

	B	C	D	E	F	G	H	I	J	K	L
2	Filing Type & Definitions										
3	Filing Period		Peak	Running macro. Please wait...				Key Code			
4	Filing Year		2021					Blue Text / Yellow Highlight - Enter Input			
5	Report Type		CGA					Black Text - Calculation; No Input Required			
6											
7	Tariff Issued Date		9/17/2021								
8											
9	Return to Main Tab, Shortcut [Ctrl+m]										
10				Workbook is currently: UnLocked							
11											
12		Month		Year							
13	Peak Period Start Month	November	11	2021							
14	Peak Period End Month	April	4	2022							
15	Off Peak Period Start Month	May	5	2022							
16	Off Peak Period End Month	October	10	2022							
17											
18											
19	Test Year Months	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22
20	Days in Month	30	31	31	28	31	30	31	30	31	31
21											
22	Hyperlinks to Data Entry			Hyperlinks to Maine Division CGF Schedules (1)				Hyperlinks to New Hampshire Division COG Schedules (3)			
23											
24	CGA Inputs	Notes	Last Updated	ME CGF Schedules	Notes	Schedule	NH COG Schedules	Notes	Schedule		
25	NUI Demand Cost	Peak Only	9/1/21 CAK	Allocation of NUI Fixed Capacity Costs		Attachment NUI-CAK-1	Summary		Attachment NUI-CAK-10		
26	NUI Contract Detail	Peak Only	9/1/21 CAK	SMBA Allocations		Attachment NUI-CAK-2	Allocation of NUI Fixed Capacity Costs		Attachment NUI-CAK-1		
27	PR Allocator Volumes	Peak Only	9/1/21 CAK	Adjustment for PNGTS Litigation Expense		Adjustment to PNGTS	SMBA Allocations		Attachment NUI-CAK-2		
28	Design Day Demand	Peak Only	9/1/21 CAK	Division Sales and Sendout Forecast		Attachment NUI-CAK-3	Division Sales and Sendout Forecast		Attachment NUI-CAK-3		
29											
30	ME Division Specific Cost Adders & Credits		9/1/21 CAK				Allocation of Gas Costs to Firm Sales Rate Classes		Attachment NUI-CAK-8		
31	NH Division Specific Cost Adders & Credits		9/1/21 CAK	Allocation of Gas Costs to Firm Sales Rate Classes		Attachment NUI-CAK-4	Commodity Costs		Attachment NUI-CAK-4		
32				Demand Costs		Attachment NUI-CAK-8	Demand Costs Allocated by Rate Class		Attachment NUI-CAK-4		
33	Sales Forecast, Delivery to Throughput Ratios		9/1/21 CAK	Commodity Costs		Attachment NUI-CAK-5	Allocation of Commodity Costs to Divisions		Attachment NUI-CAK-5		
34	Sendout Volumes by Supply Source		9/1/21 CAK	Allocation of Commodity Costs to Divisions		Attachment NUI-CAK-6	Sales Sendout Quantities & Commodity Costs		Attachment NUI-CAK-6		
35	Interruptible Volumes (Included in Sendout)		N/A	Commodity Cost Analysis							
36											
37	Pipeline Commodity Costs		9/1/21 CAK	Tariff Sheets			Supporting Detail to the Tariff Sheets				
38	Storage Commodity Costs		9/1/21 CAK	ME Tariff p. 60.1 (Calculation of GCF)		Attachment NUI-CAK-9	NH Gas Accting Report p2		Attachment NUI-CAK-12		
39	Peaking Commodity Costs		9/1/21 CAK				Average Cost of Gas & Residential Cost Re-allocation		Attachment NUI-CAK-9		
40	Inventory		9/1/21 CAK	Supporting Detail to the Tariff Sheets			NH Supply Detail				
41	NYMEX Settlement Price		9/1/21 CAK	Calculation of Working Capital & Bad Debt		Attachment NUI-CAK-10	Gas Inventory		Attachment NUI-CAK-7		
42	NYMEX Settlement Price Log		9/1/21 CAK				Variance Analysis	Manual Update	Schedule 2-CAK		
43	Hedging Contract Information		9/1/21 CAK	ME Gas Accting Report p2	Manual Update						
44				Gas Inventory		Attachment NUI-CAK-7	Bad Debt		Attachment NUI-CAK-11		
45				Variance Analysis	Manual Update						
46											
47											
48											
49											
50											
51											
52											
53	Hyperlinks to Data Entry			Hyperlinks to Maine Monthly Gas Report (2)				Hyperlinks to New Hampshire Monthly Gas Report (4)			
54											
55											
56	Monthly Report Inputs		Last Updated	ME Monthly Gas Report (For Internal Purposes)		Schedule	NH Monthly Gas Report Schedules		Schedule		
57	NYMEX Settlement Price Used for Update			ME Gas Accting Report p1	Manual Update		NH Gas Accting Report p1	Manual Update			
58	NYMEX Settlement Price Log			ME Gas Accting Report p2	Manual Update		NH Gas Accting Report p2	Manual Update			
59											
60	NH Peak										
61	Firm Sales Volumes (Actuals or Revised Est.)										
62	CGA Rates (Historical & Current)										
63	Actual Firm Sales Revenues										
64	Actual Direct Cost of Gas										
65											
66	NH Off Peak										
67	Firm Sales Volumes (Actuals or Revised Est.)										
68	CGA Rates (Historical & Current)										
69	Actual Firm Sales Revenues										
70	Actual Direct Cost of Gas										
71											
72											
73	NEED TO ADD MAINE INPUTS.										
74											
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80	Return to Main Tab, Shortcut [Ctrl+m]										
81											
82											
83	(For Internal Purposes)										
84	Log of Model Revisions										
85											

NUI COMPANY TOTAL ALLOCATED DEMAND COSTS			Input Instructions	
	MDQ, Dth	NUI Annual Demand Cost		
Pipeline Reservation			new	old
Algonquin		\$ 5,570,999		
Granite		\$ 1,863,695		
Iroquois		\$ 412,720		
Maritimes		\$ 1,204,500		
PNGTS		\$ 2,737,500		
Tennessee		\$ 3,567,276		
Texas Eastern		\$ 81,824		
TransCanada		\$ 2,134,174		
Union		\$ 380,587		
---- Blank 2 of 6 ----		\$ -		
---- Blank 3 of 6 ----		\$ -		
---- Blank 4 of 6 ----		\$ -		
---- Blank 5 of 6 ----		\$ -		
---- Blank 6 of 6 ----		\$ -		
Total Pipeline	40,586	\$ 17,953,274	\$ -	\$ -
Storage				
Granite		\$ 3,014,392		
PNGTS		\$ 8,760,657		
Tennessee		\$ 223,021		
TransCanada		\$ 8,522,847		
Union		\$ 1,511,950		
Tennessee		\$ 119,638		
Union		\$ 2,840,000		
Total Storage	42,507	\$ 24,992,506		
Peaking (Excluding Local Production)				
Granite		\$ 2,216,171		
LNG Contract		\$ 1,776,000		
Peaking Contract 1		\$ 9,621,667		
Total Peaking		\$ 13,613,838		
Total Demand Excluding Local Prod		\$ 56,559,617		
Adjustments to Demand Costs				
Capacity Release (Credit)		\$ -	Reductions to Demand Costs should be inputted as negative values.	
Asset Management (Credit)		\$ (9,902,100)		
Subtotal		\$ (9,902,100)		
Total Demand Costs		\$ 46,657,517		

Key Code
Blue Text / Green Highlight - Update Input for Peak Filings Only.
Blue Text / Yellow Highlight - Enter Input
Black Text - Calculation; No Input Required

Adjustments to Demand Costs Monthly Detail															
	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	Check	
Capacity Release (Credit)													\$ -	\$ -	
Asset Management (Credit)	\$ (810,930)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (9,902,100)	\$ -	

PR ALLOCATOR FOR CAPACITY COSTS

Key Code
Blue Text / Green Highlight - Update Input for Peak/Winter Filings Only.
Black Text - Calculation; No Input Required
Calculation Check
Input Instructions (A)
In cells highlighted in green, enter the 12 month historical Sendout for most recent May-April period adjusted from Actual EDD to Design Winter EDD. These inputs should be updated during Winter Filing Only. The resulting PR Allocator should remain fixed for 12 months effective November 1st.
Input Instructions (B)
In cells highlighted in green, enter the supply dispatch volume results from SENDOUT™ Portfolio Optimization Modeling that meet the Design Winter demand requirements as entered in Section (A) above. Available Portfolio options should be modeled on a current basis and not back cast. These inputs should be updated during Winter Filing Only.

(A) FIRM DESIGN YEAR SENDOUT VOLUMES

Calendar Month Sendout Volumes, MMBtu (Includes Lost & Unaccounted For)

Actual Historical Volumes Adjusted for Design Year Weather

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	Winter	Summer
MAINE DIVISION															
Total Sales Volume	769,970	1,118,218	1,373,487	1,222,295	1,075,734	602,565	335,601	186,167	184,179	197,150	232,899	397,265	7,695,530	6,162,269	1,533,261
Total Assigned Capacity for Transportation [1]	183,108	245,068	281,875	248,523	223,267	140,304	92,311	66,054	56,316	57,847	73,169	116,193	1,784,034	1,322,144	461,889
Total	953,078	1,363,286	1,655,363	1,470,818	1,299,001	742,868	427,912	252,221	240,495	254,997	306,067	513,458	9,479,564	7,484,414	1,995,150
NEW HAMPSHIRE DIVISION															
Total Sales Volume	473,924	746,005	884,060	759,575	635,070	312,572	164,969	91,875	82,497	87,972	108,619	227,211	4,574,349	3,811,206	763,143
Total Non-Grandfathered Transportation [2]	211,315	261,312	308,701	274,388	250,505	162,592	101,738	85,196	85,929	86,996	100,814	149,989	2,079,476	1,468,813	610,662
Total	685,239	1,007,317	1,192,761	1,033,962	885,575	475,164	266,707	177,072	168,426	174,968	209,433	377,201	6,653,824	5,280,019	1,373,805
COMPANY TOTAL	1,638,317	2,370,603	2,848,124	2,504,780	2,184,576	1,218,032	694,618	429,292	408,921	429,965	515,500	890,659	16,133,388	12,764,433	3,368,955

Notes:

[1] Includes ME Assigned Transportation for Special Contracts.

[2] Includes Special Contract.

(B) COMPANY TOTAL SUPPLY DISPATCH

Calendar Month Sendout Volumes, MMBtu (Includes Loss & Unaccounted For)

Actual Historical Volumes Adjusted for Design Winter Weather

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	Winter	Summer
NUI COMPANY TOTAL															
Pipeline	1,251,924	1,257,819	1,257,819	1,207,638	1,484,768	1,216,238	692,758	427,492	407,061	428,105	513,700	888,799	11,034,122		
Storage Withdrawals (Excl Peaking Supplies)	384,599	949,630	1,116,303	1,034,206	647,868	0	0	0	0	0	0	0	4,132,606		
Storage Injections TGP Only	0	0	0	0	0	0	0	0	0	0	0	0	0		
On-system Peaking Supplies (Withdrawals)	1,794	79,083	112,600	79,389	13,513	1,794	1,860	1,800	1,860	1,860	1,800	1,860	299,212		
Total Supply (Excluding Injections)	1,638,317	2,286,532	2,486,722	2,321,232	2,146,149	1,218,032	694,618	429,292	408,921	429,965	515,500	890,659	15,465,941		
Off-system Peaking Supplies	0	84,071	361,402	183,548	38,427	0	0	0	0	0	0	0	667,448		
	1,638,317	2,370,603	2,848,124	2,504,780	2,184,576	1,218,032	694,618	429,292	408,921	429,965	515,500	890,659	16,133,388		
Supply Difference from Demand															
Including ME Assigned Capacity for All Mo	(0)	0	(0)	(0)	0	(0)	(0)	0	0	(0)	(0)	(0)	(0)		
Including ME Assigned Capacity for Nov-Apr	(0)	0	(0)	(0)	0	(0)	(0)	0	0	(0)	(0)	(0)	(0)		

DESIGN DAY DEMANDS - BOTH DIVISIONS (MMBtu)

Key Code
Blue Text / Green Highlight - Update Input for Peak/Winter Filings Only.
Black Text - Calculation; No Input Required
Input Instructions
Enter (A) Design Day Forecast and (B) Design Day Base for ME & NH Divisions in Cells Highlighted in Green.
Calculated Temperature Sensitive Design Day Demand percentages of totals feed into "Remaining" tab. These values are used to allocate division level monthly remaining costs to customer classes.

Sendout for Design Day Calculation							
Northern Utilities - MAINE DIVISION							
	Customer Class	Design Day Forecast Maine	% of Total Total	Design Day Base Maine	% of Total Total	Temperature Sensitive Design Day Maine	% of Total Total
1							
2							
3							
4							
5							
6	Res Heat	18,547	26.76%	1,348	14.37%	17,199	28.69%
7	Res General	347	0.50%	56	0.60%	290	0.48%
8	G50 Low Annual-Low Winter	705	1.02%	243	2.59%	462	0.77%
9	G40 Low Annual-High Winter	14,269	20.59%	1,018	10.86%	13,251	22.11%
10	G51 Med Annual-Low Winter	1,489	2.15%	572	6.10%	917	1.53%
11	G41 Med Annual-High Winter	16,834	24.28%	1,434	15.29%	15,400	25.69%
12	G52 High Annual-Low Winter	1,242	1.79%	748	7.97%	494	0.82%
13	G42 High Annual-High Winter	15,885	22.92%	3,958	42.21%	11,928	19.90%
14	Total	69,320		9,377		59,942	
15							
16	Residential	18,894	27.26%	1,404	14.98%	17,490	29.18%
17	SALES HLF CLASSES	3,436	4.96%	1,563	16.67%	1,873	3.13%
18	SALES LLF CLASSES	46,989	67.79%	6,410	68.36%	40,579	67.70%
19	Grand Total	69,320	100.00%	9,377	100.00%	59,942	100.00%

Sendout for Design Day Calculation							
Northern Utilities - NEW HAMPSHIRE DIVISION							
	Customer Class	Design Day Forecast NH	% of Total Total	Design Day Base NH	% of Total Total	Temperature Sensitive Design Day NH	% of Total Total
1							
2							
3							
4							
5							
6	Res Heat	24,141	48.16%	1,406	39.76%	22,735	48.80%
7	Res General	222	0.44%	32	0.91%	190	0.41%
8	G50 Low Annual-Low Winter	905	1.81%	265	7.51%	640	1.37%
9	G40 Low Annual-High Winter	11,858	23.66%	533	15.07%	11,325	24.31%
10	G51 Med Annual-Low Winter	1,441	2.87%	399	11.30%	1,041	2.23%
11	G41 Med Annual-High Winter	9,240	18.43%	563	15.93%	8,677	18.62%
12	G52 High Annual-Low Winter	365	0.73%	160	4.54%	205	0.44%
13	G42 High Annual-High Winter	1,952	3.90%	177	5.00%	1,776	3.81%
14	Total	50,124		3,536		46,588	
15							
16	Residential	24,363	48.61%	1,438	40.67%	22,925	49.21%
17	SALES HLF CLASSES	2,711	5.41%	825	23.34%	1,886	4.05%
18	SALES LLF CLASSES	23,050	45.99%	1,273	35.99%	21,778	46.75%
19	Grand Total	50,124	#####	3,536	100.00%	46,588	100.00%

Northern Utilities - MAINE DIVISION

DIVISION SPECIFIC DEMAND COSTS & CREDITS											
<i>These costs are assigned directly to Divisions outside of the PR Allocation model.</i>											
Local Production (Peak Only)	Annual	Peak	Off Peak	Input Instructions / Notes							
LNG Production & Capacity	\$ 371,708			Local Production & Capacity established during last rate case. Currently using proposed costs in 2011-092							
LP Production & Capacity	\$ -										
Total Maine Local Production & Capacity	\$ 371,708	\$ 371,708	\$ -								
Other A&G Misc.	Annual	Peak	Off Peak	Input Instructions / Notes							
	\$ 766,463	\$ 733,573	\$ 32,890	Other A&G established during last rate case. Recovery by month fixed in Winter Filing. Currently using proposed costs in 2011-092							
	\$ 1,105,281										
Monthly Allocation of Other A&G Misc (NOT REQUIRED)				Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22
				\$ 42,098	\$ 107,703	\$ 237,602	\$ 110,479	\$ 100,230	\$ 41,464	\$ 10,728	\$ 2,166
				\$ 47	\$ 1,554	\$ 4,979	\$ 16,514				
Source: Peak Filing, Demand.ME.NH tab, row 93											
Reductions to Demand Costs	Annual	Peak	Off Peak	Input Instructions / Notes							
Estimated Interruptible Margin		\$ -	\$ -	90% of estimated annual Interruptible Margins (Per MPUC Tariff, p.51)							
Re-entry and Conversion Revenue Estimate	\$ 5,000	\$ 5,000	\$ -								
Capacity Assignment Demand Revenue Estimate	\$ (4,419,945)			Estimate for Nov 2021 - Oct 2022; Required for Peak Filing Only.							

OTHER RECOVERY FACTORS	PEAK		OFF PEAK	
Demand Cost Factors	\$\$	Per ccf	\$\$	Per ccf
Reconciliation Adjustment for Under/(Over) Collection	(214,327)	From Winter Period Reconciliation	88,775	From Summer Period Reconciliation
Working Capital Reconciliation for Under/(Over) Collection	(10,761)		497	
Supplier Refund R1d		\$0.0000		\$0.0000
Supplier Refund R2d		\$0.0000		\$0.0000
Commodity Cost Factors	\$\$	Per ccf	\$\$	Per ccf
Reconciliation Adjustment for Under/(Over) Collection	1,006,980	From Winter Period Reconciliation	64,950	From Summer Period Reconciliation
Working Capital Reconciliation for Under/(Over) Collection	21,048		(4,240)	
Bad Debt Reconciliation	(157,022)		(6,955)	
Unit Supplier Refund R1c		\$0.0000		\$0.0000
Unit Supplier Refund R2c		\$0.0000		\$0.0000

Working Capital Factor	0.362%
Bad Debt - Old Value	NA
Approved Rate Docket 2017-00065	1.06%

Prior approved rate docket - 97-393

Projected Bad Debt						
Nov	Dec	Jan	Feb	Mar	Apr	
\$40,000	\$40,000	\$40,000	\$40,000	\$40,000	\$40,000	
May	June	July	Aug	Sep	Oct	
\$10,000	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000	
Winter		Summer				

Northern Utilities - NEW HAMPSHIRE DIVISION

DIVISION SPECIFIC DEMAND COSTS & CREDITS				
<i>These costs are assigned directly to Divisions outside of the PR Allocation model.</i>				
	<u>Annual</u>	<u>Peak</u>	<u>Off Peak</u>	Input Instructions / Notes
Local Production & Capacity (Peak Only)	\$ 476,106	\$ 476,106	\$ -	Local Production & Capacity established during last rate case. (See NHPUC Tariff p.21)
Miscellaneous Overhead	\$ 580,455	Peak	Off Peak	Input Instructions / Notes
Allocation of Misc Overhead to Season (NOT REQUIRED)		79.87%	20.13%	Misc Overhead established during last rate case (See NHPUC Tariff p.21). Recovery by season fixed in Winter Filing.
Allocated Misc Overhead	\$ 1,056,561	\$ 463,606	\$ 116,849	
Reductions to Demand Costs	<u>Annual</u>	<u>Peak</u>	<u>Off Peak</u>	Input Instructions / Notes
Estimated Interruptible Margin	\$ -	\$ -	\$ -	Estimate for Nov 2021 - Oct 2022; Required for Peak Filing Only.
Re-Entry Fee Credits	\$ 5,000	\$ 5,000	\$ -	Estimate for Nov 2021 - Oct 2022; Required for Peak Filing Only.
Capacity Assignment Demand Revenue Estimate	\$ 5,012,735			Estimate for Nov 2021 - Oct 2022; Required for Peak Filing Only.

