668	\$ -
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	Supply Costs															
11	Purchased Volumes	Sendout Optimization	232,496	247,593	247,593	223,632	247,593	52,514	-	-	-	-	-	-	1,251,420	-
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$ 2.901	\$ 3.266	\$ 3.375	\$ 3.327	\$ 3.185	\$ 2.823	\$ 2.776	\$ 2.800	\$ 2.831	\$ 2.838	\$ 2.826	\$ 2.848	\$ 3.196	
13	NYMEX Cost	Line 9 times Line 10	\$ 674,472	\$ 808,637	\$ 835,625	\$ 744,024	\$ 788,582	\$ 148,247	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,999,587	\$ -
14	NYMEX Basis Price	Sch 27-FXW, Line 14 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	Transportation Fuel Losses and Variable Charges															
20	Transportation Segment 2B															
21	Transportation Segment 3															
22	TransCanada Pipeline (Contract 33322)															
23	Receipt Point: Union Dawn															
24	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)															
25	Total Contract Received Volume	Sendout Optimization	232,496	247,593	247,593	223,632	247,593	52,514	-	-	-	-	-	-	1,251,420	-
26	Received Volume	Line 11	232,496	247,593	247,593	223,632	247,593	52,514	-	-	-	-	-	-	1,251,420	-
27	Percentage Allocated	Line 26 divided by Line 25	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
28	Received Volume	Line 11	232,496	247,593	247,593	223,632	247,593	52,514	-	-	-	-	-	-	1,251,420	-
29	Fuel Loss Rate	#N/A	1.10%	1.10%	1.10%	1.10%	1.10%	0.60%							1.08%	
30	Delivered Volume	Line 28 times (1 - Line 29)	229,939	244,869	244,869	221,172	244,869	52,199	-	-	-	-	-	-	1,237,917	-
31	Variable Transportation Rate	#N/A	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -							\$ -	
32	Variable Transportation Costs	Line 30 times Line 31	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
33																
34	Transportation Segment 2B															
35	Transportation Segment 3															
36	TransCanada Pipeline (Contract 33322)															
37	Receipt Point: Union Dawn															
38	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)															
39	Total Contract Received Volume	Sendout Optimization	229,939	244,869	244,869	221,172	244,869	52,199	-	-	-	-	-	-	1,237,917	-
40	Received Volume	Line 30	229,939	244,869	244,869	221,172	244,869	52,199	-	-	-	-	-	-	1,237,917	-
41	Percentage Allocated	Line 40 divided by Line 39	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
42	Received Volume	Line 30	229,939	244,869	244,869	221,172	244,869	52,199	-	-	-	-	-	-	1,237,917	-
43	Fuel Loss Rate	#N/A	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%							1.50%	
44	Delivered Volume	Line 42 times (1 - Line 43)	226,490	241,196	241,196	217,854	241,196	51,416	-	-	-	-	-	-	1,219,348	-
45	Variable Transportation Rate	#N/A	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -							\$ -	
46	Variable Transportation Costs	Line 44 times Line 45	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47																
48	Transportation Segment 2B															
49	Transportation Segment 3															
50	TransCanada Pipeline (Contract 33322)															
51	Receipt Point: Union Dawn															
52	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburgh)															
53	Total Contract Received Volume	Sendout Optimization	226,490	241,196	241,196	217,854	241,196	51,416	-	-	-	-	-	-	1,219,348	-
54	Received Volume	Line 44	226,490	241,196	241,196	217,854	241,196	51,416	-	-	-	-	-	-	1,219,348	-
55	Percentage Allocated	Line 54 divided by Line 53	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
56	Received Volume	Line 44	226,490	241,196	241,196	217,854	241,196	51,416	-	-	-	-	-	-	1,219,348	-
57	Fuel Loss Rate	#N/A	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%							0.38%	
58	Delivered Volume	Line 56 times (1 - Line 57)	225,629	240,279	240,279	217,027	240,279	51,221	-	-	-	-	-	-	1,214,715	-
59	Variable Transportation Rate	#N/A	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011							\$ 0.0011	
60	Variable Transportation Costs	Line 58 times Line 59	\$ 248	\$ 264	\$ 264	\$ 239	\$ 264	\$ 56	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,336	\$ -
61																
62	Granite State Gas Transmission (Contract 19-100-FT-NN)															
63	Receipt Point: Westbrook, Newington, Elliot															
64	Delivery Point: Northern City Gates															
65	Received Volume	Line 58	225,629	240,279	240,279	217,027	240,279	51,221	-	-	-	-	-	-	1,214,715	-
66	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
67	City Gate Delivered Volume	Line 65 times (1 - Line 66)	224,840	239,438	239,438	216,267	239,438	51,041	-	-	-	-	-	-	1,210,463	-
68	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	
69	Variable Transportation Costs	Line 67 times Line 68	\$ 247	\$ 263	\$ 263	\$ 238	\$ 263	\$ 56	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,332	\$ -

Source of Supply: Northern LNG Inventory
 On-System Storage

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	2020-2021 Winter	2021 Summer
1	Gross Withdrawn Volume	Line 9	1,794	22,761	52,503	33,254	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040
2	City Gate Delivered Volume	Line 15	1,794	22,761	52,503	33,254	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040
3	Total Withdrawal Costs	Line 16														
4	Variable Transportation Costs	N/A	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4														
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Northern LNG Withdrawn Inventory															
9	Gross Withdrawn Volume	Sendout Optimization	1,794	22,761	52,503	33,254	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040
10	Withdrawal Rate	N/A	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
11	Withdrawal Charges	Line 9 times Line 10	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
12	Inventory Rate	FXW-8														
13	Withdrawn Inventory Value	Line 9 times Line 12														
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,794	22,761	52,503	33,254	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040
16	Total Withdrawal Costs	Line 11 plus Line 13														

Source of Supply: Peaking Contract 1
 Delivered to Northern via Granite Pipeline

Denotes Confidential Information

			2020-2021 Winter	2020-2021 Winter	2020-2021 Winter	2020-2021 Winter	2020-2021 Winter	2020-2021 Winter	2021 Summer	2021 Summer	2021 Summer	2021 Summer	2021 Summer	2021 Summer	2020-2021 Winter	2021 Summer
Line	City Gate Delivered Costs	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21		
3	Purchased Volumes	Line 9	-	7,425	201,348	8,415	-	-	-	-	-	-	-	-	217,188	-
4	City Gate Delivered Volume	Line 27	-	7,425	201,313	8,415	-	-	-	-	-	-	-	-	217,152	-
5	Total Purchase Cost	Line 15														
6	Variable Transportation Costs	Line 29	\$	-	\$	-	\$	11	\$	-	\$	-	\$	-	\$	11
7	Total City Gate Delivered Costs	Sum Lines 3 and 4														
8	Average Delivered Price	Line 5 divided by Line 2														
9																
10	<u>Peaking Contract 1 Costs</u>															
11	Purchased Volumes	Sendout Optimization	-	7,425	201,348	8,415	-	-	-	-	-	-	-	-	217,188	-
12	Monthly NYMEX Price	Sch 27-FXW, Line 18 of Page 1	\$	2.901	\$	3.266	\$	3.375	\$	3.327	\$	3.185	\$	2.823	\$	2.776
13	NYMEX Cost	Line 9 times Line 10	\$	-	\$	24,248	\$	679,551	\$	27,997	\$	-	\$	-	\$	-
14	NYMEX Basis Price	Sch 27-FXW, Line 16 of Page 1														
15	NYMEX Basis Costs	Line 9 times Line 12														
16	Total Purchase Price	Line 10 plus Line 12														
17	Total Purchase Cost	Line 11 plus Line 13														
18																
19	<u>Transportation Fuel Losses and Variable Charges</u>															
20	Transportation Segment 1															
21	Granite State Gas Transmission (Contract 19-100-FT-NN)															
22	Receipt Point: Pleasant St.															
23	Delivery Point: Northern City Gates															
24	City Gate Delivered Volume	Lewiston City-Gate - Non-GSGT	-	7,425	191,136	8,415	-	-	-	-	-	-	-	-	-	-
25	Received Volume	Line 11	-	-	10,212	-	-	-	-	-	-	-	-	-	10,212	-
26	Fuel Loss Rate	Sch 27-FXW, Line 32 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	-
27	City Gate Delivered Volume	Line 25 times (1 - Line 26)	-	-	10,177	-	-	-	-	-	-	-	-	-	10,177	-
28	Variable Transportation Rate	Sch 27-FXW, Line 17 of Page 2	\$	0.0011	\$	0.0011	\$	0.0011	\$	0.0011	\$	0.0011	\$	0.0011	\$	0.0011
29	Variable Transportation Costs	Line 27 times Line 28	\$	-	\$	-	\$	11	\$	-	\$	-	\$	-	\$	11
	Purchased Volumes	Sendout Optimization	-	7,425	201,348	8,415	-	-	-	-	-	-	-	-	217,188	-
	Purchased Volumes	Sendout Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			0%	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%		

Northern Utilities, Inc.
New Hampshire Division
Schedule 26-CAK

Formula for Supplier Balancing Charge

Balancing Resources

Line	NU Storage Capacity Costs (Fixed)		NU Storage Space (Dth)	Reference
1	\$ 122,375	TGP	259,337	Schedule 20-FXW, Page 4
2	<u>\$ 2,840,000</u>	Union	<u>4,000,000</u>	Schedule 20-FXW, Page 4
3	\$ 2,962,375	TOTAL	4,259,337	LN 1 + LN 2
4	Weighted Average Capacity Cost		\$ 0.6955 per Dth	LN 3 Cost / LN3 Space
NU Storage Commodity Costs (Variable)				
5	TGP FS-MA	Withdraw/Inject	\$ 0.0174	Schedule 25-FXW, PG 9, LN 10 * 2
6	Union	Withdraw/Inject	\$ 0.0100	Schedule 25-FXW, PG 10, LN 10 * 2
7	Weighted Average Commodity Cost		\$ 0.0105 per Dth	LN 5, LN 6 (weighted)
8	Supplier Balancing Charge		\$ 0.71 per Dth	LN 4 + LN 7

Re-entry Rate & Conversion Rate
Volumes and Revenues

Month	Re-entry Surcharge		Conversion Surcharge	
	Volumes	Revenues	Volumes	Revenues
May-19	0	\$0	0	\$0
Jun-19	0	\$0	0	\$0
Jul-19	0	\$0	0	\$0
Aug-19	0	\$0	0	\$0
Sep-19	0	\$0	0	\$0
Oct-19	0	\$0	0	\$0
Nov-19	3,048	\$125	0	\$0
Dec-19	17,478	\$715	0	\$0
Jan-20	7,646	\$313	0	\$0
Feb-20	12,152	\$497	0	\$0
Mar-20	11,464	\$469	0	\$0
Apr-20	6,890	\$282	0	\$0
May-20	0	\$0	0	\$0
Jun-20	2,230	\$91	0	\$0
Total	60,908	\$2,490	0	\$0

Northern Utilities, Inc.
Short-Term Debt Limit
(\$ in thousands)

NU Short-Term Debt Limit Calculation (11/1/20 - 10/31/2021)

Fuel Financing Purposes

NU ME winter gas costs	34,992
NU NH winter gas costs	25,530
Total	60,522

30% of total winter gas costs 18,157 (a)

Non-Fuel Financing Purposes

Estimated net utility plant @ 12/31/20 529,790

15% of Net Utility Plant 79,468 (b)

Short-Term Debt Limit

Short Term Debt Limit **97,625** (a) + (b)

REDACTED

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for September 1, 2020

Denotes Confidential Information

		Estimated Adders to NYMEX Last Day Settlement											
Line	Supply Source	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
1	Tennessee Zone 0												
2	Tennessee Zone L												
3	Tennessee Niagara												
4	Iroquois Receipts												
5	Transco Zone 6, non-NY												
6	Texas Eastern Zone M-3												
7	Leidy Hub												
8	Tennessee Zone 4 Station 313 Pool												
9	Tennessee Zone 4 Storage Injection												
10	Union Dawn Storage - Dawn Supply												
11	Union Dawn Storage Injection												
12	LNG Contract												
13	Atlantic Bridge - Ramapo												
14	PXP - Dawn Supply												
15	Incremental Supply												
16	Peaking Contract 1												
17	WXP - Dawn Supply												
18	NYMEX	\$ 2.901	\$ 3.266	\$ 3.375	\$ 3.327	\$ 3.185	\$ 2.823	\$ 2.776	\$ 2.800	\$ 2.831	\$ 2.838	\$ 2.826	\$ 2.848

Northern Utilities, Inc.
Transportation Contract Rates
November 2020 through October 2021
Fixed Demand Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
1	Algonquin	AFT-1	N/A	N/A	Page 4	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927	\$ 8.5927
2	Algonquin	AFT-1 (AB)	N/A	N/A	Negotiated	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173	\$ 54.9173
3	Granite	FT-NN	N/A	N/A	Page 7	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212	\$ 4.4212
4	Iroquois	RTS-1	Zone 1	Zone 1	Page 8	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357	\$ 5.2357
5	Maritimes	MN365	N/A	N/A	Negotiated	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833	\$ 13.3833
6	PNGTS	FT (C2C)	N/A	N/A	Page 9	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500	\$ 18.2500
7	PNGTS	FT (PXP)	N/A	N/A	Negotiated	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125	\$ 22.8125
8	Tennessee	FT-A	Zone 0	Zone 6	Page 10, 13	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504	\$ 20.3504
9	Tennessee	FT-A	Zone L	Zone 6	Page 10, 13	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643	\$ 18.0643
10	Tennessee	FT-A	Zone 4	Zone 6	Page 10, 13	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413	\$ 7.1413
11	Tennessee	FT-A	Zone 5	Zone 6	Page 10, 13	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725	\$ 6.2725
12	Texas Eastern	FT-1/FTS	M3	M3	Page 14	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960	\$ 7.0960
13	TransCanada	FT	Parkway	E. Hereford	Page 18	\$ 12.9437	\$ 12.9437	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050	\$ 16.6050
14	Union	M12	Dawn	Parkway	Page 18	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203	\$ 2.8203

Variable Transportation Commodity Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
15	Algonquin	AFT-1	N/A	N/A	Page 4, 26	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543	\$ 0.0543
16	Algonquin	AFT-1 (AB)	N/A	N/A	Page 5, 26	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017	\$ 0.2017
17	Granite	FT-NN	N/A	N/A	Page 26	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011
18	Iroquois	RTS-1	Zone 1	Zone 1	Pages 8, 26	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045
19	Iroquois	RTS-1	Zone 1	Zone 1	Pages 8, 26	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045	\$ 0.0045
20	Maritimes	MN365	N/A	N/A	Page 30, 26	\$ 0.0061	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297	\$ 0.0297
21	PNGTS	FT	N/A	N/A	Page 26	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011	\$ 0.0011
22	Tennessee	FT-A	Zone 0	Zone 6	Page 10, 12, 26	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919	\$ 0.2919
23	Tennessee	FT-A	Zone L	Zone 6	Page 10, 12, 26	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545	\$ 0.2545
24	Tennessee	FT-A	Zone 4	Zone 6	Page 10, 12, 26	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991	\$ 0.0991
25	Tennessee	FT-A	Zone 5	Zone 6	Page 10, 12, 26	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749	\$ 0.0749
26	Texas Eastern	FT-1/FTS	M3	M3	Page 10, 12, 26	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449	\$ 0.0449
27	TransCanada	FT	Parkway	E. Hereford	Page 18	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
28	Union	M12	Dawn	Parkway	Page 18	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
29	LNG Trucking		Everett, MA	LNG Plant	Negotiated	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300	\$ 1.2300

Transportation Fuel Rates

Line	Pipeline	Rate Schedule	Receipt	Delivery	Reference	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
30	Algonquin	AFT-1	N/A	N/A	Page 6	0.91%	0.95%	0.95%	0.95%	0.95%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%
31	Algonquin	AFT-1 (AB)	N/A	N/A	Page 6	0.00%	1.41%	1.41%	1.41%	1.41%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
32	Granite	FT-NN	N/A	N/A	Page 7	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
33	Iroquois	RTS-1	Zone 1	Zone 1	12 Month Avg.	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	PNGTS	FT (C2C)	N/A	N/A	12 Month Avg.	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
35	PNGTS	FT (PXP)	N/A	N/A	12 Month Avg.	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%
36	Tennessee	FT-A	Zone 0	Zone 6	Page 12	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%
37	Tennessee	FT-A	Zone L	Zone 6	Page 12	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%
38	Tennessee	FT-A	Zone 4	Zone 6	Page 12	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
39	Tennessee	FT-A	Zone 5	Zone 6	Page 12	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%	0.84%
40	Texas Eastern	FT-1/FTS	M3	M3	Page 16	1.51%	1.86%	1.86%	1.86%	1.86%	1.51%	1.51%	1.51%	1.51%	1.51%	1.51%	1.51%
41	TransCanada	FT	Parkway	E. Hereford	12 Month Avg.	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
42	Union	M12	Dawn	Parkway	Page 24	1.10%	1.10%	1.10%	1.10%	1.10%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%

Northern Utilities, Inc. Underground Storage Contract Rates November 2020 through October 2021										
Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		Page 11	\$ 0.0179	\$ 1.3094	\$ 0.0087	0.00%	\$ 0.0087	1.51%
2	Union	Storage	1	Page 28	\$ 0.0592	\$ -	\$ 0.005	0.60%	\$ 0.005	0.60%

Note 1 The demand charge for Union Storage shall be \$236,666.67 per month divided by Maximum Storage Balance of 4,000,000 Dth.
The Withdrawal Rate and Injection Rate are equal to \$0.007 CDN/GJ divided by 1.055056 (GJ/Dth conversion) times exchange rate.

**Rate Schedule AFT-1
Firm Transportation Service**

Maximum Reservation Charge:	Base-----\$/Dth ----- Tariff Rate 1/	Total Rate
AFT-1	\$8.5927	\$8.5927
AFT-1 (PSS-T)	\$8.5626	\$8.5626
AFT-1 (AFT-3)	\$8.7363	\$8.7363
Minimum Reservation Charge:	\$0.0000	\$0.0000

Maximum Commodity Charge:	Base \$/Dth Tariff Rate 1/ 2/
AFT-1	\$0.0042
AFT-1 (PSS-T)	\$0.0000
AFT-1 (AFT-3)	\$0.0000

Minimum Commodity Charge:	
AFT-1	\$0.0042
AFT-1 (PSS-T)	\$0.0000
AFT-1 (AFT-3)	\$0.0000

Maximum Reservation Charge Adjustment:	Base-----\$/Dth ----- Tariff Rate 1/	Total Rate
AFT-1	\$0.2825	\$0.2825
AFT-1 (PSS-T)	\$0.2815	\$0.2815
AFT-1 (AFT-3)	\$0.2872	\$0.2872

Minimum Reservation Charge Adjustment:	\$0.0000	\$0.0000

Maximum Authorized Overrun Commodity Charge:	Base \$/Dth Tariff Rate 1/ 2/
AFT-1	\$0.2867
AFT-1 (PSS-T)	\$0.2815
AFT-1 (AFT-3)	\$0.2872

Minimum Authorized Overrun Commodity Charge:	
AFT-1	\$0.0042
AFT-1 (PSS-T)	\$0.0000
AFT-1 (AFT-3)	\$0.0000

- 1/ The Base Tariff is the effective rate on file with the Commission, excluding adjustments approved by the Commission.
- 2/ Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions.

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Currently Effective Rates 12/01/2019

RATE SCHEDULE AFT-1

	Reservation	Commodity		Authorized Overrun		Capacity Release		FRQ	Deferral Surchage Rate	
		Max	Min	Max	Min	Vol	Res		Non Beverly	Beverly
(F-1/WS-1)	\$ 6.5734	\$0.0112	\$0.0112	\$0.2273	\$0.0112	\$0.2161			\$0.0582	\$0.0407
(F-2/F-3)	\$ 6.5734	\$0.0112	\$0.0112	\$0.2273	\$0.0112	\$0.2161			\$0.0582	\$0.0407
(F-4)	\$ 6.5734	\$0.0112	\$0.0112	\$0.2273	\$0.0112	\$0.2161			\$0.0582	\$0.0407
(STB/SS-3)	\$ 6.5734	\$0.0112	\$0.0112	\$0.2273	\$0.0112	\$0.2161			\$0.0582	\$0.0407
(FTP)	\$11.8368	\$0.0000	\$0.0000	\$0.3892	\$0.0000	\$0.3892			\$0.0582	\$0.0407
(PSS-T)	\$ 9.7854	\$0.0000	\$0.0000	\$0.3217	\$0.0000	\$0.3217			\$0.0582	\$0.0407
(AFT-2)	\$ 6.1138	\$0.0000	\$0.0000	\$0.2010	\$0.0000	\$0.2010			\$0.0582	\$0.0407
(AFT-3)	\$10.7554	\$0.0000	\$0.0000	\$0.3536	\$0.0000	\$0.3536			\$0.0582	\$0.0407
(AFT-5)	\$12.6265	\$0.0000	\$0.0000	\$0.4151	\$0.0000	\$0.4151			\$0.0582	\$0.0407
(ITP)	\$13.0110	\$0.0000	\$0.0000	\$0.4278	\$0.0000	\$0.4278			\$0.0582	\$0.0407
(X-35)	\$10.2027	\$0.0000	\$0.0000	\$0.3354	\$0.0000	\$0.3354			\$0.0582	\$0.0407
(X-39)	\$13.2089	\$0.0000	\$0.0000	\$0.4343	\$0.0000	\$0.4343			\$0.0582	\$0.0407
Incremental Surcharges										
Hubline	\$ 1.8607	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0612			\$0.0582	\$0.0407*
Secondary 1/		\$0.0612	\$0.0000						\$0.0582	\$0.0407
Tiverton	\$ 1.6424	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0540			\$0.0582	\$0.0407
Ramapo	\$ 7.5608	\$0.0000	\$0.0000	\$0.2486	\$0.0000	\$0.2486			\$0.1124	\$0.0787
AIM	\$48.5073	\$0.0069	\$0.0069	\$1.6017	\$0.0069	\$1.5948			\$0.0996	\$0.0697
Atlantic Br.	\$55.6932	\$0.0115	\$0.0115	\$1.8425	\$0.0115	\$1.8310			\$0.2006	\$0.1404

*For Deliveries off of Hubline Facilities

RATE SCHEDULE AFT-1S

	Reservation	Commodity		Authorized Overrun		Capacity Release		FRQ	Deferral Surchage Rate	
		Max	Min	Max	Min	Vol	Res		Non Beverly	Beverly
(F-1/WS-1)	\$ 2.6294	\$0.2273	\$0.0000	\$0.2273	\$0.0000	\$0.0864			\$0.0582	\$0.0407
(F-2/F-3)	\$ 2.6294	\$0.2273	\$0.0000	\$0.2273	\$0.0000	\$0.0864			\$0.0582	\$0.0407
(F-4)	\$ 2.6294	\$0.2273	\$0.0000	\$0.2273	\$0.0000	\$0.0864			\$0.0582	\$0.0407
(STB/SS-3)	\$ 2.6294	\$0.2273	\$0.0000	\$0.2273	\$0.0000	\$0.0864			\$0.0582	\$0.0407
(Hubline) 2/		\$0.0612	\$0.0000						\$0.0582	\$0.0407*

*For Deliveries off of Hubline Facilities

OTHER FIRM RATE SCHEDULES

	Reservation	Commodity		Authorized Overrun		Capacity Release		FRQ	Deferral Surchage Rate	
		Max	Min	Max	Min	Vol	Res		Non Beverly	Beverly
AFT-E	\$ 6.5734	\$0.0112	\$0.0112	\$0.2273	\$0.0112	\$0.2161			\$0.0582	\$0.0407
(Hubline) 2/		\$0.0612	\$0.0000						\$0.0582	\$0.0407*
AFT-ES	\$ 2.6294	\$0.2273	\$0.0112	\$0.2273	\$0.0112	\$0.0864			\$0.0582	\$0.0407
(Hubline) 2/		\$0.0612	\$0.0000						\$0.0582	\$0.0407*
T-1	\$ 1.6480	\$0.0039		\$0.0581					\$0.0582	\$0.0407
AFT-4	\$ 3.5211	\$0.0013		\$0.1171					\$0.0582	\$0.0407
AFT-CL:										
Canal	\$ 2.0858	\$0.0000	\$0.0000	\$0.0686	\$0.0000	\$0.0686				
Middletown	\$ 3.2764	\$0.0000	\$0.0000	\$0.1077	\$0.0000	\$0.1077				
Cleary	\$ 1.4529	\$0.0000	\$0.0000	\$0.0478	\$0.0000	\$0.0478				
Lake Road	\$ 0.6476	\$0.0000	\$0.0000	\$0.0213	\$0.0000	\$0.0213				
Brayton Pt.	\$ 1.2700	\$0.0000	\$0.0000	\$0.0418	\$0.0000	\$0.0418				
Manchester	\$ 2.4500	\$0.0000	\$0.0000	\$0.0805	\$0.0000	\$0.0805				
Bellingham	\$ 0.9714	\$0.0000	\$0.0000	\$0.0319	\$0.0000	\$0.0319				
Phelps Dodge	\$ 0.0000	\$0.0166	\$0.0000	\$0.0166	\$0.0000	\$0.0000				
Cape Cod	\$ 9.0501	\$0.0000	\$0.0000	\$0.2975	\$0.0000	\$0.2975				
Northeast Gateway	\$ 4.3449	\$0.0000	\$0.0000	\$0.1428	\$0.0000	\$0.1428				
J-2 Facility	\$ 4.6346	\$0.0000	\$0.0000	\$0.1524	\$0.0000	\$0.1524				

Kleen Energy	\$ 1.2247	\$0.0000	\$0.0000	\$0.0403	\$0.0000	\$0.0403
X-33	\$ 3.0873	\$0.0395		\$0.1410		
*For Deliveries off of Hubline Facilities						

\$0.0582 \$0.0407

INTERRUPTIBLE SERVICE

	Commodity		Authorized Overrun		FRQ Deferral Surcharge Rate	
	Max	Min	Max	Min	Non Beverly	Beverly
AIT-1	\$0.2421	\$0.0076	\$0.2421	\$0.0076	\$0.0582	\$0.0407
(Hubline 2/)	\$0.0612	\$0.0000			\$0.0582	\$0.0407*
AIT-2						
Brayton Pt.	\$0.0418	\$0.0000	\$0.0418	\$0.0000		
Manchester	\$0.0805	\$0.0000	\$0.0805	\$0.0000		
Canal	\$0.0686	\$0.0000	\$0.0686	\$0.0000		
Cape Cod	\$0.2975	\$0.0000	\$0.2975	\$0.0000		
Northeast Gateway	\$0.1428	\$0.0000	\$0.1428	\$0.0000		
J-2 Facility	\$0.1524	\$0.0000	\$0.1524	\$0.0000		
Kleen Energy	\$0.0403	\$0.0000	\$0.0403	\$0.0000		
PAL	\$0.2421	\$0.0000	\$0.0000	\$0.0000	\$0.0582	\$0.0407

TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	\$5.3900	\$0.0000

Rates are per MMBTU. Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions.

FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
<u>System Services 1/</u>		
Winter	Dec 1 - Mar 31	0.95%
Spring, Summer and Fall	Apr 1 - Nov 30	0.91%
<u>Incremental Ramapo Service 1/</u>		
Winter	Dec 1 - Mar 31	2.01%
Spring, Summer and Fall	Apr 1 - Nov 30	1.55%
<u>Incremental AIM Service 1/</u>		
Winter	Dec 1 - Mar 31	3.94%
Spring, Summer and Fall	Apr 1 - Nov 30	2.29%
<u>Incremental Atlantic Bridge Service 1/</u>		
Winter	Dec 1 - Mar 31	1.41%
Spring, Summer and Fall	Apr 1 - Nov 30	0.00%

1/ For all receipt points other than Beverly, Meter No. 00215

System Services - Beverly Receipts/Non-Hubline Deliveries

Winter	Dec 1 - Mar 31	0.69%
Spring, Summer and Fall	Apr 1 - Nov 30	0.65%

4.2 Rate Schedule FT-NN
Firm Transportation Service
Currently Effective Rates

	\$/Dth	
	Base Tariff Rate	ACA Adj.
Reservation Charge:		
Maximum	\$4.4212	N/A
Minimum	\$0.0000	N/A
Commodity Charge:		
Maximum	\$0.0000	a/
Minimum	\$0.0000	a/
Authorized Overrun Commodity Charge:		
Maximum	\$0.1453	a/
Minimum	\$0.0000	a/
Fuel and Losses		
Percentage	0.35%	N/A
Volumetric Reservation Charge		
Maximum	\$0.1453	a/
Minimum	\$0.0000	a/

a/ The ACA Adj. Surcharge is revised annually and posted on the FERC website at the web address <http://www.ferc.gov> on the Annual Charges page of the Natural Gas Section. The ACA Adj. Surcharge is incorporated by reference in the Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Section 6.17 of the General Terms and Conditions.

Iroquois Gas Transmission System, L.P.
FERC Gas Tariff
Second Revised Volume No. 1

Fourth Revised Sheet No. 4
Superseding
Third Revised Sheet No. 4

----- NON-EASTCHESTER RATES (All in \$ Per Dth) 1/ -----

	Minimum	RP16-301 Rates 2/ Maximum			RP19-445 Rates Maximum	
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018	Effective 3/1/2019	Effective 4/1/2020
RTS DEMAND (Monthly):						
Zone 1	\$0.0000	\$ 6.1928	\$ 5.9982	\$ 5.5997	\$5.4177	\$5.2357
Zone 2	\$0.0000	\$ 5.3381	\$ 5.1678	\$ 4.7998	\$4.6438	\$4.4878
Inter-Zone	\$0.0000	\$10.4755	\$ 9.8672	\$ 8.8026	\$8.5165	\$8.2304
RTS COMMODITY (Daily):						
Zone 1	\$0.0034	\$ 0.0034	\$ 0.0034	\$ 0.0034	\$0.0034	\$0.0034
Zone 2	\$0.0022	\$ 0.0022	\$ 0.0022	\$ 0.0022	\$0.0022	\$0.0022
Inter-Zone	\$0.0056	\$ 0.0056	\$ 0.0056	\$ 0.0056	\$0.0056	\$0.0056
ITS COMMODITY (Daily):						
Zone 1	\$0.0034	\$ 0.2070	\$ 0.2006	\$ 0.1875	\$0.1815	\$0.1755
Zone 2	\$0.0022	\$ 0.1777	\$ 0.1721	\$ 0.1600	\$0.1549	\$0.1497
Inter-Zone	\$0.0056	\$ 0.3500	\$ 0.3300	\$ 0.2950	\$0.2856	\$0.2762
VOLUMETRIC CAPACITY RELEASE (Daily) 3/:						
Zone 1	\$0.0000	\$ 0.2036	\$ 0.1972	\$ 0.1841	\$0.1781	\$0.1721
Zone 2	\$0.0000	\$ 0.1755	\$ 0.1699	\$ 0.1578	\$0.1527	\$0.1475
Inter-Zone	\$0.0000	\$ 0.3444	\$ 0.3244	\$ 0.2894	\$0.2800	\$0.2706

**SEE SHEET NOS. 4A, 4B, AND 4C FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

Issued On: June 12, 2019

Effective On: July 1, 2019

Exhibit B to Precedent Agreement

NEGOTIATED RATES

Negotiated Rate: \$0.60/Dth/Day

Additional Terms: Shipper shall have the right to deliver, on a secondary basis, to the following meters, at the Negotiated Rate of \$0.60/Dth/day. Delivery to all other secondary delivery points on this Negotiated Rate contract shall be priced at the Maximum Recourse Rate.

Meter #	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-0725	Eliot	Granite State
05-0750	Eliot CNG	XPress Natural Gas
02-0775	Newington	Essential Power
02-0900	Newington	Eversource
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1025	Haverhill	National Grid
05-1050	Methuen	M&NE
05-1150	Dracut	Tennessee Gas Pipeline

NEGOTIATED RATE SURCHARGE MECHANISM:

PNGTS may file a limited Section 4 rate proceeding to add a surcharge to Shipper's negotiated rate, taking into account Shipper's contractual obligation(s) relative to the total contractual obligations of all classes of transportation agreements, to reflect a cost of service impact of certain "Eligible Costs," defined as costs resulting from mandated compliance with new or revised requirements, regulations or legislation, that becomes effective on or after November 1, 2014, addressing (a) government-mandated environmental compliance obligations, e.g., climate change and greenhouse gas emissions, (b) compliance with the required use of best available control technology for emissions as mandated by the Environmental Protection Agency (or successor thereto), (c) Commission-mandated generic pipeline initiatives implemented on an industry-wide basis, including but not limited to the Commission's proposed policy regarding the modernization of natural gas facilities in Docket No. PL15-1-000 and (d) additional pipeline safety requirements issued by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (or successor thereto) as a result of either new

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 Appendix A-2
 Page 1 of 2

Tennessee Gas Pipeline Company, L.L.C.
Settlement Rates effective November 1, 2020 - Base Reservation and Commodity
 10.5 % Rate Reduction from the Appendix A-0 Rates

 Line
 No.
General System Transportation Services**Rate Schedule FT-A, FT-G, NET, NET-284****Reservation**

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
1	Zone 0	\$4.8571		\$10.1498	\$13.6529	\$13.8945	\$15.2673	\$16.2055	\$20.3323
2	Zone L		\$4.3119						
3	Zone 1	\$7.3119		\$7.0090	\$9.3276	\$13.2135	\$13.0132	\$14.6759	\$18.0462
4	Zone 2	\$13.6530		\$9.2716	\$4.8222	\$4.5078	\$5.7679	\$7.9331	\$10.2407
5	Zone 3	\$13.8945		\$7.3440	\$4.8611	\$3.5070	\$5.3870	\$9.7428	\$11.2581
6	Zone 4	\$17.6413		\$16.2638	\$6.1979	\$9.4190	\$4.6105	\$4.9861	\$7.1232
7	Zone 5	\$21.0347		\$14.7807	\$6.5015	\$7.8669	\$5.1218	\$4.8044	\$6.2544
8	Zone 6	\$24.3333		\$16.9768	\$11.6840	\$12.8717	\$9.0920	\$4.7831	\$4.1405

Commodity

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
9	Zone 0	\$0.0032		\$0.0115	\$0.0177	\$0.0219	\$0.2339	\$0.2232	\$0.2656
10	Zone L		\$0.0012						
11	Zone 1	\$0.0042		\$0.0081	\$0.0147	\$0.0179	\$0.1989	\$0.2028	\$0.2315
12	Zone 2	\$0.0167		\$0.0087	\$0.0012	\$0.0028	\$0.0644	\$0.1032	\$0.1144
13	Zone 3	\$0.0207		\$0.0169	\$0.0026	\$0.0002	\$0.0860	\$0.1190	\$0.1300
14	Zone 4	\$0.0250		\$0.0205	\$0.0087	\$0.0105	\$0.0398	\$0.0563	\$0.0912
15	Zone 5	\$0.0284		\$0.0256	\$0.0100	\$0.0118	\$0.0560	\$0.0555	\$0.0689
16	Zone 6	\$0.0346		\$0.0300	\$0.0143	\$0.0163	\$0.0862	\$0.0467	\$0.0284

Min. Commodity**Delivery Zone**

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
17	Zone 0	\$0.0032		\$0.0115	\$0.0177	\$0.0219	\$0.0250	\$0.0284	\$0.0346
18	Zone L		\$0.0012						
19	Zone 1	\$0.0042		\$0.0081	\$0.0147	\$0.0179	\$0.0210	\$0.0256	\$0.0300
20	Zone 2	\$0.0167		\$0.0087	\$0.0012	\$0.0028	\$0.0056	\$0.0100	\$0.0143
21	Zone 3	\$0.0207		\$0.0169	\$0.0026	\$0.0002	\$0.0081	\$0.0118	\$0.0163
22	Zone 4	\$0.0250		\$0.0205	\$0.0087	\$0.0105	\$0.0028	\$0.0046	\$0.0092
23	Zone 5	\$0.0284		\$0.0256	\$0.0100	\$0.0118	\$0.0046	\$0.0046	\$0.0066
24	Zone 6	\$0.0346		\$0.0300	\$0.0143	\$0.0163	\$0.0086	\$0.0041	\$0.0020

Rate Schedule FT-GS

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
25	Zone 0	\$0.2689		\$0.5659	\$0.7632	\$0.7799	\$1.0705	\$1.1111	\$1.3797
26	Zone L		\$0.2373						
27	Zone 1	\$0.4042		\$0.3909	\$0.5236	\$0.7393	\$0.9119	\$1.0070	\$1.2203
28	Zone 2	\$0.7624		\$0.5154	\$0.2653	\$0.2494	\$0.3804	\$0.5380	\$0.6755
29	Zone 3	\$0.7789		\$0.4168	\$0.2686	\$0.1923	\$0.3813	\$0.6529	\$0.7468
30	Zone 4	\$0.9879		\$0.9086	\$0.3471	\$0.5250	\$0.2924	\$0.3294	\$0.4816
31	Zone 5	\$1.1767		\$0.8317	\$0.3648	\$0.4411	\$0.3367	\$0.3189	\$0.4116
32	Zone 6	\$1.3628		\$0.9557	\$0.6524	\$0.7191	\$0.5844	\$0.3087	\$0.2553

Rate Schedule IT, PTR and FT Overrun

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
33	Zone 0	\$0.1624		\$0.3435	\$0.4639	\$0.4754	\$0.7358	\$0.7559	\$0.9341
34	Zone L		\$0.1428						
35	Zone 1	\$0.2440		\$0.2373	\$0.3192	\$0.4496	\$0.6267	\$0.6853	\$0.8247
36	Zone 2	\$0.4631		\$0.3122	\$0.1596	\$0.1505	\$0.2540	\$0.3641	\$0.4511
37	Zone 3	\$0.4744		\$0.2559	\$0.1621	\$0.1155	\$0.2631	\$0.4394	\$0.5000
38	Zone 4	\$0.6012		\$0.5521	\$0.2111	\$0.3186	\$0.1914	\$0.2203	\$0.3254
39	Zone 5	\$0.7156		\$0.5077	\$0.2221	\$0.2687	\$0.2245	\$0.2135	\$0.2747
40	Zone 6	\$0.8294		\$0.5836	\$0.3963	\$0.4370	\$0.3851	\$0.2039	\$0.1645

Docket No. RP19-_____
 Appendix A-2
 Page 2 of 2

Tennessee Gas Pipeline Company, L.L.C.
Settlement Rates effective November 1, 2020 - Base Reservation and Commodity
 10.5 % Rate Reduction from the Appendix A-0 Rates

 Line
 No.
Rate Schedule FT-BH**Reservation**

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
1	Zone 0	\$2.4285							
2	Zone L		\$2.1560						
3	Zone 1	\$3.6559		\$3.5045					
4	Zone 2	\$6.8265		\$4.6357	\$2.4110				
5	Zone 3	\$6.9473		\$3.6721	\$2.4306	\$1.7535			
6	Zone 4	\$8.8207		\$8.1319	\$3.0989	\$4.7096	\$2.3052		
7	Zone 5	\$10.5173		\$7.3904	\$3.2507	\$3.9334	\$2.5609	\$2.4022	
8	Zone 6	\$12.1665		\$8.4884	\$5.8421	\$6.4358	\$4.5461	\$2.3916	\$2.0703

Commodity

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
9	Zone 0	\$0.0427							
10	Zone L		\$0.0365						
11	Zone 1	\$0.0637		\$0.0645					
12	Zone 2	\$0.1265		\$0.0836	\$0.0406				
13	Zone 3	\$0.1318		\$0.0747	\$0.0422	\$0.0290			
14	Zone 4	\$0.1663		\$0.1511	\$0.0584	\$0.0863	\$0.0777		
15	Zone 5	\$0.1971		\$0.1433	\$0.0619	\$0.0746	\$0.0981	\$0.0950	
16	Zone 6	\$0.2295		\$0.1650	\$0.1081	\$0.1198	\$0.1609	\$0.0859	\$0.0624

Rate Schedule FT-A EDS/ERS (Extended Delivery/Receipt)**Reservation**

		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
17	Zone 0			\$0.3337	\$0.4488	\$0.4568	\$0.5019	\$0.5328	\$0.6685
18	Zone L								
19	Zone 1	\$0.2404			\$0.3067	\$0.4344	\$0.4278	\$0.4825	\$0.5932
20	Zone 2	\$0.4488		\$0.3048		\$0.1482	\$0.1897	\$0.2609	\$0.3367
21	Zone 3	\$0.4568		\$0.2415	\$0.1598		\$0.1771	\$0.3204	\$0.3701
22	Zone 4	\$0.5800		\$0.5348	\$0.2037	\$0.3097		\$0.1640	\$0.2341
23	Zone 5	\$0.6915		\$0.4860	\$0.2136	\$0.2587	\$0.1684		\$0.2057
24	Zone 6	\$0.8000		\$0.5581	\$0.3841	\$0.4232	\$0.2988	\$0.1573	

Rate Schedule PAL**Commodity**

		Commodity	Overrun
25	PAL (Daily)	\$0.3478	\$0.3478
26	PAL (Term)	\$0.3478	\$0.3478

Incremental Transportation Services

		Reservation	Commodity	Overrun	Min. Comm.
27	Stagecoach - CP00-65	FT-A	\$3.2691	\$0.0000	\$0.1075
28	ConneXion NY/NJ - CP05-355	FT-A	\$9.1876	\$0.0000	\$0.3021
29	Concord - CP08-65	FT-A	\$10.8352	\$0.0000	\$0.3562
30	Tewksbury - CP04-60	FT-IL	\$5.4734	\$0.0000	\$0.1800
31	300 Line Market - CP09-444	FT-A	\$22.9057	\$0.0000	\$0.7531
32	NSD - CP11-30	FT-A	\$5.5453	\$0.0000	\$0.1823
33	Northampton - CP11-36	FT-A	\$24.7109	\$0.0000	\$0.8124
34	NEUP - CP11-161	FT-A	\$7.9158	\$0.0000	\$0.2603
35	Niagara Expansion - CP14-88	FT-A	\$8.9155	\$0.0000	\$0.2931
36	Connecticut Expansion - CP14-529	FT-A	\$17.3352	\$0.0689	\$0.6389
37	Broad Run Expansion Project - CP15-77	FT-A	\$26.7737	\$0.0336	\$0.9103
38	Susquehanna West Project - CP15-148	FT-A	\$15.3219	\$0.0398	\$0.5435
39	Triad Expansion Project - CP 15-520	FT-A	\$6.7386	\$0.0398	\$0.2613
40	Orion Project - CP 16-4	FT-A	\$14.7861	\$0.0398	\$0.5259

Storage Services

		Deliverability	Space	Inj/With	Overrun
41	FS - PA [1]	\$1.7824	\$0.0181	\$0.0073	\$0.2139
42	FS - MA	\$1.3094	\$0.0179	\$0.0087	\$0.1572
43	IS - PA		\$0.0893	\$0.0073	
44	IS - MA		\$0.0720	\$0.0087	

Notes:

[1] The Rate Schedule FS-PA Rates set forth herein do not include the impact of the Bear Creek Proceeding, if any.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Seventeenth Revised Sheet No. 15
Superseding
Sixteenth Revised Sheet No. 15

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base
Commodity Rates

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0032		\$0.0115	\$0.0177	\$0.0219	\$0.2391	\$0.2282	\$0.2716
L		\$0.0012						
1	\$0.0042		\$0.0081	\$0.0147	\$0.0179	\$0.2033	\$0.2073	\$0.2367
2	\$0.0167		\$0.0087	\$0.0012	\$0.0028	\$0.0658	\$0.1055	\$0.1169
3	\$0.0207		\$0.0169	\$0.0026	\$0.0002	\$0.0879	\$0.1217	\$0.1329
4	\$0.0250		\$0.0205	\$0.0087	\$0.0105	\$0.0407	\$0.0576	\$0.0932
5	\$0.0284		\$0.0256	\$0.0100	\$0.0118	\$0.0573	\$0.0567	\$0.0705
6	\$0.0346		\$0.0300	\$0.0143	\$0.0163	\$0.0881	\$0.0478	\$0.0290

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0032		\$0.0115	\$0.0177	\$0.0219	\$0.0250	\$0.0284	\$0.0346
L		\$0.0012						
1	\$0.0042		\$0.0081	\$0.0147	\$0.0179	\$0.0210	\$0.0256	\$0.0300
2	\$0.0167		\$0.0087	\$0.0012	\$0.0028	\$0.0056	\$0.0100	\$0.0143
3	\$0.0207		\$0.0169	\$0.0026	\$0.0002	\$0.0081	\$0.0118	\$0.0163
4	\$0.0250		\$0.0205	\$0.0087	\$0.0105	\$0.0028	\$0.0046	\$0.0092
5	\$0.0284		\$0.0256	\$0.0100	\$0.0118	\$0.0046	\$0.0046	\$0.0066
6	\$0.0346		\$0.0300	\$0.0143	\$0.0163	\$0.0086	\$0.0041	\$0.0020

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.0039		\$0.0122	\$0.0184	\$0.0226	\$0.2398	\$0.2289	\$0.2723
L		\$0.0019						
1	\$0.0049		\$0.0088	\$0.0154	\$0.0186	\$0.2040	\$0.2080	\$0.2374
2	\$0.0174		\$0.0094	\$0.0019	\$0.0035	\$0.0665	\$0.1062	\$0.1176
3	\$0.0214		\$0.0176	\$0.0033	\$0.0009	\$0.0886	\$0.1224	\$0.1336
4	\$0.0257		\$0.0212	\$0.0094	\$0.0112	\$0.0414	\$0.0583	\$0.0939
5	\$0.0291		\$0.0263	\$0.0107	\$0.0125	\$0.0580	\$0.0574	\$0.0712
6	\$0.0353		\$0.0307	\$0.0150	\$0.0170	\$0.0888	\$0.0485	\$0.0297

Notes:

- 1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at <http://www.ferc.gov> on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
- 2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
- 3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of **\$0.0007**.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Fifteenth Revised Sheet No. 14
Superseding
Fourteenth Revised Sheet No. 14

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base
Reservation Rates

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$4.9656		\$10.3766	\$13.9580	\$14.2050	\$15.6084	\$16.5676	\$20.7866
L		\$4.4083						
1	\$7.4753		\$7.1656	\$9.5360	\$13.5088	\$13.3040	\$15.0039	\$18.4494
2	\$13.9581		\$9.4788	\$4.9299	\$4.6086	\$5.8968	\$8.1104	\$10.4695
3	\$14.2050		\$7.5081	\$4.9697	\$3.5853	\$5.5074	\$9.9605	\$11.5097
4	\$18.0356		\$16.6272	\$6.3364	\$9.6295	\$4.7135	\$5.0976	\$7.2824
5	\$21.5048		\$15.1110	\$6.6468	\$8.0427	\$5.2363	\$4.9117	\$6.3942
6	\$24.8770		\$17.3562	\$11.9451	\$13.1593	\$9.2952	\$4.8900	\$4.2331

Daily Base
Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$0.1633		\$0.3411	\$0.4589	\$0.4670	\$0.5132	\$0.5447	\$0.6834
L		\$0.1449						
1	\$0.2458		\$0.2356	\$0.3135	\$0.4441	\$0.4374	\$0.4933	\$0.6066
2	\$0.4589		\$0.3116	\$0.1621	\$0.1515	\$0.1939	\$0.2666	\$0.3442
3	\$0.4670		\$0.2468	\$0.1634	\$0.1179	\$0.1811	\$0.3275	\$0.3784
4	\$0.5930		\$0.5466	\$0.2083	\$0.3166	\$0.1550	\$0.1676	\$0.2394
5	\$0.7070		\$0.4968	\$0.2185	\$0.2644	\$0.1722	\$0.1615	\$0.2102
6	\$0.8179		\$0.5706	\$0.3927	\$0.4326	\$0.3056	\$0.1608	\$0.1392

Maximum Reservation
Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE							
	0	L	1	2	3	4	5	6
0	\$4.9837		\$10.3947	\$13.9761	\$14.2231	\$15.6265	\$16.5857	\$20.8047
L		\$4.4264						
1	\$7.4934		\$7.1837	\$9.5541	\$13.5269	\$13.3221	\$15.0220	\$18.4675
2	\$13.9762		\$9.4969	\$4.9480	\$4.6267	\$5.9149	\$8.1285	\$10.4876
3	\$14.2231		\$7.5262	\$4.9878	\$3.6034	\$5.5255	\$9.9786	\$11.5278
4	\$18.0537		\$16.6453	\$6.3545	\$9.6476	\$4.7316	\$5.1157	\$7.3005
5	\$21.5229		\$15.1291	\$6.6649	\$8.0608	\$5.2544	\$4.9298	\$6.4123
6	\$24.8951		\$17.3743	\$11.9632	\$13.1774	\$9.3133	\$4.9081	\$4.2512

Notes:

- 1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
- 2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of \$0.0000.
- 3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of **\$0.0181**.