OTHER INDIRECT COST RECOVERY FACTORS (\$\$)	PEAK	OFF PEAK
	<u>Per Therm</u>	<u>Per Therm</u>
Working Capital Reconciliation	\$ (5,834)	\$ (1,470)
Bad Debt Reconciliation	\$ (61,950)	\$ (15,614)
Refunds	\$ -	

	PEAK	OFF PEAK
	Balance as of:	Balance as of:
Prior Under/(Over) Collection	May 1, 2021 \$ 189,294	November 1, 2021 \$ 47,710
ATV Reconciliation	May 1, 2021 \$ -	November 1, 2021 \$ -

Interest Rates (%) 1.30%

Working Capital Factor 0.0892%
 Bad Debt Factor - old rate no longer used NA
 (NHPUC No. 10 Section 4.06.1)

Prime Rate 3.250%

FORECASTED FIRM SALES VOLUMES

MAINE DIVISION

Calendar Month Sales Volumes, MMBtu

Normal Winter

MAINE DIVISION	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	Winter	Summer
Firm Sales (Dth)															
Res Heat	193,998	280,401	329,156	288,179	254,353	161,600	69,458	45,694	40,837	41,527	45,487	84,345	1,835,035	1,507,687	327,348
Res General	3,629	5,245	6,157	5,390	4,758	3,023	2,910	1,915	1,711	1,740	1,906	3,534	41,918	28,201.6	13,716.6
G50 Low Annual-Low Winter	10,359	14,972	17,576	15,388	13,582	8,629	12,532	8,244	7,368	7,493	8,207	15,218	139,567	80,505.3	59,062.0
G40 Low Annual-High Winter	166,320	240,396	282,195	247,064	218,064	138,544	52,466	34,515	30,847	31,368	34,359	63,712	1,539,851	1,292,583.2	247,268.0
G51 Med Annual-Low Winter	23,482	33,941	39,843	34,882	30,788	19,561	29,477	19,392	17,331	17,624	19,304	35,795	321,418	182,497.1	138,921.3
G41 Med Annual-High Winter	188,943	273,095	320,579	280,670	247,725	157,389	73,886	48,607	43,441	44,175	48,387	89,722	1,816,619	1,468,401.9	348,217.0
G52 High Annual-Low Winter	26,763	24,896	26,087	23,697	24,740	23,858	23,761	21,902	22,552	23,125	22,574	26,324	290,280	150,041.3	140,238.2
G42 High Annual-High Winter	214,971	272,237	318,301	287,006	291,544	231,804	161,840	117,376	120,611	121,222	120,898	155,154	2,412,963	1,615,861.4	797,101.2
Total Firm Sales	828,466	1,145,183	1,339,894	1,182,277	1,085,552	744,408	426,330	297,644	284,698	288,274	301,122	473,804	8,397,651	6,325,779	2,071,872
Subtotal															
Residential Heat & Non Heat	197,627	285,646	335,313	293,570	259,111	164,623	72,368	47,608	42,549	43,267	47,393	87,879	1,876,953	1,535,889	341,064
Sales HLF Classes	60,604	73,810	83,505	73,967	69,109	52,048	65,770	49,538	47,251	48,241	50,085	77,337	751,265	413,044	338,222
Sales LLF Classes	570,234	785,727	921,075	814,740	757,333	527,738	288,192	200,498	194,899	196,765	203,644	308,588	5,769,433	4,376,847	1,392,586
Sendout to Sales Ratio (%)	Assumed values used to convert sales & delivery forecast to sendout forecast														
Res Heat	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
Res General	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
G50 Low Annual-Low Winter	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
G40 Low Annual-High Winter	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
G51 Med Annual-Low Winter	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
G41 Med Annual-High Winter	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
G52 High Annual-Low Winter	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			
G42 High Annual-High Winter	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%			

FORECASTED FIRM SALES VOLUMES

NEW HAMPSHIRE DIVISION

Calendar Month Sales Volumes, MMBtu

Normal Winter

NEW HAMPSHIRE DIVISION	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Total	Winter	Summer
Firm Sales (Dth)															
Res Heat	221,484	317,676	371,797	319,078	272,023	160,114	77,414	50,568	42,733	43,338	48,090	97,002	2,021,317	1,662,172	359,145
Res General	2,036	2,920	3,417	2,933	2,500	1,472	1,761	1,150	972	986	1,094	2,206	23,447	15,277	8,169
G50 Low Annual-Low Winter	11,832	16,971	19,862	17,046	14,532	8,554	14,616	9,547	8,068	8,182	9,080	18,314	156,605	88,798	67,808
G40 Low Annual-High Winter	112,857	161,872	189,449	162,586	138,609	81,586	29,330	19,159	16,191	16,420	18,220	36,752	983,033	846,960	136,073
G51 Med Annual-Low Winter	19,614	28,132	32,925	28,256	24,089	14,179	21,996	14,368	12,142	12,314	13,664	27,562	249,241	147,195	102,047
G41 Med Annual-High Winter	82,895	118,898	139,154	119,422	101,811	59,926	31,016	20,260	17,121	17,363	19,267	38,864	765,997	622,105	143,892
G52 High Annual-Low Winter	5,390	5,213	5,859	5,663	5,832	5,343	5,274	4,588	4,819	4,999	4,834	5,327	63,141	33,300	29,841
G42 High Annual-High Winter	15,211	20,363	25,566	22,475	20,030	14,481	9,354	6,083	5,374	5,440	6,562	10,915	161,855	118,126	43,729
Total Firm Sales	471,318	672,045	788,030	677,460	579,426	345,654	190,761	125,725	107,420	109,042	120,812	236,943	4,424,636	3,533,933	890,703
Subtotal															
Residential Heat & Non Heat	223,519	320,596	375,215	322,011	274,523	161,586	79,174	51,718	43,705	44,324	49,184	99,208	2,044,763	1,677,450	367,314
Sales HLF Classes	36,836	50,316	58,647	50,965	44,453	28,076	41,886	28,504	25,030	25,495	27,578	51,204	468,988	269,292	199,696
Sales LLF Classes	210,963	301,132	354,169	304,484	260,450	155,993	69,701	45,502	38,685	39,224	44,050	86,531	1,910,885	1,587,191	323,693
Total NH Firm Sales	471,318	672,045	788,030	677,460	579,426	345,654	190,761	125,725	107,420	109,042	120,812	236,943	4,424,636	3,533,933	890,703

Sendout to Sales Ratio (%)	Assumed values used to convert sales & delivery forecast to sendout forecast														
Res Heat	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
Res General	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
G50 Low Annual-Low Winter	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
G40 Low Annual-High Winter	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
G51 Med Annual-Low Winter	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
G41 Med Annual-High Winter	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
G52 High Annual-Low Winter	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%
G42 High Annual-High Winter	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%	1.27%

SUPPLY SOURCE FORECASTED DISPATCH VOLUMES & COMMODITY COSTS

Inputs entered here are results from SENDOUT™ Portfolio Optimization Modeling.

SUPPLY SOURCE VOLUMES

Monthly Dispatch Results, MMBtu

Forecast for Normal Weather

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	TOTAL
Pipeline	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	
Total Pipeline	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	8,854,520
Storage													
Total Storage	334,018	731,204	814,153	870,348	598,789	-	-	-	-	-	-	-	3,348,512
Peaking													
Total Peaking	1,794	132,447	416,567	168,774	66,406	1,794	1,860	1,800	1,860	1,860	1,800	1,860	798,822
Total Supply Sendout	1,317,939	1,842,583	2,157,613	1,885,708	1,688,286	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854
Less Interruptible - ME (Incl. Above)	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Interruptible - NH (Incl. Above)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total (excluding Inter)	1,317,939	1,842,583	2,157,613	1,885,708	1,688,286	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854
ME & NH Firm Sales Sendout													
(Incl. Company Use)	1,317,940	1,842,584	2,157,613	1,885,708	1,688,285	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854
Difference	1	1	0	0	1	0	0	0	0	0	0	0	0

SUPPLY SOURCE GAS COSTS

Commodity Costs, \$'s

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	TOTAL
Pipeline	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526
Total Pipeline	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526
NYMEX Pricing Adjustment to Pipeline Commodity Costs													Settled Prices
NYMEX Price Used for Forecast	\$ 5.305	\$ 5.398	\$ 5.465	\$ 5.370	\$ 5.013	\$ 3.939	\$ 3.810	\$ 3.839	\$ 3.871	\$ 3.879	\$ 3.863	\$ 3.890	9/14/2021
NYMEX Price Used for Update	\$ 5.305	\$ 5.398	\$ 5.465	\$ 5.370	\$ 5.013	\$ 3.939	\$ 3.810	\$ 3.839	\$ 3.871	\$ 3.879	\$ 3.863	\$ 3.890	9/14/2021
Increase/(Decrease) NYMEX Price	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	
Forecasted Pipeline Sendout Volume	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	8,854,520
Increase/(Decrease) in Gas Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Updated Pipeline Costs	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526
Storage (Withdrawal Value Excluding Carrying Cost)													
Total Storage	\$ 1,044,295	\$ 2,265,206	\$ 2,524,545	\$ 2,702,360	\$ 1,867,551	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,403,958
Peaking (Withdrawal Value Excluding Carrying Cost)													
Total Peaking	\$ 9,526	\$ 2,091,388	\$ 4,553,220	\$ 2,865,280	\$ 1,286,222	\$ 10,221	\$ 10,555	\$ 11,094	\$ 11,464	\$ 11,464	\$ 13,455	\$ 14,402	\$ 10,888,290
Total Storage & Peaking	\$ 1,053,822	\$ 4,356,594	\$ 7,077,765	\$ 5,567,640	\$ 3,153,773	\$ 10,221	\$ 10,555	\$ 11,094	\$ 11,464	\$ 11,464	\$ 13,455	\$ 14,402	\$ 21,292,248
Storage (Inventory Finance Charge)													
Tennessee Storage	\$ 606	\$ 509	\$ 314	\$ 130	\$ 21	\$ -	\$ 72	\$ 145	\$ 214	\$ 354	\$ 489	\$ 618	\$ 3,470
Washington 10 Storage	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

SUPPLY SOURCE FORECASTED DISPATCH VOLUMES & COMMODITY COSTS

Inputs entered here are results from SENDOUT™ Portfolio Optimization Modeling.

Total Storage	\$	606	\$	509	\$	314	\$	130	\$	21	\$	-	\$	72	\$	145	\$	214	\$	354	\$	489	\$	618	\$	3,470
Peaking (Inventory Finance Charge)																										
LNG	\$	64	\$	53	\$	43	\$	33	\$	29	\$	52	\$	74	\$	77	\$	74	\$	61	\$	76	\$	99	\$	735
Peaking Contract 1	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Total Peaking	\$	64	\$	53	\$	43	\$	33	\$	29	\$	52	\$	74	\$	77	\$	74	\$	61	\$	76	\$	99	\$	735

Total Supply Costs

Incl NYMEX Adj	\$	6,302,351	\$	10,091,778	\$	13,140,440	\$	11,023,635	\$	8,590,113	\$	4,231,017	\$	2,207,586	\$	1,486,950	\$	1,384,547	\$	1,394,443	\$	1,424,238	\$	2,526,676	\$	63,803,774
Average Supply Cost (\$/MMBtu)	\$	4.7820	\$	5.4770	\$	6.0903	\$	5.8459	\$	5.0881	\$	3.8276	\$	3.5277	\$	3.4633	\$	3.4817	\$	3.4607	\$	3.3285	\$	3.5058		
Interruptible Included Above	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-

NYMEX Pricing Log

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Settlement Date	Notes
1	\$ 2.811	\$ 3.077	\$ 3.221	\$ 3.239	\$ 3.231	\$ 3.227	\$ 3.267	\$ 3.313	\$ 3.353	\$ 3.374	\$ 3.377	\$ 3.405	8/28/2012	Att NUI-FXW7A
2	\$ 3.475	\$ 3.783	\$ 3.923	\$ 3.937	\$ 3.906	\$ 3.870	\$ 3.893	\$ 3.930	\$ 3.971	\$ 3.986	\$ 3.988	\$ 4.022	10/10/2012	
3	\$ 3.471	\$ 3.503	\$ 3.634	\$ 3.647	\$ 3.622	\$ 3.611							11/9/2012	
4	\$ 3.471	\$ 3.719	\$ 3.837	\$ 3.852	\$ 3.823	\$ 3.799	\$ 3.830	\$ 3.865	\$ 3.903	\$ 3.923	\$ 3.925	\$ 3.959	11/19/2012	
5	\$ 3.471	\$ 3.696	\$ 3.314	\$ 3.358	\$ 3.380	\$ 3.420	\$ 3.467	\$ 3.508	\$ 3.551	\$ 3.578	\$ 3.584	\$ 3.617	12/14/2012	
6	\$ 3.471	\$ 3.696	\$ 3.358	\$ 3.398	\$ 3.416	\$ 3.444	\$ 3.488	\$ 3.530	\$ 3.574	\$ 3.600	\$ 3.606	\$ 3.639	12/17/2012	
7							\$ 3.549	\$ 3.603	\$ 3.655	\$ 3.678	\$ 3.683	\$ 3.715	1/24/2013	
8	\$ 3.467	\$ 3.648	\$ 3.736	\$ 3.738	\$ 3.704	\$ 3.656	\$ 3.679	\$ 3.711	\$ 3.744	\$ 3.760	\$ 3.760	\$ 3.781	8/12/2013	
9	\$ 3.666	\$ 3.830	\$ 3.912	\$ 3.912	\$ 3.877	\$ 3.809	\$ 3.827	\$ 3.855	\$ 3.887	\$ 3.904	\$ 3.904	\$ 3.928	9/5/2013	
10	\$ 3.820	\$ 3.966	\$ 4.059	\$ 4.064	\$ 4.038	\$ 3.971	\$ 3.987	\$ 4.014	\$ 4.045	\$ 4.056	\$ 4.048	\$ 4.065	10/14/2013	
11	\$ 3.496	\$ 3.818	\$ 4.407	\$ 5.557	\$ 5.375	\$ 4.665	\$ 4.579	\$ 4.590	\$ 4.611	\$ 4.604	\$ 4.582	\$ 4.596	2/5/2014	
12	\$ 3.496	\$ 3.818	\$ 4.407	\$ 5.557	\$ 4.855	\$ 4.609	\$ 4.550	\$ 4.568	\$ 4.599	\$ 4.586	\$ 4.557	\$ 4.565	2/28/2014	
13	\$ 4.209	\$ 4.280	\$ 4.341	\$ 4.321	\$ 4.247	\$ 3.972	\$ 3.958	\$ 3.980	\$ 4.009	\$ 4.015	\$ 4.000	\$ 4.018	7/9/2014	
14	\$ 3.957	\$ 4.052	\$ 4.134	\$ 4.124	\$ 4.050	\$ 3.783	\$ 3.760	\$ 3.788	\$ 3.816	\$ 3.825	\$ 3.814	\$ 3.844	10/7/2014	
15							\$ 2.938	\$ 2.979	\$ 3.035	\$ 3.044	\$ 3.029	\$ 3.059	1/27/2015	
16							\$ 2.697	\$ 2.748	\$ 2.804	\$ 2.813	\$ 2.806	\$ 2.839	2/3/2015	
17							\$ 2.849	\$ 2.885	\$ 2.938	\$ 2.947	\$ 2.936	\$ 2.964	2/11/2015	
18							\$ 2.605	\$ 2.654	\$ 2.714	\$ 2.747	\$ 2.754	\$ 2.783	4/1/2015	
19	\$ 2.920	\$ 3.110	\$ 3.220	\$ 3.220	\$ 3.180	\$ 3.040	\$ 3.050	\$ 3.080	\$ 3.110	\$ 3.130	\$ 3.120	\$ 3.150	7/10/2015	
20	\$ 2.502	\$ 2.718	\$ 2.857	\$ 2.863	\$ 2.835	\$ 2.712	\$ 2.724	\$ 2.761	\$ 2.801	\$ 2.810	\$ 2.804	\$ 2.828	10/9/2015	
21							\$ 2.250	\$ 2.320	\$ 2.380	\$ 2.400	\$ 2.400	\$ 2.430	1/15/2016	
22							\$ 1.787	\$ 1.900	\$ 1.996	\$ 2.046	\$ 2.065	\$ 2.107	3/4/2016	
23	\$ 2.931	\$ 3.200	\$ 3.333	\$ 3.323	\$ 3.277	\$ 3.045	\$ 3.023	\$ 3.061	\$ 3.096	\$ 3.104	\$ 3.081	\$ 3.104	7/10/2016	\$ 3.185
24	\$ 2.923	\$ 3.170	\$ 3.306	\$ 3.314	\$ 3.268	\$ 3.035	\$ 2.998	\$ 3.027	\$ 3.054	\$ 3.059	\$ 3.043	\$ 3.062	10/3/2016	\$ 3.169
25	\$ 2.764	\$ 2.703	\$ 2.875	\$ 2.921	\$ 2.928	\$ 2.896							11/17/2016	\$ 0.015
26	\$ 2.764	\$ 3.232	\$ 3.507	\$ 3.510	\$ 3.486	\$ 3.359							12/12/2016	
27							\$ 3.305	\$ 3.351	\$ 3.392	\$ 3.395	\$ 3.374	\$ 3.387	1/30/2017	
28							\$ 3.293	\$ 3.365	\$ 3.430	\$ 3.451	\$ 3.437	\$ 3.449	4/4/2017	
							\$ 3.266	\$ 3.344	\$ 3.416	\$ 3.440	\$ 3.425	\$ 3.437	4/4/2017	
29							\$ 2.844	\$ 2.869	\$ 2.895	\$ 2.899	\$ 2.875	\$ 2.894	8/9/2017	
30	\$ 3.000	\$ 3.150	\$ 3.250	\$ 3.230	\$ 3.180	\$ 2.820							7/24/2017	
	\$ 2.993	\$ 3.137	\$ 3.237	\$ 3.228	\$ 3.184	\$ 2.869								
	\$ 2.895	\$ 3.085	\$ 3.217	\$ 3.222	\$ 3.176	\$ 2.906								
	\$ 2.820	\$ 2.940	\$ 3.020	\$ 2.990	\$ 2.890	\$ 2.630	\$ 2.600	\$ 2.630	\$ 2.660	\$ 2.670	\$ 2.660	\$ 2.680	7/10/2018	
	\$ 2.890	\$ 2.979	\$ 3.066	\$ 3.030	\$ 2.926	\$ 2.635	\$ 2.603	\$ 2.634	\$ 2.667	\$ 2.671	\$ 2.653	\$ 2.669	8/29/2018	
	\$ 2.324	\$ 2.485	\$ 2.588	\$ 2.556	\$ 2.473	\$ 2.277	\$ 2.261	\$ 2.297	\$ 2.336	\$ 2.345	\$ 2.329	\$ 2.354	8/30/2019	
	\$ 2.566	\$ 2.630	\$ 2.585	\$ 2.482	\$ 2.324	\$ 2.312							11/18/2019	
	\$ 2.597	\$ 2.470	\$ 2.341	\$ 2.326	\$ 2.265	\$ 2.200								
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 2.202	\$ 2.168	\$ 2.164							1/10/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 2.182	\$ 2.158	\$ 2.163							1/13/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 2.077	\$ 2.046	\$ 2.064							1/16/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 2.003	\$ 1.985	\$ 2.011							1/20/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 1.905	\$ 1.900	\$ 1.950							1/22/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 1.877	\$ 1.971	\$ 1.971							2/18/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 1.877	\$ 1.920	\$ 1.931							2/20/2020	
	\$ 2.597	\$ 2.470	\$ 2.158	\$ 1.877	\$ 1.821	\$ 1.602							3/20/2020	
							\$ 1.733	\$ 1.863	\$ 2.060	\$ 2.128	\$ 2.156	\$ 2.217	4/10/2020	
						\$ 1.634	\$ 1.939	\$ 2.053	\$ 2.236	\$ 2.320	\$ 2.354	\$ 2.419	4/22/2020	
						\$ 1.634	\$ 1.794	\$ 1.646	\$ 1.833	\$ 1.935	\$ 2.000	\$ 2.098	5/15/2020	
						\$ 1.634	\$ 1.794	\$ 1.783	\$ 1.959	\$ 2.050	\$ 2.110	\$ 2.198	5/18/2020	
						\$ 1.634	\$ 1.794	\$ 1.830	\$ 1.985	\$ 2.064	\$ 2.122	\$ 2.206		
						\$ 1.794	\$ 1.722	\$ 1.669	\$ 1.760	\$ 1.814	\$ 1.917		6/15/2020	
						\$ 1.794	\$ 1.722	\$ 1.638	\$ 1.727	\$ 1.784	\$ 1.900		6/17/2020	
						\$ 1.794	\$ 1.722	\$ 1.669	\$ 1.748	\$ 1.799	\$ 1.904		6/19/2020	
						\$ 1.794	\$ 1.722	\$ 1.495	\$ 1.743	\$ 1.788	\$ 1.891		7/14/2020	
						\$ 1.794	\$ 1.722	\$ 1.495	\$ 1.642	\$ 1.684	\$ 1.808		7/20/2020	
						\$ 1.794	\$ 1.722	\$ 1.495	\$ 1.854	\$ 2.339	\$ 2.476		8/17/2020	
						\$ 1.794	\$ 1.722	\$ 1.495	\$ 1.854	\$ 2.352	\$ 2.503		8/20/2020	
	\$ 4.663	\$ 4.749	\$ 4.798	\$ 4.683	\$ 4.321	\$ 3.553	\$ 3.442	\$ 3.467	\$ 3.499	\$ 3.506	\$ 3.492	\$ 3.521	9/1/2021	
	\$ 5.305	\$ 5.398	\$ 5.465	\$ 5.370	\$ 5.013	\$ 3.939	\$ 3.810	\$ 3.839	\$ 3.871	\$ 3.879	\$ 3.863	\$ 3.890	9/14/2021	

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	\$ 17,953,274	
Storage Demand	\$ 24,992,506	
<u>On-system Peaking Demand</u>	<u>\$ 3,992,171</u>	
Subtotal Demand	\$ 46,937,950	
Capacity Release (Credit)	\$ -	
<u>Asset Management (Credit)</u>	<u>\$ (9,902,100)</u>	
Total Net Demand Costs	\$ 37,035,850	
Off-System Peaking Demand	\$ 9,621,667	PR Allocation on Page 5
Total Demand Costs	\$ 46,657,516	

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	1,251,924	1,257,820	1,257,819	1,207,638	1,484,768	1,216,238	692,758	427,492	407,061	428,105	513,700	888,799	11,034,123
Rank	4	2	3	6	1	5	8	11	12	10	9	7	
% Max Month	84.32%	84.71%	84.71%	81.34%	100.00%	81.91%	46.66%	28.79%	27.42%	28.83%	34.60%	59.86%	
PR	0.60%	0.00%	0.13%	3.58%	15.29%	0.12%	1.51%	0.13%	2.28%	0.00%	0.64%	1.89%	26.16%
CumPR	10.74%	10.88%	10.88%	10.03%	26.16%	10.14%	4.56%	2.41%	2.28%	2.41%	3.05%	6.45%	100.00%
Product and Pipeline Demand Costs	\$ 1,928,863	\$ 1,952,631	\$ 1,952,625	\$ 1,800,189	\$ 4,696,796	\$ 1,820,988	\$ 819,006	\$ 432,629	\$ 410,169	\$ 433,369	\$ 548,367	\$ 1,157,641	\$ 17,953,274

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	1,251,924	1,257,820	1,257,819	1,207,638	1,484,768	1,216,238	692,758	427,492	407,061	428,105	513,700	888,799	11,034,123
% 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	384,599	949,630	1,116,303	1,034,206	647,868	-	-	-	-	-	-	-	4,132,606
Rank	5	3	1	2	4	6	6	6	6	6	6	6	
% Max Month	34.45%	85.07%	100.00%	92.65%	58.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	6.89%	9.01%	7.35%	3.79%	5.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	32.94%
CumPR	6.89%	21.80%	32.94%	25.59%	12.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	\$ 1,722,128	\$ 5,447,705	\$ 8,232,513	\$ 6,394,467	\$ 3,195,692	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 24,992,506
Plus Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
TOTAL	\$ 1,722,128	\$ 5,447,705	\$ 8,232,513	\$ 6,394,467	\$ 3,195,692	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 24,992,506

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	79,083	112,600	79,389	13,513	1,794	1,860	1,800	1,860	1,860	1,800	1,860	299,213
Rank	11	3	1	2	4	12	8	10	7	6	9	5	
% Max Month	1.59%	70.23%	100.00%	70.51%	12.00%	1.59%	1.65%	1.60%	1.65%	1.65%	1.60%	1.65%	
PR	0.00%	19.41%	29.49%	0.14%	2.59%	0.13%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	51.77%
CumPR	0.13%	22.14%	51.77%	22.27%	2.73%	0.13%	0.14%	0.13%	0.14%	0.14%	0.13%	0.14%	100.00%
Peaking Demand Costs	\$ 5,304	\$ 883,785	\$ 2,066,699	\$ 889,215	\$ 108,876	\$ 5,300	\$ 5,587	\$ 5,321	\$ 5,587	\$ 5,587	\$ 5,321	\$ 5,587	\$ 3,992,171

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

Pipeline Demand	NUI-FXW-5, PG 1, LN 1
Storage Demand	NUI-FXW-5, PG 1, LN 2 + 3
<u>On-system Peaking Demand</u>	NUI-FXW-5, PG 1, LN 4 + 5
Subtotal Demand	Sum LN 3 : LN 5
Capacity Release (Credit)	NUI-FXW-5, PG 6
<u>Asset Management (Credit)</u>	NUI-FXW-5, PG 6
Total Net Demand Costs	Sum LN 6 : LN 9
Off-System Peaking Demand	NUI-FXW-5, 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-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
Pipeline & Product Demand	\$ 1,928,863	\$ 1,952,631	\$ 1,952,625	\$ 1,800,189	\$ 4,696,796	\$ 1,820,988	\$ 819,006	\$ 432,629	\$ 410,169	\$ 433,369	\$ 548,367	\$ 1,157,641	\$ 17,953,274
Storage Incl Inj Fees	\$ 1,722,128	\$ 5,447,705	\$ 8,232,513	\$ 6,394,467	\$ 3,195,692	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 24,992,506
On-system Peaking	\$ 5,304	\$ 883,785	\$ 2,066,699	\$ 889,215	\$ 108,876	\$ 5,300	\$ 5,587	\$ 5,321	\$ 5,587	\$ 5,587	\$ 5,321	\$ 5,587	\$ 3,992,171
Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Less: Capacity Release	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Less: Asset Mgmt	\$ (1,650,350)	\$ (1,650,350)	\$ (1,650,350)	\$ (1,650,350)	\$ (1,650,350)	\$ (1,650,350)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (9,902,100)
Total Demand	\$ 2,005,945	\$ 6,633,771	\$ 10,601,487	\$ 7,433,521	\$ 6,351,014	\$ 175,938	\$ 824,593	\$ 437,950	\$ 415,757	\$ 438,956	\$ 553,689	\$ 1,163,229	\$ 37,035,850

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	953,078	1,363,286	1,655,363	1,470,818	1,299,001	742,868	427,912	252,221	240,495	254,997	306,067	513,458	9,479,564
New Hampshire	685,239	1,007,317	1,192,761	1,033,962	885,575	475,164	266,707	177,072	168,426	174,968	209,433	377,201	6,653,824
Total	1,638,317	2,370,603	2,848,124	2,504,780	2,184,576	1,218,032	694,618	429,292	408,921	429,965	515,500	890,659	16,133,388

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
Percentage of Total													
Maine	58.17%	57.51%	58.12%	58.72%	59.46%	60.99%	61.60%	58.75%	58.81%	59.31%	59.37%	57.65%	58.49%
New Hampshire	41.83%	42.49%	41.88%	41.28%	40.54%	39.01%	38.40%	41.25%	41.19%	40.69%	40.63%	42.35%	41.51%
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	\$1,166,942	\$3,814,947	\$6,161,708	\$4,364,996	\$3,776,464	\$107,303	\$507,981	\$257,307	\$244,515	\$260,330	\$328,741	\$670,593	\$21,661,828
New Hampshire	\$839,002	\$2,818,823	\$4,439,780	\$3,068,525	\$2,574,550	\$68,635	\$316,612	\$180,643	\$171,242	\$178,627	\$224,948	\$492,636	\$15,374,022
Total	\$ 2,005,945	\$ 6,633,771	\$ 10,601,487	\$ 7,433,521	\$ 6,351,014	\$ 175,938	\$ 824,593	\$ 437,950	\$ 415,757	\$ 438,956	\$ 553,689	\$ 1,163,229	\$ 37,035,850

Detailed Allocation of Demand Costs by Division

Maine	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Pipeline & Product Demand	\$ 1,122,101	\$ 1,122,918	\$ 1,134,888	\$ 1,057,079	\$ 2,792,827	\$ 1,110,606	\$ 504,539	\$ 254,181	\$ 241,229	\$ 257,016	\$ 325,582	\$ 667,372	\$ 10,590,338	58.99%
Storage Incl Injection Fees	\$ 1,001,834	\$ 3,132,865	\$ 4,784,832	\$ 3,754,859	\$ 1,900,235	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 14,574,625	58.32%
On-system Peaking	\$ 3,085	\$ 508,247	\$ 1,201,190	\$ 522,151	\$ 64,740	\$ 3,233	\$ 3,442	\$ 3,126	\$ 3,286	\$ 3,314	\$ 3,159	\$ 3,221	\$ 2,322,194	58.17%
Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Capacity Release (Credit)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Asset Management (Credit)	\$ (960,078)	\$ (949,083)	\$ (959,203)	\$ (969,093)	\$ (981,337)	\$ (1,006,536)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (5,825,329)	58.83%
Total Allocated Demand	\$ 1,166,942	\$ 3,814,947	\$ 6,161,708	\$ 4,364,996	\$ 3,776,464	\$ 107,303	\$ 507,981	\$ 257,307	\$ 244,515	\$ 260,330	\$ 328,741	\$ 670,593	\$ 21,661,828	58.49%

New Hampshire	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Pipeline & Product Demand	\$ 806,762	\$ 829,712	\$ 817,737	\$ 743,110	\$ 1,903,969	\$ 710,382	\$ 314,467	\$ 178,448	\$ 168,940	\$ 176,353	\$ 222,786	\$ 490,270	\$ 7,362,936	41.01%
Storage Incl Injection Fees	\$ 720,294	\$ 2,314,840	\$ 3,447,681	\$ 2,639,608	\$ 1,295,457	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,417,880	41.68%
On-system Peaking	\$ 2,218	\$ 375,538	\$ 865,510	\$ 367,064	\$ 44,136	\$ 2,068	\$ 2,145	\$ 2,195	\$ 2,301	\$ 2,274	\$ 2,162	\$ 2,366	\$ 1,669,977	41.83%
Less: Injection Fees	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Capacity Release	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	0.00%
Asset Management	\$ (690,272)	\$ (701,267)	\$ (691,147)	\$ (681,257)	\$ (669,013)	\$ (643,814)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (4,076,771)	41.17%
Total Allocated Demand	\$ 839,002	\$ 2,818,823	\$ 4,439,780	\$ 3,068,525	\$ 2,574,550	\$ 68,635	\$ 316,612	\$ 180,643	\$ 171,242	\$ 178,627	\$ 224,948	\$ 492,636	\$ 15,374,022	41.51%

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	Terms	
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	-	84,071	361,402	183,548	38,427	-	-	-	-	-	-	-	667,448
Rank	5	3	1	2	4	5	5	5	5	5	5	5	
% Max Month	0.00%	23.26%	100.00%	50.79%	10.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	0.00%	4.21%	49.21%	13.76%	2.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	69.84%
CumPR	0.00%	6.87%	69.84%	20.63%	2.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Peaking Demand Costs	\$ -	\$ 660,823	\$ 6,720,056	\$ 1,985,025	\$ 255,763	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,621,667

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108 **Capacity Cost Allocator based on Design Year Sales**

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
Therms													
Maine	769,970	1,118,218	1,373,487	1,222,295	1,075,734	602,565	335,601	186,167	184,179	197,150	232,899	397,265	7,695,530
New Hampshire	473,924	746,005	884,060	759,575	635,070	312,572	164,969	91,875	82,497	87,972	108,619	227,211	4,574,349
Total	1,243,894	1,864,223	2,257,548	1,981,870	1,710,804	915,137	500,570	278,043	266,676	285,122	341,518	624,476	12,269,879

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	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	61.90%	59.98%	60.84%	61.67%	62.88%	65.84%	67.04%	66.96%	69.06%	69.15%	68.20%	63.62%	61.01%
New Hampshire	38.10%	40.02%	39.16%	38.33%	37.12%	34.16%	32.96%	33.04%	30.94%	30.85%	31.80%	36.38%	38.99%
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

120 **Allocation of Off-System Peaking Demand Costs by Division**

Maine	\$0	\$396,382	\$4,088,469	\$1,224,241	\$160,821	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$5,869,912
New Hampshire	\$0	\$264,441	\$2,631,588	\$760,784	\$94,942	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$3,751,755
Total	\$ -	\$ 660,823	\$ 6,720,056	\$ 1,985,025	\$ 255,763	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,621,667

123

Total Weighted Average MPR Factor

Maine	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Total Pipeline, Storage & On-system	\$ 1,166,942	\$ 3,814,947	\$ 6,161,708	\$ 4,364,996	\$ 3,776,464	\$ 107,303	\$ 507,981	\$ 257,307	\$ 244,515	\$ 260,330	\$ 328,741	\$ 670,593	\$ 21,661,828	58.49%
Total Off-system Peaking	\$0	\$396,382	\$4,088,469	\$1,224,241	\$160,821	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$ 5,869,912	61.01%
Total Demand Cost Allocation	\$ 1,166,942	\$ 4,211,329	\$ 10,250,176	\$ 5,589,237	\$ 3,937,285	\$ 107,303	\$ 507,981	\$ 257,307	\$ 244,515	\$ 260,330	\$ 328,741	\$ 670,593	\$ 27,531,741	59.01%
New Hampshire	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Total Pipeline, Storage & On-system	\$ 839,002	\$ 2,818,823	\$ 4,439,780	\$ 3,068,525	\$ 2,574,550	\$ 68,635	\$ 316,612	\$ 180,643	\$ 171,242	\$ 178,627	\$ 224,948	\$ 492,636	\$ 15,374,022	41.51%
Total Off-system Peaking	\$0	\$264,441	\$2,631,588	\$760,784	\$94,942	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$ 3,751,755	38.99%
Total Demand Cost Allocation	\$ 839,002	\$ 3,083,265	\$ 7,071,367	\$ 3,829,309	\$ 2,669,492	\$ 68,635	\$ 316,612	\$ 180,643	\$ 171,242	\$ 178,627	\$ 224,948	\$ 492,636	\$ 19,125,776	40.99%
Total Northern	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Total Pipeline, Storage & On-system	\$ 2,005,945	\$ 6,633,771	\$ 10,601,487	\$ 7,433,521	\$ 6,351,014	\$ 175,938	\$ 824,593	\$ 437,950	\$ 415,757	\$ 438,956	\$ 553,689	\$1,163,229	\$ 37,035,850	
Total Off-system Peaking	\$ -	\$ 660,823	\$ 6,720,056	\$ 1,985,025	\$ 255,763	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 9,621,667	
Total Demand Cost Allocation	\$ 2,005,945	\$ 7,294,594	\$ 17,321,544	\$ 9,418,546	\$ 6,606,777	\$ 175,938	\$ 824,593	\$ 437,950	\$ 415,757	\$ 438,956	\$ 553,689	\$1,163,229	\$ 46,657,517	

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97	Off-System Peaking Demand Costs	LN 12
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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	\$ 7,362,936
3	Storage	\$ 10,417,880
4	On-system Peaking	\$ 1,669,977
5	Total Gross Demand Cost	\$ 19,450,793
6		
7	Capacity Assignment Demand Revenue Estimate	\$ 5,012,735
8	NH Total Pipeline, Storage & Peaking Demand Cost	\$ 19,450,793
9	Capacity Assignment as % of Total Gross Demand Cost	25.77%
10		
11		Costs
12	Pipeline & Product Demand	\$ 1,897,529
13	Storage	\$ 2,684,830
14	On-system Peaking	\$ 430,376
15	Total Capacity Assignment Credit	\$ 5,012,735
16		
17	NH Net Annual Demand Cost (Less Capacity Assignment)	
18		Costs
19	Pipeline & Product Demand	\$ 5,465,407
20	Storage	\$ 7,733,050
21	On-system Peaking	\$ 1,239,601
22	Total Net Demand Cost (Less Capacity Assignment)	\$ 14,438,058

DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS

25		MMBtu/day
26	Pipeline MDQ	16,645
27	Less 25.77% NH Transp. Capacity Assignment	(4,290)
28	Net Pipeline MDQ	12,355
29		
30	Net Pipeline MDQ	12,355
31	Less: Firm Sales Base Use	3,536
32	Remaining Pipeline MDQ	8,820
33		
34		Unit Cost
35	Pipeline Unit Cost	\$442.35
36		
37		Costs
38	Pipeline & Product Demand	\$ 5,465,407
39	Less: Base Pipeline Use	\$ 1,563,940
40	Remaining Pipeline Use	\$ 3,901,466

1	Resource	
2	Pipeline & Product Demand	Attachment NUI-CAK-1, LN 90 + Attachment NUI-CAK-1, LN 93
3	Storage	Attachment NUI-CAK-1, LN 91
4	On-system Peaking	Attachment NUI-CAK-1, LN 92
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Attachment NUI-FXW-6, 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 25.77% 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	Attachment NUI-CAK-3, 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)
43

44 All Months	Nov	Dec	Jan	Feb	Mar	Apr
45 Remaining Load for All Months	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637
46 Rank	5	3	1	2	4	6
47 % Max Month	53.92%	82.94%	100.00%	85.28%	69.31%	35.44%
48 PR	3.70%	4.54%	14.72%	1.17%	3.85%	2.75%
49 CumPR	8.87%	17.25%	33.15%	18.42%	12.71%	5.17%

51 Peak Months Only	Nov	Dec	Jan	Feb	Mar	Apr
52 Remaining Load for Peak Months Only	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637
53 Rank	5	3	1	2	4	6
54 % Max Month	53.92%	82.94%	100.00%	85.28%	69.31%	35.44%
55 PR	3.70%	4.54%	14.72%	1.17%	3.85%	5.91%
56 CumPR	9.60%	17.99%	33.89%	19.16%	13.45%	5.91%

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	8.87%	17.25%	33.15%	18.42%	12.71%	5.17%
62 Storage & Peaking	8.87%	17.25%	33.15%	18.42%	12.71%	5.17%
63 Capacity Release	9.60%	17.99%	33.89%	19.16%	13.45%	5.91%
64 Off-system Peaking	9.29%	17.64%	34.66%	18.93%	13.70%	5.79%
65 Interr. Margins & Off Sys Sales	9.60%	17.99%	33.89%	19.16%	13.45%	5.91%

66 **DEMAND COSTS ALLOCATED TO MONTHS**

68	Nov	Dec	Jan	Feb	Mar	Apr
69 Pipeline - Base	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328
70 Pipeline - Remaining	\$ 345,883	\$ 673,169	\$ 1,293,229	\$ 718,765	\$ 495,985	\$ 201,641
71 Total Pipeline	\$ 476,211	\$ 803,497	\$ 1,423,557	\$ 849,094	\$ 626,313	\$ 331,970
72						
73 Storage & On-system Peaking	\$ 795,466	\$ 1,548,164	\$ 2,974,187	\$ 1,653,027	\$ 1,140,674	\$ 463,738
74 Off-system Peaking	\$348,528	\$661,712	\$1,300,321	\$710,247	\$513,808	\$217,139
75 Outage Replacement	\$ 3,933	\$ 7,655	\$ 14,707	\$ 8,174	\$ 5,640	\$ 2,293
76 Less Credits to Demand Cost						
77 Cap Rel Margins & Asset Mgt Credits	\$ 391,517	\$ 733,509	\$ 1,381,430	\$ 781,155	\$ 548,364	\$ 240,795
78 Interruptible Margins	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
79 Conversion Rate and Re-entry Rate Credits	\$ 480	\$ 900	\$ 1,694	\$ 958	\$ 673	\$ 295
80 Total Direct Demand Costs	\$ 1,232,141	\$ 2,286,619	\$ 4,329,647	\$ 2,438,429	\$ 1,737,398	\$ 774,050

81 Indirect Demand Costs/(Credits)

82 Miscellaneous Overhead

83 Local Production & Storage

84 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 Sensit ive Load)

43	44	May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
45	All Months									
46	Remaining Load for All Months	835,747	214,153	0	8,214	162,755	1,303,416	31,911,637	29,387,353	2,524,285
47	Rank	8	9	12	11	10	7			
48	% Max Month	12.14%	3.11%	0.00%	0.12%	2.36%	18.93%			
49	PR	1.13%	0.08%	0.00%	0.01%	0.22%	0.97%	33.15%		
50	CumPR	1.45%	0.32%	0.00%	0.01%	0.24%	2.42%	100.00%	95.57%	4.43%

51	52	Annual	Winter	Summer
53	Peak Months Only			
54	Remaining Load for Peak Months Only	29,387,353	29,387,353	
55	Rank			
56	% Max Month			
57	PR	33.89%		
58	CumPR	100.00%	100.00%	0.00%

58 **DEMAND COST PR ALLOCATORS**

59	May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
60	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
61	Pipeline - Remaining	1.45%	0.32%	0.00%	0.01%	0.24%	100.00%	95.57%	4.43%
62	Storage & Peaking	1.45%	0.32%	0.00%	0.01%	0.24%	100.00%	95.57%	4.43%
63	Capacity Release	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%	100.00%	100.00%	0.00%
65	Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

67 **DEMAND COSTS ALLOCATED TO MONTHS**

68	May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer	Winter	Summer
69	Pipeline - Base	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 1,563,940	\$ 781,970	\$ 781,970	50.00%	50.00%
70	Pipeline - Remaining	\$ 56,454	\$ 12,418	\$ -	\$ 423	\$ 9,182	\$ 3,901,466	\$ 3,728,672	\$ 172,794	95.57%	4.43%
71	Total Pipeline	\$ 186,782	\$ 142,747	\$ 130,328	\$ 130,752	\$ 139,510	\$ 5,465,407	\$ 4,510,642	\$ 954,764	82.53%	17.47%
72	Storage & On-system Peaking	\$ 129,833	\$ 28,560	\$ -	\$ 973	\$ 21,116	\$ 8,972,651	\$ 8,575,256	\$ 397,395	95.57%	4.43%
73	Off-system Peaking	\$0	\$0	\$0	\$0	\$0	\$ 3,751,755	\$ 3,751,755	\$ -	100.00%	0.00%
74	Outage Replacement	\$ 642	\$ 141	\$ -	\$ 5	\$ 104	\$ 44,367	\$ 42,402	\$ 1,965		
75	Less Credits to Demand Cost										
76	Cap Rel Margins & Asset Mgt Credits	\$ -	\$ -	\$ -	\$ -	\$ -	\$4,076,771	\$ 4,076,771	\$ -	100.00%	0.00%
77	Interruptible Margins	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
78	Conversion Rate and Re-entry Rate Credits	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,000	\$ 5,000	\$ -		
79	Total Direct Demand Costs	\$ 317,257	\$ 171,448	\$ 130,328	\$ 131,730	\$ 160,731	\$ 14,152,409	\$ 12,798,284	\$ 1,354,125	90.43%	9.57%

81	Indirect Demand Costs/(Credits)										
82	Miscellaneous Overhead						\$ 580,455	\$ 463,606	\$ 116,849	79.87%	20.13%
83	Local Production & Storage						\$ 476,106	\$ 476,106	\$ -	100.00%	0.00%
84	Subtotal						\$ 1,056,561	\$ 939,712	\$ 116,849	88.94%	11.06%

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 Sensit ive Load)

43

44	All Months	
45	Remaining Load for All Months	Attachment NUI-CAK-3, 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	Attachment NUI-CAK-1, LN 122,* LN 64
75	Outage Replacement	Attachment NUI-CAK-2A
76	Less Credits to Demand Cost	
77	Cap Rel Margins & Asset Mgt Credits	Attachment NUI-CAK-1, 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
2021 - 2022 Period**