TEXAS EASTERN TRANSMISSION, LP

SUMMARY OF RATES

PROPOSED INTERIM ASA RATES 06/01/2020

RESERVATION CHARGES 1/

Path	CDS	FT-1	SCT
STX-AAB	7.3830	7.1600	2.9530
WLA-AAB	4.0630	3.8400	1.6250
ELA-AAB	2.8650	2.6420	1.1460
ETX-AAB	2.9470	2.7240	1.1780
STX-STX	5.2410	5.0180	2.0870
STX-WLA	6.4390	6.2160	2.5670
STX-ELA	7.4050	7.1820	2.9530
STX-ETX	7.4050	7.1820	2.9530
WLA-WLA	3.1190	2.8960	1.2390
WLA-ELA	4.0850	3.8620	1.6250
WLA-ETX	4.0820	3.8590	1.6240
ELA-ELA	2.8870	2.6640	1.1460
ETX-ETX	2.9690	2.7460	1.1780
ETX-ELA	2.8870	2.6640	1.1460
M1-M1	3.4740	3.2510	1.3790
M1-M2	7.2090	6.9860	2.8680
M1-M3	12.6080	12.3850	5.0200
M2-M2	5.6560	5.4330	2.2480
M2-M3	11.0530	10.8300	4.4000
M3-M3	7.3190	7.0960	2.9110

Other Rate Schedules 1/

FTS (M3 - M3)	5.9370
FTS-2 (M2 - M2)	8.6870
FTS-2 (M2 - M3)	8.9610
FTS-2 (M3 - M3)	8.7600
FTS-4 (M3 - M3)	7.6980
FTS-5 (M2 - M2)	6.2060
FTS-5 (M2 - M3)	6.4800
FTS-5 (M3 - M3)	6.2790
FTS-7 (M2 - M2)	7.6490
FTS-7 (M2 - M3)	7.9230
FTS-7 (M3 - M3)	7.7220
FTS-8 (M2 - M2)	7.5050
FTS-8 (M2 - M3)	7.7790
FTS-8 (M3 - M3)	7.5780
X-127 (M2 - M3)	8.7700
X-127 (M3 - M3)	8.5690
X-129 (M3 - M3)	7.5820
X-130 (M3 - M3)	7.5820
X-135 (M2 - M2)	3.9190
X-135 (M2 - M3)	4.1930
X-135 (M3 - M3)	3.9920
X-137 (M2 - M2)	5.7240
X-137 (M2 - M3)	5.9980
X-137 (M3 - M3)	5.7970

SCT Demand Charges

Access Area	0.0270
M1-M1	0.0330
M1-M2	0.0490
M1-M3	0.0730

1/ The Total Adjusted Rate includes the applicable base rate and tracked system rate adjustments. The currently effective system rate adjustments are illustrated on the translation table on page 5 of 5.

USAGE CHARGES

CDS & FT-1 Usage-1

Forward Haul Path		STX	WLA	ELA	ETX	M1	M2	M3
from	STX	0.0124	0.0140	0.0204	0.0204	0.0360	0.0641	0.1050
from	WLA	0.0140	0.0070	0.0142	0.0142	0.0298	0.0579	0.0988
from	ELA	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from	ETX	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from	M1	0.0360	0.0298	0.0277	0.0277	0.0156	0.0437	0.0846
from	M2	0.0641	0.0579	0.0558	0.0558	0.0437	0.0320	0.0718
from	M3	0.1050	0.0988	0.0967	0.0967	0.0846	0.0718	0.0438
Back Haul Path		STX	WLA	ELA	ETX	M1	M2	M3
from	STX	0.0083						
from	WLA		0.0042					
from	ELA			0.0081				
from	ETX				0.0081			
from	M1				0.0244	0.0123		
from	M2				0.0496	0.0375	0.0270	
from	M3						0.0624	0.0373

SCT Usage-1

Forward Haul Path		STX	WLA	ELA	ETX	M1	M2	M3
from	STX	0.1767	0.2176	0.2558	0.2558	0.3775	0.5279	0.7456
from	WLA	0.2176	0.1015	0.1405	0.1404	0.2621	0.4125	0.6303
from	ELA	0.2558	0.1405	0.0990	0.0990	0.2207	0.3709	0.5887
from	ETX	0.2558	0.1404	0.0990	0.1017	0.2234	0.3736	0.5914
from	M1	0.3775	0.2621	0.2207	0.2234	0.1217	0.2721	0.4898
from	M2	0.5279	0.4125	0.3709	0.3736	0.2721	0.2094	0.4261
from	M3	0.7456	0.6303	0.5887	0.5914	0.4898	0.4261	0.2757
Back Haul Path		STX	WLA	ELA	ETX	M1	M2	M3
from	STX	0.1726						
from	WLA		0.0987					
from	ELA			0.0950				
from	ETX				0.0977			
from	M1				0.2201	0.1184		
from	M2				0.3674	0.2659	0.2044	
from	M3						0.4167	0.2692

IT-1 Usage-1

Forward Haul Path		STX	WLA	ELA	ETX	M1	M2	M3
from	STX	0.1774	0.2183	0.2565	0.2565	0.3791	0.5298	0.7482
from	WLA	0.2183	0.1022	0.1412	0.1411	0.2638	0.4145	0.6329
from	ELA	0.2565	0.1412	0.0996	0.0996	0.2222	0.3729	0.5913
from	ETX	0.2565	0.1411	0.0996	0.1023	0.2249	0.3756	0.5940
from	M1	0.3791	0.2638	0.2222	0.2249	0.1226	0.2733	0.4918
from	M2	0.5298	0.4145	0.3729	0.3756	0.2733	0.2106	0.4280
from	M3	0.7482	0.6329	0.5913	0.5940	0.4918	0.4280	0.2771
Back Haul Path		STX	WLA	ELA	ETX	M1	M2	M3
from	STX	0.1733						
from	WLA		0.0994					
from	ELA			0.0956				
from	ETX				0.0983			
from	M1				0.2216	0.1193		
from	M2				0.3694	0.2671	0.2056	
from	M3						0.4186	0.2706

APPLICABLE SHRINKAGE PERCENTAGES - RATES EFFECTIVE 6/1/2020

ASA Transportation Rate Schedules

December 1 through March 31 (Winter Rate) for Transportation Service

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.91%	0.98%	1.38%	1.38%	2.39%	3.21%	4.38%
from WLA	0.98%	0.68%	1.10%	1.10%	2.11%	2.93%	4.10%
from ELA	1.38%	1.10%	1.19%	1.19%	2.20%	3.02%	4.19%
from ETX	1.38%	1.10%	1.19%	1.19%	2.20%	3.02%	4.19%
from M1	2.39%	2.11%	2.20%	2.20%	1.01%	1.83%	3.01%
from M2	3.21%	2.93%	3.02%	3.02%	1.83%	1.49%	2.67%
from M3	4.38%	4.10%	4.19%	4.19%	3.01%	2.67%	1.86%

December 1 through March 31 (Winter Rate) for Transportation Service with Partial Backhaul Paths

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.00%						
from WLA		0.00%					
from ELA			0.00%				
from ETX				1.19%			
from M1				1.19%	0.00%		
from M2				1.19%	0.00%	0.00%	
from M3						0.00%	0.00%

April 1 through November 30 (Non-Winter Rate) for Transportation Service

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.89%	0.94%	1.22%	1.22%	2.18%	2.71%	3.47%
from WLA	0.94%	0.73%	1.03%	1.03%	1.99%	2.52%	3.28%
from ELA	1.22%	1.03%	1.07%	1.07%	2.03%	2.56%	3.32%
from ETX	1.22%	1.03%	1.07%	1.07%	2.03%	2.56%	3.32%
from M1	2.18%	1.99%	2.03%	2.03%	0.96%	1.49%	2.25%
from M2	2.71%	2.52%	2.56%	2.56%	1.49%	1.27%	2.04%
from M3	3.47%	3.28%	3.32%	3.32%	2.25%	2.04%	1.51%

April 1 through November 30 (Non-Winter Rate) for Transportation Service

	STX	WLA	ELA	ETX	M1	M2	M3
from STX	0.00%						
from WLA		0.00%					
from ELA			0.00%				
from ETX				1.07%			
from M1				1.07%	0.00%		
from M2				1.07%	0.00%	0.00%	
from M3						0.00%	0.00%

Non-ASA Rate Schedules

FTS	1.29%	FTS-7 (M3)	2.00%
FTS-2	0.00%	FTS-8 (M1,M2)	0.00%
FTS-4 Leidy		FTS-8 (M3)	1.50%
(11/15 - 3/31)	4.89%	X-127	0.00%
(4/1 - 11/14)	1.00%	X-129	0.00%
FTS-4 Chambersburg	0.00%	X-130	0.00%
FTS-5	0.00%	X-135	0.00%
FTS-7 (M1,M2)	0.00%	X-137	1.30%

ASA Storage Rate Schedules 12/01-3/31 4/01-11/30

Withdrawl (SS,SS-1,X-28)	1.81%	1.67%
Withdrawl (FSS,ISS-1)	0.54%	0.54%
Injections	0.54%	0.54%
Inventory Level	0.04%	0.04%

SURCHARGES

ACA Commodity Surcharge to applicable customers, pursuant to section 15.5 of the General Terms and Conditions

The Summary of Rates serves as a handy reference and does not replace Texas Eastern's Tariff.

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Canadian Transportation Rates

Line	Item	Units	Currently Approved Tolls	Reference
1	Union Parkway Belt to East Hereford on TCPL			
2	Demand Toll	\$CAD / GJ	\$ 20.86766	Page 18
3	Delivery Pressure Demand Toll	\$CAD / GJ	\$ 0.67038	Page 17
4	Abandonment Surcharge	\$CAD / GJ	\$ 1.62212	Page 17
5	Total Demand Toll	\$CAD / GJ	\$23.16016	Line 2 plus Line 3
6	\$CAD to \$US	Ratio	0.7690	Page 20
7	Total Demand Toll	\$US / GJ	\$ 17.8102	Line 4 times Line 5
8	GJ per Dth	Ratio	1.055056	
9	Total Demand Toll	\$US / Dth	\$ 18.7908	Line 6 divided by Line 7
10				
11	Dawn to Parkway on Union Pipeline			
12	Total Demand Toll	\$CAD / GJ	\$ 3.7160	Page 19
13	\$CAD to \$US	Ratio	0.7690	Page 20
14	Total Demand Toll	\$US / GJ	\$ 2.8576	Line 13 times Line 14
15	GJ per Dth	Ratio	1.055056	
16	Total Demand Toll	\$US / Dth	\$ 3.0149	Line 15 divided by Line 16
17	Dawn to Parkway on Union Pipeline - Commodity			
18				
19	Total Demand Toll	\$CAD / GJ	\$ 0.0060	Page 19
20	\$CAD to \$US	Ratio	0.7690	Page 20
21	Total Demand Toll	\$US / GJ	\$ 0.0046	Line 19 times Line 20
22	GJ per Dth	Ratio	1.055056	
23	Total Demand Toll	\$US / Dth	\$ 0.0049	Line 21 divided by Line 22

2018 Interim Mainline Tolls

Enhanced Market Balancing Service

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)	Abandonment Surcharge (\$/GJ/Month)	Daily Equivalent Abandonment Surcharge (\$/GJ)
	(a)	(b)	(c)	(d)	(e)
1	Union Parkway Belt to Union EDA	11.32565	0.3724	0.65092	0.0214

Delivery Pressure

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
2	Average Delivery Pressure Toll	0.67038	0.0220

Note: Delivery Pressure toll applies to the following locations: Emerson 1, Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford.
 The Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, STFT and SSS.

Union Dawn Receipt Point Surcharge

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
3	Union Dawn Receipt Point Surcharge	0.14587	0.0048

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll (\$/GJ/Month)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
4	SNB Toll	3.43648	0.1130

Note: This SNB Toll is a representative toll for the Eastern Region.

Energy Deficient Gas Allowance (EDGA) Service

Line No.	Particulars	Capacity Charge (\$/GJ/D)
	(a)	(b)
5	Western Section	1.4886
6	Eastern Section	0.3640

Note: The EDGA Service capacity charge for the Western Section is the effective Empress to North Bay Junction FT Toll and the capacity charge for the Eastern Section is the effective Parkway to North Bay Junction FT Toll.
 The EDGA Service fuel charge for the Western Section includes the effective Empress to North Bay Junction monthly fuel ratio and the fuel charge for the Eastern Section includes the effective Parkway to North Bay Junction monthly fuel ratio.

Line No.	Receipt Point	Delivery Point	FT Toll (\$/GJ/Month)	Daily Equivalent FT for IT / STFT (\$/GJ)	Abandonment Surcharge (\$/GJ/Month)	Daily Equivalent Abandonment Surcharge (\$/GJ)
1	Union NDA	Enbridge CDA	-	0.3109	-	0.0265
2	Union NDA	Enbridge Parkway CDA	-	0.3140	-	0.0268
3	Union NDA	Enbridge EDA	-	0.3374	-	0.0294
4	Union NDA	KPUC EDA	-	0.3974	-	0.0359
5	Union NDA	Energir EDA	-	0.4369	-	0.0401
6	Union NDA	Enbridge SWDA	-	0.4158	-	0.0379
7	Union NDA	Union SWDA	-	0.4174	-	0.0380
8	Union NDA	Chippawa	-	0.3746	-	0.0334
9	Union NDA	Cornwall	-	0.3613	-	0.0319
10	Union NDA	East Hereford	-	0.5211	-	0.0493
11	Union NDA	Emerson 1	-	0.7626	-	0.0762
12	Union NDA	Emerson 2	-	0.7626	-	0.0762
13	Union NDA	Iroquois	-	0.3464	-	0.0303
14	Union NDA	Kirkwall	-	0.3312	-	0.0287
15	Union NDA	Napierville	-	0.4302	-	0.0394
16	Union NDA	Niagara Falls	-	0.3736	-	0.0333
17	Union NDA	North Bay Junction	-	0.1518	-	0.0094
18	Union NDA	Philipsburg	-	0.4380	-	0.0403
19	Union NDA	Spruce	-	0.6995	-	0.0693
20	Union NDA	St. Clair	-	0.4228	-	0.0390
21	Union NDA	Welwyn	-	0.8732	-	0.0883
22	Union NDA	Dawn Export	-	0.4158	-	0.0379
23	Union Parkway Belt	Empress	44.68817	1.4692	4.22944	0.1391
24	Union Parkway Belt	TransGas SSDA	38.24166	1.2573	3.58765	0.1180
25	Union Parkway Belt	Centram SSDA	35.60058	1.1704	3.32454	0.1093
26	Union Parkway Belt	Centram MDA	31.60535	1.0391	2.92669	0.0962
27	Union Parkway Belt	Centrat MDA	31.29480	1.0289	2.89567	0.0952
28	Union Parkway Belt	Union WDA	24.40938	0.8025	2.21008	0.0727
29	Union Parkway Belt	Nipigon WDA	21.58275	0.7096	1.92872	0.0634
30	Union Parkway Belt	Union CDA	10.40311	0.3420	0.81547	0.0268
31	Union Parkway Belt	Calstock NDA	16.66773	0.5480	1.43932	0.0473
32	Union Parkway Belt	Tunis NDA	12.79873	0.4208	1.05424	0.0347
33	Union Parkway Belt	Energir NDA	9.92283	0.3262	0.76772	0.0252
34	Union Parkway Belt	Union SSMDA	14.89778	0.4898	1.26320	0.0415
35	Union Parkway Belt	Union NCDA	5.21920	0.1716	0.29930	0.0098
36	Union Parkway Belt	Union CDA	3.39085	0.1115	0.11741	0.0039
37	Union Parkway Belt	Union ECDA	2.65538	0.0873	0.04410	0.0015
38	Union Parkway Belt	Union EDA	7.27780	0.2393	0.50431	0.0166
39	Union Parkway Belt	Union Parkway Belt	2.48413	0.0817	0.02707	0.0009
40	Union Parkway Belt	Enbridge CDA	3.72330	0.1224	0.15056	0.0050
41	Union Parkway Belt	Enbridge Parkway CDA	2.48413	0.0817	0.02707	0.0009
42	Union Parkway Belt	Enbridge EDA	9.31997	0.3064	0.70780	0.0233
43	Union Parkway Belt	KPUC EDA	7.00009	0.2301	0.47663	0.0157
44	Union Parkway Belt	Energir EDA	11.96865	0.3935	0.97151	0.0319
45	Union Parkway Belt	Enbridge SWDA	5.85551	0.1925	0.36287	0.0119
46	Union Parkway Belt	Union SWDA	5.90905	0.1943	0.36804	0.0121
47	Union Parkway Belt	Chippawa	4.49163	0.1477	0.22691	0.0075
48	Union Parkway Belt	Cornwall	9.45715	0.3109	0.72148	0.0237
49	Union Parkway Belt	East Hereford	14.75026	0.4849	1.24830	0.0410
50	Union Parkway Belt	Emerson 1	29.48227	0.9693	2.71530	0.0893
51	Union Parkway Belt	Emerson 2	29.48227	0.9693	2.71530	0.0893
52	Union Parkway Belt	Iroquois	8.82783	0.2902	0.65883	0.0217
53	Union Parkway Belt	Kirkwall	3.05201	0.1003	0.08365	0.0028
54	Union Parkway Belt	Napierville	11.74023	0.3860	0.94870	0.0312
55	Union Parkway Belt	Niagara Falls	4.45604	0.1465	0.22356	0.0074
56	Union Parkway Belt	North Bay Junction	7.82590	0.2573	0.55906	0.0184
57	Union Parkway Belt	Philipsburg	11.99968	0.3945	0.97455	0.0320
58	Union Parkway Belt	Spruce	31.29480	1.0289	2.89567	0.0952
59	Union Parkway Belt	St. Clair	6.20956	0.2042	0.39815	0.0131
60	Union Parkway Belt	Welwyn	35.60058	1.1704	3.32454	0.1093
61	Union Parkway Belt	Dawn Export	5.85551	0.1925	0.36287	0.0119
62	Union SSMDA	Empress	-	1.0386	-	0.1064
63	Union SSMDA	TransGas SSDA	-	0.8457	-	0.0853
64	Union SSMDA	Centram SSDA	-	0.7667	-	0.0766
65	Union SSMDA	Centram MDA	-	0.6471	-	0.0636
66	Union SSMDA	Centrat MDA	-	0.6467	-	0.0635
67	Union SSMDA	Union WDA	-	0.8702	-	0.0880
68	Union SSMDA	Nipigon WDA	-	0.9373	-	0.0953
69	Union SSMDA	Union NDA	-	0.6827	-	0.0675
70	Union SSMDA	Calstock NDA	-	0.8702	-	0.0880
71	Union SSMDA	Tunis NDA	-	0.7544	-	0.0753
72	Union SSMDA	Energir NDA	-	0.6684	-	0.0659
73	Union SSMDA	Union SSMDA	-	0.0743	-	0.0009
74	Union SSMDA	Union NCDA	-	0.5323	-	0.0505
75	Union SSMDA	Union CDA	-	0.4473	-	0.0413
76	Union SSMDA	Union ECDA	-	0.4549	-	0.0421
77	Union SSMDA	Union EDA	-	0.5944	-	0.0572
78	Union SSMDA	Union Parkway Belt	-	0.4497	-	0.0415
79	Union SSMDA	Enbridge CDA	-	0.4823	-	0.0451
80	Union SSMDA	Enbridge Parkway CDA	-	0.4497	-	0.0415
81	Union SSMDA	Enbridge EDA	-	0.6561	-	0.0639

TransCanada PipeLines Limited

Appendix G

Mainline Transportation Tolls
Page 2 of 27**North Bay Junction Long Term Fixed Price (NBJ LTFP) Service**

Line No.	Particulars	Monthly Toll (\$/GJ/MO)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
1	NBJ LTFP	28.28750	0.9300
2	NBJ LTFP Differential Surcharge	0.00000	0.0000

Note: The toll for NBJ LTFP is inclusive of the applicable Abandonment Surcharge for FT service from Empress to North Bay Junction.
The NBJ LTFP Differential Surcharge is zero provided the Abandonment Surcharge for FT service from Empress to North Bay Junction is equal or less than \$6.69167/GJ/Month.

Enhanced Market Balancing Service

Line No.	Particulars	Monthly Toll (2021) (\$/GJ/MO)	Daily Equivalent (2021) (\$/GJ)	Monthly Toll (2022-2026) (\$/GJ/MO)	Daily Equivalent (2022-2026) (\$/GJ)
	(a)	(b)	(c)	(d)	(e)
3	Union Parkway Belt to Union EDA	10.03081	0.3297	10.03081	0.3297

Delivery Pressure

Line No.	Particulars	Monthly Toll (\$/GJ/MO)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
4	Average Delivery Pressure Toll	0.60833	0.0200

Note: Delivery Pressure toll applies to the following locations: Emerson 1, Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford.
The Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, STFT and SSS.

Union Dawn Receipt Point Surcharge

Line No.	Particulars	Monthly Toll (2021) (\$/GJ/MO)	Daily Equivalent (2021) (\$/GJ)	Monthly Toll (2022-2026) (\$/GJ/MO)	Daily Equivalent (2022-2026) (\$/GJ)
	(a)	(b)	(c)	(d)	(e)
5	Union Dawn Receipt Point Surcharge	0.13140	0.0043	0.13140	0.0043

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll (\$/GJ/MO)	Daily Equivalent (\$/GJ)
	(a)	(b)	(c)
6	SNB Toll	2.97627	0.0979

Note: This SNB Toll is a representative toll for the Eastern Region.

Energy Deficient Gas Allowance (EDGA) Service

Line No.	Particulars	Capacity Charge (2021) (\$/GJ/D)	Capacity Charge (2022-2026) (\$/GJ/D)
	(a)	(b)	(b)
7	Western Section	0.9917	0.9333
8	Eastern Section	0.3339	0.3339

Note: The EDGA Service capacity charge for the Western Section is the effective Empress to North Bay Junction FT Toll and the capacity charge for the Eastern Section is the effective Parkway to North Bay Junction FT Toll.
The EDGA Service fuel charge for the Western Section includes the effective Empress to North Bay Junction monthly fuel ratio and the fuel charge for the Eastern Section includes the effective Parkway to North Bay Junction monthly fuel ratio.