Forecasted Normal Sales By Class- Therms																
Calendar Month Firm Sales Volumes																
Line No.	Normal Winter	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
1	Res Heat	2,214,836	3,176,763	3,717,973	3,190,785	2,720,227	1,601,139	774,136	505,683	427,329	433,379	480,902	970,020	20,213,169	16,621,722	3,591,447
2	Res General	20,357	29,198	34,173	29,327	25,002	14,716	17,608	11,502	9,720	9,858	10,939	22,064	234,465	152,774	81,691
3	Total Residential	2,235,193	3,205,961	3,752,145	3,220,112	2,745,230	1,615,855	791,744	517,185	437,049	443,237	491,840	992,084	20,447,634	16,774,496	3,673,138
4	G50 Low Annual-Low Winter	118,323	169,711	198,624	170,460	145,322	85,537	146,159	95,474	80,681	81,823	90,796	183,143	1,566,054	887,978	678,076
5	G40 Low Annual-High Winter	1,128,570	1,618,720	1,894,493	1,625,865	1,386,092	815,860	293,304	191,593	161,906	164,199	182,204	367,521	9,830,327	8,469,600	1,360,727
6	G51 Med Annual-Low Winter	196,136	281,320	329,247	282,562	240,891	141,790	219,962	143,684	121,421	123,140	136,643	275,620	2,492,415	1,471,945	1,020,469
7	G41 Med Annual-High Winter	828,952	1,188,975	1,391,535	1,194,223	1,018,107	599,262	310,158	202,602	171,210	173,634	192,674	388,639	7,659,971	6,221,055	1,438,916
8	G52 High Annual-Low Winter	53,899	52,129	58,595	56,625	58,318	53,429	52,740	45,879	48,194	49,987	48,339	53,274	631,408	332,996	298,412
9	G42 High Annual-High Winter	152,111	203,629	255,657	224,755	200,301	144,806	93,544	60,828	53,739	54,403	65,622	109,154	1,618,550	1,181,259	437,291
10	Total C&I	2,477,990	3,514,485	4,128,152	3,554,490	3,049,031	1,840,685	1,115,867	740,061	637,150	647,185	716,278	1,377,351	23,798,725	18,564,833	5,233,892
11	Total Sales	4,713,183	6,720,446	7,880,297	6,774,602	5,794,261	3,456,540	1,907,611	1,257,246	1,074,199	1,090,422	1,208,118	2,369,434	44,246,359	35,339,329	8,907,030
12																
13	Residential Heat & Non Heat	2,235,193	3,205,961	3,752,145	3,220,112	2,745,230	1,615,855	791,744	517,185	437,049	443,237	491,840	992,084	20,447,634	16,774,496	3,673,138
14	SALES HLF CLASSES	368,357	503,160	586,466	509,647	444,531	280,756	418,861	285,038	250,296	254,950	275,778	512,036	4,689,876	2,692,919	1,996,958
15	SALES LLF CLASSES	2,109,633	3,011,324	3,541,686	3,044,843	2,604,500	1,559,929	697,006	455,024	386,854	392,235	440,500	865,314	19,108,849	15,871,915	3,236,934
16	Total Firm Sales	4,713,183	6,720,446	7,880,297	6,774,602	5,794,261	3,456,540	1,907,611	1,257,246	1,074,199	1,090,422	1,208,118	2,369,434	44,246,359	35,339,329	8,907,030
17																
18	ESTIMATED SENDOUT BY CLASS - Therms															
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)															
20	Normal Winter	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
21	Res Heat	2,242,870	3,216,973	3,765,033	3,231,172	2,754,659	1,621,405	783,934	512,083	432,738	438,865	486,989	982,298	20,469,017	16,832,111	3,636,906
22	Res General	20,615	29,568	34,605	29,699	25,319	14,903	17,831	11,648	9,843	9,982	11,077	22,343	237,433	154,708	82,725
23	G50 Low Annual-Low Winter	119,820	171,859	201,138	172,618	147,161	86,620	148,009	96,683	81,702	82,859	91,945	185,461	1,585,876	899,217	686,659
24	G40 Low Annual-High Winter	1,142,855	1,639,209	1,918,473	1,646,444	1,403,637	826,187	297,017	194,018	163,956	166,277	184,510	372,173	9,954,754	8,576,804	1,377,950
25	G51 Med Annual-Low Winter	198,619	284,881	333,414	286,138	243,940	143,584	222,746	145,503	122,958	124,699	138,372	279,109	2,523,962	1,490,576	1,033,386
26	G41 Med Annual-High Winter	839,445	1,204,025	1,409,149	1,209,339	1,030,993	606,847	314,084	205,167	173,377	175,832	195,112	393,558	7,756,927	6,299,798	1,457,129
27	G52 High Annual-Low Winter	54,581	52,789	59,336	57,342	59,056	54,106	53,407	46,460	48,804	50,619	48,951	53,948	639,400	337,210	302,189
28	G42 High Annual-High Winter	154,036	206,207	258,893	227,600	202,837	146,639	94,728	61,598	54,419	55,092	66,453	110,536	1,639,037	1,196,211	442,826
29	Subtotal															
30	Residential	2,263,485	3,246,541	3,799,638	3,260,870	2,779,977	1,636,308	801,765	523,731	442,581	448,847	498,066	1,004,641	20,706,450	16,986,819	3,719,631
31	SALES HLF CLASSES	373,020	509,529	593,889	516,098	450,158	284,310	424,162	288,645	253,464	258,177	279,268	518,517	4,749,238	2,727,004	2,022,234
32	SALES LLF CLASSES	2,136,335	3,049,440	3,586,515	3,083,383	2,637,466	1,579,674	705,829	460,783	391,751	397,200	446,076	876,267	19,350,718	16,072,813	3,277,905
33	Total Firm Sales	4,772,840	6,805,510	7,980,042	6,860,351	5,867,601	3,500,291	1,931,757	1,273,159	1,087,795	1,104,224	1,223,410	2,399,425	44,806,406	35,786,636	9,019,770

Northern Utilities - NEW HAMPSHIRE DIVISION
2021 - 2022 Period

Line No.	Forecasted Normal Sales By Class- Therms	
	Calendar Month Firm Sales Volumes	
	Firm Sales	
1	Res Heat	(Attachment NUI-FXW-2, Page 1) * 10
2	Res General	(Attachment NUI-FXW-2, Page 1) * 10
3	Total Residential	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	(Attachment NUI-FXW-2, Page 1) * 10
5	G40 Low Annual-High Winter	(Attachment NUI-FXW-2, Page 1) * 10
6	G51 Med Annual-Low Winter	(Attachment NUI-FXW-2, Page 1) * 10
7	G41 Med Annual-High Winter	(Attachment NUI-FXW-2, Page 1) * 10
8	G52 High Annual-Low Winter	(Attachment NUI-FXW-2, Page 1) * 10
9	G42 High Annual-High Winter	(Attachment NUI-FXW-2, 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)	Unaccounted For)
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Attachment NUI-FXW-2, Page 4)
22	Res General	LN 2 x Adj factor (Attachment NUI-FXW-2, Page 4)
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Attachment NUI-FXW-2, Page 4)
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Attachment NUI-FXW-2, Page 4)
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Attachment NUI-FXW-2, Page 4)
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Attachment NUI-FXW-2, Page 4)
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Attachment NUI-FXW-2, Page 4)
28	G42 High Annual-High Winter	LN 9 x Adj factor (Attachment NUI-FXW-2, Page 4)
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

Northern Utilities - NEW HAMPSHIRE DIVISION

Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	DAILY BASE GAS ENTITLEMENT - Therms/day	
36	Res Heat	14,058
37	Res General	320
38	G50 Low Annual-Low Winter	2,654
39	G40 Low Annual-High Winter	5,326
40	G51 Med Annual-Low Winter	3,994
41	G41 Med Annual-High Winter	5,632
42	G52 High Annual-Low Winter	1,604
43	G42 High Annual-High Winter	1,766
44	Subtotal	
45	Residential	14,378
46	SALES HLF CLASSES	8,252
47	SALES LLF CLASSES	12,725
48	Total Firm Sales	35,355

49	BASE SENDOUT BY CLASS - Therms															
50	Days per Month	30	31	31	28	31	30	31	30	31	31	30	31			
51		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
52	Res Heat	421,743	435,801	435,801	393,627	435,801	421,743	435,801	421,743	432,738	435,801	421,743	435,801	5,128,145	2,544,517	2,583,628
53	Res General	9,593	9,913	9,913	8,953	9,913	9,593	9,913	9,593	9,843	9,913	9,593	9,913	116,644	57,877	58,767
54	G50 Low Annual-Low Winter	79,626	82,281	82,281	74,318	82,281	79,626	82,281	79,626	81,702	82,281	79,626	82,281	968,209	480,412	487,797
55	G40 Low Annual-High Winter	159,790	165,116	165,116	149,137	165,116	159,790	165,116	159,790	163,956	165,116	159,790	165,116	1,942,950	964,066	978,884
56	G51 Med Annual-Low Winter	119,834	123,828	123,828	111,845	123,828	119,834	123,828	119,834	122,958	123,828	119,834	123,828	1,457,105	722,996	734,109
57	G41 Med Annual-High Winter	168,972	174,604	174,604	157,707	174,604	168,972	174,604	168,972	173,377	174,604	168,972	174,604	2,054,595	1,019,463	1,035,133
58	G52 High Annual-Low Winter	48,108	49,712	49,712	44,901	49,712	48,108	49,712	46,460	48,804	49,712	48,108	49,712	582,759	290,252	292,507
59	G42 High Annual-High Winter	52,989	54,755	54,755	49,456	54,755	52,989	54,755	52,989	54,419	54,755	52,989	54,755	644,362	319,700	324,662
60	Subtotal															
61	Residential	431,336	445,714	445,714	402,580	445,714	431,336	445,714	431,336	442,581	445,714	431,336	445,714	5,244,789	2,602,394	2,642,395
62	SALES HLF CLASSES	247,568	255,820	255,820	231,063	255,820	247,568	255,820	245,920	253,464	255,820	247,568	255,820	3,008,073	1,493,660	1,514,413
63	SALES LLF CLASSES	381,751	394,476	394,476	356,301	394,476	381,751	394,476	381,751	391,751	394,476	381,751	394,476	4,641,907	2,303,228	2,338,679
64	Total Firm Sales	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486

67	REMAINING SENDOUT BY CLASS - Therms																	
		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER		
68	Res Heat	1,821,127	2,781,171	3,329,231	2,837,545	2,318,857	1,199,662	348,133	90,340	-	3,064	65,245	546,496	15,340,872	14,287,594	1,053,279		
69	Res General	11,022	19,655	24,693	20,745	15,406	5,310	7,919	2,055	-	70	1,484	12,431	120,789	96,831	23,958		
70	G50 Low Annual-Low Winter	40,194	89,579	118,858	98,300	64,881	6,994	65,729	17,056	-	578	12,319	103,180	617,667	418,805	198,862		
71	G40 Low Annual-High Winter	983,065	1,474,093	1,753,357	1,497,307	1,238,520	666,397	131,900	34,228	-	1,161	24,720	207,056	8,011,804	7,612,738	399,066		
72	G51 Med Annual-Low Winter	78,785	161,053	209,586	174,293	120,112	23,751	98,918	25,669	-	870	18,539	155,281	1,066,858	767,580	299,277		
73	G41 Med Annual-High Winter	670,473	1,029,421	1,234,544	1,051,632	856,389	437,876	139,480	36,195	-	1,227	26,141	218,954	5,702,332	5,280,335	421,997		
74	G52 High Annual-Low Winter	6,473	3,077	9,625	12,441	9,344	5,998	3,695	-	-	908	843	4,236	56,640	46,958	9,682		
75	G42 High Annual-High Winter	101,047	151,451	204,138	178,143	148,081	93,650	39,973	8,610	-	336	13,464	55,781	994,676	876,512	118,164		
76	Subtotal																	
77	Residential	1,832,149	2,800,827	3,353,924	2,858,290	2,334,263	1,204,972	356,051	92,395	-	3,133	66,730	558,927	15,461,661	14,384,425	1,077,236		
78	SALES HLF CLASSES	125,452	253,709	338,069	285,035	194,337	36,742	168,342	42,726	-	2,356	31,700	262,697	1,741,165	1,233,344	507,822		
79	SALES LLF CLASSES	1,754,585	2,654,964	3,192,039	2,727,082	2,242,991	1,197,923	311,353	79,032	-	2,725	64,325	481,791	14,708,811	13,769,585	939,227		
80	Total Firm Sales	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637	835,747	214,153	-	8,214	162,755	1,303,416	31,911,637	29,387,353	2,524,285		

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

	BASE SENDOUT BY CLASS	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
1	Total Therms															
2	Res Heat	421,743	435,801	435,801	393,627	435,801	421,743	435,801	421,743	432,738	435,801	421,743	435,801	5,128,145	2,544,517	2,583,628
3	Res General	9,593	9,913	9,913	8,953	9,913	9,593	9,913	9,593	9,843	9,913	9,593	9,913	116,644	57,877	58,767
4	G50 Low Annual-Low Winter	79,626	82,281	82,281	74,318	82,281	79,626	82,281	79,626	81,702	82,281	79,626	82,281	968,209	480,412	487,797
5	G40 Low Annual-High Winter	159,790	165,116	165,116	149,137	165,116	159,790	165,116	159,790	163,956	165,116	159,790	165,116	1,942,950	964,066	978,884
6	G51 Med Annual-Low Winter	119,834	123,828	123,828	111,845	123,828	119,834	123,828	119,834	122,958	123,828	119,834	123,828	1,457,105	722,996	734,109
7	G41 Med Annual-High Winter	168,972	174,604	174,604	157,707	174,604	168,972	174,604	168,972	173,377	174,604	168,972	174,604	2,054,595	1,019,463	1,035,133
8	G52 High Annual-Low Winter	48,108	49,712	49,712	44,901	49,712	48,108	49,712	46,460	48,804	49,712	48,108	49,712	582,759	290,252	292,507
9	G42 High Annual-High Winter	52,989	54,755	54,755	49,456	54,755	52,989	54,755	52,989	54,419	54,755	52,989	54,755	644,362	319,700	324,662
10	Total Firm Sales	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
11	% of Total															
12	Res Heat	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.82%	39.78%	39.76%	39.76%	39.76%			
13	Res General	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.91%	0.90%	0.90%	0.90%	0.90%			
14	G50 Low Annual-Low Winter	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.52%	7.51%	7.51%	7.51%	7.51%			
15	G40 Low Annual-High Winter	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.09%	15.07%	15.07%	15.07%	15.07%			
16	G51 Med Annual-Low Winter	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.32%	11.30%	11.30%	11.30%	11.30%			
17	G41 Med Annual-High Winter	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.96%	15.94%	15.93%	15.93%	15.93%			
18	G52 High Annual-Low Winter	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.39%	4.49%	4.54%	4.54%	4.54%			
19	G42 High Annual-High Winter	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%			
20	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%			
21																
22	PIPELINE BASE DEMAND COSTS	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
23	TOTAL PIPELINE BASE DEMAND COST	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 130,328	\$ 1,563,940	\$ 781,970	\$ 781,970
24	Res Heat	\$ 51,822	\$ 51,822	\$ 51,822	\$ 51,822	\$ 51,822	\$ 51,822	\$ 51,822	\$ 51,903	\$ 51,846	\$ 51,822	\$ 51,822	\$ 51,822	\$ 621,967	\$ 310,931	\$ 311,036
25	Res General	\$ 1,179	\$ 1,179	\$ 1,179	\$ 1,179	\$ 1,179	\$ 1,179	\$ 1,179	\$ 1,181	\$ 1,179	\$ 1,179	\$ 1,179	\$ 1,179	\$ 14,147	\$ 7,072	\$ 7,075
26	G50 Low Annual-Low Winter	\$ 9,784	\$ 9,784	\$ 9,784	\$ 9,784	\$ 9,784	\$ 9,784	\$ 9,784	\$ 9,799	\$ 9,789	\$ 9,784	\$ 9,784	\$ 9,784	\$ 117,429	\$ 58,705	\$ 58,725
27	G40 Low Annual-High Winter	\$ 19,634	\$ 19,634	\$ 19,634	\$ 19,634	\$ 19,634	\$ 19,634	\$ 19,634	\$ 19,665	\$ 19,643	\$ 19,634	\$ 19,634	\$ 19,634	\$ 235,651	\$ 117,805	\$ 117,845
28	G51 Med Annual-Low Winter	\$ 14,725	\$ 14,725	\$ 14,725	\$ 14,725	\$ 14,725	\$ 14,725	\$ 14,725	\$ 14,748	\$ 14,731	\$ 14,725	\$ 14,725	\$ 14,725	\$ 176,725	\$ 88,348	\$ 88,377
29	G41 Med Annual-High Winter	\$ 20,762	\$ 20,762	\$ 20,762	\$ 20,762	\$ 20,762	\$ 20,762	\$ 20,762	\$ 20,795	\$ 20,772	\$ 20,762	\$ 20,762	\$ 20,762	\$ 249,192	\$ 124,575	\$ 124,617
30	G52 High Annual-Low Winter	\$ 5,911	\$ 5,911	\$ 5,911	\$ 5,911	\$ 5,911	\$ 5,911	\$ 5,911	\$ 5,718	\$ 5,847	\$ 5,911	\$ 5,911	\$ 5,911	\$ 70,678	\$ 35,468	\$ 35,210
31	G42 High Annual-High Winter	\$ 6,511	\$ 6,511	\$ 6,511	\$ 6,511	\$ 6,511	\$ 6,511	\$ 6,511	\$ 6,521	\$ 6,520	\$ 6,511	\$ 6,511	\$ 6,511	\$ 78,151	\$ 39,066	\$ 39,085
32																
33	Residential	\$ 53,001	\$ 53,001	\$ 53,001	\$ 53,001	\$ 53,001	\$ 53,001	\$ 53,001	\$ 53,083	\$ 53,025	\$ 53,001	\$ 53,001	\$ 53,001	\$ 636,114	\$ 318,004	\$ 318,111
34	SALES HLF CLASSES	\$ 30,420	\$ 30,420	\$ 30,420	\$ 30,420	\$ 30,420	\$ 30,420	\$ 30,420	\$ 30,265	\$ 30,367	\$ 30,420	\$ 30,420	\$ 30,420	\$ 364,832	\$ 182,520	\$ 182,312
35	SALES LLF CLASSES	\$ 46,908	\$ 46,908	\$ 46,908	\$ 46,908	\$ 46,908	\$ 46,908	\$ 46,908	\$ 46,981	\$ 46,936	\$ 46,908	\$ 46,908	\$ 46,908	\$ 562,994	\$ 281,446	\$ 281,547

38

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

Base Capacity Costs

1	BASE SENDOUT BY CLASS	
2	Total Therms	
3	Res Heat	Attachment NUI-CAK-3, LN 52
4	Res General	Attachment NUI-CAK-3, LN 53
5	G50 Low Annual-Low Winter	Attachment NUI-CAK-3, LN 54
6	G40 Low Annual-High Winter	Attachment NUI-CAK-3, LN 55
7	G51 Med Annual-Low Winter	Attachment NUI-CAK-3, LN 56
8	G41 Med Annual-High Winter	Attachment NUI-CAK-3, LN 57
9	G52 High Annual-Low Winter	Attachment NUI-CAK-3, LN 58
10	G42 High Annual-High Winter	Attachment NUI-CAK-3, 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	Attachment NUI-CAK-2, 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
39				
40	24,141	1,406	22,735	48.80%
41	222	32	190	0.41%
42	905	265	640	1.37%
43	11,858	533	11,325	24.31%
44	1,441	399	1,041	2.23%
45	9,240	563	8,677	18.62%
46	365	160	205	0.44%
47	1,952	177	1,776	3.81%
48	TOTAL	50,124	46,588	100.00%

REMAINING PIPELINE DEMAND

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
51	NH DIVISION TOTAL - REMAINING PIPELINE	\$ 345,883	\$ 673,169	\$ 1,293,229	\$ 718,765	\$ 495,985	\$ 201,641	\$ 56,454	\$ 12,418	\$ -	\$ 423	\$ 9,182	\$ 94,318	\$ 3,901,466	\$ 3,728,672	\$ 172,794
52																
53																
54	Res Heat	\$ 168,790	\$ 328,505	\$ 631,093	\$ 350,756	\$ 242,040	\$ 98,401	\$ 27,549	\$ 6,060	\$ -	\$ 207	\$ 4,481	\$ 46,027	\$ 1,903,907	\$ 1,819,584	\$ 84,323
55	Res General	\$ 1,411	\$ 2,745	\$ 5,274	\$ 2,931	\$ 2,023	\$ 822	\$ 230	\$ 51	\$ -	\$ 2	\$ 37	\$ 385	\$ 15,911	\$ 15,207	\$ 705
56	G50 Low Annual-Low Winter	\$ 4,750	\$ 9,244	\$ 17,759	\$ 9,870	\$ 6,811	\$ 2,769	\$ 775	\$ 171	\$ -	\$ 6	\$ 126	\$ 1,295	\$ 53,576	\$ 51,203	\$ 2,373
57	G40 Low Annual-High Winter	\$ 84,082	\$ 163,643	\$ 314,376	\$ 174,727	\$ 120,571	\$ 49,018	\$ 13,724	\$ 3,019	\$ -	\$ 103	\$ 2,232	\$ 22,928	\$ 948,422	\$ 906,417	\$ 42,005
58	G51 Med Annual-Low Winter	\$ 7,730	\$ 15,044	\$ 28,902	\$ 16,063	\$ 11,084	\$ 4,506	\$ 1,262	\$ 278	\$ -	\$ 9	\$ 205	\$ 2,108	\$ 87,191	\$ 83,330	\$ 3,862
59	G41 Med Annual-High Winter	\$ 64,418	\$ 125,372	\$ 240,853	\$ 133,864	\$ 92,373	\$ 37,554	\$ 10,514	\$ 2,313	\$ -	\$ 79	\$ 1,710	\$ 17,566	\$ 726,617	\$ 694,435	\$ 32,182
60	G52 High Annual-Low Winter	\$ 1,519	\$ 2,956	\$ 5,679	\$ 3,156	\$ 2,178	\$ 886	\$ 248	\$ 55	\$ -	\$ 2	\$ 40	\$ 414	\$ 17,133	\$ 16,375	\$ 759
61	G42 High Annual-High Winter	\$ 13,184	\$ 25,659	\$ 49,293	\$ 27,397	\$ 18,905	\$ 7,686	\$ 2,152	\$ 473	\$ -	\$ 16	\$ 350	\$ 3,595	\$ 148,709	\$ 142,123	\$ 6,586
62	TOTAL	\$ 345,883	\$ 673,169	\$ 1,293,229	\$ 718,765	\$ 495,985	\$ 201,641	\$ 56,454	\$ 12,418	\$ -	\$ 423	\$ 9,182	\$ 94,318	\$ 3,901,466	\$ 3,728,672	\$ 172,794
63																
64	Residential	\$ 170,201	\$ 331,250	\$ 636,367	\$ 353,687	\$ 244,062	\$ 99,223	\$ 27,779	\$ 6,111	\$ -	\$ 208	\$ 4,518	\$ 46,411	\$ 1,919,818	\$ 1,834,790	\$ 85,028
65	SALES HLF CLASSES	\$ 13,999	\$ 27,245	\$ 52,340	\$ 29,090	\$ 20,074	\$ 8,161	\$ 2,285	\$ 503	\$ -	\$ 17	\$ 372	\$ 3,817	\$ 157,900	\$ 150,907	\$ 6,993
66	SALES LLF CLASSES	\$ 161,683	\$ 314,674	\$ 604,522	\$ 335,988	\$ 231,849	\$ 94,258	\$ 26,389	\$ 5,805	\$ -	\$ 198	\$ 4,292	\$ 44,089	\$ 1,823,748	\$ 1,742,975	\$ 80,773