Line No.	Receipt Point	Delivery Point	FT Toll (2021) (\$/GJ/Month)	Daily Equivalent FT for IT / STFT (2021) (\$/GJ)	FT Toll (2022-2026) (\$/GJ/Month)	Daily Equivalent FT for IT / STFT (2022-2026) (\$/GJ)
1	Union NDA	Enbridge CDA	-	0.4518	-	0.4512
2	Union NDA	Enbridge Parkway CDA	-	0.4574	-	0.4568
3	Union NDA	Enbridge EDA	-	0.4810	-	0.4804
4	Union NDA	KPUC EDA	-	0.5804	-	0.5798
5	Union NDA	Energir EDA	-	0.6413	-	0.6407
6	Union NDA	Enbridge SWDA	-	0.6074	-	0.6068
7	Union NDA	Union SWDA	-	0.6089	-	0.6082
8	Union NDA	Chippawa	-	0.5467	-	0.5461
9	Union NDA	Cornwall	-	0.5272	-	0.5266
10	Union NDA	East Hereford	-	0.7628	-	0.7621
11	Union NDA	Emerson 1	-	0.6452	-	0.6099
12	Union NDA	Emerson 2	-	0.6452	-	0.6099
13	Union NDA	Iroquois	-	0.5052	-	0.5046
14	Union NDA	Kirkwall	-	0.4827	-	0.4820
15	Union NDA	Napierville	-	0.6288	-	0.6282
16	Union NDA	Niagara Falls	-	0.5452	-	0.5445
17	Union NDA	North Bay Junction	-	0.1242	-	0.1235
18	Union NDA	Philipsburg	-	0.6404	-	0.6397
19	Union NDA	Spruce	-	0.5952	-	0.5632
20	Union NDA	St. Clair	-	0.6232	-	0.6225
21	Union NDA	Welwyn	-	0.7330	-	0.6918
22	Union NDA	Dawn Export	-	0.6074	-	0.6068
23	Union Parkway Belt	Empress	38.21619	1.2564	36.43469	1.1979
24	Union Parkway Belt	TransGas SSDA	34.39845	1.1309	32.87105	1.0807
25	Union Parkway Belt	Centram SSDA	31.65348	1.0407	30.30878	0.9965
26	Union Parkway Belt	Centram MDA	28.94698	0.9517	27.78241	0.9134
27	Union Parkway Belt	Centrat MDA	29.56448	0.9720	28.50444	0.9371
28	Union Parkway Belt	Union WDA	24.65995	0.8107	23.92633	0.7866
29	Union Parkway Belt	Nipigon WDA	22.55057	0.7414	21.95735	0.7219
30	Union Parkway Belt	Union NDA	13.92193	0.4577	13.90302	0.4571
31	Union Parkway Belt	Calstock NDA	19.00133	0.6247	18.64434	0.6130
32	Union Parkway Belt	Tunis NDA	16.20700	0.5328	16.03600	0.5272
33	Union Parkway Belt	Energir NDA	13.83905	0.4550	13.82565	0.4545
34	Union Parkway Belt	Union SSMMDA	16.70252	0.5491	16.35293	0.5376
35	Union Parkway Belt	Union NCDA	6.70746	0.2205	6.70746	0.2205
36	Union Parkway Belt	Union CDA	4.18307	0.1375	4.18307	0.1375
37	Union Parkway Belt	Union ECDA	3.48667	0.1146	3.48667	0.1146
38	Union Parkway Belt	Union EDA	9.11800	0.2998	9.11800	0.2998
39	Union Parkway Belt	Union Parkway Belt	2.92516	0.0962	2.92516	0.0962
40	Union Parkway Belt	Enbridge CDA	4.59012	0.1509	4.59012	0.1509
41	Union Parkway Belt	Enbridge Parkway CDA	2.92516	0.0962	2.92516	0.0962
42	Union Parkway Belt	Enbridge EDA	12.16398	0.3999	12.16398	0.3999
43	Union Parkway Belt	KPUC EDA	9.03743	0.2971	9.03743	0.2971
44	Union Parkway Belt	Energir EDA	15.83498	0.5206	15.83498	0.5206
45	Union Parkway Belt	Enbridge SWDA	7.48820	0.2462	7.48820	0.2462
46	Union Parkway Belt	Union SWDA	7.53210	0.2476	7.53210	0.2476
47	Union Parkway Belt	Chippawa	5.64231	0.1855	5.64231	0.1855
48	Union Parkway Belt	Cornwall	12.36317	0.4065	12.36317	0.4065
49	Union Parkway Belt	East Hereford	19.52731	0.6420	19.52731	0.6420
50	Union Parkway Belt	Emerson 1	27.23504	0.8954	26.18442	0.8609
51	Union Parkway Belt	Emerson 2	27.23504	0.8954	26.18442	0.8609
52	Union Parkway Belt	Iroquois	11.51122	0.3785	11.51122	0.3785
53	Union Parkway Belt	Kirkwall	3.69364	0.1214	3.69364	0.1214
54	Union Parkway Belt	Napierville	15.45320	0.5081	15.45320	0.5081
55	Union Parkway Belt	Niagara Falls	5.59424	0.1839	5.59424	0.1839
56	Union Parkway Belt	North Bay Junction	10.15506	0.3339	10.15506	0.3339
57	Union Parkway Belt	Philipsburg	15.80435	0.5196	15.80435	0.5196
58	Union Parkway Belt	Spruce	29.56448	0.9720	28.50444	0.9371
59	Union Parkway Belt	St. Clair	7.96747	0.2619	7.96747	0.2619
60	Union Parkway Belt	Welwyn	31.65348	1.0407	30.30878	0.9965
61	Union Parkway Belt	Dawn Export	7.48820	0.2462	7.48820	0.2462
62	Union SSMMDA	Empress	-	0.8460	-	0.7973
63	Union SSMMDA	TransGas SSDA	-	0.7205	-	0.6802
64	Union SSMMDA	Centram SSDA	-	0.6303	-	0.5959
65	Union SSMMDA	Centram MDA	-	0.5413	-	0.5129
66	Union SSMMDA	Centrat MDA	-	0.5351	-	0.5071
67	Union SSMMDA	Union WDA	-	0.7105	-	0.6708
68	Union SSMMDA	Nipigon WDA	-	0.9946	-	0.9613
69	Union SSMMDA	Union NDA	-	0.8295	-	0.8151
70	Union SSMMDA	Calstock NDA	-	0.9968	-	0.9713
71	Union SSMMDA	Tunis NDA	-	0.9049	-	0.8855
72	Union SSMMDA	Energir NDA	-	0.8270	-	0.8129
73	Union SSMMDA	Union SSMMDA	-	0.0962	-	0.0962
74	Union SSMMDA	Union NCDA	-	0.6768	-	0.6656
75	Union SSMMDA	Union CDA	-	0.5453	-	0.5341
76	Union SSMMDA	Union ECDA	-	0.5703	-	0.5591
77	Union SSMMDA	Union EDA	-	0.7561	-	0.7448
78	Union SSMMDA	Union Parkway Belt	-	0.5525	-	0.5412
79	Union SSMMDA	Enbridge CDA	-	0.6004	-	0.5891
80	Union SSMMDA	Enbridge Parkway CDA	-	0.5525	-	0.5412
81	Union SSMMDA	Enbridge EDA	-	0.8562	-	0.8450

Effective
2020-04-01
Rate M12
Page 1 of 4

ENBRIDGE GAS INC.
UNION SOUTH
TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

Applicable Points

Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).
Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Parkway facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically.
Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charges (applied to daily contract demand) <u>Rate/GJ</u>	<u>Fuel and Commodity Charges</u>		
		<u>Union Supplied Fuel</u> Fuel and Commodity Charge <u>Rate/GJ</u>	<u>Shipper Supplied Fuel</u>	
			<u>Fuel Ratio %</u>	<u>AND</u> <u>Commodity Charge Rate/GJ</u>
<u>Firm Transportation (1), (5)</u>				
Dawn to Parkway	\$3.632	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".	
Dawn to Kirkwall	\$3.083			
Kirkwall to Parkway	\$0.550			
<u>M12-X Firm Transportation</u>				
Between Dawn, Kirkwall and Parkway	\$4.488	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".	
<u>Limited Firm/Interruptible Transportation (1)</u>				
Dawn to Parkway – Maximum	\$8.717	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".	
Dawn to Kirkwall – Maximum	\$8.717			
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.162%	
<u>Carbon Charge (applied to all quantities transported)</u>				
Facility Carbon Charge		\$0.002		\$0.002

SCHEDULE "C"

ENBRIDGE GAS INC.

Union South

M12 Monthly Transportation Fuel Ratios and Fuel Rates

Firm or Interruptible Transportation Commodity

Effective April 1, 2020

Month	VT1 Easterly Dawn to Parkway (TCPL), Parkway (EGT) With Dawn Compression		VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression		M12-X Westerly Kirkwall to Dawn	
	Fuel Ratio	Fuel Rate	Fuel Ratio	Fuel Rate	Fuel Ratio	Fuel Rate
	(%)	(\$/GJ)	(%)	(\$/GJ)	(%)	(\$/GJ)
April	0.899	0.023	0.559	0.015	0.162	0.004
May	0.640	0.017	0.382	0.009	0.162	0.004
June	0.535	0.015	0.282	0.007	0.162	0.004
July	0.519	0.014	0.269	0.007	0.162	0.004
August	0.414	0.010	0.163	0.004	0.162	0.004
September	0.410	0.010	0.163	0.004	0.162	0.004
October	0.768	0.020	0.472	0.013	0.162	0.004
November	0.915	0.024	0.639	0.017	0.162	0.004
December	1.036	0.027	0.760	0.020	0.162	0.004
January	1.193	0.031	0.902	0.023	0.162	0.004
February	1.133	0.029	0.850	0.023	0.162	0.004
March	1.057	0.028	0.760	0.020	0.162	0.004

Month	M12-X Easterly Kirkwall to Parkway (TCPL), Parkway (EGT)		M12-X Easterly Kirkwall to Lisgar, Parkway (Consumers)		M12-X Westerly Parkway to Kirkwall, Dawn	
	Fuel Ratio	Fuel Rate	Fuel Ratio	Fuel Rate	Fuel Ratio	Fuel Rate
	(%)	(\$/GJ)	(%)	(\$/GJ)	(%)	(\$/GJ)
April	0.501	0.014	0.162	0.004	0.307	0.008
May	0.420	0.010	0.162	0.004	0.307	0.008
June	0.415	0.010	0.162	0.004	0.307	0.008
July	0.413	0.010	0.162	0.004	0.307	0.008
August	0.413	0.010	0.162	0.004	0.307	0.008
September	0.409	0.010	0.162	0.004	0.307	0.008
October	0.457	0.012	0.162	0.004	0.307	0.008
November	0.437	0.011	0.162	0.004	0.162	0.004
December	0.437	0.011	0.162	0.004	0.162	0.004
January	0.452	0.011	0.162	0.004	0.162	0.004
February	0.444	0.011	0.162	0.004	0.162	0.004
March	0.459	0.012	0.162	0.004	0.162	0.004



Daily Exchange Rates Lookup



All Bank of Canada exchange rates are indicative rates only, obtained from averages of aggregated price quotes from financial institutions. For details, please read our full [Terms and Conditions](#).

US dollar (USD)

Date	USD → CAD	CAD → USD
2020-06-19	1.3587	0.7360



Effective January 1, 2020, we are no longer publishing exchange rates for the following currencies: Malaysian ringgit, Thai baht, and Vietnamese dong. These currencies no longer satisfy the inclusion criteria that are documented in our [Methodology for Foreign Exchange Rates](#).

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2020 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 15, 2020

The annual charges unit charge (ACA) to be applied to in fiscal year 2021 for recovery of FY 2020 Current year and 2019 True-Up is **\$0.0011** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2020.

The following calculations were used to determine the FY 2020 unit charge:

2020 CURRENT:

Estimated Program Cost \$67,023,000 divided by 60,657,793,693 Dth = 0.0011049363

2019 TRUE-UP:

Debit/Credit Cost (\$2,266,032) divided by 56,276,625,816 Dth = (0.0000402660)

TOTAL UNIT CHARGE = 0.0010646704

If you have any questions, please contact Raven A. Rodriguez at (202)502-6276 or e-mail at Raven.Rodriguez@ferc.gov.

PUBLIC

Pipeline	Receipt	Delivery	Historic Fuel Retention Ratios													May - Oct, Apr	Average
			May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Nov - Mar		
Iroquois	Zone 1	Zone 1	-1.00%	-0.30%	0.00%	0.10%	-0.30%	-0.30%	-0.30%	0.10%	0.30%	0.30%	-0.20%	-0.50%	0.04%	-0.33%	-0.18%
PNGTS	N/A	N/A	-0.80%	-0.80%	-0.80%	-0.80%	-0.80%	-0.80%	-0.80%	-0.80%	-0.60%	-0.60%	-0.60%	-0.40%	-0.68%	-0.74%	-0.72%
TransCanada	Parkway	E. Hereford	0.90%	1.28%	0.78%	0.48%	1.07%	0.85%	1.68%	1.63%	1.55%	1.74%	1.33%	1.34%	1.59%	0.96%	1.22%

SCHEDULE 2
Page 1 of 1
Contract No. LST086

PRICING PROVISIONS

Shipper agrees to pay Union the following for the Storage Services:

- (a) **Monthly Demand Charge:** For the period of April, 2018 to March, 2023 inclusive, a monthly demand charge of \$236,666.67 US if the Maximum Storage Balance is 4,220,224 GJ (4,000,000 MMBtu); or a monthly demand charge of \$201,666.67 US if Shipper elects a lower Maximum Storage Balance of 3,587,190 GJ (3,400,000 MMBtu).
- (b) **Demand Charge Escalation:** *Intentionally blank*
- (c) **Variable Storage Charges:**
 - (i) Firm: For each GJ of gas withdrawn from or injected into the Storage Account on a firm basis, a charge equal to \$0.007 CDN/GJ;
 - (ii) Interruptible: For each GJ of gas withdrawn from or injected into the Storage Account on an interruptible basis, a charge equal to the price set out under the heading 'If Shipper supplies fuel Commodity Charge Price/GJ' in the 'Storage Services' section under '(C) Pricing' in the MPSS (currently \$0.041CDN/GJ);
 - (iii) Authorized Overrun: For each GJ of gas withdrawn from or injected into the Storage Account on an authorized overrun basis, a charge equal to the price set out under the heading 'If Shipper supplies fuel Commodity Charge Price/GJ' in the 'Authorized Overrun' section under '(C) Pricing' in the MPSS (currently \$0.041CDN/GJ);
 - (iv) Dehydration Charge: Not Applicable.
- (d) **Fuel:**
 - (i) Firm and Interruptible: For each GJ of gas withdrawn from or injected into the Storage Account on a firm or interruptible basis, an amount of fuel in kind equal to the fuel ratio set out under the heading of 'If Shipper supplies fuel' in the 'Storage Services' section under '(C) Pricing' in the MPSS (currently 0.600%).
 - (ii) Authorized Overrun: For each GJ of gas withdrawn from or injected into the Storage Account on an authorized overrun basis, an amount of fuel in kind equal to the fuel ratio set out under the heading of 'If Shipper supplies fuel' in the 'Authorized Overrun' section under '(C) Pricing' in the MPSS (currently 1.03%).
- (e) **Late Season Balance Charge and Early Season Balance Charge:** *Intentionally blank*
- (f) **Shortfall Charge:** *Intentionally blank*
- (g) **Other Charges:** Any and all other charges as may be set out in this Contract, and any charges relating to Unauthorized Overrun, Drafted Storage Balance and Overrun of Maximum Storage Balance as set out in the MPSS.

MARITIMES & NORTHEAST PIPELINE, LLC**SUMMARY OF RATES****CURRENTLY EFFECTIVE RATES 11/01/2019**

FUEL REIMBURSEMENT PERCENTAGES:

<u>Period</u>	<u>FRP</u>
Winter (November 1 - March 31)	0.82%
Non-Winter (April 1 - October 31)	1.01%

The Summary of Rates serves as a handy reference and does not replace Maritimes & Northeast Tariff. The rates are subject to Commission approval.

FORWARD HAUL RATES
(All rates in \$/Dth)

Rate Schedule	MN365	MNIT
MAXIMUM		
Reservation	\$14.9042	
MES Reservation Charge	\$0.4900	
Usage Charge Within Tolerances	\$0.0050	\$0.4950*
Usage Charge Outside Tolerances	\$0.4950	\$0.4950*
MINIMUM		
Reservation	\$0.0000	
MES Reservation Charge	\$0.0000	
Usage Charge Within Tolerances	\$0.0050	\$0.0050
Usage Charge Outside Tolerances	\$0.0050	\$0.0050

The following adjustment(s) apply to all Rate Schedules:

ACA SURCHARGE TO APPLICABLE CUSTOMERS: PURSUANT TO SECTION 21 OF THE GT&C.

FUEL RETAINAGE PERCENTAGE: PURSUANT TO SECTION 20 OF THE GT&C.

- * The Usage Charge within Tolerances or outside Tolerances, as applicable, for MNIT service on a portion of Pipeline's system designated as an Incremental Lateral shall be the 100 percent load factor equivalent of the applicable rate specified for the applicable Incremental Lateral on the currently effective Statement of Rates for Rate Schedule MNLFT.

Northern Utilities, Inc. Normal Year Weather - Sales Service Load and Company Managed Sales Commodity Volumes by Supply Source (Dth) November 2020 through October 2021														
Description	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Winter	Summer
Pipeline Supplies														
Tennessee Long-Haul Pipeline Path	235,209	320,438	320,438	289,427	320,438	3,595	0	0	0	0	0	0	1,489,544	0
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	35,028	38,781	37,530	38,781	37,530	38,781	38,781	37,530	38,781	226,431	230,184
Iroquois Receipts Pipeline Path	187,700	193,957	193,957	175,187	193,957	0	0	0	0	0	0	0	944,757	0
Tennessee Niagara Pipeline Path	55,067	56,902	56,902	51,395	56,902	6,740	0	0	0	0	0	0	283,909	0
Atlantic Bridge Ramapo Pipeline Path	169,702	183,303	183,303	165,564	183,303	0	0	0	0	0	0	0	885,175	0
PXP Dawn Pipeline Path	224,840	239,438	239,438	216,267	239,438	51,041	0	0	0	0	0	0	1,210,463	0
WXP Dawn Pipeline Path	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Pipeline	910,047	1,032,819	1,032,819	932,869	1,032,819	98,907	38,781	37,530	38,781	38,781	37,530	38,781	5,040,279	230,184
Underground Storage														
Tennessee Storage	0	66,417	66,417	59,639	14,333	0	0	0	0	0	0	0	206,805	0
TGP Zone 4 300 Leg Supply	64,274	0	0	351	52,083	64,274	66,417	64,274	66,417	66,417	64,274	66,417	180,982	394,215
Tennessee FS-MA Storage Path	64,274	66,417	66,417	59,989	66,417	64,274	66,417	64,274	66,417	66,417	64,274	66,417	387,788	394,215
Union Dawn Storage	233,918	603,977	694,287	720,022	426,513	0	0	0	0	0	0	0	2,678,717	0
Dawn Supply	0	0	0	704	17,762	754,936	394,130	235,369	185,825	188,904	218,379	514,162	773,402	1,736,770
Union Dawn Storage Path	233,918	603,977	694,287	720,726	444,275	754,936	394,130	235,369	185,825	188,904	218,379	514,162	3,452,119	1,736,770
Subtotal Storage	298,192	670,393	760,704	780,715	510,691	819,210	460,547	299,643	252,242	255,321	282,653	580,579	3,839,907	2,130,985
Peaking Supplies														
Lewiston LNG	1,794	22,761	52,503	33,254	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040
Peaking Contract 1	0	7,425	201,313	8,415	0	0	0	0	0	0	0	0	217,152	0
Incremental Delivered Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Peaking	1,794	30,186	253,815	41,669	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	331,112	11,040
Total Delivered (Dth)	1,210,034	1,733,398	2,047,338	1,755,253	1,545,364	919,911	501,188	338,973	292,883	295,962	321,983	621,220	9,211,298	2,372,209

Northern Utilities, Inc. Design Year Weather - Planning Load Commodity Volumes by Supply Source (Dth) November 2020 through October 2021														
Description	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Winter	Summer
Pipeline Supplies														
Tennessee Long-Haul Pipeline Path	338,763	406,378	406,378	367,051	406,378	0	0	0	0	0	0	0	1,924,946	0
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	35,028	38,781	37,530	38,781	37,530	38,781	38,781	37,530	38,781	226,431	230,184
Iroquois Receipts Pipeline Path	193,021	199,455	199,455	180,153	199,455	0	0	0	0	0	0	0	971,541	0
Tennessee Niagara Pipeline Path	69,805	72,132	72,132	65,151	72,132	1,479	0	0	0	0	0	0	352,830	0
Atlantic Bridge Ramapo Pipeline Path	217,500	232,500	232,500	210,000	232,500	0	0	0	0	0	0	0	1,125,000	0
PXP Dawn Pipeline Path	288,839	303,640	303,640	274,256	303,640	56,260	3,793	0	0	0	0	0	1,530,276	3,793
WXP Dawn Pipeline Path	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Pipeline	1,145,458	1,252,886	1,252,886	1,131,639	1,252,886	95,269	42,574	37,530	38,781	38,781	37,530	38,781	6,131,024	233,977
Underground Storage														
Tennessee Storage	0	81,955	81,955	73,607	17,760	0	0	0	0	0	0	0	255,276	0
TGP Zone 4 300 Leg Supply	79,311	0	0	417	64,196	79,311	81,955	79,311	81,955	81,955	79,311	81,955	223,236	486,443
Tennessee FS-MA Storage Path	79,311	81,955	81,955	74,024	81,955	79,311	81,955	79,311	81,955	81,955	79,311	81,955	478,512	486,443
Union Dawn Storage	417,268	987,008	1,063,885	908,758	478,946	0	0	0	0	0	0	0	3,855,864	0
Dawn Supply	0	0	0	114,802	180,025	941,783	605,665	372,477	302,352	321,937	392,128	746,042	1,236,610	2,740,602
Union Dawn Storage Path	417,268	987,008	1,063,885	1,023,560	658,970	941,783	605,665	372,477	302,352	321,937	392,128	746,042	5,092,473	2,740,602
Subtotal Storage	496,579	1,068,963	1,145,840	1,097,584	740,925	1,021,094	687,621	451,789	384,307	403,892	471,440	827,997	5,570,986	3,227,045
Peaking Supplies														
Lewiston LNG	1,794	50,051	41,215	9,030	10,076	1,794	1,860	1,800	1,860	1,860	1,800	1,860	113,960	11,040
Peaking Contract 1	0	71,125	338,579	149,734	0	0	0	0	0	0	0	0	559,438	0
Incremental Delivered Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Peaking	1,794	121,177	379,793	158,764	10,076	1,794	1,860	1,800	1,860	1,860	1,800	1,860	673,398	11,040
Total Delivered (Dth)	1,643,831	2,443,026	2,778,519	2,387,987	2,003,887	1,118,157	732,055	491,119	424,948	444,533	510,770	868,638	12,375,407	3,472,062

Northern Utilities, Inc. Normal Year Weather - Sales Service Load and Company Managed Sales Capacity Utilization by Supply Source November 2020 through October 2021									
Description	Winter Projected Volume (Dth)	Winter Maximum Volume (Dth)	Winter Capacity Utilization	Summer Projected Volume (Dth)	Summer Maximum Volume (Dth)	Summer Capacity Utilization	Annual Projected Volume (Dth)	Annual Maximum Volume (Dth)	Annual Capacity Utilization
Pipeline Supplies									
Tennessee Long-Haul Pipeline Path	1,489,544	1,870,942	80%	0	1,901,952	0%	1,489,544	3,772,894	39%
Algonquin Receipts Pipeline Path	226,431	226,431	100%	230,184	230,184	100%	456,615	456,615	100%
Iroquois Receipts Pipeline Path	944,757	1,125,317	84%	0	1,144,176	0%	944,757	2,269,494	42%
Tennessee Niagara Pipeline Path	283,909	332,235	85%	0	337,742	0%	283,909	669,977	42%
Atlantic Bridge Ramapo Pipeline Path	885,175	1,070,253	83%	0	1,087,992	0%	885,175	2,158,245	41%
PXP Dawn Pipeline Path	1,210,463	1,422,190	85%	0	1,445,762	0%	1,210,463	2,867,952	42%
Subtotal Pipeline	5,040,279	6,047,368	83%	230,184	6,147,808	4%	5,270,463	12,195,176	43%
Underground Storage									
Tennessee Storage	206,805			0			206,805		
TGP Zone 4 300 Leg Supply	180,982			394,215			575,198		
Tennessee FS-MA Storage Path	387,788	387,788	100%	394,215	394,215	100%	782,003	782,003	100%
Union Dawn Storage	2,678,717			0			2,678,717		
Dawn Supply	773,402			1,736,770			2,510,172		
Union Dawn Storage Path	3,452,119	5,845,137	59%	1,736,770	5,942,018	29%	5,188,888	11,787,156	44%
Subtotal Storage	3,839,907	6,232,925	62%	2,130,985	6,336,234	34%	5,970,892	12,569,159	48%
Peaking Supplies									
Lewiston LNG	113,960	113,960	100%	11,040	11,040	100%	125,000	125,000	100%
Peaking Contract 1	217,152	597,900	36%	0	0		217,152	597,900	
Subtotal Peaking	331,112	711,860	47%	11,040	11,040	100%	342,152	722,900	47%
Portfolio Utilization	9,211,298	12,992,153	71%	2,372,209	12,495,081	19%	11,583,507	25,487,235	45%
Incremental Delivered Supplies	0	N/A		0	N/A		0	N/A	
Total Delivered	9,211,298	N/A		2,372,209	N/A		11,583,507	N/A	

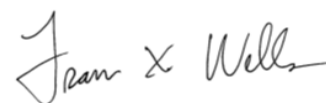
Northern Utilities, Inc. Design Year Weather - Planning Load Capacity Utilization by Supply Source November 2020 through October 2021									
Description	Winter Projected Volume (Dth)	Winter Maximum Volume (Dth)	Winter Capacity Utilization	Summer Projected Volume (Dth)	Summer Maximum Volume (Dth)	Summer Capacity Utilization	Annual Projected Volume (Dth)	Annual Maximum Volume (Dth)	Annual Capacity Utilization
Pipeline Supplies									
Tennessee Long-Haul Pipeline Path	1,924,946	2,372,721	81%	0	2,412,048	0%	1,924,946	4,784,770	40%
Algonquin Receipts Pipeline Path	226,431	226,431	100%	230,184	230,184	100%	456,615	456,615	100%
Iroquois Receipts Pipeline Path	971,541	1,157,423	84%	0	1,176,814	0%	971,541	2,334,236	42%
Tennessee Niagara Pipeline Path	352,830	421,156	84%	0	428,136	0%	352,830	849,292	42%
Atlantic Bridge Ramapo Pipeline Path	1,125,000	1,357,500	83%	0	1,380,000	0%	1,125,000	2,737,500	41%
PXP Dawn Pipeline Path	1,530,276	1,803,665	85%	3,793	1,833,560	0%	1,534,069	3,637,225	42%
Subtotal Pipeline	6,131,024	7,338,896	84%	233,977	7,460,742	3%	6,365,001	14,799,638	43%
Underground Storage									
Tennessee Storage	255,276			0			255,276		
TGP Zone 4 300 Leg Supply	223,236			486,443			709,679		
Tennessee FS-MA Storage Path	478,512	478,512	100%	486,443	486,443	100%	964,956	964,956	100%
Union Dawn Storage	3,855,864			0			3,855,864		
Dawn Supply	1,236,610			2,740,602			3,977,211		
Union Dawn Storage Path	5,092,473	7,215,201	71%	2,740,602	7,334,790	37%	7,833,075	14,549,991	54%
Subtotal Storage	5,570,986	7,693,713	72%	3,227,045	7,821,233	41%	8,798,031	15,514,946	57%
Peaking Supplies									
Lewiston LNG	113,960	113,960	100%	11,040	11,040	100%	125,000	125,000	100%
Peaking Contract 1	559,438	597,900	94%	0	0		559,438	597,900	
Subtotal Peaking	673,398	711,860	95%	11,040	11,040	100%	684,438	722,900	95%
Portfolio Utilization	12,375,407	15,744,469	79%	3,472,062	15,293,015	23%	15,847,470	31,037,484	51%
Incremental Delivered Supplies	0	N/A		0	N/A		0	N/A	
Total Delivered	12,375,407	N/A		3,472,062	N/A		15,847,470	N/A	

Northern Utilities Inc.
Forecast of Upcoming Winter Period Design Day Report
2020 / 2021 Winter Period
(Therms)

Demand	
NH Firm Sales	471,540
NH Non-Capacity Exempt Transportation	132,520
NH Capacity Exempt Transportation	95,860
NH Interruptible Sales	0
NH Interruptible Transportation	0
NH Design Day Demand	699,920
ME Firm Sales	615,670
ME Non-Capacity Exempt Transportation	132,690
ME Capacity Exempt Transportation	120,940
ME Interruptible Sales	0
ME Interruptible Transportation	0
ME Design Day Demand	869,300
Total Firm Sales	1,087,210
Total Non-Capacity Exempt Transportation	265,210
Total Capacity Exempt Transportation	216,800
Total Interruptible Sales	0
Total Interruptible Transportation	0
Total Design Day Demand	1,569,220
Supplies	
Capacity Exempt Transportation	216,800
Pipeline	405,860
Storage	425,070
On-System LNG	65,000
Off-System Peaking Contracts & Delivered Baseload	398,600
Additional Granite Capacity	133,910
Total	1,645,240
Effective Degree Day	
New Hampshire	80.2
Maine	78.6
Probability	1 in 30

Report Prepared By
Title
Signature

Francis X. Wells
Manager, Energy Planning



Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2020 through October 2021

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	892,604	39%	87%
G50	118,732	5%	85%
G41	812,488	36%	56%
G51	199,577	9%	49%
G42	158,455	7%	26%
G52	100,683	4%	6%
Special Contracts	-	0%	0%
Total C&I	2,282,539	100%	36%

C&I Rate Class	Annual Transport- Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
G40	135,304	3%	13%
G50	21,410	1%	15%
G41	637,861	16%	44%
G51	210,160	5%	51%
G42	460,071	12%	74%
G52	1,497,326	38%	94%
Special Contracts	1,029,564	26%	100%
Total C&I	3,991,696	100%	64%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G40	1,027,907	16%
G50	140,142	2%
G41	1,450,349	23%
G51	409,738	7%
G42	618,526	10%
G52	1,598,010	25%
Special Contracts	1,029,564	16%
Total C&I	6,274,235	100%

Northern Utilities Inc.
New Hampshire 7 Day Cold Snap Analysis
Winter 2019-2020

Coldest 7 Consecutive Days

Based on historic Portsmouth weather data

<u>Date</u>	<u>EDD</u>
February 11, 1979	68
February 12, 1979	60
February 13, 1979	73
February 14, 1979	73
February 15, 1979	64
February 16, 1979	69
February 17, 1979	72
Total	479

Maximum Projected Design Week Demand (Dth)

Daily Baseload	5,742
Weekly Baseload	40,197
Heating Increment*	651
Effective Degree Days	479
Total Heat Load	311,839
<u>Projected Cold Snap Demand</u>	<u>352,036</u>

New Hampshire Allocation **40.88%**

Based on the latest demand cost allocator in the Winter COG filing.

Maximum Supply Capability (Dth)

Amount to be Supplied by Natural Gas Pipelines	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Tennessee Firm Storage	2,644
Union Dawn Storage	39,863
Peaking Contract 1	39,860
Total Daily Pipeline	122,953
Pipeline for 7 days	860,671
<u>New Hampshire Allocation</u>	<u>351,842</u>

Available LNG Storage

Facility	Gallons	Dth
Lewiston LNG	145,134	12,140
Total	145,134	12,140

New Hampshire Allocation - 7 Days 4,963

LNG Delivery Contract

Northern Utilities plans to secure a contract for LNG Delivery for up to three loads of LNG per day.

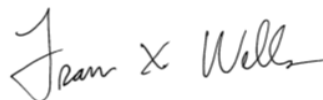
The storage credit for LNG is calculated as follows:

Number of Days	7
Number of Loads	5
Delivery Reliability	70%
Assumed Number of LNG Deliveries	25
Dth Per Load	900
Total Storage Credit	22,050
<u>NH Storage Credit - 7 Days</u>	<u>9,014</u>

Summary	
Maximum projected design week demand	352,036
Amount to be furnished by natural gas pipeline	351,842
Remaining Balance	194
Storage available	4,963
Credit from LNG delivery supply contract	9,014
Total available storage and LNG deliveries	13,977
Net Surplus/(Deficiency)	13,783

Report Prepared By
Title
Signature

Francis X. Wells
Manager, Energy Planning



Winter Period Re-Entry Surcharge Calculation
(Applicable to Capacity Assigned Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Weighted Average	Reference
1	Winter Demand Cost of Gas Rate	\$0.2777	\$0.3868	\$0.3533	Page 3 of Summary
2	Winter Commodity Cost of Gas Rate	\$0.3214	\$0.3095	\$0.3132	Page 3 of Summary
3	Winter Indirect Cost of Gas	\$0.0486	\$0.0486	\$0.0486	Page 3 of Summary, Removing any Prior Period Over-Collection or Supplier Refunds
4	Winter Cost of Gas Rate (Exclusive of Credits)	\$0.6477	\$0.7449	\$0.7151	Sum Lines 1 through 3
5	Winter Cost of Gas Rate for Incumbent Sales Customers	\$0.6465	\$0.7437	\$0.7139	Page 3 of Summary
6	Winter Re-Entry Surcharge	\$0.0012	\$0.0012	\$0.0012	Positive Difference between Line 4 and Line 5
7	Projected Sales (therms)	11,338,982	25,623,890	36,962,872	Schedule 17-FXW - Distribution Service Delilveries, excluding Special Contracts

Summer Period Re-Entry Surcharge & Conversion Surcharge Calculation
(Applicable to Capacity Assigned & Capacity Exempt Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Weighted Average	Reference
8	Summer Demand Cost of Gas Rate	\$0.0990	\$0.1780	\$0.1538	Page 7 of Summary
9	Summer Commodity Cost of Gas Rate	\$0.2686	\$0.2686	\$0.2686	Page 7 of Summary
10	Summer Indirect Cost of Gas	\$0.0278	\$0.0278	\$0.0278	Page 7 of Summary, Removing any Prior Period Over-Collection or Supplier Refunds
11	Summer Cost of Gas Rate (Exclusive of Credits)	\$0.3954	\$0.4744	\$0.4502	Sum Lines 8 through 10
12	Summer Cost of Gas Rate for Incumbent Sales Customers	\$0.3943	\$0.4733	\$0.4491	Page 7 of Summary
13	Summer Re-Entry Surcharge	\$0.0011	\$0.0011	\$0.0011	Positive Difference between Line 11 and Line 12
14	Projected Sales (therms)	10,139,908	5,343,930	15,483,838	Schedule 17-FXW - Distribution Service Delilveries, excluding Special Contracts

Winter Period Conversion Surcharge Calculation
(Applicable to Capacity Exempt Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Reference
1	LLF Winter Demand Cost of Gas Rate	\$0.3868	\$0.3868	Page 3 of Summary
2	LLF Winter Commodity Cost of Gas Rate	\$0.3095	\$0.3095	Page 3 of Summary
3	LLF Winter Indirect Cost of Gas	\$0.0486	\$0.0486	Page 3 of Summary, Removing any Prior Period Over-Collection or Supplier Refunds
4	Floor Price (LLF Winter Cost of Gas Rate, Exclusive of Credits)	\$0.7449	\$0.7449	Sum Lines 1 through 3.
5	Total Incremental Cost	\$0.6567	\$0.6567	See Line 15 of Incremental Commodity Price Worksheet
6	Total Conversion Rate	\$0.7449	\$0.7449	Maximum of Line 4 and Line 5
7	Winter Gas Adjustment Factor for Incumbent Sales Customers	\$0.6465	\$0.7437	Page 3 of Summary
8	Conversion Surcharge	\$0.0984	\$0.0012	Positive Difference between Line 6 and Line 7

Incremental Commodity Price Worksheet

Line	Month	NYMEX	Projected PNGTS Delivered Basis	Projected FOM Index	Projected Non-Capacity Assigned Delivery Service Loads	Comments
1	Nov-20	\$ 2.901	\$ 1.823	\$ 4.724	208,617	
2	Dec-20	\$ 3.266	\$ 3.413	\$ 6.679	200,336	
3	Jan-21	\$ 3.375	\$ 4.393	\$ 7.768	217,128	
4	Feb-21	\$ 3.327	\$ 4.438	\$ 7.765	209,159	
5	Mar-21	\$ 3.185	\$ 2.360	\$ 5.545	217,322	
6	Apr-21	\$ 2.823	\$ 1.308	\$ 4.131	183,124	
7	Winter Period Weighed Average Baseload Price (\$/Dth)			\$ 6.147	1,235,686	Average, Weighted by Loads, Lines 1 through 6
8	Load Shape Price Factor			1.027		See Load Shape Price Factor Worksheet
9	Winter Period Incremental Load Shape Price (\$/Dth)			\$ 6.313		Line 7 times Line 8
10	Granite Fuel			0.35%		Granite Tariff
11	Granite Variable Transport (\$/Dth)			\$ 0.1464		Granite Tariff (IT Daily Rate plus ACA)
12	Northern City-Gate Price (\$/Dth)			\$ 6.482		Line 9 times (1 plus Line 10) plus Line 11
13	New Hampshire Division City-Gate Sendout to Sales Ratio			1.0132		See Att 2 to Sch 10B
14	Northern Retail Meter Price (\$/Dth)			\$ 6.567		Line 12 times Line 13
15	Northern Retail Meter Price (\$/therm)			\$ 0.6567		Line 14 divided by 10

Load Shape Price Factor Worksheet

Historic Delivery Service Loads					Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis		
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost	
Nov-19	11/1/2019	6,855	5,080	11,935	6,855	-	6,855	\$ 1.955	\$ 13,402	
Nov-19	11/2/2019	6,599	5,242	11,841	6,599	-	6,599	\$ 2.295	\$ 15,145	
Nov-19	11/3/2019	7,233	5,149	12,382	7,233	-	7,233	\$ 2.295	\$ 16,600	
Nov-19	11/4/2019	8,097	5,144	13,241	8,097	-	8,097	\$ 2.295	\$ 18,583	
Nov-19	11/5/2019	8,218	4,920	13,138	8,218	-	8,218	\$ 2.335	\$ 19,189	
Nov-19	11/6/2019	8,262	5,639	13,901	8,262	-	8,262	\$ 2.845	\$ 23,505	
Nov-19	11/7/2019	7,849	5,996	13,845	7,849	-	7,849	\$ 3.080	\$ 24,175	
Nov-19	11/8/2019	8,529	7,307	15,836	8,529	-	8,529	\$ 5.210	\$ 44,436	
Nov-19	11/9/2019	7,217	6,136	13,353	7,217	-	7,217	\$ 3.045	\$ 21,976	
Nov-19	11/10/2019	7,464	5,187	12,651	7,464	-	7,464	\$ 3.045	\$ 22,728	
Nov-19	11/11/2019	8,637	6,626	15,263	8,637	-	8,637	\$ 3.045	\$ 26,300	
Nov-19	11/12/2019	9,452	8,565	18,017	9,452	-	9,452	\$ 5.865	\$ 55,436	
Nov-19	11/13/2019	9,850	8,494	18,344	9,850	-	9,850	\$ 6.385	\$ 62,892	
Nov-19	11/14/2019	8,998	7,208	16,206	8,998	-	8,998	\$ 3.935	\$ 35,407	
Nov-19	11/15/2019	8,316	6,250	14,566	8,316	-	8,316	\$ 2.920	\$ 24,283	
Nov-19	11/16/2019	8,386	7,399	15,785	8,386	-	8,386	\$ 3.480	\$ 29,183	
Nov-19	11/17/2019	8,394	6,684	15,078	8,394	-	8,394	\$ 3.480	\$ 29,211	
Nov-19	11/18/2019	8,929	6,510	15,439	8,929	-	8,929	\$ 3.480	\$ 31,073	
Nov-19	11/19/2019	9,049	6,384	15,433	9,049	-	9,049	\$ 3.600	\$ 32,576	
Nov-19	11/20/2019	9,216	6,732	15,948	9,216	-	9,216	\$ 3.855	\$ 35,528	
Nov-19	11/21/2019	7,868	5,971	13,839	7,868	-	7,868	\$ 3.465	\$ 27,263	
Nov-19	11/22/2019	7,935	6,310	14,245	7,935	-	7,935	\$ 2.820	\$ 22,377	
Nov-19	11/23/2019	6,564	6,077	12,641	6,564	-	6,564	\$ 2.965	\$ 19,462	
Nov-19	11/24/2019	7,778	6,391	14,169	7,778	-	7,778	\$ 2.965	\$ 23,062	
Nov-19	11/25/2019	8,108	6,132	14,240	8,108	-	8,108	\$ 2.965	\$ 24,040	
Nov-19	11/26/2019	7,619	5,527	13,146	7,619	-	7,619	\$ 2.730	\$ 20,800	
Nov-19	11/27/2019	5,571	5,424	10,995	5,571	-	5,571	\$ 3.215	\$ 17,911	
Nov-19	11/28/2019	4,617	6,390	11,007	4,617	-	4,617	\$ 3.215	\$ 14,844	
Nov-19	11/29/2019	5,008	7,186	12,194	5,008	-	5,008	\$ 3.215	\$ 16,101	

Load Shape Price Factor Worksheet

Historic Delivery Service Loads					Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis		
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost	
Nov-19	11/30/2019	7,089	7,765	14,854	7,089	-	7,089	\$ 3.215	\$ 22,791	
Dec-19	12/1/2019	7,531	7,649	15,180	7,531	-	7,531	\$ 4.495	\$ 33,852	
Dec-19	12/2/2019	7,296	8,179	15,475	7,296	-	7,296	\$ 4.495	\$ 32,796	
Dec-19	12/3/2019	8,206	8,000	16,206	8,206	-	8,206	\$ 4.245	\$ 34,834	
Dec-19	12/4/2019	7,831	7,561	15,392	7,831	-	7,831	\$ 3.750	\$ 29,366	
Dec-19	12/5/2019	7,613	7,384	14,997	7,613	-	7,613	\$ 3.730	\$ 28,396	
Dec-19	12/6/2019	7,850	7,927	15,777	7,850	-	7,850	\$ 4.205	\$ 33,009	
Dec-19	12/7/2019	6,605	8,351	14,956	6,605	-	6,605	\$ 4.220	\$ 27,873	
Dec-19	12/8/2019	4,925	6,985	11,910	4,925	-	4,925	\$ 4.220	\$ 20,784	
Dec-19	12/9/2019	6,523	5,531	12,054	6,523	-	6,523	\$ 4.220	\$ 27,527	
Dec-19	12/10/2019	7,441	6,317	13,758	7,441	-	7,441	\$ 2.455	\$ 18,268	
Dec-19	12/11/2019	8,311	7,989	16,300	8,311	-	8,311	\$ 4.365	\$ 36,278	
Dec-19	12/12/2019	8,151	7,122	15,273	8,151	-	8,151	\$ 4.495	\$ 36,639	
Dec-19	12/13/2019	6,596	5,319	11,915	6,596	-	6,596	\$ 2.445	\$ 16,127	
Dec-19	12/14/2019	4,248	4,740	8,988	4,248	-	4,248	\$ 3.065	\$ 13,020	
Dec-19	12/15/2019	7,131	7,143	14,274	7,131	-	7,131	\$ 3.065	\$ 21,857	
Dec-19	12/16/2019	7,927	8,203	16,130	7,927	-	7,927	\$ 3.065	\$ 24,296	
Dec-19	12/17/2019	7,661	8,030	15,691	7,661	-	7,661	\$ 5.415	\$ 41,484	
Dec-19	12/18/2019	8,437	9,172	17,609	8,437	-	8,437	\$ 11.050	\$ 93,229	
Dec-19	12/19/2019	8,452	10,538	18,990	8,452	-	8,452	\$ 13.950	\$ 117,905	
Dec-19	12/20/2019	7,962	9,020	16,982	7,962	-	7,962	\$ 12.030	\$ 95,783	
Dec-19	12/21/2019	6,956	7,766	14,722	6,956	-	6,956	\$ 6.175	\$ 42,953	
Dec-19	12/22/2019	6,972	7,131	14,103	6,972	-	6,972	\$ 6.175	\$ 43,052	
Dec-19	12/23/2019	6,123	5,919	12,042	6,123	-	6,123	\$ 6.175	\$ 37,810	
Dec-19	12/24/2019	5,273	7,025	12,298	5,273	-	5,273	\$ 4.450	\$ 23,465	
Dec-19	12/25/2019	4,598	6,862	11,460	4,598	-	4,598	\$ 3.190	\$ 14,668	
Dec-19	12/26/2019	7,144	7,158	14,302	7,144	-	7,144	\$ 3.190	\$ 22,789	
Dec-19	12/27/2019	6,313	5,753	12,066	6,313	-	6,313	\$ 2.220	\$ 14,015	
Dec-19	12/28/2019	6,186	6,340	12,526	6,186	-	6,186	\$ 2.010	\$ 12,434	

Load Shape Price Factor Worksheet

Historic Delivery Service Loads					Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis		
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost	
Dec-19	12/29/2019	6,491	6,777	13,268	6,491	-	6,491	\$ 2.010	\$ 13,047	
Dec-19	12/30/2019	6,823	7,157	13,980	6,823	-	6,823	\$ 2.010	\$ 13,714	
Dec-19	12/31/2019	4,896	6,955	11,851	4,896	-	4,896	\$ 2.320	\$ 11,359	
Jan-20	1/1/2020	4,541	7,298	11,839	4,541	-	4,541	\$ 2.345	\$ 10,649	
Jan-20	1/2/2020	6,721	6,487	13,208	6,721	-	6,721	\$ 2.345	\$ 15,761	
Jan-20	1/3/2020	6,446	5,936	12,382	6,446	-	6,446	\$ 2.210	\$ 14,246	
Jan-20	1/4/2020	6,175	6,424	12,599	6,175	-	6,175	\$ 2.570	\$ 15,870	
Jan-20	1/5/2020	7,245	8,153	15,398	7,245	-	7,245	\$ 2.570	\$ 18,620	
Jan-20	1/6/2020	7,493	7,944	15,437	7,493	-	7,493	\$ 2.570	\$ 19,257	
Jan-20	1/7/2020	7,619	7,278	14,897	7,619	-	7,619	\$ 2.985	\$ 22,743	
Jan-20	1/8/2020	8,067	8,569	16,636	8,067	-	8,067	\$ 3.160	\$ 25,492	
Jan-20	1/9/2020	7,719	8,658	16,377	7,719	-	7,719	\$ 2.785	\$ 21,497	
Jan-20	1/10/2020	6,446	5,579	12,025	6,446	-	6,446	\$ 1.920	\$ 12,376	
Jan-20	1/11/2020	5,106	2,765	7,871	5,106	-	5,106	\$ 1.865	\$ 9,523	
Jan-20	1/12/2020	6,648	6,138	12,786	6,648	-	6,648	\$ 1.865	\$ 12,399	
Jan-20	1/13/2020	7,580	7,777	15,357	7,580	-	7,580	\$ 1.865	\$ 14,137	
Jan-20	1/14/2020	7,325	6,847	14,172	7,325	-	7,325	\$ 2.370	\$ 17,360	
Jan-20	1/15/2020	7,352	6,558	13,910	7,352	-	7,352	\$ 2.470	\$ 18,159	
Jan-20	1/16/2020	8,698	8,938	17,636	8,698	-	8,698	\$ 3.970	\$ 34,531	
Jan-20	1/17/2020	8,396	10,291	18,687	8,396	-	8,396	\$ 7.225	\$ 60,661	
Jan-20	1/18/2020	7,446	8,829	16,275	7,446	-	7,446	\$ 4.910	\$ 36,560	
Jan-20	1/19/2020	7,574	8,418	15,992	7,574	-	7,574	\$ 4.910	\$ 37,188	
Jan-20	1/20/2020	8,446	9,857	18,303	8,446	-	8,446	\$ 4.910	\$ 41,470	
Jan-20	1/21/2020	8,489	9,584	18,073	8,489	-	8,489	\$ 4.910	\$ 41,681	
Jan-20	1/22/2020	8,235	8,445	16,680	8,235	-	8,235	\$ 2.695	\$ 22,193	
Jan-20	1/23/2020	6,696	7,246	13,942	6,696	-	6,696	\$ 2.095	\$ 14,028	
Jan-20	1/24/2020	5,211	6,317	11,528	5,211	-	5,211	\$ 2.035	\$ 10,604	
Jan-20	1/25/2020	4,754	5,930	10,684	4,754	-	4,754	\$ 1.905	\$ 9,056	
Jan-20	1/26/2020	5,092	6,136	11,228	5,092	-	5,092	\$ 1.905	\$ 9,700	

Load Shape Price Factor Worksheet

Historic Delivery Service Loads					Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis		
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost	
Jan-20	1/27/2020	7,407	6,470	13,877	7,407	-	7,407	\$ 1.905	\$ 14,110	
Jan-20	1/28/2020	8,177	7,600	15,777	8,177	-	8,177	\$ 2.070	\$ 16,926	
Jan-20	1/29/2020	8,888	8,408	17,296	8,888	-	8,888	\$ 2.355	\$ 20,931	
Jan-20	1/30/2020	8,804	8,291	17,095	8,804	-	8,804	\$ 2.185	\$ 19,237	
Jan-20	1/31/2020	7,419	6,703	14,122	7,419	-	7,419	\$ 1.810	\$ 13,428	
Feb-20	2/1/2020	7,082	6,737	13,819	7,082	-	7,082	\$ 1.840	\$ 13,031	
Feb-20	2/2/2020	6,964	6,948	13,912	6,964	-	6,964	\$ 1.840	\$ 12,814	
Feb-20	2/3/2020	7,541	6,660	14,201	7,541	-	7,541	\$ 1.840	\$ 13,875	
Feb-20	2/4/2020	7,842	6,611	14,453	7,842	-	7,842	\$ 1.945	\$ 15,253	
Feb-20	2/5/2020	8,114	7,425	15,539	8,114	-	8,114	\$ 2.200	\$ 17,851	
Feb-20	2/6/2020	9,853	7,219	17,072	9,853	-	9,853	\$ 1.980	\$ 19,509	
Feb-20	2/7/2020	9,822	8,065	17,887	9,822	-	9,822	\$ 2.420	\$ 23,769	
Feb-20	2/8/2020	10,452	8,915	19,367	10,452	-	10,452	\$ 2.955	\$ 30,886	
Feb-20	2/9/2020	10,241	7,463	17,704	10,241	-	10,241	\$ 2.955	\$ 30,262	
Feb-20	2/10/2020	9,857	7,094	16,951	9,857	-	9,857	\$ 2.955	\$ 29,127	
Feb-20	2/11/2020	8,506	7,262	15,768	8,506	-	8,506	\$ 2.010	\$ 17,097	
Feb-20	2/12/2020	7,750	6,870	14,620	7,750	-	7,750	\$ 1.955	\$ 15,151	
Feb-20	2/13/2020	8,035	7,621	15,656	8,035	-	8,035	\$ 2.495	\$ 20,047	
Feb-20	2/14/2020	9,186	10,275	19,461	9,186	-	9,186	\$ 3.760	\$ 34,539	
Feb-20	2/15/2020	8,123	8,158	16,281	8,123	-	8,123	\$ 2.165	\$ 17,586	
Feb-20	2/16/2020	7,649	6,894	14,543	7,649	-	7,649	\$ 2.165	\$ 16,560	
Feb-20	2/17/2020	7,992	8,046	16,038	7,992	-	7,992	\$ 2.165	\$ 17,303	
Feb-20	2/18/2020	8,601	7,195	15,796	8,601	-	8,601	\$ 2.165	\$ 18,621	
Feb-20	2/19/2020	7,485	8,091	15,576	7,485	-	7,485	\$ 2.405	\$ 18,001	
Feb-20	2/20/2020	7,737	9,137	16,874	7,737	-	7,737	\$ 2.785	\$ 21,548	
Feb-20	2/21/2020	6,679	7,854	14,533	6,679	-	6,679	\$ 2.400	\$ 16,030	
Feb-20	2/22/2020	6,055	6,453	12,508	6,055	-	6,055	\$ 1.990	\$ 12,049	
Feb-20	2/23/2020	6,532	6,364	12,896	6,532	-	6,532	\$ 1.990	\$ 12,999	
Feb-20	2/24/2020	7,608	5,700	13,308	7,608	-	7,608	\$ 1.990	\$ 15,140	