STORAGE AND ON-SYSTEM PEAKING DEMAND

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
69	NH DIVISION TOTAL - PEAKING & STORA	\$ 795,466	\$ 1,548,164	\$ 2,974,187	\$ 1,653,027	\$ 1,140,674	\$ 463,738	\$ 129,833	\$ 28,560	\$ -	\$ 973	\$ 21,116	\$ 216,913	\$ 8,972,651	\$ 8,575,256	\$ 397,395
70																
71																
72	Res Heat	\$ 388,186	\$ 755,501	\$ 1,451,397	\$ 806,674	\$ 556,646	\$ 226,303	\$ 63,358	\$ 13,937	\$ -	\$ 475	\$ 10,305	\$ 105,853	\$ 4,378,634	\$ 4,184,706	\$ 193,928
73	Res General	\$ 3,244	\$ 6,314	\$ 12,130	\$ 6,741	\$ 4,652	\$ 1,891	\$ 529	\$ 116	\$ -	\$ 4	\$ 86	\$ 885	\$ 36,593	\$ 34,972	\$ 1,621
74	G50 Low Annual-Low Winter	\$ 10,923	\$ 21,260	\$ 40,842	\$ 22,700	\$ 15,664	\$ 6,368	\$ 1,783	\$ 392	\$ -	\$ 13	\$ 290	\$ 2,979	\$ 123,214	\$ 117,757	\$ 5,457
75	G40 Low Annual-High Winter	\$ 193,373	\$ 376,349	\$ 723,006	\$ 401,840	\$ 277,291	\$ 112,732	\$ 31,562	\$ 6,943	\$ -	\$ 237	\$ 5,133	\$ 52,730	\$ 2,181,195	\$ 2,084,591	\$ 96,604
76	G51 Med Annual-Low Winter	\$ 17,777	\$ 34,599	\$ 66,468	\$ 36,942	\$ 25,492	\$ 10,364	\$ 2,902	\$ 638	\$ -	\$ 22	\$ 472	\$ 4,848	\$ 200,524	\$ 191,643	\$ 8,881
77	G41 Med Annual-High Winter	\$ 148,149	\$ 288,333	\$ 553,918	\$ 307,863	\$ 212,441	\$ 86,368	\$ 24,180	\$ 5,319	\$ -	\$ 181	\$ 3,933	\$ 40,398	\$ 1,671,084	\$ 1,597,073	\$ 74,012
78	G52 High Annual-Low Winter	\$ 3,493	\$ 6,799	\$ 13,061	\$ 7,259	\$ 5,009	\$ 2,037	\$ 570	\$ 125	\$ -	\$ 4	\$ 93	\$ 953	\$ 39,404	\$ 37,658	\$ 1,745
79	G42 High Annual-High Winter	\$ 30,320	\$ 59,010	\$ 113,365	\$ 63,007	\$ 43,478	\$ 17,676	\$ 4,949	\$ 1,089	\$ -	\$ 37	\$ 805	\$ 8,268	\$ 342,003	\$ 326,856	\$ 15,147
80	TOTAL	\$ 795,466	\$ 1,548,164	\$ 2,974,187	\$ 1,653,027	\$ 1,140,674	\$ 463,738	\$ 129,833	\$ 28,560	\$ -	\$ 973	\$ 21,116	\$ 216,913	\$ 8,972,651	\$ 8,575,256	\$ 397,395
81																
82	Residential	\$ 391,430	\$ 761,814	\$ 1,463,526	\$ 813,415	\$ 561,298	\$ 228,194	\$ 63,888	\$ 14,054	\$ -	\$ 479	\$ 10,391	\$ 106,738	\$ 4,415,227	\$ 4,219,678	\$ 195,549
83	SALES HLF CLASSES	\$ 32,194	\$ 62,657	\$ 120,372	\$ 66,901	\$ 46,165	\$ 18,768	\$ 5,255	\$ 1,156	\$ -	\$ 39	\$ 855	\$ 8,779	\$ 363,142	\$ 347,058	\$ 16,083
84	SALES LLF CLASSES	\$ 371,842	\$ 723,692	\$ 1,390,289	\$ 772,711	\$ 533,210	\$ 216,775	\$ 60,691	\$ 13,350	\$ -	\$ 455	\$ 9,871	\$ 101,396	\$ 4,194,282	\$ 4,008,519	\$ 185,763

OFF-SYSTEM PEAKING DEMAND & OUTAGE REPLACEMENT

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
87	NH DIVISION - OFF-SYSTEM PEAKING	\$ 352,462	\$ 669,367	\$ 1,315,028	\$ 718,421	\$ 519,448	\$ 219,432	\$ 642	\$ 141	\$ -	\$ 5	\$ 104	\$ 1,073	\$ 3,796,122	\$ 3,794,157	\$ 1,965
89																
90	Res Heat	\$ 172,000	\$ 326,650	\$ 641,731	\$ 350,588	\$ 253,489	\$ 107,082	\$ 313	\$ 69	\$ -	\$ 2	\$ 51	\$ 523	\$ 1,852,499	\$ 1,851,540	\$ 959
91	Res General	\$ 1,437	\$ 2,730	\$ 5,363	\$ 2,930	\$ 2,118	\$ 895	\$ 3	\$ 1	\$ -	\$ 0	\$ 0	\$ 4	\$ 15,482	\$ 15,474	\$ 8
92	G50 Low Annual-Low Winter	\$ 4,840	\$ 9,192	\$ 18,058	\$ 9,865	\$ 7,133	\$ 3,013	\$ 9	\$ 2	\$ -	\$ 0	\$ 1	\$ 15	\$ 52,129	\$ 52,102	\$ 27
93	G40 Low Annual-High Winter	\$ 85,681	\$ 162,719	\$ 319,675	\$ 174,644	\$ 126,274	\$ 53,343	\$ 156	\$ 34	\$ -	\$ 1	\$ 25	\$ 261	\$ 922,813	\$ 922,336	\$ 478
94	G51 Med Annual-Low Winter	\$ 7,877	\$ 14,959	\$ 29,389	\$ 16,056	\$ 11,609	\$ 4,904	\$ 14	\$ 3	\$ -	\$ 0	\$ 2	\$ 24	\$ 84,837	\$ 84,793	\$ 44
95	G41 Med Annual-High Winter	\$ 65,643	\$ 124,664	\$ 244,913	\$ 133,800	\$ 96,743	\$ 40,867	\$ 120	\$ 26	\$ -	\$ 1	\$ 19	\$ 200	\$ 706,997	\$ 706,631	\$ 366
96	G52 High Annual-Low Winter	\$ 1,548	\$ 2,940	\$ 5,775	\$ 3,155	\$ 2,281	\$ 964	\$ 3	\$ 1	\$ -	\$ 0	\$ 0	\$ 5	\$ 16,671	\$ 16,662	\$ 9
97	G42 High Annual-High Winter	\$ 13,434	\$ 25,514	\$ 50,124	\$ 27,383	\$ 19,799	\$ 8,364	\$ 24	\$ 5	\$ -	\$ 0	\$ 4	\$ 41	\$ 144,694	\$ 144,619	\$ 75
98	TOTAL	\$ 352,462	\$ 669,367	\$ 1,315,028	\$ 718,421	\$ 519,448	\$ 219,432	\$ 642	\$ 141	\$ -	\$ 5	\$ 104	\$ 1,073	\$ 3,796,122	\$ 3,794,157	\$ 1,965
99																
100	Residential	\$ 173,438	\$ 329,379	\$ 647,094	\$ 353,518	\$ 255,608	\$ 107,977	\$ 316	\$ 69	\$ -	\$ 2	\$ 51	\$ 528	\$ 1,867,981	\$ 1,867,014	\$ 967
101	SALES HLF CLASSES	\$ 15,702	\$ 29,821	\$ 58,585	\$ 32,006	\$ 23,142	\$ 9,776	\$ 29	\$ 6	\$ -	\$ 0	\$ 5	\$ 48	\$ 169,119	\$ 169,031	\$ 88
102	SALES LLF CLASSES	\$ 336,759	\$ 639,546	\$ 1,256,443	\$ 686,415	\$ 496,306	\$ 209,656	\$ 613	\$ 135	\$ -	\$ 5	\$ 100	\$ 1,025	\$ 3,627,003	\$ 3,625,126	\$ 1,877

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

REMAINING PIPELINE DEMAND

50		
51		
52	NH DIVISION TOTAL - REMAINING PIPELINE DEMAND	Attachment NUI-CAK-2, 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

STORAGE AND ON-SYSTEM PEAKING DEMAND

67		
68		
69		
70	NH DIVISION TOTAL - PEAKING & STORAGE DEMAND	Attachment NUI-CAK-2, 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

Off-SYSTEM PEAKING DEMAND & OUTAGE

85		
86		
87		
88	NH DIVISION - OFF-SYSTEM PEAKING	Attachment NUI-CAK-2, 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

123 MISCELLANEOUS CREDITS BY CLASS (Includes Re-entry Rate & Conversion Rate Revenues)141 TOTAL NON-BASE CAPACITY COSTS

157 TOTAL CAPACITY COSTS

[illegible]

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

106		
107	NH DIVISION - MONTHLY CAP. RELEASE	Attachment NUI-CAK-2, 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 Rate)**

124		
125	NH DIVISION - MISCELLANEOUS CREDIT	Attachment NUI-CAK-2, 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 SALES LLF CLASSES	
174	SALES HLF CLASSES	LN 170 / (LN170 + LN 171)
175	SALES LLF CLASSES	LN 171 / (LN 170 + LN 171)

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
Supply Volumes - MMBtu															
Total Pipeline	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	8,854,520	5,861,225	2,993,295
Total Storage	334,018	731,204	814,153	870,348	598,789	0	0	0	0	0	0	0	3,348,512	3,348,512	0
Total Peaking	1,794	132,447	416,567	168,774	66,406	1,794	1,860	1,800	1,860	1,860	1,800	1,860	798,822	787,782	11,040
Total Off-system Sales													0	0	0
Subtotal	1,317,939	1,842,583	2,157,613	1,885,708	1,688,286	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854	9,997,519	3,004,335
Less Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sup	1,317,939	1,842,583	2,157,613	1,885,708	1,688,286	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854	9,997,519	3,004,335
Total Fir	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	8,854,520	5,861,225	2,993,295
Variable Costs															
Base Pipeline C	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526	\$ 32,159,520	\$ 10,352,007
NYMEX															
Price Used	\$ 5.305	\$ 5.398	\$ 5.465	\$ 5.370	\$ 5.013	\$ 3.939	\$ 3.810	\$ 3.839	\$ 3.871	\$ 3.879	\$ 3.863	\$ 3.890			
for															
NYMEX															
Price Used	\$ 5.305	\$ 5.398	\$ 5.465	\$ 5.370	\$ 5.013	\$ 3.939	\$ 3.810	\$ 3.839	\$ 3.871	\$ 3.879	\$ 3.863	\$ 3.890			
for Update	\$ 5.305	\$ 5.398	\$ 5.465	\$ 5.370	\$ 5.013	\$ 3.939	\$ 3.810	\$ 3.839	\$ 3.871	\$ 3.879	\$ 3.863	\$ 3.890			
Increase/(De	\$ 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/(Decre	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		\$ -	
Total Updated F	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526	\$ 32,159,520	\$ 10,352,007
Total Pipeline	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526	\$ 32,159,520	\$ 10,352,007
Total Storage	\$ 1,044,295	\$ 2,265,206	\$ 2,524,545	\$ 2,702,360	\$ 1,867,551	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,403,958	\$ 10,403,958	\$ -
Total Peaking	\$ 9,526	\$ 2,091,388	\$ 4,553,220	\$ 2,865,280	\$ 1,286,222	\$ 10,221	\$ 10,555	\$ 11,094	\$ 11,464	\$ 11,464	\$ 13,455	\$ 14,402	\$ 10,888,290	\$ 10,815,857	\$ 72,433
Total Off-system	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Subtotal	\$ 6,302,351	\$ 10,091,778	\$ 13,140,440	\$ 11,023,635	\$ 8,590,113	\$ 4,231,017	\$ 2,207,586	\$ 1,486,950	\$ 1,384,547	\$ 1,394,443	\$ 1,424,238	\$ 2,526,676	\$ 63,803,774	\$ 53,379,334	\$ 10,424,440
Interruptible Cost Estimate															
Variable Pip	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526	\$ 32,159,520	\$ 10,352,007
Average Sup	\$ 5.344	\$ 5.859	\$ 6.541	\$ 6.445	\$ 5.314	\$ 3.825	\$ 3.521	\$ 3.452	\$ 3.469	\$ 3.448	\$ 3.311	\$ 3.495			
Interruptible	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Interruptible	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Pipeline	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526	\$ 32,159,520	\$ 10,352,007
Total Storage	\$ 1,044,295	\$ 2,265,206	\$ 2,524,545	\$ 2,702,360	\$ 1,867,551	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,403,958	\$ 10,403,958	\$ -
Total Peaking	\$ 9,526	\$ 2,091,388	\$ 4,553,220	\$ 2,865,280	\$ 1,286,222	\$ 10,221	\$ 10,555	\$ 11,094	\$ 11,464	\$ 11,464	\$ 13,455	\$ 14,402	\$ 10,888,290	\$ 10,815,857	\$ 72,433
Off-system Sale	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Firm	\$ 6,302,351	\$ 10,091,778	\$ 13,140,440	\$ 11,023,635	\$ 8,590,113	\$ 4,231,017	\$ 2,207,586	\$ 1,486,950	\$ 1,384,547	\$ 1,394,443	\$ 1,424,238	\$ 2,526,676	\$ 63,803,774	\$ 53,379,334	\$ 10,424,440
Sales Variable Costs															

Northern Utilities
ALLOCATION OF COMMODITY COSTS

1	Supply Volumes - MMBtu	
2	Total Pipeline	Attachment NU
3	Total Storage	Attachment NU
4	Total Peaking	Attachment NU
5	Total Off-system	NA
6	Subtotal	SUM LN 2: LN 5
7	Less Interruptible	Company Analy
8	Less Interruptible	Company Analy
9	Total Firm Supply	LN 7 - LN 8 - LN
10	Total Firm Pipeline	LN 2 + LN 3- LN
11	Variable Costs	
12	Pipeline Costs	Attachment NU
13	NYMEX Price U	Attachment NU
14	NYMEX Price U	Attachment NU
15	Increase/(Decrease)	LN 13 - LN 14
16	Increase/(Decrease)	LN 2 * LN 15
17	Total Updated	LN 12 + LN 16
18		
19	Total Pipeline	LN 17
20	Total Storage	Attachment NU
21	Total Peaking	Attachment NU
22	Total Off-system	NA
23		
24	Subtotal	Sum LN 19 : LN
25		
26	Interruptible Co	Company Analy
27	Variable Pipeline	LN 17
28	Average Supply	LN 27 / LN 2
29	Interruptible Co	LN 28 * LN 7
30	Interruptible Co	LN 28 * LN 8
31		
32	Firm Sales Pipeline	LN 19 - LN 29
33	Total Storage	LN 20
34	Total Peaking	LN 21
35	Off-system Sales	LN 22
	Total Firm	
36	Sales Variable Costs	SUM LN 32 : LN

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
Maine	840,656	1,162,033	1,359,609	1,199,672	1,101,525	755,361	432,603	302,023	288,888	292,515	305,552	480,776	8,521,213	6,418,856	2,102,357
New Hampsh	477,284	680,551	798,004	686,035	586,760	350,029	193,176	127,316	108,780	110,422	122,341	239,943	4,480,641	3,578,664	901,977
Total	1,317,940	1,842,584	2,157,613	1,885,708	1,688,285	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854	9,997,520	3,004,334

Percentage of Total

Maine	63.79%	63.07%	63.01%	63.62%	65.25%	68.33%	69.13%	70.35%	72.65%	72.60%	71.41%	66.71%	65.54%	64.20%	69.98%
New Hampsh	36.21%	36.93%	36.99%	36.38%	34.75%	31.67%	30.87%	29.65%	27.35%	27.40%	28.59%	33.29%	34.46%	35.80%	30.02%
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%

Commodity Allocation by Jurisdiction

Maine

Total Pipeline	\$ 3,347,806	\$ 3,616,916	\$ 3,820,363	\$ 3,471,061	\$ 3,546,951	\$ 2,884,253	\$ 1,518,815	\$ 1,038,207	\$ 997,484	\$ 1,003,983	\$ 1,007,419	\$ 1,675,884	\$ 27,929,145	\$ 20,687,352	\$ 7,241,793
Storage	\$ 666,110	\$ 1,428,561	\$ 1,590,829	\$ 1,719,221	\$ 1,218,487	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,623,208	\$ 6,623,208	\$ -
Peaking	\$ 6,076	\$ 1,318,942	\$ 2,869,188	\$ 1,822,868	\$ 839,198	\$ 6,984	\$ 7,297	\$ 7,804	\$ 8,328	\$ 8,322	\$ 9,608	\$ 9,607	\$ 6,914,224	\$ 6,863,258	\$ 50,966
Off-system	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Maine Co	\$ 4,019,993	\$ 6,364,420	\$ 8,280,380	\$ 7,013,150	\$ 5,604,637	\$ 2,891,238	\$ 1,526,112	\$ 1,046,011	\$ 1,005,812	\$ 1,012,305	\$ 1,017,028	\$ 1,685,492	\$ 41,466,577	\$ 34,173,818	\$ 7,292,759
Maine Inventory	\$ 335	\$ 522	\$ 640	\$ 561	\$ 485	\$ 284	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,827	\$ 2,827	\$ -
Total Maine Val	\$ 4,020,328	\$ 6,364,941	\$ 8,281,020	\$ 7,013,711	\$ 5,605,122	\$ 2,891,522	\$ 1,526,112	\$ 1,046,011	\$ 1,005,812	\$ 1,012,305	\$ 1,017,028	\$ 1,685,492	\$ 41,469,404	\$ 34,176,644	\$ 7,292,759

New Hampshire

Total Pipeline	\$ 1,900,723	\$ 2,118,268	\$ 2,242,311	\$ 1,984,934	\$ 1,889,389	\$ 1,336,543	\$ 678,216	\$ 437,649	\$ 375,599	\$ 378,996	\$ 403,363	\$ 836,389	\$ 14,582,381	\$ 11,472,168	\$ 3,110,213
Storage	\$ 378,185	\$ 836,645	\$ 933,716	\$ 983,140	\$ 649,063	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,780,749	\$ 3,780,749	\$ -
Peaking	\$ 3,450	\$ 772,446	\$ 1,684,032	\$ 1,042,411	\$ 447,024	\$ 3,237	\$ 3,258	\$ 3,290	\$ 3,136	\$ 3,142	\$ 3,847	\$ 4,795	\$ 3,974,066	\$ 3,952,599	\$ 21,467
Off-system	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total New Ham	\$ 2,282,359	\$ 3,727,358	\$ 4,860,059	\$ 4,010,484	\$ 2,985,476	\$ 1,339,779	\$ 681,474	\$ 440,939	\$ 378,735	\$ 382,138	\$ 407,210	\$ 841,184	\$ 22,337,197	\$ 19,205,516	\$ 3,131,680
New Hampshire	\$ 174	\$ 268	\$ 323	\$ 275	\$ 224	\$ 114	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,378	\$ 1,378	\$ -
Total New Ham	\$ 2,282,533	\$ 3,727,626	\$ 4,860,382	\$ 4,010,760	\$ 2,985,700	\$ 1,339,894	\$ 681,474	\$ 440,939	\$ 378,735	\$ 382,138	\$ 407,210	\$ 841,184	\$ 22,338,575	\$ 19,206,895	\$ 3,131,680

Northern Utilities

Total Pipeline	\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274	\$ 42,511,526	\$ 32,159,520	\$ 10,352,007
Storage	\$ 1,044,295	\$ 2,265,206	\$ 2,524,545	\$ 2,702,360	\$ 1,867,551	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 10,403,958	\$ 10,403,958	\$ -
Peaking	\$ 9,526	\$ 2,091,388	\$ 4,553,220	\$ 2,865,280	\$ 1,286,222	\$ 10,221	\$ 10,555	\$ 11,094	\$ 11,464	\$ 11,464	\$ 13,455	\$ 14,402	\$ 10,888,290	\$ 10,815,857	\$ 72,433
Off-system	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Northern	\$ 6,302,351	\$ 10,091,778	\$ 13,140,440	\$ 11,023,635	\$ 8,590,113	\$ 4,231,017	\$ 2,207,586	\$ 1,486,950	\$ 1,384,547	\$ 1,394,443	\$ 1,424,238	\$ 2,526,676	\$ 63,803,774	\$ 53,379,334	\$ 10,424,440
Northern Invent	\$ 509	\$ 789	\$ 963	\$ 836	\$ 709	\$ 398	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4,205	\$ 4,205	\$ -
Total Northern	\$ 6,302,860	\$ 10,092,567	\$ 13,141,403	\$ 11,024,471	\$ 8,590,822	\$ 4,231,415	\$ 2,207,586	\$ 1,486,950	\$ 1,384,547	\$ 1,394,443	\$ 1,424,238	\$ 2,526,676	\$ 63,807,979	\$ 53,383,539	\$ 10,424,440

Northern Utilities
ALLOCATION OF COMMODITY CC

Commodity Allocation Factors

Firm Sales Sendout for Normal \

Maine	Company Anal	
New Hampsh	NUI-CAK-3, LN	
Total	LN 40 + LN 41	

Percentage of Total

Maine	LN 40 / LN 42
New Hampsh	LN 41 / LN 42
Total	LN 45 + LN 46

Commodity Allocation by Juris

Maine

Firm Sales	
Pipeline	
Commodity	LN 32 * LN 45
Storage	LN 33 * LN 45
Peaking	LN 34 * LN 45
Off-system S	LN 35 * LN 45
Total Maine Co	SUM LN 51 : L
Maine Inventory	LN 95
Total Maine Val	LN 55 + LN 56

New Hampshire

Firm Sales	
Pipeline	
Commodity	
Excl'd Hedg	LN 32 * LN 46
Storage	LN 33 * LN 46
Peaking	LN 34 * LN 46
Off-system S	LN 35 * LN 46
Total New Ham	SUM LN 59 : L
New Hampshire	LN 100
Total New Ham	LN 63 + LN 64

Northern Utilities

Firm Sales	
Pipeline	
Commodity	
Excl'd Hedg	LN 51 + LN 59
Storage	LN 52 + LN 60
Peaking	LN 53 + LN 61
Off-system S	LN 54 + LN 62
Total Northern	LN 55 + LN 63
Northern Invent	LN 56 + LN 64
Total Northern	LN 57 + LN 65

[illegible]

Northern Utilities
ALLOCATION OF COMMODITY CC

75 **Northern Utilities**
76 **Simplified Market Base**
77 **ALLOCATION OF NOR**
78
79
80

Inventory Finance Charge	
Storage	Attachment NU
Peaking	Attachment NU
Total	SUM LN 82 : L

Inventory Finance Charge Allo	
Maine	LN 45 * LN 84
New Hampsh	LN 46 * LN 84
Total	SUM LN 87 : L

Inventory Finance Charge Allo
Maine

Firm Sales	Attachment NU
Monthly % S	LN 93 / LN 93
ME Allocate	LN 94 * LN 84

New Hampshire

Firm Sales	Attachment NU
Monthly % S	LN 98 / LN 98
NH Allocate	LN 99 * LN 84

100

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

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
Supply Volumes - Therms															
New Hampshire Sales Pipeline	3,556,713	3,615,649	3,428,159	3,079,946	3,555,734	3,494,609	1,926,016	1,267,821	1,082,707	1,099,128	1,218,262	2,393,235	29,717,980	20,730,811	8,987,169
New Hampshire Sales Storage	1,209,626	2,700,672	3,011,188	3,166,394	2,081,078	0	0	0	0	0	0	0	12,168,959	12,168,959	0
New Hampshire Sales Peaking	6,497	489,187	1,540,696	614,012	230,792	5,681	5,742	5,338	5,088	5,097	5,146	6,192	2,919,468	2,886,865	32,603
Total New Hampshire Firm Sales Sendout	4,772,837	6,805,508	7,980,043	6,860,353	5,867,604	3,500,290	1,931,758	1,273,159	1,087,795	1,104,225	1,223,408	2,399,427	44,806,406	35,786,634	9,019,772
New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sendout	4,772,837	6,805,508	7,980,043	6,860,353	5,867,604	3,500,290	1,931,758	1,273,159	1,087,795	1,104,225	1,223,408	2,399,427	44,806,406	35,786,634	9,019,772
Total Firm Sales	4,713,183	6,720,446	7,880,297	6,774,602	5,794,261	3,456,540	1,907,611	1,257,246	1,074,199	1,090,422	1,208,118	2,369,434	44,246,359	35,339,329	8,907,030
Difference (LAUF & Company Use)	59,654	85,062	99,746	85,751	73,343	43,750	24,147	15,913	13,597	13,803	15,291	29,993	560,047	447,305	112,742
Percent Difference	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Variable Costs															
New Hampshire Sales Pipeline	\$ 1,900,723	\$ 2,118,268	\$ 2,242,311	\$ 1,984,934	\$ 1,889,389	\$ 1,336,543	\$ 678,216	\$ 437,649	\$ 375,599	\$ 378,996	\$ 403,363	\$ 836,389	\$ 14,582,381	\$ 11,472,168	\$ 3,110,213
New Hampshire Total Storage	\$ 378,185	\$ 836,645	\$ 933,716	\$ 983,140	\$ 649,063	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,780,749	\$ 3,780,749	\$ -
New Hampshire Total Peaking	\$ 3,450	\$ 772,446	\$ 1,684,032	\$ 1,042,411	\$ 447,024	\$ 3,237	\$ 3,258	\$ 3,290	\$ 3,136	\$ 3,142	\$ 3,847	\$ 4,795	\$ 3,974,066	\$ 3,952,599	\$ 21,467
New Hampshire Inventory Finance Charge	\$ 174	\$ 268	\$ 323	\$ 275	\$ 224	\$ 114	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,378	\$ 1,378	\$ -
Total New Hampshire Sales Variable Costs	\$ 2,282,533	\$ 3,727,626	\$ 4,860,382	\$ 4,010,760	\$ 2,985,700	\$ 1,339,894	\$ 681,474	\$ 440,939	\$ 378,735	\$ 382,138	\$ 407,210	\$ 841,184	\$ 22,338,575	\$ 19,206,895	\$ 3,131,680
New Hampshire Interruptible Commodity Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total New Hampshire Commodity Costs	\$ 2,282,533	\$ 3,727,626	\$ 4,860,382	\$ 4,010,760	\$ 2,985,700	\$ 1,339,894	\$ 681,474	\$ 440,939	\$ 378,735	\$ 382,138	\$ 407,210	\$ 841,184	\$ 22,338,575	\$ 19,206,895	\$ 3,131,680
Supply Cost/Therm															
New Hampshire Sales Pipeline	\$ 0.534	\$ 0.586	\$ 0.654	\$ 0.644	\$ 0.531	\$ 0.382	\$ 0.352	\$ 0.345	\$ 0.347	\$ 0.345	\$ 0.331	\$ 0.349	\$ 0.491	\$ 0.553	\$ 0.346
New Hampshire Storage Excl'd Inventory Finance Costs	\$ 0.313	\$ 0.310	\$ 0.310	\$ 0.310	\$ 0.312	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.311	\$ 0.311	\$ -
New Hampshire Peaking Excl'd Inventory Finance Costs	\$ 0.531	\$ 1.579	\$ 1.093	\$ 1.698	\$ 1.937	\$ 0.570	\$ 0.567	\$ 0.616	\$ 0.616	\$ 0.616	\$ 0.748	\$ 0.774	\$ 1.361	\$ 1.369	\$ 0.658
New Hampshire Inventory Finance Costs per Dth Stor and Peak	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.020	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.000	\$ 0.000	\$ -
Weighted Average Cost per Dth Sendout	\$ 0.478	\$ 0.548	\$ 0.609	\$ 0.585	\$ 0.509	\$ 0.383	\$ 0.353	\$ 0.346	\$ 0.348	\$ 0.346	\$ 0.333	\$ 0.351	\$ 0.499	\$ 0.537	\$ 0.347
New Hampshire Interruptible Cost / Therm	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Commodity Costs															
Base Commodity, therms	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
Base Commodity Cost	\$ 566,819	\$ 642,109	\$ 716,885	\$ 637,990	\$ 582,380	\$ 405,656	\$ 385,942	\$ 365,567	\$ 377,364	\$ 377,921	\$ 351,180	\$ 383,034	\$ 5,792,848	\$ 3,551,839	\$ 2,241,009
Remaining Commodity	\$ 1,715,714	\$ 3,085,517	\$ 4,143,497	\$ 3,372,770	\$ 2,403,320	\$ 934,237	\$ 295,532	\$ 75,372	\$ 1,371	\$ 4,217	\$ 56,030	\$ 458,150	\$ 16,545,727	\$ 15,655,056	\$ 890,671
Total Commodity	\$ 2,282,533	\$ 3,727,626	\$ 4,860,382	\$ 4,010,760	\$ 2,985,700	\$ 1,339,894	\$ 681,474	\$ 440,939	\$ 378,735	\$ 382,138	\$ 407,210	\$ 841,184	\$ 22,338,575	\$ 19,206,895	\$ 3,131,680

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

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Attachment NUI-CAK-5, LN 2 * LN 46 * 10
2	New Hampshire Sales Storage	Attachment NUI-CAK-5, LN 3 * LN 46 * 10
3	New Hampshire Sales Peaking	Attachment NUI-CAK-5, LN 4 * LN 46 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Attachment NUI-CAK-5, LN 8 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Attachment NUI-CAK-3, LN 11
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	Variable Costs	
14	New Hampshire Sales Pipeline Commodity	Attachment NUI-CAK-5, LN 59
15	New Hampshire Total Storage	Attachment NUI-CAK-5, LN 60
16	New Hampshire Total Peaking	Attachment NUI-CAK-5, LN 61
17	New Hampshire Inventory Finance Charge	Attachment NUI-CAK-5, LN 64
18	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 17
19		
20	New Hampshire Interruptible Commodity Costs	Attachment NUI-CAK-5, LN 30
21	Total New Hampshire Commodity Costs	LN 18 + LN 20
22		
23	Supply Cost/Therm	
24	New Hampshire Sales Pipeline Commodity	LN 14 / LN 1
25	New Hampshire Storage Excl Inventory Finance Costs	LN 15 / LN 2
26	New Hampshire Peaking Excl Inventory Finance Costs	LN 16 / LN 3
27	New Hampshire Inventory Finance Costs per Dth Stor and Peak	LN 17 / Sum (LN 2 : LN 3)
28	Weighted Average Cost per Dth Sendout	LN 18 / LN 8
29		
30	New Hampshire Interruptible Cost / Therm	LN 20 / LN 6
31		
32	Commodity Costs	
33	Base Commodity, therms	Attachment NUI-CAK-3, LN 64
34	Base Commodity Cost	Min (LN 24 * LN 33), LN 18
35	Remaining Commodity	LN 21 - LN 34
36	Total Commodity	LN 34 + LN 35

Tennessee Storage

Union Storage

LNG Storage

[illegible]

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

Base Commodity Costs

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
1 BASE SENDOUT BY CLASS															
2 Total Therms															
3 Res Heat	421,743	435,801	435,801	393,627	435,801	421,743	435,801	421,743	432,738	435,801	421,743	435,801	5,128,145	2,544,517	2,583,628
4 Res General	9,593	9,913	9,913	8,953	9,913	9,593	9,913	9,593	9,843	9,913	9,593	9,913	116,644	57,877	58,767
5 G50 Low Annual-Low Winter	79,626	82,281	82,281	74,318	82,281	79,626	82,281	79,626	81,702	82,281	79,626	82,281	968,209	480,412	487,797
6 G40 Low Annual-High Winter	159,790	165,116	165,116	149,137	165,116	159,790	165,116	159,790	163,956	165,116	159,790	165,116	1,942,950	964,066	978,884
7 G51 Med Annual-Low Winter	119,834	123,828	123,828	111,845	123,828	119,834	123,828	119,834	122,958	123,828	119,834	123,828	1,457,105	722,996	734,109
8 G41 Med Annual-High Winter	168,972	174,604	174,604	157,707	174,604	168,972	174,604	168,972	173,377	174,604	168,972	174,604	2,054,595	1,019,463	1,035,133
9 G52 High Annual-Low Winter	48,108	49,712	49,712	44,901	49,712	48,108	49,712	46,460	48,804	49,712	48,108	49,712	582,759	290,252	292,507
10 G42 High Annual-High Winter	52,989	54,755	54,755	49,456	54,755	52,989	54,755	52,989	54,419	54,755	52,989	54,755	644,362	319,700	324,662
11 Total Firm Sales	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
12 % of Total															
13 Res Heat	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.82%	39.78%	39.76%	39.76%	39.76%			
14 Res General	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.91%	0.90%	0.90%	0.90%	0.90%			
15 G50 Low Annual-Low Winter	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.52%	7.51%	7.51%	7.51%	7.51%			
16 G40 Low Annual-High Winter	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.09%	15.07%	15.07%	15.07%	15.07%			
17 G51 Med Annual-Low Winter	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.32%	11.30%	11.30%	11.30%	11.30%			
18 G41 Med Annual-High Winter	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.96%	15.94%	15.93%	15.93%	15.93%			
19 G52 High Annual-Low Winter	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.39%	4.49%	4.54%	4.54%	4.54%			
20 G42 High Annual-High Winter	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%			
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%			
22 BASE COMMODITY COSTS															
23 TOTAL BASE COMMODITY	\$ 566,819	\$ 642,109	\$ 716,885	\$ 637,990	\$ 582,380	\$ 405,656	\$ 385,942	\$ 365,567	\$ 377,364	\$ 377,921	\$ 351,180	\$ 383,034	\$ 5,792,848	\$ 3,551,839	\$ 2,241,009
24 Res Heat	\$ 225,381	\$ 255,319	\$ 285,052	\$ 253,681	\$ 231,569	\$ 161,299	\$ 153,460	\$ 145,585	\$ 150,120	\$ 150,271	\$ 139,638	\$ 152,304	\$ 2,303,679	\$ 1,412,301	\$ 891,378
25 Res General	\$ 5,127	\$ 5,807	\$ 6,484	\$ 5,770	\$ 5,267	\$ 3,669	\$ 3,491	\$ 3,311	\$ 3,415	\$ 3,418	\$ 3,176	\$ 3,464	\$ 52,399	\$ 32,124	\$ 20,275
26 G50 Low Annual-Low Winter	\$ 42,553	\$ 48,205	\$ 53,819	\$ 47,896	\$ 43,721	\$ 30,454	\$ 28,974	\$ 27,487	\$ 28,343	\$ 28,372	\$ 26,364	\$ 28,755	\$ 434,942	\$ 266,647	\$ 168,295
27 G40 Low Annual-High Winter	\$ 85,392	\$ 96,735	\$ 108,000	\$ 96,115	\$ 87,737	\$ 61,113	\$ 58,143	\$ 55,159	\$ 56,877	\$ 56,935	\$ 52,906	\$ 57,705	\$ 872,817	\$ 535,092	\$ 337,725
28 G51 Med Annual-Low Winter	\$ 64,040	\$ 72,546	\$ 80,994	\$ 72,081	\$ 65,798	\$ 45,831	\$ 43,604	\$ 41,366	\$ 42,655	\$ 42,698	\$ 39,677	\$ 43,276	\$ 654,565	\$ 401,289	\$ 253,275
29 G41 Med Annual-High Winter	\$ 90,299	\$ 102,294	\$ 114,206	\$ 101,637	\$ 92,778	\$ 64,625	\$ 61,484	\$ 58,329	\$ 60,146	\$ 60,206	\$ 55,946	\$ 61,021	\$ 922,971	\$ 565,840	\$ 357,132
30 G52 High Annual-Low Winter	\$ 25,709	\$ 29,124	\$ 32,516	\$ 28,937	\$ 26,415	\$ 18,399	\$ 17,505	\$ 16,038	\$ 16,931	\$ 17,141	\$ 15,928	\$ 17,373	\$ 262,017	\$ 161,101	\$ 100,917
31 G42 High Annual-High Winter	\$ 28,317	\$ 32,079	\$ 35,815	\$ 31,873	\$ 29,095	\$ 20,266	\$ 19,281	\$ 18,292	\$ 18,878	\$ 18,880	\$ 17,544	\$ 19,136	\$ 289,457	\$ 177,445	\$ 112,012
32															
33 Residential	\$ 230,508	\$ 261,126	\$ 291,535	\$ 259,451	\$ 236,836	\$ 164,968	\$ 156,951	\$ 148,896	\$ 153,534	\$ 153,689	\$ 142,814	\$ 155,768	\$ 2,356,079	\$ 1,444,425	\$ 911,654
34 SALES HLF CLASSES	\$ 132,301	\$ 149,875	\$ 167,329	\$ 148,914	\$ 135,934	\$ 94,684	\$ 90,083	\$ 84,891	\$ 87,928	\$ 88,211	\$ 81,969	\$ 89,404	\$ 1,351,524	\$ 829,037	\$ 522,487
35 SALES LLF CLASSES	\$ 204,009	\$ 231,108	\$ 258,021	\$ 229,625	\$ 209,610	\$ 146,004	\$ 138,908	\$ 131,780	\$ 135,901	\$ 136,021	\$ 126,397	\$ 137,862	\$ 2,085,246	\$ 1,278,377	\$ 806,869

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	Attachment NUI-CAK-3, LN 52
4	Res General	Attachment NUI-CAK-3, LN 53
5	G50 Low Annual-Low Winter	Attachment NUI-CAK-3, LN 54
6	G40 Low Annual-High Winter	Attachment NUI-CAK-3, LN 55
7	G51 Med Annual-Low Winter	Attachment NUI-CAK-3, LN 56
8	G41 Med Annual-High Winter	Attachment NUI-CAK-3, LN 57
9	G52 High Annual-Low Winter	Attachment NUI-CAK-3, LN 58
10	G42 High Annual-High Winter	Attachment NUI-CAK-3, 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	Attachment NUI-CAK-6, LN 34
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

[illegible]

57	REMAINING COMMODITY COSTS	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
58	REMAINING COMMODITY	\$ 1,715,714	\$ 3,085,517	\$ 4,143,497	\$ 3,372,770	\$ 2,403,320	\$ 934,237	\$ 295,532	\$ 75,372	\$ 1,371	\$ 4,217	\$ 56,030	\$ 458,150	\$ 16,545,727	\$ 15,655,056	\$ 890,677
59	Res Heat	\$ 841,696	\$ 1,502,995	\$ 2,003,864	\$ 1,630,276	\$ 1,167,945	\$ 459,400	\$ 123,105	\$ 31,796	\$ 511	\$ 1,573	\$ 22,462	\$ 192,093	\$ 7,977,716	\$ 7,606,177	\$ 371,533
60	Res General	\$ 5,094	\$ 10,622	\$ 14,862	\$ 11,919	\$ 7,760	\$ 2,033	\$ 2,800	\$ 723	\$ 12	\$ 36	\$ 511	\$ 4,369	\$ 60,741	\$ 52,290	\$ 8,451
61	G50 Low Annual-Low Winter	\$ 18,577	\$ 48,410	\$ 71,540	\$ 56,477	\$ 32,679	\$ 2,678	\$ 23,243	\$ 6,003	\$ 97	\$ 297	\$ 4,241	\$ 36,268	\$ 300,509	\$ 230,361	\$ 70,148
62	G40 Low Annual-High Winter	\$ 454,357	\$ 796,626	\$ 1,055,345	\$ 860,259	\$ 623,809	\$ 255,191	\$ 46,642	\$ 12,047	\$ 194	\$ 596	\$ 8,510	\$ 72,780	\$ 4,186,356	\$ 4,045,587	\$ 140,768
63	G51 Med Annual-Low Winter	\$ 36,413	\$ 87,036	\$ 126,150	\$ 100,138	\$ 60,497	\$ 9,095	\$ 34,979	\$ 9,034	\$ 145	\$ 447	\$ 6,382	\$ 54,581	\$ 524,898	\$ 419,329	\$ 105,568
64	G41 Med Annual-High Winter	\$ 309,882	\$ 556,317	\$ 743,072	\$ 604,202	\$ 431,340	\$ 167,681	\$ 49,322	\$ 12,739	\$ 205	\$ 630	\$ 8,999	\$ 76,962	\$ 2,961,352	\$ 2,814,924	\$ 148,857
65	G52 High Annual-Low Winter	\$ 2,992	\$ 1,663	\$ 5,793	\$ 7,148	\$ 4,707	\$ 2,297	\$ 1,307	\$ -	\$ 151	\$ 466	\$ 290	\$ 1,489	\$ 28,302	\$ 24,599	\$ 3,703
66	G42 High Annual-High Winter	\$ 46,702	\$ 81,847	\$ 122,871	\$ 102,350	\$ 74,585	\$ 35,862	\$ 14,135	\$ 3,030	\$ 56	\$ 173	\$ 4,635	\$ 19,607	\$ 505,853	\$ 464,217	\$ 41,636
67																
68	Residential	\$ 846,791	\$ 1,513,617	\$ 2,018,726	\$ 1,642,195	\$ 1,175,705	\$ 461,433	\$ 125,905	\$ 32,519	\$ 523	\$ 1,608	\$ 22,972	\$ 196,462	\$ 8,038,457	\$ 7,658,467	\$ 379,990
69	SALES LFL CLASSES	\$ 57,982	\$ 137,109	\$ 203,484	\$ 163,763	\$ 97,882	\$ 14,070	\$ 59,528	\$ 15,037	\$ 393	\$ 1,210	\$ 10,913	\$ 92,338	\$ 853,710	\$ 674,290	\$ 179,420
70	SALES HLF CLASSES	\$ 810,942	\$ 1,434,791	\$ 1,921,288	\$ 1,566,811	\$ 1,129,733	\$ 458,734	\$ 110,099	\$ 27,816	\$ 455	\$ 1,399	\$ 22,145	\$ 169,349	\$ 7,653,561	\$ 7,322,299	\$ 331,262