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Feb-20	2/25/2020	7,471	5,935	13,406	7,471	-	7,471	\$ 1.870	\$ 13,971
Feb-20	2/26/2020	7,633	6,050	13,683	7,633	-	7,633	\$ 1.870	\$ 14,274
Feb-20	2/27/2020	8,142	7,439	15,581	8,142	-	8,142	\$ 2.105	\$ 17,139
Feb-20	2/28/2020	7,848	7,327	15,175	7,848	-	7,848	\$ 2.240	\$ 17,580
Feb-20	2/29/2020	7,888	7,920	15,808	7,888	-	7,888	\$ 2.240	\$ 17,669
Mar-20	3/1/2020	8,590	7,664	16,254	8,590	-	8,590	\$ 1.740	\$ 14,947
Mar-20	3/2/2020	7,663	5,508	13,171	7,663	-	7,663	\$ 1.740	\$ 13,334
Mar-20	3/3/2020	7,163	5,091	12,254	7,163	-	7,163	\$ 1.600	\$ 11,461
Mar-20	3/4/2020	7,922	6,004	13,926	7,922	-	7,922	\$ 1.665	\$ 13,190
Mar-20	3/5/2020	7,485	6,171	13,656	7,485	-	7,485	\$ 1.685	\$ 12,612
Mar-20	3/6/2020	7,561	6,594	14,155	7,561	-	7,561	\$ 1.760	\$ 13,307
Mar-20	3/7/2020	7,017	6,270	13,287	7,017	-	7,017	\$ 1.575	\$ 11,052
Mar-20	3/8/2020	6,864	5,159	12,023	6,864	-	6,864	\$ 1.575	\$ 10,811
Mar-20	3/9/2020	6,636	4,248	10,884	6,636	-	6,636	\$ 1.575	\$ 10,452
Mar-20	3/10/2020	6,755	5,232	11,987	6,755	-	6,755	\$ 1.545	\$ 10,436
Mar-20	3/11/2020	7,751	5,868	13,619	7,751	-	7,751	\$ 1.690	\$ 13,099
Mar-20	3/12/2020	7,291	5,933	13,224	7,291	-	7,291	\$ 1.745	\$ 12,723
Mar-20	3/13/2020	6,360	5,277	11,637	6,360	-	6,360	\$ 1.615	\$ 10,271
Mar-20	3/14/2020	6,324	5,111	11,435	6,324	-	6,324	\$ 1.780	\$ 11,257
Mar-20	3/15/2020	7,652	6,555	14,207	7,652	-	7,652	\$ 1.780	\$ 13,621
Mar-20	3/16/2020	7,907	6,873	14,780	7,907	-	7,907	\$ 1.780	\$ 14,074
Mar-20	3/17/2020	7,324	6,173	13,497	7,324	-	7,324	\$ 1.690	\$ 12,378
Mar-20	3/18/2020	7,264	5,407	12,671	7,264	-	7,264	\$ 1.585	\$ 11,513
Mar-20	3/19/2020	6,992	5,720	12,712	6,992	-	6,992	\$ 1.415	\$ 9,894
Mar-20	3/20/2020	6,238	3,995	10,233	6,238	-	6,238	\$ 1.350	\$ 8,421
Mar-20	3/21/2020	6,806	5,881	12,687	6,806	-	6,806	\$ 1.605	\$ 10,924
Mar-20	3/22/2020	7,608	6,475	14,083	7,608	-	7,608	\$ 1.605	\$ 12,211
Mar-20	3/23/2020	7,830	6,459	14,289	7,830	-	7,830	\$ 1.605	\$ 12,567
Mar-20	3/24/2020	8,067	5,733	13,800	8,067	-	8,067	\$ 1.495	\$ 12,060

Load Shape Price Factor Worksheet

Historic Delivery Service Loads				Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis		
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Mar-20	3/25/2020	7,572	5,577	13,149	7,572	-	7,572	\$ 1.660	\$ 12,570
Mar-20	3/26/2020	6,838	4,911	11,749	6,838	-	6,838	\$ 1.550	\$ 10,599
Mar-20	3/27/2020	6,328	4,500	10,828	6,328	-	6,328	\$ 1.385	\$ 8,764
Mar-20	3/28/2020	6,198	4,311	10,509	6,198	-	6,198	\$ 1.220	\$ 7,562
Mar-20	3/29/2020	4,993	5,197	10,190	4,993	-	4,993	\$ 1.220	\$ 6,091
Mar-20	3/30/2020	7,489	5,705	13,194	7,489	-	7,489	\$ 1.220	\$ 9,137
Mar-20	3/31/2020	7,786	5,652	13,438	7,786	-	7,786	\$ 1.525	\$ 11,874
Apr-20	4/1/2020	7,663	5,373	13,036	7,663	-	7,663	\$ 1.625	\$ 12,452
Apr-20	4/2/2020	7,208	5,171	12,379	7,208	-	7,208	\$ 1.490	\$ 10,740
Apr-20	4/3/2020	6,879	5,107	11,986	6,879	-	6,879	\$ 1.410	\$ 9,699
Apr-20	4/4/2020	4,959	4,799	9,758	4,959	-	4,959	\$ 1.395	\$ 6,918
Apr-20	4/5/2020	5,103	4,634	9,737	5,103	-	5,103	\$ 1.395	\$ 7,119
Apr-20	4/6/2020	7,769	4,668	12,437	7,769	-	7,769	\$ 1.395	\$ 10,838
Apr-20	4/7/2020	7,034	4,535	11,569	7,034	-	7,034	\$ 1.450	\$ 10,199
Apr-20	4/8/2020	7,409	5,097	12,506	7,409	-	7,409	\$ 1.620	\$ 12,003
Apr-20	4/9/2020	6,913	5,697	12,610	6,913	-	6,913	\$ 1.635	\$ 11,303
Apr-20	4/10/2020	6,187	5,299	11,486	6,187	-	6,187	\$ 1.455	\$ 9,002
Apr-20	4/11/2020	4,257	5,024	9,281	4,257	-	4,257	\$ 1.455	\$ 6,194
Apr-20	4/12/2020	4,393	3,884	8,277	4,393	-	4,393	\$ 1.455	\$ 6,392
Apr-20	4/13/2020	6,628	4,016	10,644	6,628	-	6,628	\$ 1.455	\$ 9,644
Apr-20	4/14/2020	7,676	4,368	12,044	7,676	-	7,676	\$ 1.500	\$ 11,514
Apr-20	4/15/2020	8,268	5,347	13,615	8,268	-	8,268	\$ 1.770	\$ 14,634
Apr-20	4/16/2020	6,951	5,558	12,509	6,951	-	6,951	\$ 1.725	\$ 11,990
Apr-20	4/17/2020	5,439	3,830	9,269	5,439	-	5,439	\$ 1.610	\$ 8,757
Apr-20	4/18/2020	4,688	4,107	8,795	4,688	-	4,688	\$ 1.610	\$ 7,548
Apr-20	4/19/2020	5,170	2,321	7,491	5,170	-	5,170	\$ 1.610	\$ 8,324
Apr-20	4/20/2020	7,422	3,879	11,301	7,422	-	7,422	\$ 1.610	\$ 11,949
Apr-20	4/21/2020	8,011	4,318	12,329	8,011	-	8,011	\$ 1.800	\$ 14,420
Apr-20	4/22/2020	8,027	4,500	12,527	8,027	-	8,027	\$ 2.000	\$ 16,054

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2019-2020 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Apr-20	4/23/2020	7,259	3,007	10,266	7,259	-	7,259	\$ 1.955	\$ 14,191
Apr-20	4/24/2020	6,439	3,200	9,639	6,439	-	6,439	\$ 1.920	\$ 12,363
Apr-20	4/25/2020	4,285	2,913	7,198	4,285	-	4,285	\$ 1.825	\$ 7,820
Apr-20	4/26/2020	4,589	3,664	8,253	4,589	-	4,589	\$ 1.825	\$ 8,375
Apr-20	4/27/2020	7,891	4,128	12,019	7,891	-	7,891	\$ 1.825	\$ 14,401
Apr-20	4/28/2020	8,473	3,450	11,923	8,473	-	8,473	\$ 1.775	\$ 15,040
Apr-20	4/29/2020	8,118	3,604	11,722	8,118	-	8,118	\$ 1.750	\$ 14,207
Apr-20	4/30/2020	7,122	3,382	10,504	7,122	-	7,122	\$ 1.660	\$ 11,823
Winter Period		1,325,586	1,163,564	2,489,150	1,325,586	-	1,325,586	\$ 2.785	\$ 3,692,101
Weighted Average Daily Price								\$ 2.785	
Straight Average Daily Price								\$ 2.711	
Load Shape Price Factor								1.027	

Month	Projected Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment		
	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total
Nov-20	208,617	161,248	369,865	208,617	-	208,617
Dec-20	200,336	209,076	409,412	200,336	-	200,336
Jan-21	217,128	225,622	442,750	217,128	-	217,128
Feb-21	209,159	202,424	411,583	209,159	-	209,159
Mar-21	217,322	208,317	425,639	217,322	-	217,322
Apr-21	183,124	143,166	326,290	183,124	-	183,124
Winter	1,235,686	1,149,853	2,385,539	1,235,686	-	1,235,686

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
Gas Assistance Program and Regulatory Assessment (GAPRA)

	Customer Charge	First Block	Last Block	Cost of Gas	Total
1 Peak Period					
2 R-10 Base Rates	\$22.20	\$0.6920	\$0.6920	\$0.7315	
3 R-10 Rate Discounted 45%	\$12.21	\$0.3806	\$0.3806	\$0.4023	
4 Program Subsidy	\$9.99	\$0.3114	\$0.3114	\$0.3292	
5 Average Annual Therms		266	289	555	
6					
7 Peak Period Subsidy	\$59.94	\$82.96	\$89.87	\$182.69	\$415.46
8					
9					
10 Number of Estimated 2020/21 Participants					697
11					
12 Annual Subsidy times Number of Participants (Ln 7 * Ln 10)					\$289,640
13 Prior Year Ending Balance 10/31/2020 - RLIARA Page 2					(\$33,560)
14 Estimated Annual Administrative Costs					\$0
15 Estimated Non-Distribution Regulatory Assessment (Based off of NHPUC invoice dated August 19, 2020)					\$63,505
16 Total Program Costs					\$319,585
17					
18 Estimated weather normalized firm therms billed for					
19 the twelve months ended 10/31/21 sales and transportation					72,579,945
20 (Attachment 2 to Schedule 10B, Page 2 of 3, "Total Division"					
21 subtract "Special Contracts").					
22 Total Gas Assistance Program and Regulatory Assessment Charge					\$0.0044

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2019 THROUGH OCTOBER 2020
GAS ASSISTANCE PROGRAM AND REGULATORY ASSESSMENT (GAPRA) RECONCILIATION

		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	Total
1 FOR THE MONTH OF:	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Total
2 DAYS IN MONTH	30	31	31	29	31	30	31	30	31	31	30	31	366
3													Average
4 GAPRA Participant Count	521	759	718	749	728	780	761	677	668	686	666	653	697
5													Total
6 Beginning Balance	(\$165,246)	(\$162,111)	(\$143,556)	(\$130,607)	(\$117,225)	(\$104,298)	(\$86,723)	(\$74,246)	(\$60,996)	(\$52,101)	(\$45,500)	(\$38,995)	(\$165,246)
7													
8 Add: Actual Costs	\$18,112	\$37,740	\$39,013	\$50,483 (1)	\$39,628	\$35,052	\$24,284	\$18,438	\$12,176	\$10,190	\$10,411	\$11,673	\$307,199
9													
10 Add: Regulatory Assessments	\$8,613	\$14,434	\$11,421	\$605	\$6,013	\$6,013	\$6,013	\$6,013	\$6,013	\$5,292	\$5,292	\$5,292	\$81,014
11													
12 Less: Collected Revenue	\$22,876	\$32,952	\$36,944	\$37,230	\$32,276	\$23,113	\$17,501	\$10,934	\$9,142	\$8,749	\$9,084	\$11,432	(\$252,230)
13													
14 Add: Administrative and Start Up Costs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15													
16 Ending Balance Pre-Interest	(\$161,396)	(\$142,889)	(\$130,066)	(\$116,749)	(\$103,861)	(\$86,346)	(\$73,928)	(\$60,729)	(\$51,948)	(\$45,368)	(\$38,881)	(\$33,462)	
17													
18 Month's Average Balance	(\$163,321)	(\$152,500)	(\$136,811)	(\$123,678)	(\$110,543)	(\$95,322)	(\$80,326)	(\$67,487)	(\$56,472)	(\$48,735)	(\$42,191)	(\$36,228)	
19													
20 Interest Rate	5.25%	5.25%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	3.25%	3.25%	3.25%	3.25%	
21													
22 Interest Applied	(\$715)	(\$667)	(\$542)	(\$477)	(\$438)	(\$377)	(\$318)	(\$267)	(\$153)	(\$132)	(\$114)	(\$98)	
23													
24 Ending Balance	(\$162,111)	(\$143,556)	(\$130,607)	(\$117,225)	(\$104,298)	(\$86,723)	(\$74,246)	(\$60,996)	(\$52,101)	(\$45,500)	(\$38,995)	(\$33,560)	

(1) Over Collection

(1) Includes correction of lost revenue related to prior month and associated interest.

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
Calculation of Distribution and Non-Distribution Revenues of the NHPUC Annual Regulatory Assessment
NHPUC Assessment Invoice dated August 19, 2020

	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Total Fiscal Year
Distribution	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$30,747.00	\$368,964.00
Non-Distribution	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$5,292.08	\$63,505.00
Total	\$108,117.25			\$108,117.25			\$108,117.25			\$108,117.25			\$432,469.00

(1) The \$368,964.00 for Distribution represents the amount established in Docket DG 17-070.

(2) Total Invoice amount minus Distribution amount.

Northern Utilities, Inc. -- New Hampshire Division

EEC Budget

	Residential	Low-Income	Gen Service	Total
July-20	\$51,728	\$9,161	\$58,020	\$118,909
August-20	\$59,199	\$33,463	\$66,401	\$159,063
September-20	\$66,096	\$37,362	\$80,013	\$183,471
October-20	\$73,568	\$41,585	\$82,518	\$197,671
November-20	\$81,040	\$45,809	\$90,898	\$217,747
December-20	\$88,512	\$50,032	\$105,155	\$243,699
January-21	\$33,101	\$16,281	\$57,210	\$106,592
February-21	\$55,169	\$27,135	\$57,210	\$139,514
March-21	\$66,203	\$32,562	\$85,815	\$184,580
April-21	\$77,237	\$37,989	\$100,117	\$215,343
May-21	\$77,237	\$37,989	\$57,210	\$172,436
June-21	\$132,406	\$65,125	\$71,512	\$269,043
July-21	\$143,440	\$70,552	\$100,117	\$314,108
August-21	\$77,237	\$37,989	\$157,327	\$272,553
September-21	\$154,473	\$75,979	\$171,629	\$402,082
October-21	\$110,338	\$54,271	\$185,932	\$350,541
Total	\$1,346,983	\$673,283	\$1,527,084	\$3,547,351

Budget with Low-Income Costs Allocated

to Residential and General Service Classes

	Residential	Low-Income	Gen Service	Total
July-20	\$56,539	0	\$62,370	\$118,909
August-20	\$63,760	0	\$95,304	\$159,063
September-20	\$71,689	0	\$111,782	\$183,471
October-20	\$80,185	0	\$117,486	\$197,671
November-20	\$92,872	0	\$124,875	\$217,747
December-20	\$104,446	0	\$139,252	\$243,699
January-21	\$38,314	0	\$68,279	\$106,592
February-21	\$64,133	0	\$75,381	\$139,514
March-21	\$76,417	0	\$108,163	\$184,580
April-21	\$88,503	0	\$126,840	\$215,343
May-21	\$86,905	0	\$85,531	\$172,436
June-21	\$145,513	0	\$123,530	\$269,043
July-21	\$154,320	0	\$159,788	\$314,108
August-21	\$82,237	0	\$190,316	\$272,553
September-21	\$165,211	0	\$236,870	\$402,082
October-21	\$118,650	0	\$231,891	\$350,541
Total	\$1,489,693	\$0	\$2,057,658	\$3,547,351

EEC Charge Factor Calculation

EEC Charge Factors for Residential Customers

	Effective November 1, 2020	
EEC Reconciliation Adjustment	\$276,963	Schedule 38 Page 3 Nov '20 Beginning Balance
EEC Costs	\$1,096,392	Schedule 38 Page 3 Nov '20 - Oct '21 Totals; Company Budget
EEC Performance Incentive	\$56,430	Schedule 38 Page 3 Nov '20 - Oct '21 Totals; Company Budget
EEC Low-Income Costs	\$121,129	Schedule 38 Page 3 Nov '20 - Oct '21 Totals; Company Budget
EEC Allocated Low-Income Performance Incentive	\$6,532	Schedule 38 Page 3 Nov '20 - Oct '21 Totals; Company Budget
Total	\$1,557,446	
Forecasted Annual Throughput Volumes for Residential Customers	20,133,234	Schedule 38 Page 3 Nov '20 - Oct '21 Totals; Company Forecast

Energy Efficiency Charge Factor for Residential Customers	\$0.0774

EEC Charge Factors for Commercial and Industrial Customers (C&I)

EEC Reconciliation Adjustment	(\$60,459)	Schedule 38 Page 4 Nov '20 Beginning Balance
EEC Costs	\$1,240,133	Schedule 38 Page 4 Nov '20 - Oct '21 Totals; Company Budget
EEC Performance Incentive	\$73,557	Schedule 38 Page 4 Nov '20 - Oct '21 Totals; Company Budget
EEC Low-Income Costs	\$430,584	Schedule 38 Page 4 Nov '20 - Oct '21 Totals; Company Budget
EEC Allocated Low-Income Performance Incentive	\$21,181	Schedule 38 Page 4 Nov '20 - Oct '21 Totals; Company Budget
Total	\$1,704,995	
Forecasted Annual Throughput Volumes for C&I Customers	52,446,711	Schedule 38 Page 4 Nov '20 - Oct '21 Totals; Company Forecast

Energy Efficiency Charge Factor for C&I Customers	\$0.0337

Northern Utilities, Inc.																
New Hampshire Division																
Calculation of the EEC Charge, a Component of the Local Distribution Adjustment Charge																
To Be Effective November 1, 2020 through October 31, 2021																
Residential Customers																
		Beginning Balance (Over)/Under		EEC Rate per Therm	EEC Collections	EEC Costs	DSM PI	Allocated Low Income Costs	Allocated Low Income PI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-19	Actual	\$107,098		\$0.0501	\$16,801	\$37,242	\$3,633	\$1,184	\$69	\$132,424	\$119,761	5.50%	\$559	\$132,983	335,427	31
September-19	Actual	\$132,983		\$0.0501	\$16,810	\$21,383	\$3,633	\$11,591	\$675	\$153,455	\$143,219	5.50%	\$647	\$154,102	335,597	30
October-19	Actual	\$154,102		\$0.0501	\$30,568	\$57,526	\$3,633	\$1,339	\$78	\$186,110	\$170,106	5.25%	\$758	\$186,868	610,233	31
November-19	Actual	\$186,868		\$0.0499	\$68,678	\$20,599	\$3,633	\$20,128	\$1,171	\$163,721	\$175,295	5.25%	\$1,262	\$164,984	1,373,589	30
December-19	Actual	\$164,984		\$0.0499	\$137,485	\$32,245	\$3,633	\$4,023	\$234	\$67,634	\$116,309	5.25%	\$519	\$68,152	2,755,471	31
January-20	Actual	\$68,152		\$0.0499	\$154,006	\$19,025	\$3,906	\$3,272	\$190	(\$59,461)	\$4,346	4.75%	\$17	(\$59,444)	3,086,303	31
February-20	Actual	\$556 (1)		\$0.0499	\$156,856	\$111,389	\$3,906	\$7,729	\$450	(\$32,826)	(\$16,135)	4.75%	\$3,669	(\$29,158)	3,143,380	29
March-20	Actual	\$45,842 (1)		\$0.0499	\$133,675	\$132,910	\$15,890	\$25,651	\$1,493	\$88,111	\$66,977	4.75%	\$1,675	\$89,786	2,678,854	31
April-20	Actual	\$89,786		\$0.0499	\$93,387	\$84,604	\$3,906	\$11,124	\$647	\$96,680	\$93,233	4.75%	\$414	\$97,093	1,871,517	30
May-20	Actual	\$97,093		\$0.0499	\$66,832	\$18,542 (\$976)	\$3,996	\$233	\$52,056	\$74,575	\$74,575	4.75%	\$300	\$52,356	1,339,252	31
June-20	Actual	\$52,356		\$0.0499	\$28,689	\$43,423	\$2,929	\$1,527	\$89	\$71,635	\$61,996	4.75%	\$241	\$71,877	574,945	30
July-20	Forecast	\$71,877		\$0.0499	\$20,894	\$51,728	\$2,929	\$4,811	\$234	\$110,685	\$91,281	3.25%	\$251	\$110,936	418,711	31
August-20	Forecast	\$110,936		\$0.0499	\$16,527	\$59,199	\$2,929	\$4,560	\$193	\$161,292	\$136,114	3.25%	\$375	\$161,666	331,195	31
September-20	Forecast	\$161,666		\$0.0499	\$18,846	\$66,096	\$2,929	\$5,592	\$212	\$217,651	\$189,659	3.25%	\$505	\$218,156	377,676	30
October-20	Forecast	\$218,156		\$0.0499	\$25,214	\$73,568	\$2,929	\$6,617	\$226	\$276,283	\$247,219	3.25%	\$681	\$276,963	505,288	31
November-20	Forecast	\$276,963		\$0.0774	\$115,178	\$81,040	\$2,929	\$11,832	\$367	\$257,953	\$267,458	3.25%	\$712	\$258,665	1,488,092	30
December-20	Forecast	\$258,665		\$0.0774	\$212,948	\$88,512	\$2,929	\$15,935	\$452	\$153,546	\$206,105	3.25%	\$567	\$154,113	2,751,261	31
January-21	Forecast	\$154,113		\$0.0774	\$261,213	\$33,101	\$5,057	\$5,212	\$796	(\$62,933)	\$45,590	3.25%	\$126	(\$62,807)	3,374,845	31
February-21	Forecast	(\$62,807)		\$0.0774	\$291,762	\$55,169	\$5,057	\$8,964	\$822	(\$284,557)	(\$173,682)	3.25%	(\$433)	(\$284,990)	3,769,530	28
March-21	Forecast	(\$284,990)		\$0.0774	\$245,174	\$66,203	\$5,057	\$10,214	\$780	(\$447,910)	(\$366,450)	3.25%	(\$1,012)	(\$448,921)	3,167,624	31
April-21	Forecast	(\$448,921)		\$0.0774	\$165,238	\$77,237	\$5,057	\$11,267	\$738	(\$519,861)	(\$484,391)	3.25%	(\$1,294)	(\$521,155)	2,134,862	30
May-21	Forecast	(\$521,155)		\$0.0774	\$93,796	\$77,237	\$5,057	\$9,668	\$633	(\$522,357)	(\$521,756)	3.25%	(\$1,440)	(\$523,797)	1,211,836	31
June-21	Forecast	(\$523,797)		\$0.0774	\$48,120	\$132,406	\$5,057	\$13,107	\$501	(\$420,846)	(\$472,321)	3.25%	(\$1,262)	(\$422,108)	621,702	30
July-21	Forecast	(\$422,108)		\$0.0774	\$30,763	\$143,440	\$5,057	\$10,880	\$384	(\$293,110)	(\$357,609)	3.25%	(\$987)	(\$294,097)	397,455	31
August-21	Forecast	(\$294,097)		\$0.0774	\$26,040	\$77,237	\$5,057	\$5,000	\$327	(\$232,516)	(\$263,306)	3.25%	(\$727)	(\$233,243)	336,440	31
September-21	Forecast	(\$233,243)		\$0.0774	\$28,829	\$154,473	\$5,057	\$10,738	\$352	(\$91,451)	(\$162,347)	3.25%	(\$434)	(\$91,885)	372,462	30
October-21	Forecast	(\$91,885)		\$0.0774	\$39,252	\$110,338	\$5,057	\$8,312	\$381	(\$7,049)	(\$49,467)	3.25%	(\$137)	(\$7,185)	507,126	31
Nov 20 thru Oct 21 Totals						\$1,558,312	\$1,096,392	\$56,430	\$121,129	\$6,532					20,133,234	
Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 2 of 3, filed on September 17, 2019 in the Cost of Gas Docket. Actual Performance Incentives includes reconciliations from prior year(s). (1) Reflects correction and transfer to On Bill Financing plus associated interest.																

Northern Utilities, Inc.
NHPUC Docket No. DG 20-xxx
Schedule 37 EEC
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Northern Utilities, Inc. New Hampshire Division Calculation of the EEC Charge, a Component of the Local Distribution Adjustment Charge To Be Effective November 1, 2020 through October 31, 2021 General Service Customers															
		Beginning Balance (Over)/Under	EEC Rate per Therm	EEC Collections	EEC Costs	DSM PI	Allocated Low Income Costs	Allocated Low Income PI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-19	Actual	(\$704,375)	\$0.0264	\$63,986	\$29,331	\$4,684	\$8,553	\$498	(\$725,295)	(\$714,835)	5.50%	(\$3,339)	(\$728,634)	2,423,706	31
September-19	Actual	(\$728,634)	\$0.0264	\$62,483	\$110,426	\$4,684	\$81,746	\$4,758	(\$589,503)	(\$659,069)	5.50%	(\$2,979)	(\$592,483)	2,366,753	30
October-19	Actual	(\$592,483)	\$0.0264	\$83,920	\$220,316	\$4,684	\$6,982	\$406	(\$444,015)	(\$518,249)	5.25%	(\$2,311)	(\$446,326)	3,182,362	31
November-19	Actual	(\$446,326)	\$0.0247	\$114,869	\$248,775	\$4,684	\$66,982	\$3,898	(\$236,854)	(\$341,590)	5.25%	(\$1,459)	(\$238,312)	4,571,040	30
December-19	Actual	(\$238,312)	\$0.0247	\$158,016	\$190,099	\$4,684	\$9,339	\$544	(\$191,662)	(\$214,987)	5.25%	(\$959)	(\$192,621)	6,397,368	31
January-20	Actual	(\$192,621)	\$0.0247	\$177,242	\$53,455	\$5,336	\$7,606	\$443	(\$303,024)	(\$247,822)	4.75%	(\$997)	(\$304,021)	7,174,996	31
February-20	Actual	(\$198,021)	(1) \$0.0247	\$177,778	\$72,005	\$5,336	\$17,680	\$1,029	(\$279,749)	(\$238,885)	4.75%	\$4,654	(\$275,096)	7,197,470	29
March-20	Actual	(\$125,096)	(1) \$0.0247	\$155,281	\$54,638	(\$3,397)	\$60,197	\$3,504	(\$165,435)	(\$145,265)	4.75%	\$564	(\$164,871)	6,286,658	31
April-20	Actual	(\$164,871)	\$0.0247	\$112,351	\$30,445	\$5,336	\$27,036	\$1,574	(\$212,832)	(\$188,852)	4.75%	(\$735)	(\$213,567)	4,548,589	30
May-20	Actual	(\$213,567)	\$0.0247	\$87,004	\$71,762	(\$1,334)	\$10,511	\$612	(\$219,021)	(\$216,294)	4.75%	(\$870)	(\$219,891)	3,522,410	31
June-20	Actual	(\$219,891)	\$0.0247	\$60,861	\$41,870	\$4,002	\$6,546	\$381	(\$227,954)	(\$223,923)	4.75%	(\$872)	(\$228,826)	2,463,920	30
July-20	Forecast	(\$228,826)	\$0.0247	\$65,835	\$58,020	\$4,002	\$4,350	\$253	(\$228,035)	(\$228,431)	3.25%	(\$629)	(\$228,664)	2,125,963	31
August-20	Forecast	(\$228,664)	\$0.0247	\$51,849	\$66,401	\$4,002	\$28,903	\$1,226	(\$179,981)	(\$204,323)	3.25%	(\$562)	(\$180,544)	2,099,142	31
September-20	Forecast	(\$180,544)	\$0.0247	\$52,996	\$80,013	\$4,002	\$31,769	\$1,207	(\$116,548)	(\$148,546)	3.25%	(\$396)	(\$116,944)	2,145,572	30
October-20	Forecast	(\$116,944)	\$0.0247	\$65,953	\$82,518	\$4,002	\$34,968	\$1,194	(\$60,216)	(\$88,580)	3.25%	(\$244)	(\$60,459)	2,670,168	31
November-20	Forecast	(\$60,459)	\$0.0325	\$138,874	\$90,898	\$4,002	\$33,976	\$1,053	(\$69,404)	(\$64,932)	3.25%	(\$173)	(\$69,577)	4,273,046	30
December-20	Forecast	(\$69,577)	\$0.0325	\$191,330	\$105,155	\$4,002	\$34,097	\$968	(\$116,685)	(\$93,131)	3.25%	(\$256)	(\$116,941)	5,887,088	31
January-21	Forecast	(\$116,941)	\$0.0325	\$232,929	\$57,210	\$6,555	\$11,069	\$1,691	(\$273,345)	(\$195,143)	3.25%	(\$539)	(\$273,884)	7,167,043	31
February-21	Forecast	(\$273,884)	\$0.0325	\$248,358	\$57,210	\$6,555	\$18,172	\$1,666	(\$438,639)	(\$356,262)	3.25%	(\$888)	(\$439,528)	7,641,797	28
March-21	Forecast	(\$439,528)	\$0.0325	\$225,235	\$85,815	\$6,555	\$22,348	\$1,707	(\$548,338)	(\$493,933)	3.25%	(\$1,363)	(\$549,701)	6,930,321	31
April-21	Forecast	(\$549,701)	\$0.0325	\$164,566	\$100,117	\$6,555	\$26,723	\$1,750	(\$579,122)	(\$564,412)	3.25%	(\$1,508)	(\$580,630)	5,063,577	30
May-21	Forecast	(\$580,630)	\$0.0325	\$115,374	\$57,210	\$6,555	\$28,321	\$1,854	(\$602,063)	(\$591,346)	3.25%	(\$1,632)	(\$603,695)	3,549,981	31
June-21	Forecast	(\$603,695)	\$0.0325	\$80,188	\$71,512	\$6,555	\$52,018	\$1,987	(\$551,811)	(\$577,753)	3.25%	(\$1,543)	(\$553,354)	2,467,336	30
July-21	Forecast	(\$553,354)	\$0.0325	\$70,840	\$100,117	\$6,555	\$59,671	\$2,104	(\$455,747)	(\$504,551)	3.25%	(\$1,393)	(\$457,140)	2,179,685	31
August-21	Forecast	(\$457,140)	\$0.0325	\$72,143	\$157,327	\$6,555	\$32,989	\$2,160	(\$330,251)	(\$393,695)	3.25%	(\$1,087)	(\$331,338)	2,219,780	31
September-21	Forecast	(\$331,338)	\$0.0325	\$73,543	\$171,629	\$6,555	\$65,241	\$2,136	(\$159,320)	(\$245,329)	3.25%	(\$655)	(\$159,975)	2,262,857	30
October-21	Forecast	(\$159,975)	\$0.0325	\$91,136	\$185,932	\$6,555	\$45,959	\$2,106	(\$10,558)	(\$85,267)	3.25%	(\$235)	(\$10,794)	2,804,200	31

Nov 20 thru Oct 21 Totals	\$1,704,516	\$1,240,133	\$73,557	\$430,584	\$21,181									52,446,710	

Forecast therm Sales from Company Forecast as seen in Attachment 2 to Schedule 10 B, Page 2 of 3, filed on September 17, 2019 in the Cost of Gas Docket. Does not include Special Contracts.

Actual Performance Incentives includes reconciliations from prior year(s).

(1) Reflects correction and transfer to On Bill Financing plus associated interest.

Northern Utilities, Inc.
Calculation of Lost Revenue Rate (LRR)

Line	Sector		Reference
Residential Classes- R5, R6, R10, R11			
		Effective November 1, 2020	
1	Sector Ending Balance-October 31	\$ 98,805	Page 2, Ln 2
2	Lost Distribution Revenue-November through October	344,524	Page 2, Ln 4, Total
3	Interest- November through October	(850)	Page 2, Ln 17, Total
4	Total to be recovered	\$ 442,479	Line 1 + Line 2 + Line 3
5	Sector Sales - Therms- November through October	20,133,234	Page 2, Line 7
6	Lost Revenue Rate (\$ per therm)	\$0.0220	Line 4 / Line 5
Commercial & Industrial Classes-G40/T40, G50/T50, G41/T41, G51/T51, G42/T42, G-52/T52			
7	Sector Ending Balance-October 31	(5,831)	Page 2, Ln 21
8	Lost Distribution Revenue-November through October	\$ 162,437	Page 2, Ln 24, Total
9	Interest- November through October	\$ (388)	Page 2, Ln 37, Total
10	Total to be recovered	\$ 156,217	Line 7 + Line 8 + Line 9
11	Sector Sales - Therms- November through October	52,446,710	Page 2, Line 27
12	Lost Revenue Rate (\$ per therm)	\$0.0030	Line 10 / Line 11

Northern Utilities, Inc.
Lost Revenue Reconciliation
2020

Line	Sector / Description	Unit	Actual Nov-19	Actual Dec-19	Estimate Jan-20	Estimate Feb-20	Estimate Mar-20	Estimate Apr-20	Estimate May-20	Estimate Jun-20	Estimate Jul-20	Estimate Aug-20	Estimate Sep-20	Estimate Oct-20	Total
1	RESIDENTIAL														
2	Beginning Balance - (Over)/Under	\$'s	\$ 51,276	\$ 58,859	\$ 47,805	\$ 33,086	\$ 18,072	\$ 8,767	\$ 9,173	\$ 13,589	\$ 27,557	\$ 44,192	\$ 62,340	\$ 80,938	
3	COSTS														
4	Lost Distribution Revenue	\$'s	\$ 20,120	\$ 20,120	\$ 20,348	\$ 20,726	\$ 21,180	\$ 21,709	\$ 19,640	\$ 20,442	\$ 21,310	\$ 21,777	\$ 22,712	\$ 23,380	\$ 253,465
5															
6	REVENUE														
7	Sector Sales	Therms	1,373,589	2,755,471	3,086,303	3,143,380	2,678,854	1,871,517	1,339,252	574,945	418,712	331,195	377,676	505,288	18,456,181
8	Lost Revenue Rate	\$/Therm	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	\$0.0114	
9	Revenue	\$'s	\$ 12,774	\$ 31,411	\$ 35,229	\$ 35,836	\$ 30,539	\$ 21,338	\$ 15,270	\$ 6,554	\$ 4,773	\$ 3,776	\$ 4,306	\$ 5,760	\$ 207,566
10															
11	(Over)/Under-Recovery (Exc interest)		\$ 58,622	\$ 47,568	\$ 32,924	\$ 17,976	\$ 8,713	\$ 9,138	\$ 13,543	\$ 27,477	\$ 44,093	\$ 62,194	\$ 80,747	\$ 98,558	
12															
13	INTEREST														
14	Average Monthly Balance		\$ 54,949	\$ 53,213	\$ 40,364	\$ 25,531	\$ 13,393	\$ 8,952	\$ 11,358	\$ 20,533	\$ 35,825	\$ 53,193	\$ 71,544	\$ 89,748	
15	Interest Rate-WSJ Prime Rate	Annual %	5.25%	5.25%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	3.25%	3.25%	3.25%	3.25%	
16	Days per Month		30	31	31	29	31	30	31	30	31	31	30	31	366
17	Computed Interest	\$'s	\$ 237	\$ 237	\$ 162	\$ 96	\$ 54	\$ 35	\$ 46	\$ 80	\$ 99	\$ 146	\$ 191	\$ 247	\$ 1,630
18															
19	Ending Balance	\$'s	\$ 58,859	\$ 47,805	\$ 33,086	\$ 18,072	\$ 8,767	\$ 9,173	\$ 13,589	\$ 27,557	\$ 44,192	\$ 62,340	\$ 80,938	\$ 98,805	
20	COMMERCIAL & INDUSTRIAL														
21	Beginning Balance - (Over)/Under	\$'s	\$ (27,418)	\$ (24,343)	\$ (25,195)	\$ (27,303)	\$ (29,281)	\$ (29,268)	\$ (25,626)	\$ (24,861)	\$ (21,939)	\$ (18,150)	\$ (13,999)	\$ (9,598)	
22															
23	COSTS														
24	Lost Distribution Revenue	\$'s	\$ 11,295	\$ 11,413	\$ 11,624	\$ 11,804	\$ 12,075	\$ 12,391	\$ 7,558	\$ 7,694	\$ 7,884	\$ 8,183	\$ 8,509	\$ 8,862	\$ 119,293
25															
26	REVENUE														
27	Sector Sales	Therms	4,571,040	6,397,368	7,174,996	7,197,471	6,286,658	4,548,589	3,522,410	2,463,920	2,125,963	2,099,142	2,145,572	2,670,168	51,203,298
28	Lost Revenue Rate	\$/Therm	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	\$0.0019	
29	Revenue	\$'s	\$ 8,108	\$ 12,155	\$ 13,627	\$ 13,675	\$ 11,945	\$ 8,643	\$ 6,692	\$ 4,682	\$ 4,039	\$ 3,988	\$ 4,077	\$ 5,073	\$ 96,704
30															
31	(Over)/Under-Recovery (Exc interest)	\$'s	\$ (24,231)	\$ (25,084)	\$ (27,198)	\$ (29,175)	\$ (29,151)	\$ (25,519)	\$ (24,760)	\$ (21,849)	\$ (18,095)	\$ (13,955)	\$ (9,567)	\$ (5,810)	
32															
33	INTEREST														
34	Average Monthly Balance		\$ (25,825)	\$ (24,714)	\$ (26,196)	\$ (28,239)	\$ (29,216)	\$ (27,394)	\$ (25,193)	\$ (23,355)	\$ (20,017)	\$ (16,052)	\$ (11,783)	\$ (7,704)	
35	Interest Rate-WSJ Prime Rate	Annual %	5.25%	5.25%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	3.25%	3.25%	3.25%	3.25%	
36	Days per Month		30	31	31	29	31	30	31	30	31	31	30	31	366
37	Computed Interest	\$'s	\$ (111)	\$ (110)	\$ (105)	\$ (106)	\$ (118)	\$ (107)	\$ (101)	\$ (91)	\$ (55)	\$ (44)	\$ (31)	\$ (21)	\$ (1,002)
38															
39	Ending Balance	\$'s	\$ (24,343)	\$ (25,195)	\$ (27,303)	\$ (29,281)	\$ (29,268)	\$ (25,626)	\$ (24,861)	\$ (21,939)	\$ (18,150)	\$ (13,999)	\$ (9,598)	\$ (5,831)	

NOTES:

Line 1: DE 17-136 2019 Annual Report
Line 4: Page 3, Line 7
Line 21: DE 17-136 2019 Annual Report
Line 24: Page 3, Line 11

Northern Utilities, Inc.
Lost Revenue Reconciliation
2021

Line	Sector / Description	Unit	Estimate Nov-20	Estimate Dec-20	Estimate Jan-21	Estimate Feb-21	Estimate Mar-21	Estimate Apr-21	Estimate May-21	Estimate Jun-21	Estimate Jul-21	Estimate Aug-21	Estimate Sep-21	Estimate Oct-21	Total
1	RESIDENTIAL														
2	Beginning Balance - (Over)/Under	\$'s	\$ 98,805	\$ 93,400	\$ 60,767	\$ 14,588	\$ (39,942)	\$ (80,803)	\$ (98,360)	\$ (98,527)	\$ (84,693)	\$ (64,811)	\$ (42,951)	\$ (20,662)	
3	COSTS														
4	Lost Distribution Revenue	\$'s	\$ 27,078	\$ 27,683	\$ 27,963	\$ 28,432	\$ 28,993	\$ 29,649	\$ 26,764	\$ 27,757	\$ 28,832	\$ 29,410	\$ 30,568	\$ 31,395	\$344,524
5															
6	REVENUE														
7	Sector Sales	Therms	1,488,092	2,751,261	3,374,845	3,769,530	3,167,624	2,134,862	1,211,836	621,702	397,455	336,440	372,462	507,126	20,133,234
8	Lost Revenue Rate	\$/Therm	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	<u>\$0.0220</u>	
9	Revenue	\$'s	\$ 32,738	\$ 60,528	\$ 74,247	\$ 82,930	\$ 69,688	\$ 46,967	\$ 26,660	\$ 13,677	\$ 8,744	\$ 7,402	\$ 8,194	\$ 11,157	442,931
10															
11	(Over)/Under-Recovery (Exc interest)	\$	\$ 93,144	\$ 60,555	\$ 14,484	\$ (39,910)	\$ (80,636)	\$ (98,121)	\$ (98,256)	\$ (84,448)	\$ (64,605)	\$ (42,802)	\$ (20,577)	\$ (423)	
12															
13	INTEREST														
14	Average Monthly Balance		\$ 95,975	\$ 76,978	\$ 37,625	\$ (12,661)	\$ (60,289)	\$ (89,462)	\$ (98,308)	\$ (91,488)	\$ (74,649)	\$ (53,807)	\$ (31,764)	\$ (10,543)	
15	Interest Rate-WSJ Prime Rate	Annual %	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	
16	Days per Month		<u>30</u>	<u>31</u>	<u>31</u>	<u>28</u>	<u>31</u>	<u>30</u>	<u>31</u>	<u>30</u>	<u>31</u>	<u>31</u>	<u>30</u>	<u>31</u>	365
17	Computed Interest	\$'s	\$ 256	\$ 212	\$ 104	\$ (32)	\$ (166)	\$ (239)	\$ (271)	\$ (244)	\$ (206)	\$ (149)	\$ (85)	\$ (29)	\$ (850)
18															
19	Ending Balance	\$'s	\$ 93,400	\$ 60,767	\$ 14,588	\$ (39,942)	\$ (80,803)	\$ (98,360)	\$ (98,527)	\$ (84,693)	\$ (64,811)	\$ (42,951)	\$ (20,662)	\$ (452)	
20	COMMERCIAL & INDUSTRIAL														
21	Beginning Balance - (Over)/Under	\$'s	\$ (5,831)	\$ (3,380)	\$ (5,094)	\$ (10,471)	\$ (17,100)	\$ (21,336)	\$ (19,648)	\$ (20,061)	\$ (17,081)	\$ (13,036)	\$ (8,793)	\$ (4,332)	
22															
23	COSTS														
24	Lost Distribution Revenue	\$'s	\$ 15,282	\$ 15,960	\$ 16,145	\$ 16,331	\$ 16,609	\$ 16,933	\$ 10,292	\$ 10,431	\$ 10,626	\$ 10,933	\$ 11,267	\$ 11,629	162,437
25															
26	REVENUE														
27	Sector Sales	Therms	4,273,046	5,887,088	7,167,043	7,641,797	6,930,321	5,063,577	3,549,981	2,467,336	2,179,685	2,219,780	2,262,857	2,804,200	52,446,710
28	Lost Revenue Rate	\$/Therm	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	<u>\$0.0030</u>	
29	Revenue	\$'s	\$ 12,819	\$ 17,661	\$ 21,501	\$ 22,925	\$ 20,791	\$ 15,191	\$ 10,650	\$ 7,402	\$ 6,539	\$ 6,659	\$ 6,789	\$ 8,413	157,340
30															
31	(Over)/Under-Recovery (Exc interest)	\$'s	\$ (3,368)	\$ (5,082)	\$ (10,450)	\$ (17,066)	\$ (21,283)	\$ (19,593)	\$ (20,006)	\$ (17,032)	\$ (12,994)	\$ (8,763)	\$ (4,314)	\$ (1,115)	
32															
33	INTEREST														
34	Average Monthly Balance		\$ (4,600)	\$ (4,231)	\$ (7,772)	\$ (13,768)	\$ (19,191)	\$ (20,464)	\$ (19,827)	\$ (18,546)	\$ (15,038)	\$ (10,899)	\$ (6,554)	\$ (2,724)	
35	Interest Rate-WSJ Prime Rate	Annual %	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	<u>3.25%</u>	
36	Days per Month		<u>30</u>	<u>31</u>	<u>31</u>	<u>28</u>	<u>31</u>	<u>30</u>	<u>31</u>	<u>30</u>	<u>31</u>	<u>31</u>	<u>30</u>	<u>31</u>	365
37	Computed Interest	\$'s	\$ (12)	\$ (12)	\$ (21)	\$ (34)	\$ (53)	\$ (55)	\$ (55)	\$ (50)	\$ (42)	\$ (30)	\$ (18)	\$ (8)	\$ (388)
38															
39	Ending Balance	\$'s	\$ (3,380)	\$ (5,094)	\$ (10,471)	\$ (17,100)	\$ (21,336)	\$ (19,648)	\$ (20,061)	\$ (17,081)	\$ (13,036)	\$ (8,793)	\$ (4,332)	\$ (1,123)	

NOTES:

Line 1: Page 2, Line 19
Line 4: Page 3a, Line 7
Line 21: Page 2, Line 39
Line 24: Page 3a, Line 11

Northern Utilities
Monthly and Cumulative Savings (Therms) and Lost Base Revenue
November 1, 2019 to October 31, 2020

Northern Utilities Inc.
NHPUC Docket No. DG 20-xxx
Schedule 37 LRR
Page 3 of 5

Line	Description	10/31/2019	Actual Nov-19	Actual Dec-19	Estimate Jan-20	Estimate Feb-20	Estimate Mar-20	Estimate Apr-20	Estimate May-20	Estimate Jun-20	Estimate Jul-20	Estimate Aug-20	Estimate Sep-20	Estimate Oct-20	Period Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Residential Annualized Savings	349,140	-	-	3,936	6,560	7,872	9,184	9,184	15,745	17,057	9,184	18,369	13,121	110,213
2	C&I Annualized Savings	616,273	65,423	7,159	10,876	10,876	16,314	19,033	10,876	13,595	19,033	29,910	32,629	35,348	271,073
3	Total		65,423	7,159	14,812	17,437	24,187	28,218	20,061	29,340	36,090	39,094	50,998	48,468	381,286
			Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Period LBR
4	Monthly Residential Savings		-	-	328	547	656	765	765	1,312	1,421	765	1,531	1,093	9,184
5	Cumulative Residential Savings	29,095	29,095	29,095	29,423	29,970	30,626	31,391	32,156	33,468	34,890	35,655	37,186	38,279	391,235
6	Average Residential Distribution Rate		0.6915	0.6915	0.6916	0.6916	0.6916	0.6916	0.6108	0.6108	0.6108	0.6108	0.6108	0.6108	
7	Lost Residential Revenue		\$ 20,120	\$ 20,120	\$ 20,348	\$ 20,726	\$ 21,180	\$ 21,709	\$ 19,640	\$ 20,442	\$ 21,310	\$ 21,777	\$ 22,712	\$ 23,380	\$ 253,465
8	Monthly C&I Savings		5,452	597	906	906	1,360	1,586	906	1,133	1,586	2,492	2,719	2,946	22,589
9	Cumulative C&I Savings	51,356	56,808	57,405	58,311	59,217	60,577	62,163	63,069	64,202	65,788	68,281	71,000	73,946	760,767
10	Average C&I Distribution Rate		0.1988	0.1988	0.1993	0.1993	0.1993	0.1993	0.1198	0.1198	0.1198	0.1198	0.1198	0.1198	
11	Lost C&I Revenue		\$ 11,295	\$ 11,413	\$ 11,624	\$ 11,804	\$ 12,075	\$ 12,391	\$ 7,558	\$ 7,694	\$ 7,884	\$ 8,183	\$ 8,509	\$ 8,862	\$ 119,293
12	Total Lost Revenue		\$ 31,414	\$ 31,533	\$ 31,972	\$ 32,530	\$ 33,255	\$ 34,100	\$ 27,199	\$ 28,136	\$ 29,194	\$ 29,960	\$ 31,221	\$ 32,242	\$ 372,758