[illegible]

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	Attachment NUI-CAK-3, LN 68
39	Res General	Attachment NUI-CAK-3, LN 69
40	G50 Low Annual-Low Winter	Attachment NUI-CAK-3, LN 70
41	G40 Low Annual-High Winter	Attachment NUI-CAK-3, LN 71
42	G51 Med Annual-Low Winter	Attachment NUI-CAK-3, LN 72
43	G41 Med Annual-High Winter	Attachment NUI-CAK-3, LN 73
44	G52 High Annual-Low Winter	Attachment NUI-CAK-3, LN 74
45	G42 High Annual-High Winter	Attachment NUI-CAK-3, 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	Attachment NUI-CAK-6, LN 35
59	Res Heat	LN 58 * LN 48
60	Res General	LN 58 * LN 49
61	G50 Low Annual-Low Winter	LN 58 * LN 50
62	G40 Low Annual-High Winter	LN 58 * LN 51
63	G51 Med Annual-Low Winter	LN 58 * LN 52
64	G41 Med Annual-High Winter	LN 58 * LN 53
65	G52 High Annual-Low Winter	LN 58 * LN 54
66	G42 High Annual-High Winter	LN 58 * LN 55
67		
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	Attachment NUI-CAK-6, LN 36
73	Res Heat	LN 24 + LN 59
74	Res General	LN 25 + LN 60
75	G50 Low Annual-Low Winter	LN 26 + LN 61
76	G40 Low Annual-High Winter	LN 27 + LN 62
77	G51 Med Annual-Low Winter	LN 28 + LN 63
78	G41 Med Annual-High Winter	LN 29 + LN 64
79	G52 High Annual-Low Winter	LN 30 + LN 65
80	G42 High Annual-High Winter	LN 31 + LN 66
81		
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	\$ 12,798,284	\$ 1,354,125	\$ 14,152,409	Attachment NUI-CAK-2, LN 80
2	Commodity	\$ 19,206,895	\$ 3,131,680	\$ 22,338,575	Attachment NUI-CAK-6, LN 36
3	Total	\$ 32,005,179	\$ 4,485,805	\$ 36,490,984	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	35,339,329	8,907,030	44,246,359	Attachment NUI-CAK-3, LN 11
6	Forecasted Residential Sales (Therms)	16,774,496	3,673,138	20,447,634	Attachment NUI-CAK-3, LN 3
7	Average Residential Rate:	Winter	Summer	Annual	
8	Average Demand Rate	\$0.3622	\$0.1520		LN 1 / LN 5
9	Average Commodity Rate	\$0.5435	\$0.3516		LN 2 / LN 5
10	Average Rate	\$0.9057	\$0.5036		LN 3 / LN 5
11					
12	Residential Reallocation:	Winter	Summer	Annual	
13	Demand Costs Allocated To Residential per SMBA	\$ 6,230,944	\$ 599,654	\$ 6,830,599	Attachment NUI-CAK-4, LN 169
14	Demand Costs Allocated To Residential per Avg Res. Rate	\$ 6,074,953	\$ 558,317	\$ 6,633,270	LN 8 * LN 6
15	Demand Reallocation:	\$ 155,991	\$ 41,337	\$ 197,329	LN 13 - LN 14
16	HLF Allocation	\$ 15,887	\$ 11,258	\$ 27,144	LN 15 * LN 20
17	LLF Allocation	\$ 140,104	\$ 30,080	\$ 170,184	LN 15 * LN 21
18					
19	SMBA Capacity Cost Allocation (%)				
20	HLF	10.18%	27.23%		Attachment NUI-CAK-4, LN 174
21	LLF	89.82%	72.77%		Attachment NUI-CAK-4, LN 175
22					
23	Commodity Costs Allocated To Residential per SMBA	\$ 9,102,892	\$ 1,291,644	\$ 10,394,536	Attachment NUI-CAK-8, LN 82
24	Commodity Costs Allocated To Residential per Avg Res. Rate	\$ 9,116,924	\$ 1,291,475	\$ 10,408,399	LN 9 * LN 6
25	Commodity Reallocation:	\$ (14,032)	\$ 168	\$ (13,864)	LN 23 - LN 24
26	HLF Allocation	\$ (2,088)	\$ 64	\$ (2,024)	LN 25 * LN 30
27	LLF Allocation	\$ (11,944)	\$ 104	\$ (11,840)	LN 25 * LN 31
28					
29	SMBA Commodity Cost Allocation (%)				
30	HLF	14.88%	38.15%		Attachment NUI-CAK-8, LN 87
31	LLF	85.12%	61.85%		Attachment NUI-CAK-8, LN 88

Northern Utilities Inc.
Calculation of Bad Debt Expense

1	Actual Bad Debt Expense 12 Months Ended July 31, 2021				
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 %			90.43%	Attachment NUI-CAK-2
10	Summer Demand Cost %			9.57%	Attachment NUI-CAK-2
11					
12	Forecast Bad Debt Expense 12 Months Ended December 31, 2022				
13					*
14	Annual Total		\$	400,000	Company Forecast
15	Annual Non-Distribution		\$	151,850	LN 14 * LN 7
16	Winter Non-Distribution		\$	137,320	LN 15 * LN 9
17	Summer Non-Distribution		\$	14,529	LN 15 * LN 10

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

Sales Revenues		Winter						Summer					
		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)
Volumes	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
Residential Heat & Non Heat		2,235,193	3,205,961	3,752,145	3,220,112	2,745,230	1,615,855	791,744	517,185	437,049	443,237	491,840	992,084
Sales HLF Classes		368,357	503,160	586,466	509,647	444,531	280,756	418,861	285,038	250,296	254,950	275,778	512,036
Sales LLF Classes		2,109,633	3,011,324	3,541,686	3,044,843	2,604,500	1,559,929	697,006	455,024	386,854	392,235	440,500	865,314
Total		4,713,183	6,720,446	7,880,297	6,774,602	5,794,261	3,456,540	1,907,611	1,257,246	1,074,199	1,090,422	1,208,118	2,369,434
Rates													
Residential Heat & Non Heat CGA		\$0.9392	\$0.9392	\$0.9392	\$0.9392	\$0.9392	\$0.9392	\$0.5176	\$0.5176	\$0.5176	\$0.5176	\$0.5176	\$0.5176
Sales HLF Classes CGA		\$0.8453	\$0.8453	\$0.8453	\$0.8453	\$0.8453	\$0.8453	\$0.4740	\$0.4740	\$0.4740	\$0.4740	\$0.4740	\$0.4740
Sales LLF Classes CGA		\$0.9551	\$0.9551	\$0.9551	\$0.9551	\$0.9551	\$0.9551	\$0.5445	\$0.5445	\$0.5445	\$0.5445	\$0.5445	\$0.5445
Revenues													
Residential Heat & Non Heat		\$ (2,099,293)	\$ (3,011,039)	\$ (3,524,015)	\$ (3,024,329)	\$ (2,578,320)	\$ (1,517,611)	\$ (409,807)	\$ (267,695)	\$ (226,216)	\$ (229,419)	\$ (254,576)	\$ (513,503)
Sales HLF Classes		\$ (311,373)	\$ (425,321)	\$ (495,740)	\$ (430,805)	\$ (375,762)	\$ (237,323)	\$ (198,540)	\$ (135,108)	\$ (118,640)	\$ (120,846)	\$ (130,719)	\$ (242,705)
Sales LLF Classes		\$ (2,014,910)	\$ (2,876,116)	\$ (3,382,664)	\$ (2,908,129)	\$ (2,487,558)	\$ (1,489,888)	\$ (379,520)	\$ (247,760)	\$ (210,642)	\$ (213,572)	\$ (239,852)	\$ (471,164)
Total Sales		\$ (4,425,576)	\$ (6,312,476)	\$ (7,402,419)	\$ (6,363,263)	\$ (5,441,640)	\$ (3,244,823)	\$ (987,867)	\$ (650,563)	\$ (555,499)	\$ (563,838)	\$ (625,147)	\$ (1,227,371)

Gas Costs and Credits		Winter						Summer					
		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)
Demand Costs (net of Capacity Assignment)	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
Pipeline		\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451	\$ 455,451
Storage		\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421	\$ 644,421
On-system Peaking		\$ 208,007	\$ 208,007	\$ 208,007	\$ 208,007	\$ 208,007	\$ 97,714	\$ 16,975	\$ 16,975	\$ 16,975	\$ 16,975	\$ 16,975	\$ 16,975
Off-System Peaking		\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646	\$ 312,646
Total Demand Costs		\$ 1,620,524	\$ 1,620,524	\$ 1,620,524	\$ 1,620,524	\$ 1,620,524	\$ 1,510,232	\$ 1,429,493	\$ 1,429,493	\$ 1,429,493	\$ 1,429,493	\$ 1,429,493	\$ 1,429,493
Asset Management and Capacity Release													
NUI AMA Revenue		\$ (810,930)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)	\$ (826,470)
NUI Capacity Release								\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
NUI AMA Rev & Cap. Release Subtotal								\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
NH AMA Revenue		\$ (333,866)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)
NH Capacity Release													
NH Total Asset Management and Capacity Release		\$ (333,866)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)	\$ (340,264)
Outage Replacement		\$ 7,067	\$ 7,067	\$ 7,067	\$ 7,067	\$ 7,067	\$ 7,067	\$ 328	\$ 328	\$ 328	\$ 328	\$ 328	\$ 328
Re-entry Rate & Conversion Rate Revenue		\$ (1,000)	\$ (1,000)	\$ (1,000)	\$ (1,000)	\$ (1,000)		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Net Demand Costs		\$ 1,292,725	\$ 1,286,327	\$ 1,286,327	\$ 1,286,327	\$ 1,286,327	\$ 1,177,035	\$ 1,089,556	\$ 1,089,556	\$ 1,089,556	\$ 1,089,556	\$ 1,089,556	\$ 1,089,556
NUI Commodity Costs													
NUI Total Pipeline Volumes		982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859
Pipeline Costs Modeled in Sendout™		\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274
NYMEX Price Used for Forecast		\$ 5.3050	\$ 5.3980	\$ 5.4650	\$ 5.3700	\$ 5.0130	\$ 3.9390	\$ 3.8100	\$ 3.8390	\$ 3.8710	\$ 3.8790	\$ 3.8630	\$ 3.8900
NYMEX Price Used for Update		\$ 5.3050	\$ 5.3980	\$ 5.4650	\$ 5.3700	\$ 5.0130	\$ 3.9390	\$ 3.8100	\$ 3.8390	\$ 3.8710	\$ 3.8790	\$ 3.8630	\$ 3.8900
Increase/(Decrease) NYMEX Price		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Increase/(Decrease) in Pipeline Costs		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Updated Pipeline Costs		\$ 5,248,530	\$ 5,735,184	\$ 6,062,675	\$ 5,455,995	\$ 5,436,340	\$ 4,220,796	\$ 2,197,031	\$ 1,475,856	\$ 1,373,084	\$ 1,382,979	\$ 1,410,783	\$ 2,512,274
New Hampshire Allocated Percentage		36.21%	36.93%	36.99%	36.38%	34.75%	31.67%	30.87%	29.65%	27.35%	27.40%	28.59%	33.29%
NH Updated Pipeline Costs		\$ 1,900,723	\$ 2,118,268	\$ 2,242,311	\$ 1,984,934	\$ 1,889,389	\$ 1,336,543	\$ 678,216	\$ 437,649	\$ 375,599	\$ 378,996	\$ 403,363	\$ 836,389
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		\$ 1,900,723	\$ 2,118,268	\$ 2,242,311	\$ 1,984,934	\$ 1,889,389	\$ 1,336,543	\$ 678,216	\$ 437,649	\$ 375,599	\$ 378,996	\$ 403,363	\$ 836,389
Storage		\$ 378,185	\$ 836,645	\$ 933,716	\$ 983,140	\$ 649,063	\$ 447,024	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Peaking		\$ 3,450	\$ 772,446	\$ 1,684,032	\$ 1,042,411	\$ 447,024	\$ 3,237	\$ 3,258	\$ 3,290	\$ 3,136	\$ 3,142	\$ 3,847	\$ 4,795
Total Commodity Costs		\$ 2,282,359	\$ 3,727,358	\$ 4,860,059	\$ 4,010,484	\$ 2,985,476	\$ 1,339,779	\$ 681,474	\$ 440,939	\$ 378,735	\$ 382,138	\$ 407,210	\$ 841,184
Inventory Finance Charge		\$ 174	\$ 268	\$ 323	\$ 275	\$ 224	\$ 114	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Anticipated Direct Cost of Gas		\$ 3,575,258	\$ 5,013,954	\$ 6,146,710	\$ 5,297,087	\$ 4,272,028	\$ 2,516,929	\$ 1,771,030	\$ 1,530,495	\$ 1,468,291	\$ 1,471,694	\$ 1,496,767	\$ 1,930,741

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection An:

Sales Revenues				
Volumes	Winter	Summer	Prior Period	Total
Residential Heat & Non Heat				20,447,634
Sales HLF Classes				4,689,876
Sales LLF Classes				19,108,849
Total	35,339,329	8,907,030		44,246,359
Rates				
Residential Heat & Non Heat CGA				
Sales HLF Classes CGA				
Sales LLF Classes CGA				
Revenues				
Residential Heat & Non Heat				\$ (17,655,823)
Sales HLF Classes				\$ (3,222,882)
Sales LLF Classes				\$ (16,921,776)
Total Sales	\$ (33,190,196)	\$ (4,610,285)		\$ (37,800,481)
Gas Costs and Credits				
				Total
Demand Costs (net of Capacity Assignment)				
Pipeline	\$ 2,732,703	\$ 2,732,703		\$ 5,465,407
Storage	\$ 3,866,525	\$ 3,866,525		\$ 7,733,050
On-system Peaking	\$ 1,137,749	\$ 101,852		\$ 1,239,601
Off-System Peaking	\$ 1,875,877	\$ 1,875,877		\$ 3,751,755
Total Demand Costs	\$ 9,612,854	\$ 8,576,958		\$ 18,189,812
Asset Management and Capacity Release				
NUI AMA Revenue				\$ (9,902,100)
NUI Capacity Release				\$ -
NUI AMA Rev & Cap. Release Subtotal				\$ -
NH AMA Revenue				\$ (4,076,771)
NH Capacity Release				\$ -
NH Total Asset Management and Capacity Release		\$ -	\$ -	\$ (4,076,771)
Outage Replacement	\$ 42,402	\$ 1,965		\$ 44,367
Re-entry Rate & Conversion Rate Revenue	\$ (5,000)	\$ -		\$ (5,000)
Net Demand Costs	\$ 7,615,070	\$ 6,537,339		\$ 14,152,408
NUI Commodity Costs				
NUI Total Pipeline Volumes				8,854,520
Pipeline Costs Modeled in Sendout™				\$ 42,511,526
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				\$ 14,582,381
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				\$ 14,582,381
Storage				\$ 3,780,749
Peaking				\$ 3,974,066
Total Commodity Costs	\$ 19,205,516	\$ 3,131,680		\$ 22,337,197
Inventory Finance Charge	\$ 1,378	\$ -		\$ 1,378
Total Anticipated Direct Cost of Gas	\$ 26,821,965	\$ 9,669,019		\$ 36,490,984

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

	Oct-21	Winter						Summer					
		(Forecast) Nov-21	(Forecast) Dec-21	(Forecast) Jan-22	(Forecast) Feb-22	(Forecast) Mar-22	(Forecast) Apr-22	(Forecast) May-22	(Forecast) Jun-22	(Forecast) Jul-22	(Forecast) Aug-22	(Forecast) Sep-22	(Forecast) Oct-22
Working Capital													
Total Anticipated Direct Cost of Gas		\$ 3,575,258	\$ 5,013,954	\$ 6,146,710	\$ 5,297,087	\$ 4,272,028	\$ 2,516,929	\$ 1,771,030	\$ 1,530,495	\$ 1,468,291	\$ 1,471,694	\$ 1,496,767	\$ 1,930,741
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		\$ 3,189	\$ 4,472	\$ 5,483	\$ 4,725	\$ 3,811	\$ 2,245	\$ 1,580	\$ 1,365	\$ 1,310	\$ 1,313	\$ 1,335	\$ 1,722
Beginning Period Working Capital Balance		\$ (7,305)	\$ (4,131)	\$ 336	\$ 5,828	\$ 10,575	\$ 14,419	\$ 16,706	\$ 18,334	\$ 19,750	\$ 21,115	\$ 22,487	\$ 23,885
End of Period Working Capital Allowance		\$ (4,116)	\$ 341	\$ 5,819	\$ 10,553	\$ 14,385	\$ 16,664	\$ 18,286	\$ 19,699	\$ 21,060	\$ 22,428	\$ 23,822	\$ 25,607
Interest		\$ (15)	\$ (5)	\$ 8	\$ 22	\$ 34	\$ 42	\$ 47	\$ 52	\$ 55	\$ 59	\$ 63	\$ 67
End of period with Interest	\$ (7,305)	\$ (4,131)	\$ 336	\$ 5,828	\$ 10,575	\$ 14,419	\$ 16,706	\$ 18,334	\$ 19,750	\$ 21,115	\$ 22,487	\$ 23,885	\$ 25,674
Bad Debt													
Projected Bad Debt	\$ -	\$ 22,886.74	\$ 22,886.74	\$ 22,886.74	\$ 22,886.74	\$ 22,886.74	\$ 22,886.74	\$ 2,421.54	\$ 2,421.54	\$ 2,421.54	\$ 2,421.54	\$ 2,421.54	\$ 2,421.54
Beginning Period Bad Debt Balance		\$ (77,564)	\$ (54,857)	\$ (32,088)	\$ (9,257)	\$ 13,636	\$ 36,591	\$ 59,607	\$ 62,194	\$ 64,787	\$ 67,387	\$ 69,995	\$ 72,609
End of Period Bad Debt Balance		\$ (54,678)	\$ (31,970)	\$ (9,201)	\$ 13,630	\$ 36,523	\$ 59,477	\$ 62,029	\$ 64,615	\$ 67,208	\$ 69,809	\$ 72,416	\$ 75,030
Interest		\$ (179)	\$ (118)	\$ (56)	\$ 6	\$ 68	\$ 130	\$ 165	\$ 172	\$ 179	\$ 186	\$ 193	\$ 200
End of Period Bad Debt Balance with Interest	\$ (77,564)	\$ (54,857)	\$ (32,088)	\$ (9,257)	\$ 13,636	\$ 36,591	\$ 59,607	\$ 62,194	\$ 64,787	\$ 67,387	\$ 69,995	\$ 72,609	\$ 75,230
Local Production and Storage Capacity		\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ 79,351	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Miscellaneous Overhead		\$ 77,268	\$ 77,268	\$ 77,268	\$ 77,268	\$ 77,268	\$ 77,268	\$ 19,475	\$ 19,475	\$ 19,475	\$ 19,475	\$ 19,475	\$ 19,475
Gas Cost Other than Bad Debt and Working Capital Over/Under Collection													
Beginning Balance Over/Under Collection	\$ 237,004	\$ 237,004	\$ (456,992)	\$ (1,601,680)	\$ (2,706,597)	\$ (3,624,716)	\$ (4,648,898)	\$ (5,233,538)	\$ (4,443,986)	\$ (3,555,397)	\$ (2,631,496)	\$ (1,710,036)	\$ (822,367)
Net Costs - Revenues		\$ (693,699)	\$ (1,141,904)	\$ (1,099,091)	\$ (909,558)	\$ (1,012,993)	\$ (571,275)	\$ 802,639	\$ 899,407	\$ 932,267	\$ 927,331	\$ 891,094	\$ 722,844
Ending Balance before Interest		\$ (456,695)	\$ (1,598,896)	\$ (2,700,771)	\$ (3,616,154)	\$ (4,637,710)	\$ (5,220,174)	\$ (4,430,899)	\$ (3,544,579)	\$ (2,623,130)	\$ (1,704,165)	\$ (818,942)	\$ (99,523)
Average Balance		\$ (109,845)	\$ (1,027,944)	\$ (2,151,225)	\$ (3,161,376)	\$ (4,131,213)	\$ (4,934,536)	\$ (4,832,219)	\$ (3,994,283)	\$ (3,089,263)	\$ (2,167,831)	\$ (1,264,489)	\$ (460,945)
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		\$ (297)	\$ (2,784)	\$ (5,826)	\$ (8,562)	\$ (11,189)	\$ (13,364)	\$ (13,087)	\$ (10,818)	\$ (8,367)	\$ (5,871)	\$ (3,425)	\$ (1,248)
Ending Balance Incl Interest Expense	\$ 237,004	\$ (456,992)	\$ (1,601,680)	\$ (2,706,597)	\$ (3,624,716)	\$ (4,648,898)	\$ (5,233,538)	\$ (4,443,986)	\$ (3,555,397)	\$ (2,631,496)	\$ (1,710,036)	\$ (822,367)	\$ (100,771)
Total Over/Under Collection Ending Balance	\$ 152,135	\$ (515,980)	\$ (1,633,431)	\$ (2,710,026)	\$ (3,600,506)	\$ (4,597,889)	\$ (5,157,224)	\$ (4,363,459)	\$ (3,470,860)	\$ (2,542,994)	\$ (1,617,555)	\$ (725,873)	\$ 133
Total Indirect Cost of Gas	\$ 152,135	\$ 182,203	\$ 181,071	\$ 179,115	\$ 175,697	\$ 172,229	\$ 168,558	\$ 10,601	\$ 12,667	\$ 15,073	\$ 17,583	\$ 20,062	\$ 22,637
Total Cost of Gas	\$ 152,135	\$ 3,757,461	\$ 5,195,025	\$ 6,325,824	\$ 5,472,784	\$ 4,444,257	\$ 2,685,487	\$ 1,781,631	\$ 1,543,162	\$ 1,483,365	\$ 1,489,277	\$ 1,516,829	\$ 1,953,378
Total Interest	\$ -	\$ (492)	\$ (2,907)	\$ (5,874)	\$ (8,534)	\$ (11,087)	\$ (13,192)	\$ (12,875)	\$ (10,595)	\$ (8,133)	\$ (5,626)	\$ (3,169)	\$ (981)