Line 1: Page 4, Line 15
Line 1: Page 4, Line 21
Line 3: Line 1 + Line 2
Line 4: Line 1 / 12
Line 5: Prior Month Line 5 + Current Month Line 4
Line 6: Page 5, Line 30, Col. 3; Page 5, Line 30, Col. 3
Line 7: Line 5 x Line 6
Line 8: Line 2 / 12
Line 9: Prior Month Line 9 + Current Month Line 8
Line 10: Page 5, Line 37, Col. 3; Page 5, Line 52, Col. 3
Line 11: Line 9 x Line 10
Line 12: Line 7 + Line 11

Northern Utilities
Monthly and Cumulative Savings (Therms) and Lost Base Revenue
November 1, 2020 to October 31, 2021

Northern Utilities Inc.
NHPUC Docket No. DG 20-xxx
Schedule 37 LRR
Page 3a of 5

Line	Description	10/31/2020	Estimate Nov-20	Estimate Dec-20	Estimate Jan-21	Estimate Feb-21	Estimate Mar-21	Estimate Apr-21	Estimate May-21	Estimate Jun-21	Estimate Jul-21	Estimate Aug-21	Estimate Sep-21	Estimate Oct-21	Period Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Residential Annualized Savings	459,352	10,496	10,496	4,874	8,124	9,748	11,373	11,373	19,497	21,121	11,373	22,746	16,247	157,469
2	C&I Annualized Savings	887,347	32,629	40,786	11,161	11,161	16,742	19,532	11,161	13,952	19,532	30,693	33,484	36,274	277,107
3	Total		43,125	51,282	16,035	19,285	26,490	30,905	22,534	33,448	40,653	42,066	56,230	52,521	434,576
			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Period LBR
4	Monthly Residential Savings		875	875	406	677	812	948	948	1,625	1,760	948	1,895	1,354	13,122
5	Cumulative Residential Savings	38,279	39,154	40,029	40,435	41,112	41,924	42,872	43,820	45,444	47,205	48,152	50,048	51,402	531,597
6	Average Residential Distribution Rate		0.6916	0.6916	0.6916	0.6916	0.6916	0.6916	0.6108	0.6108	0.6108	0.6108	0.6108	0.6108	
7	Lost Residential Revenue		\$ 27,078	\$ 27,683	\$ 27,963	\$ 28,432	\$ 28,993	\$ 29,649	\$ 26,764	\$ 27,757	\$ 28,832	\$ 29,410	\$ 30,568	\$ 31,395	\$ 344,524
8	Monthly C&I Savings		2,719	3,399	930	930	1,395	1,628	930	1,163	1,628	2,558	2,790	3,023	23,092
9	Cumulative C&I Savings	73,946	76,665	80,063	80,994	81,924	83,319	84,946	85,877	87,039	88,667	91,225	94,015	97,038	1,031,771
10	Average C&I Distribution Rate		0.1993	0.1993	0.1993	0.1993	0.1993	0.1993	0.1198	0.1198	0.1198	0.1198	0.1198	0.1198	
11	Lost C&I Revenue		\$ 15,282	\$ 15,960	\$ 16,145	\$ 16,331	\$ 16,609	\$ 16,933	\$ 10,292	\$ 10,431	\$ 10,626	\$ 10,933	\$ 11,267	\$ 11,629	\$ 162,437
12	Total Lost Revenue		\$ 42,360	\$ 43,642	\$ 44,109	\$ 44,762	\$ 45,602	\$ 46,582	\$ 37,056	\$ 38,188	\$ 39,458	\$ 40,343	\$ 41,835	\$ 43,024	\$ 506,960

Line 1: Page 4, Line 15
Line 1: Page 4, Line 21
Line 3: Line 1 + Line 2
Line 4: Line 1 / 12
Line 5: Prior Month Line 5 + Current Month Line 4
Line 6: Page 5, Line 30, Col. 3; Page 5, Line 30, Col. 3
Line 7: Line 5 x Line 6
Line 8: Line 2 / 12
Line 9: Prior Month Line 9 + Current Month Line 8
Line 10: Page 5, Line 37, Col. 3; Page 5, Line 52, Col. 3
Line 11: Line 9 x Line 10
Line 12: Line 7 + Line 11

Northern Utilities, Inc.
NHPUC Docket No. DG 20-xxx
Schedule 37 LRR
Page 4 of 5

**Northern Utilities, Inc.
Gas Savings for LRR Calculation**

Planned Gas Savings - 2020		Annual
		Therms
1. Residential Programs		
2. Home Energy Assistance		21,368
3. EnergyStar Homes		15,065
4. Home Performance w/EnergyStar		17,165
5. EnergyStar Products		58,268
6. Residential Behavior		19,340
7. Residential		131,206
8.		
9. Commercial & Industrial Programs		
10. Large Business Energy Solutions		190,942
11. Small Business Energy Solutions		80,964
12. Education (Gas)		-
13. Commercial & Industrial		271,906

LBR Savings Allocation		Unit	Actual Nov-19	Actual Dec-19	Estimate Jan-20	Estimate Feb-20	Estimate Mar-20	Estimate Apr-20	Estimate May-20	Estimate Jun-20	Estimate Jul-20	Estimate Aug-20	Estimate Sep-20	Estimate Oct-20	Estimate Nov-20	Estimate Dec-20	Nov-19 to Oct- 20 Total	Jan-20 to Dec- 20 Total
14. Residential Programs					3.0%	5.0%	6.0%	7.0%	7.0%	12.0%	13.0%	7.0%	14.0%	10.0%	8.0%	8.0%		100.0%
15. Annualized Therms	Therms	0	0	3,936	6,560	7,872	9,184	9,184	15,745	17,057	9,184	18,369	13,121	10,496	10,496		110,213	131,206
16.																		
17. Monthly Incremental	Therms	0	0	328	547	656	765	765	1,312	1,421	765	1,531	1,093	875	875		9,184	10,934
18. Monthly Cumulative	Therms	29,095	29,095	29,423	29,970	30,626	31,391	32,156	33,468	34,890	35,655	37,186	38,279	39,154	40,029		391,235	412,228
19.																		
20. Commercial & Industrial Programs					4.0%	4.0%	6.0%	7.0%	4.0%	5.0%	7.0%	11.0%	12.0%	13.0%	12.0%	15.0%		100.0%
21. Annualized Therms	Therms	65,423	7,159	10,876	10,876	16,314	19,033	10,876	13,595	19,033	29,910	32,629	35,348	32,629	40,786		271,073	271,906
22.																		
23. Monthly Incremental	Therms	5,452	597	906	906	1,360	1,586	906	1,133	1,586	2,492	2,719	2,946	2,719	3,399		22,589	22,659
24. Monthly Cumulative	Therms	56,808	57,405	58,311	59,217	60,577	62,163	63,069	64,202	65,788	68,281	71,000	73,946	76,665	80,063		760,767	803,281

**Northern Utilities, Inc.
Gas Savings for LRR Calculation**

Planned Gas Savings - 2021		Annual Therms
1. Residential Programs		
2. Home Energy Assistance		24,422
3. EnergyStar Homes		27,485
4. Home Performance w/EnergyStar		14,078
5. EnergyStar Products		64,270
6. Residential Behavior		32,216
7. Residential		162,471
8.		
9. Commercial & Industrial Programs		
10. Large Business Energy Solutions		196,132
11. Small Business Energy Solutions		82,898
12. Education (Gas)		-
13. Commercial & Industrial		279,030

LBR Savings Allocation		Unit	Estimate Nov-20	Estimate Dec-20	Estimate Jan-21	Estimate Feb-21	Estimate Mar-21	Estimate Apr-21	Estimate May-21	Estimate Jun-21	Estimate Jul-21	Estimate Aug-21	Estimate Sep-21	Estimate Oct-21	Estimate Nov-21	Estimate Dec-21	Nov-20 to Oct- 21 Total	Jan-21 to Dec- 21 Total
14. Residential Programs			8.0%	8.0%	3.0%	5.0%	6.0%	7.0%	7.0%	12.0%	13.0%	7.0%	14.0%	10.0%	8.0%	8.0%		100.0%
15. Annualized Therms	Therms		10,496	10,496	4,874	8,124	9,748	11,373	11,373	19,497	21,121	11,373	22,746	16,247	12,998	12,998	157,469	162,471
16.																		
17. Monthly Incremental	Therms		875	875	406	677	812	948	948	1,625	1,760	948	1,895	1,354	1,083	1,083	13,122	13,539
18. Monthly Cumulative	Therms		39,154	40,029	40,435	41,112	41,924	42,872	43,820	45,444	47,205	48,152	50,048	51,402	52,485	53,568	531,597	558,467
19.																		
20. Commercial & Industrial Programs			12.0%	15.0%	4.0%	4.0%	6.0%	7.0%	4.0%	5.0%	7.0%	11.0%	12.0%	13.0%	12.0%	15.0%		100.0%
21. Annualized Therms	Therms		32,629	40,786	11,161	11,161	16,742	19,532	11,161	13,952	19,532	30,693	33,484	36,274	33,484	41,855	277,107	279,030
22.																		
23. Monthly Incremental	Therms		2,719	3,399	930	930	1,395	1,628	930	1,163	1,628	2,558	2,790	3,023	2,790	3,488	23,092	23,253
24. Monthly Cumulative	Therms		76,665	80,063	80,994	81,924	83,319	84,946	85,877	87,039	88,667	91,225	94,015	97,038	99,828	103,316	1,031,771	1,078,186

Northern Utilities, Inc.

Summary of Average Distribution Rate for Lost Revenue

Calculation of Average Distribution Rate for Lost Revenue (Detail)

Line		(1) Number of Customers	(2) Customer Charge	(3)=(1)X(2) Calculated Customer Charge	(4) Billing Determinants - Winter First Excess	(5) Winter Distribution Rates First Excess	(6) = (4) X (5) Winter Distribution	(7) Billing Determinants - Summer First Excess	(8) Summer Distribution Rates First Excess	(9) = (7) X (8) Summer Distribution
					Therms	Therms \$/thm	Revenue	Therms	Therms \$/thm	Revenue
	R-5 Residential, Heating	298,631	\$22.20	\$6,629,608	6,478,926	9,001,237 \$ 0.6920	\$ 0.6920 \$10,712,273	2,834,361	443,163 \$ 0.6099	\$ 0.6099 \$1,998,962
	R-10 Residential Heating, Low Income	8,632	\$8.88	\$76,652	220,721	233,658 \$ 0.6920	\$ 0.6920 \$314,430	76,929	10,603 \$ 0.6099	\$ 0.6099 \$53,386
	R-6 Residential, Non-Heating	15,334	\$22.20	\$340,415	52,030	102,959 \$ 0.6470	\$ 0.6470 \$100,278	50,338	31,354 \$ 0.6470	\$ 0.6470 \$52,855
	Total Residential Service	322,597		\$7,046,675	6,751,677	9,337,854	\$11,126,981	2,961,628	485,120	\$2,105,202
	G-40 Low Annual, High Winter Use	60,426	\$75.09	\$4,537,388	1,992,261	7,546,425 \$ 0.1865	\$ 0.1865 \$1,778,965	764,224	873,989 \$ 0.1865	\$ 0.1865 \$305,527
	G-50 Low Annual, Low Winter Use	9,931	\$75.09	\$745,719	222,671	971,369 \$ 0.1865	\$ 0.1865 \$222,688	215,924	504,561 \$ 0.1865	\$ 0.1865 \$134,370
	G-41 Medium Annual, High Winter Use	8,238	\$222.64	\$1,834,108	11,812,715	\$ 0.2425	\$2,864,583	2,550,957	\$ 0.1895	\$483,406
	G-51 Medium Annual, Low Winter Use	3,357	\$222.64	\$747,402	1,848,039	1,299,553 \$ 0.1712	\$ 0.1399 \$498,192	1,394,554	800,973 \$ 0.1337	\$ 0.1087 \$273,518
	G-42 High Annual, High Winter Use	377	\$1,335.81	\$503,600	4,461,198	\$ 0.1984	\$885,102	1,555,205	\$ 0.1206	\$187,558
	G-52 High Annual, Low Winter Use	395	\$1,335.81	\$527,645	8,729,046	\$ 0.1720	\$1,501,396	8,525,494	\$ 0.0792	\$675,219
	Total General Service	82,724		\$8,895,863	29,065,930	9,817,347	\$7,750,926	15,006,358	2,179,523	\$2,059,598
	Total Company	405,321		\$15,942,538	35,817,607	19,155,201	\$18,877,907	17,967,986	2,664,643	\$4,164,800

Notes:

Column (1), Column (4) and Column (7): 2018 actual billing determinants.

Column (2), Column (5) and Column (8): Winter and Summer distribution rates effective May 1, 2019.

R-11 Rate Class is closed May 1, 2017. R-11 Rate Class Customers migrated to R-6 Rate Class.

Calculation of Average Distribution Rate for Lost Revenue Winter and Summer (Summary)

	(10)=(3)	(11) = (6) + (9)	12=(10)+(11)	(13)=(4)+(7)
	Total Calculated Customer Revenue	Total Volumetric Revenue	Total Distribution Revenue	Total Annual Therms
R-5	\$6,629,608	\$12,711,235	\$19,340,843	18,757,687
R-10	\$76,652	\$367,816	\$444,468	541,911
R-6	\$340,415	\$153,133	\$493,547	236,681
Total Residential Service	\$7,046,675	\$13,232,183	\$20,278,858	19,536,279
G-40	\$4,537,388	\$2,084,492	\$6,621,880	11,176,899
G-50	\$745,719	\$357,059	\$1,102,778	1,914,525
G-41	\$1,834,108	\$3,347,990	\$5,182,098	14,363,672
G-51	\$747,402	\$771,709	\$1,519,112	5,343,119
G-42	\$503,600	\$1,072,659	\$1,576,260	6,016,403
G-52	\$527,645	\$2,176,615	\$2,704,260	17,254,540
Total General Service	\$8,895,863	\$9,810,524	\$18,706,387	56,069,158
Total Company	\$15,942,538	\$23,042,707	\$38,985,246	75,605,437

Based on Actual Billing Determinants for 2019 at Current Distribution Rates- Winter

	(1) Total Volumetric Revenue	(2) Total Winter therms	(3)=(1)X(2) Average Distribution Rate \$/therm
R-5	\$10,712,273	15,480,163	\$0.6920
R-10	\$314,430	454,379	\$0.6920
R-6	\$100,278	154,989	\$0.6470
Total Residential Service	\$11,126,981	16,089,531	\$0.6916
G-40	\$1,778,965	9,538,686	\$0.1865
G-50	\$222,688	1,194,040	\$0.1865
G-41	\$2,864,583	11,812,715	\$0.2425
G-51	\$498,192	3,147,592	\$0.1583
G-42	\$885,102	4,461,198	\$0.1984
G-52	\$1,501,396	8,729,046	\$0.1720
Total General Service	\$7,750,926	38,883,277	\$0.1993

Based on Actual Billing Determinants for 2019 at Current Distribution Rates- Summer

	(1) Total Volumetric Revenue	(2) Total Summer therms	(3)=(1)X(2) Average Distribution Rate \$/therm
R-5	\$1,998,962	3,277,524	\$0.6099
R-10	\$53,386	87,532	\$0.6099
R-6	\$52,855	81,692	\$0.6470
Total Residential Service	\$2,105,202	3,446,748	\$0.6108
G-40	\$305,527	1,638,213	\$0.1865
G-50	\$134,370	720,485	\$0.1865
G-41	\$483,406	2,550,957	\$0.1895
G-51	\$273,518	2,195,527	\$0.1246
G-42	\$187,558	1,555,205	\$0.1206
G-52	\$675,219	8,525,494	\$0.0792
Total General Service	\$2,059,598	17,185,881	\$0.1198
Total	\$ 23,042,707	75,605,437	

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE

November 1, 2020 through October 31, 2021

Total ERC Costs for the Period	\$421,540 (See 2020 ERC Invoice Filing, Schedule 1)
RPC/RCE Ending Balance (1)	(\$3,011)
Less Current (Over)/Under Collection (Estimated)	\$25,122 (See page 2 of 2)
Total ERC Cost to be Recovered	<u>\$443,652</u>
Forecasted Firm Sales & Firm Transportation Volumes	<u>72,579,945</u>
(Attachment 2 to Schedule 10B, Page 2 of 3, "Total Division" subtract "Special Contracts").	
ERC Recovery Rate	<u><u>\$0.0061</u></u>

(1) In DG 17-070 the Company proposed to include any over or under recovery of the Rate Case Expense (RCE) and Recoupment of the difference between Temporary and Permanent Rates (RPC) in the ERC.

**Northern Utilities, Inc. - New Hampshire Division
Environmental Response Cost 12 Month Reconciliation**

Month	Actual or Forecast	Beginning Balance (Over)/Under	Revenue	Prior Period ERC Costs To be recovered	Ending Balance (Over)/Under
November-'19	Actual	(\$13,198)	\$34,075	\$435,575	\$388,302
December	Actual	\$388,302	\$52,173		\$336,129
January- '20	Actual	\$336,129	\$58,492		\$277,637
February	Actual	\$277,637	\$58,945		\$218,692
March	Actual	\$218,692	\$51,106		\$167,586
April	Actual	\$167,586	\$36,598		\$130,988
May	Actual	\$130,988	\$27,710		\$103,278
June	Actual	\$103,278	\$17,331		\$85,947
July	Actual	\$85,947	\$14,489		\$71,458
August	Est.	\$71,458	\$13,853		\$57,605
September	Est.	\$57,605	\$14,383		\$43,223
October	Est.	\$43,223	\$18,100		\$25,122

**NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDATION ADJUSTMENT CLAUSE COMPLIANCE FILING
2019-2020 ENVIRONMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES**

Line	Description	Total	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14-10/15	11/15-10/16	11/16-10/17	11/17-10/18	11/18-10/19	11/19-10/20	11/20-10/21	11/21-10/22	11/22-10/23	11/23-10/24	11/24-10/25	11/25-10/26	11/26-10/27
ENVIRONMENTAL RESPONSE COST (ERC)																		
1	July 10 - June 11 Expenses Amortization (1/7)	\$ 121,209	\$ 17,316	\$ 17,316	\$ 17,316	\$ 17,316	\$ 17,316	\$ 17,316	\$ 17,316									
2	July 11 - June 12 Expenses Amortization (1/7)	\$ 159,020		\$ 22,717	\$ 22,717	\$ 22,717	\$ 22,717	\$ 22,717	\$ 22,717	\$ 22,717								
3	July 12 - June 13 Expenses Amortization (1/7)	\$ 175,406			\$ 25,058	\$ 25,058	\$ 25,058	\$ 25,058	\$ 25,058	\$ 25,058	\$ 25,058							
4	July 13 - June 14 Expenses Amortization (1/7)	\$ 40,881				\$ 5,840	\$ 5,840	\$ 5,840	\$ 5,840	\$ 5,840	\$ 5,840	\$ 5,840						
5	July 14 - June 15 Expenses Amortization (1/7)	\$ 112,198					\$ 16,028	\$ 16,028	\$ 16,028	\$ 16,028	\$ 16,028	\$ 16,028	\$ 16,028					
6	July 15 - June 16 Expenses Amortization (1/7)	\$ 2,179,885						\$ 311,412	\$ 311,412	\$ 311,412	\$ 311,412	\$ 311,412	\$ 311,412	\$ 311,412				
7	July 16 - June 17 Expenses Amortization (1/7)	\$ 54,154							\$ 7,736	\$ 7,736	\$ 7,736	\$ 7,736	\$ 7,736	\$ 7,736	\$ 7,736			
8	July 17 - June 18 Expenses Amortization (1/7)	\$ 283,143								\$ 40,449	\$ 40,449	\$ 40,449	\$ 40,449	\$ 40,449	\$ 40,449	\$ 40,449		
9	July 18 - June 19 Expenses Amortization (1/7)	\$ 203,357									\$ 29,051	\$ 29,051	\$ 29,051	\$ 29,051	\$ 29,051	\$ 29,051	\$ 29,051	
10	July 19 - June 20 Expenses Amortization (1/7)	\$ 77,165										\$ 11,024	\$ 11,024	\$ 11,024	\$ 11,024	\$ 11,024	\$ 11,024	\$ 11,024
11	Subtotal (Line 1 through Line 7)	\$ 3,406,418	\$ 17,316	\$ 40,033	\$ 65,091	\$ 70,931	\$ 86,959	\$ 398,371	\$ 406,108	\$ 429,241	\$ 435,575	\$ 421,540	\$ 415,700	\$ 399,672	\$ 88,260	\$ 80,524	\$ 40,074	\$ 11,024
12	Add: Excess amortization from prior years (from schedule 5, Line 10)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
13	Less: Excess amortization to be deferred (from schedule 5, Line 9)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
14	Total Environmental Response cost to be recovered (ERC)	\$ 3,406,418	\$ 17,316	\$ 40,033	\$ 65,091	\$ 70,931	\$ 86,959	\$ 398,371	\$ 406,108	\$ 429,241	\$ 435,575	\$ 421,540	\$ 415,700	\$ 399,672	\$ 88,260	\$ 80,524	\$ 40,074	\$ 11,024
15	July 2010 - June 2011 Unamortized beginning balance	\$ 121,209	\$ 103,893	\$ 86,578	\$ 69,262	\$ 51,947	\$ 34,631	\$ 17,316										
16	July 2011 - June 2012 Unamortized beginning balance		\$ 159,020	\$ 136,303	\$ 113,586	\$ 90,869	\$ 68,151	\$ 45,434	\$ 22,717									
17	July 2012 - June 2013 Unamortized beginning balance			\$ 175,406	\$ 150,348	\$ 125,290	\$ 100,232	\$ 75,174	\$ 50,116	\$ 25,058								
18	July 2013 - June 2014 Unamortized beginning balance				\$ 40,881	\$ 35,041	\$ 29,201	\$ 23,361	\$ 17,521	\$ 11,680	\$ 5,840							
19	July 2014 - June 2015 Unamortized beginning balance					\$ 112,198	\$ 96,170	\$ 80,141	\$ 64,113	\$ 48,085	\$ 32,057	\$ 16,028						
20	July 2015 - June 2016 Unamortized beginning balance						\$ 2,179,885	\$ 1,868,473	\$ 1,557,061	\$ 1,245,649	\$ 934,236	\$ 622,824	\$ 311,412					
21	July 2016 - June 2017 Unamortized beginning balance							\$ 54,154	\$ 46,418	\$ 38,681	\$ 30,945	\$ 23,209	\$ 15,473	\$ 7,736				
22	July 2017 - June 2018 Unamortized beginning balance								\$ 283,143	\$ 242,694	\$ 202,245	\$ 161,796	\$ 121,347	\$ 80,898	\$ 40,449			
23	July 2018 - June 2019 Unamortized beginning balance									\$ 203,357	\$ 174,306	\$ 145,255	\$ 116,204	\$ 87,153	\$ 58,102	\$ 29,051		
24	July 2019 - June 2020 Unamortized beginning balance										\$ 77,165	\$ 66,141	\$ 55,118	\$ 44,094	\$ 33,071	\$ 22,047	\$ 11,024	
25	Total Unamortized beginning balance	\$ 121,209	\$ 262,913	\$ 398,287	\$ 374,077	\$ 415,344	\$ 2,508,270	\$ 2,164,053	\$ 2,041,089	\$ 1,815,204	\$ 1,456,794	\$ 1,035,254	\$ 619,553	\$ 219,881	\$ 131,622	\$ 51,098	\$ 11,024	
26	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)																	
27	INSURANCE/3RD PARTY RECOVERIES (IR)																	

Northern Utilities, Inc.

Schedule 39-FXW
REDACTED

Eliot CNG Cost Detail

Denotes Confidential Material

<u>Month</u>	<u>Vendor Code</u>	<u>Expense</u>
May 2020		
May 2020		
May 2020		
May 2020		
May 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
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June 2020		
June 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
TOTAL		286,007.85