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection An:

	Winter	Summer	Prior Period	Total
Working Capital				
Total Anticipated Direct Cost of Gas				\$ 36,490,984
Working Capital Percentage				
Working Capital Allowance	\$ 23,925	\$ 8,625	\$ (7,305)	\$ 25,245
Beginning Period Working Capital Balance				
End of Period Working Capital Allowance				
Interest	\$ 86	\$ 343		\$ 429
End of period with Interest				
Bad Debt				
Projected Bad Debt	\$ 137,320	\$ 14,529	\$ (77,564)	\$ 74,285
Beginning Period Bad Debt Balance				
End of Period Bad Debt Balance				
Interest	\$ (149)	\$ 1,094		\$ 945
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				
Beginning Balance Over/Under Collection				\$ (31,198,700)
Net Costs - Revenues				\$ (252,937)
Ending Balance before Interest				\$ (31,451,637)
Average Balance				\$ (31,325,168)
Interest Rate				
Interest Expense				\$ (84,839)
Ending Balance Incl Interest Expense			\$ 237,004	
Total Over/Under Collection Ending Balance				
Total Indirect Cost of Gas	\$ 1,058,872	\$ 98,623	\$ 152,135	\$ 1,309,631
Total Cost of Gas	\$ 27,880,837	\$ 9,767,642	\$ 152,135	\$ 37,800,614
Total Interest	\$ (42,086)	\$ (41,380)		\$ (83,465)

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

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2021 - April 31, 2022

Column A	Column B	Column C
1 <u>ANTICIPATED DIRECT COST OF GAS</u>		
2 Purchased Gas for Sales Service:		
3 Demand Costs:	\$ 4,553,044	
4 Supply Costs:	\$ 11,472,168	
5		
6 Storage & Peaking Gas for Sales Service:		
7 Demand, Capacity:	\$ 12,327,011	
8 Commodity Costs:	\$ 7,733,349	
9		
10 Inventory Finance Charge	\$ 1,378	
11		
12 Capacity Release	\$ (4,076,771)	
13		
14 Re-entry Rate & Conversion Rate Revenues	\$ (5,000)	
15		
16 Total Anticipated Direct Cost of Gas		\$ 32,005,179
17		
18 <u>ANTICIPATED INDIRECT COST OF GAS</u>		
19 Adjustments:		
20 Prior Period Under/(Over) Collection	\$ 189,294	
21 Interest	\$ (42,086)	
22 Refunds	\$ -	
23 <u>Interruptible Margins</u>	\$ -	
24 Total Adjustments		\$ 147,208
25		
26 Working Capital:		
27 Total Anticipated Direct Cost of Gas	\$ 32,005,179	
28 Working Capital Allowance Percentage (10.02 [lag days]/365* prime rate)	<u>0.0892%</u>	
29 Working Capital Allowance	\$ 28,555	
30		
31 Plus: Working Capital Reconciliation (Acct 173)	<u>\$ (5,834)</u>	
32		
33 Total Working Capital Allowance		\$ 22,721
34		
35 Bad Debt:		
36 Bad Debt Allowance	\$ 137,320	
37 Plus: Bad Debt Reconciliation (Acct 173)	<u>\$ (61,950)</u>	
38 Total Bad Debt Allowance		\$ 75,370
39		
40 Local Production and Storage Capacity		\$ 476,106
41		
42 Miscellaneous Overhead-79.87% Allocated to Winter Season		<u>\$ 463,606</u>
43		
44 Total Anticipated Indirect Cost of Gas		\$ 1,185,012
45		
46 Total Cost of Gas		<u>\$ 33,190,191</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, 2021 - April 31, 2022

Column A	Column D
1 <u>ANTICIPATED DIRECT COST OF GAS</u>	
2 Purchased Gas for Sales Service:	
3 Demand Costs:	Attachment NUI-CAK-2, LN 71 + LN 75
4 Supply Costs:	Attachment NUI-CAK-6, LN 14
5	
6 Storage & Peaking Gas for Sales Service:	
7 Demand, Capacity:	Attachment NUI-CAK-2, LN 73 + LN 74
8 Commodity Costs:	Attachment NUI-CAK-6, LN 15 + LN 16
9	
10 Inventory Finance Charge	Attachment NUI-CAK-6, LN 17
11	
12 Capacity Release	-(Attachment NUI-CAK-2, LN 77)
13	
14 Re-entry Rate & Conversion Rate Revenues	Attachment NUI-CAK-2, 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	Attachment NUI-CAK-10, Page 1
21 Interest	Attachment NUI-CAK-12, LN 94: Total
22 Refunds	
23 <u>Interruptible Margins</u>	-(Attachment NUI-CAK-2, 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* prime Tariff - NHPUC No. 12 , Section 6.1	
29 Working Capital Allowance	LN 27 * LN 28
30	
31 Plus: Working Capital Reconciliation (Acct 173)	Attachment NUI-CAK-10, Attachment A
32	
33 Total Working Capital Allowance	Sum (LN 29 : LN 31)
34	
35 Bad Debt:	
36 Bad Debt Allowance	Attachment NUI-CAK-11, LN 16
37 Plus: Bad Debt Reconciliation (Acct 173)	Schedule 10-CAK, Attachment B
38 Total Bad Debt Allowance	LN 36 + LN 37
39	
40 Local Production and Storage Capacity	Attachment NUI-CAK-2, LN 84
41	
42 Miscellaneous Overhead-79.87% Allocated to Winter Season	Attachment NUI-CAK-2, 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%

48 CALCULATION OF FIRM SALES COST OF GAS RATE
49 Period Covered: November 1, 2021 - April 31, 2022

51 Column A	Column B	Column C
52		
53 Total Anticipated Direct Cost of Gas	\$ 32,005,179	
54 Projected Prorated Sales (11/01/21 - 04/30/22)	35,339,329	
55 Direct Cost of Gas Rate		\$ 0.9057 per therm
56		
57 Demand Cost of Gas Rate	\$ 12,798,284	\$ 0.3622 per therm
58 Commodity Cost of Gas Rate	\$ 19,206,895	\$ 0.5435 per therm
59 Total Direct Cost of Gas Rate	\$ 32,005,179	\$ 0.9057 per therm
60		
61 Total Anticipated Indirect Cost of Gas	\$ 1,185,012	
62 Projected Prorated Sales (11/01/21 - 04/30/22)	35,339,329	
63 Indirect Cost of Gas		\$ 0.0335 per therm
64		
65		

66 **TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21** **\$ 0.9392 per therm**

68 RESIDENTIAL COST OF GAS RATE - 11/01/21	COGwr	\$ 0.9392 per therm
69	Maximum (COG+25%)	\$ 1.1740
70		
71		

72 COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/21	COGwl	\$ 0.8453 per therm
73	Maximum (COG+25%)	\$ 1.0566
74		

75 C&I HLF Demand Costs Allocated per SMBA	\$ 668,845
76 PLUS: Residential Demand Reallocation to C&I HLF	\$ 15,887
77 C&I HLF Total Adjusted Demand Costs	\$ 684,732
78 C&I HLF Projected Prorated Sales (11/01/21 - 04/30/22)	2,692,919
79 Demand Cost of Gas Rate	\$ 0.2543

81 C&I HLF Commodity Costs Allocated per SMBA	\$ 1,503,327
82 PLUS: Residential Commodity Reallocation to C&I HLF	\$ (2,088)
83 C&I HLF Total Adjusted Commodity Costs	\$ 1,501,239
84 C&I HLF Projected Prorated Sales (11/01/21 - 05/30/22)	2,692,919
85 Commodity Cost of Gas Rate	\$ 0.5575

86

87 **Indirect Cost of Gas** **\$ 0.0335**

88

89 **Total C&I HLF Cost of Gas Rate** **\$ 0.8453**

92 COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/21	COGwh	\$ 0.9551 per therm
93	Maximum (COG+25%)	\$ 1.1939
94		

95 C&I LLF Demand Costs Allocated per SMBA	\$ 5,898,495
96 PLUS: Residential Demand Reallocation to C&I LLF	\$ 140,104
97 C&I LLF Total Adjusted Demand Costs	\$ 6,038,599
98 C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	15,871,915
99 Demand Cost of Gas Rate	\$ 0.3805

101 C&I LLF Commodity Costs Allocated per SMBA	\$ 8,600,676
102 PLUS: Residential Commodity Reallocation to C&I LLF	\$ (11,944)
103 C&I LLF Total Adjusted Commodity Costs	\$ 8,588,732
104 C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	15,871,915
105 Commodity Cost of Gas Rate	\$ 0.5411

106

107 **Indirect Cost of Gas** **\$ 0.0335**

108

109 **Total C&I LLF Cost of Gas Rate** **\$ 0.9551**

48	CALCULATION OF FIRM SALES COST OF GAS RATE	
49	Period Covered: November 1, 2021 - April 31, 2022	
50		
51	Column A	Column D
52		
53	Total Anticipated Direct Cost of Gas	LN 16
54	Projected Prorated Sales (11/01/21 - 04/30/22)	Attachment NUI-CAK-3, 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 (11/01/21 - 04/30/22)	Column B : LN 54
63	Indirect Cost of Gas	LN 61 / LN 62
64		
65		
66	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21	LN 59 + LN 63
67		
68	RESIDENTIAL COST OF GAS RATE - 11/01/21	LN 66
69		LN 68 * 1.25
70		
71		
72	COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/21	LN 89
73		LN 72 * 1.25
74		
75	C&I HLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 170
76	PLUS: Residential Demand Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 16
77	C&I HLF Total Adjusted Demand Costs	Sum (LN 75 : LN 76)
78	C&I HLF Projected Prorated Sales (11/01/21 - 04/30/22)	Attachment NUI-CAK-3, LN 14
79	Demand Cost of Gas Rate	LN 77 / LN 78
80		
81	C&I HLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 83
82	PLUS: Residential Commodity Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 26
83	C&I HLF Total Adjusted Commodity Costs	Sum (LN 81 : LN 82)
84	C&I HLF Projected Prorated Sales (11/01/21 - 05/30/22)	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 - 11/01/21	LN 109
93		LN 92 * 1.25
94		
95	C&I LLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 171
96	PLUS: Residential Demand Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 17
97	C&I LLF Total Adjusted Demand Costs	Sum (LN 95 : LN 96)
98	C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	Attachment NUI-CAK-3, LN 15
99	Demand Cost of Gas Rate	LN 97 / LN 98
100		
101	C&I LLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 84
102	PLUS: Residential Commodity Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 27
103	C&I LLF Total Adjusted Commodity Costs	Sum (LN 101 : LN 102)
104	C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	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, 2022 - October 31, 2022

Column A	Column B	Column C
110 <u>ANTICIPATED DIRECT COST OF GAS</u>		
111 Purchased Gas:		
112 Demand Costs:	\$ 956,729	
113 Supply Costs:	\$ 3,110,213	
114		
115 Storage & Peaking Gas:		
116 Demand, Capacity:	\$ 397,395	
117 Commodity Costs:	\$ 21,467	
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		\$ 4,485,805
126		
127 <u>ANTICIPATED INDIRECT COST OF GAS</u>		
128 Adjustments:		
129 Prior Period Under/(Over) Collection	\$ 47,710	
130 Interest	\$ (41,380)	
131 Refunds	\$ -	
132 Interruptible Margins	\$ -	
133 Total Adjustments		\$ 6,330
134		
135 Working Capital:		
136 Total Anticipated Direct Cost of Gas	\$ 4,485,805	
137 Working Capital Allowance Percentage (10.02 [lag days]/365* prime rate)	<u>0.089%</u>	
138 Working Capital Allowance	\$ 4,002	
139 Plus: Working Capital Reconciliation (Acct. 173)	<u>\$ (1,470)</u>	
140		
141 Total Working Capital Allowance		\$ 2,532
142		
143 Bad Debt:		
144 Projected Bad Debt	\$ 14,529	
145 Plus: Bad Debt Reconciliation (Acct 173)	<u>\$ (15,614)</u>	
146 Total Bad Debt Expense		\$ (1,085)
147		
148 Local Production and Storage Capacity		\$ -
149		
150 Miscellaneous Overhead-20.13% Allocated to Summer Season		\$ 116,849
151		
152 Total Anticipated Indirect Cost of Gas		\$ 124,627
153		
154 Total Cost of Gas		\$ 4,610,432
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, 2022 - October 31, 2022

Column A	Column D
110 <u>ANTICIPATED DIRECT COST OF GAS</u>	
111 Purchased Gas:	
112 Demand Costs:	Attachment NUI-CAK-2, LN 71 + LN 75
113 Supply Costs:	Attachment NUI-CAK-6, LN 14
114	
115 Storage & Peaking Gas:	
116 Demand, Capacity:	Attachment NUI-CAK-2, LN 73
117 Commodity Costs:	Attachment NUI-CAK-6, LN 15 + LN 16
118	
119 Inventory Finance Charge	- (Attachment NUI-CAK-6, LN 20)
120	
121 Capacity Release	- (Attachment NUI-CAK-2, 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	Attachment NUI-CAK-10, Page 1
130 Interest	Attachment NUI-CAK-12, LN 94: Total
131 Refunds	Company Analysis
132 Interruptible Margins	- (Attachment NUI-CAK-2, 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* prim	Tariff - NHPUC No. 12 , Section 6.1
138 Working Capital Allowance	LN 136 * LN 137
139 Plus: Working Capital Reconciliation (Acct. 173)	Attachment NUI-CAK-10, Attachment A
140	
141 Total Working Capital Allowance	Sum (LN 138 : LN 139)
142	
143 Bad Debt:	
144 Projected Bad Debt	Attachment NUI-CAK-11, LN 17
145 Plus: Bad Debt Reconciliation (Acct 173)	Schedule 10-CAK, Attachment B
146 Total Bad Debt Expense	Sum (LN 144 : LN 145)
147	
148 Local Production and Storage Capacity	Attachment NUI-CAK-2, LN 84
149	
150 Miscellaneous Overhead-20.13% Allocated to Summer Season	Attachment NUI-CAK-2, 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, 2022 - October 31, 2022
159

160 Column A	Column B	Column C
161		
162 Total Anticipated Direct Cost of Gas	\$ 4,485,805	
163 Projected Prorated Sales (05/01/22 - 10/31/22)	8,907,030	
164 Direct Cost of Gas Rate		\$ 0.5036 per therm
165		
166 Demand Cost of Gas Rate	\$ 1,354,125	\$ 0.1520 per therm
167 Commodity Cost of Gas Rate	\$ 3,131,680	\$ 0.3516 per therm
168 Total Direct Cost of Gas Rate	\$ 4,485,805	\$ 0.5036 per therm
169		
170 Total Anticipated Indirect Cost of Gas	\$ 124,627	
171 Projected Prorated Sales (05/01/22 - 10/31/22)	8,907,030	
172 Indirect Cost of Gas		\$ 0.0140 per therm
173		
174		
175 TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22		\$ 0.5176 per therm

177 RESIDENTIAL COST OF GAS RATE - 05/01/22	COGwr	\$ 0.5176 per therm
178 Maximum (COG+25%)		\$ 0.6470

181 COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/22	COGwl	\$ 0.4740 per therm
182 Maximum (COG+25%)		\$ 0.5925

184 C&I HLF Demand Costs Allocated per SMBA	\$ 205,468
185 PLUS: Residential Demand Reallocation to C&I HLF	\$ 11,258
186 C&I HLF Total Adjusted Demand Costs	\$ 216,726
187 C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	1,996,958
188 Demand Cost of Gas Rate	\$ 0.1085
189	
190 C&I HLF Commodity Costs Allocated per SMBA	\$ 701,906
191 PLUS: Residential Commodity Reallocation to C&I HLF	\$ 64
192 C&I HLF Total Adjusted Commodity Costs	\$ 701,970
193 C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	1,996,958
194 Commodity Cost of Gas Rate	\$ 0.3515
195	
196 Indirect Cost of Gas	\$ 0.0140
197	
198 Total C&I HLF Cost of Gas Rate	\$ 0.4740

201 COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/22	COGwh	\$ 0.5445 per therm
202 Maximum (COG+25%)		\$ 0.6806

204 C&I LLF Demand Costs Allocated per SMBA	\$ 549,002
205 PLUS: Residential Demand Reallocation to C&I LLF	\$ 30,080
206 C&I LLF Total Adjusted Demand Costs	\$ 579,082
207 C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	3,236,934
208 Demand Cost of Gas Rate	\$ 0.1789
209	
210 C&I LLF Commodity Costs Allocated per SMBA	\$ 1,138,131
211 PLUS: Residential Commodity Reallocation to C&I LLF	\$ 104
212 C&I LLF Total Adjusted Commodity Costs	\$ 1,138,235
213 C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	3,236,934
214 Commodity Cost of Gas Rate	\$ 0.3516
215	
216 Indirect Cost of Gas	\$ 0.0140
217	
218 Total C&I LLF Cost of Gas Rate	\$ 0.5445

NORTHERN UTILITIES, INC.

156		
157	CALCULATION OF FIRM SALES COST OF GAS RATE	
158	Period Covered: May 1, 2022 - October 31, 2022	
159		
160	Column A	Column D
161		
162	Total Anticipated Direct Cost of Gas	LN 125
163	Projected Prorated Sales (05/01/22 - 10/31/22)	Attachment NUI-CAK-3, 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 (05/01/22 - 10/31/22)	Column B : LN 163
172	Indirect Cost of Gas	LN 170 / LN 171
173		
174		
175	TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22	LN 168 + LN 172
176		
177	RESIDENTIAL COST OF GAS RATE - 05/01/22	LN 175
178		LN 177 * 1.25
179		
180		
181	COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/22	LN 198
182		LN 181 * 1.25
183		
184	C&I HLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 170
185	PLUS: Residential Demand Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 16
186	C&I HLF Total Adjusted Demand Costs	Sum (LN 184 : LN 185)
187	C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	Attachment NUI-CAK-3, LN 14
188	Demand Cost of Gas Rate	LN 186 / LN 187
189		
190	C&I HLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 83
191	PLUS: Residential Commodity Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 26
192	C&I HLF Total Adjusted Commodity Costs	Sum (LN 190 : LN 191)
193	C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	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 - 05/01/22	LN 218
202		LN 201 * 1.25
203		
204	C&I LLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 171
205	PLUS: Residential Demand Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 17
206	C&I LLF Total Adjusted Demand Costs	Sum (LN 204 : LN 205)
207	C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	Attachment NUI-CAK-3, LN 15
208	Demand Cost of Gas Rate	LN 206 / LN 207
209		
210	C&I LLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 84
211	PLUS: Residential Commodity Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 27
212	C&I LLF Total Adjusted Commodity Costs	Sum (LN 210 : LN 211)
213	C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	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, 2021 - October 31, 2022

	Column A	Column B	Column C
219	<u>ANTICIPATED DIRECT COST OF GAS</u>		
220	Purchased Gas for Sales Service:		
221	Demand Costs:	\$ 5,509,774	
222	Supply Costs:	\$ 14,582,381	
223			
224	Storage & Peaking Gas for Sales Service:		
225	Demand, Capacity:	\$ 12,724,406	
226	Commodity Costs:	\$ 7,754,816	
227			
228	Inventory Finance Charge	\$ 1,378	
229			
230	Capacity Release	\$ (4,076,771)	
231			
232	Re-entry Rate & Conversion Rate Revenues	\$ (5,000)	
233			
234	Total Anticipated Direct Cost of Gas		\$ 36,490,984
235			
236	<u>ANTICIPATED INDIRECT COST OF GAS</u>		
237	Adjustments:		
238	Prior Period Under/(Over) Collection	\$ 237,004	
239	Interest	\$ (83,465)	
240	Refunds	\$ -	
241	<u>Interruptible Margins</u>	\$ -	
242	Total Adjustments		\$ 153,539
243			
244	Working Capital:		
245	Total Anticipated Direct Cost of Gas	\$ 36,490,984	
246	Working Capital Percentage	<u>0.0892%</u>	
247	Working Capital Allowance	\$ 32,557	
248			
249	Plus: Working Capital Reconciliation (Acct 173)	\$ (7,304)	
250			
251	Total Working Capital Allowance		\$ 25,253
252			
253	Bad Debt:		
254	Bad Debt Allowance	\$ 151,850	
255	Plus: Bad Debt Reconciliation (Acct 173)	\$ (77,564)	
256	Total Bad Debt Allowance		\$ 74,286
257			
258	Local Production and Storage Capacity		\$ 476,106
259			
260	Miscellaneous Overhead		\$ 580,455
261			
262	Total Anticipated Indirect Cost of Gas		\$ 1,309,638
263			
264	Total Cost of Gas		<u>\$ 37,800,622</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, 2021 - October 31, 2022

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)

[illegible]

Re-entry Rate & Conversion Rate
Volumes and Revenues

Month	Re-entry Surcharge		Conversion Surcharge	
	Volumes	Revenues	Volumes	Revenues
May-20	0	\$0	0	\$0
Jun-20	1,161	\$47	0	\$0
Jul-20	1,069	\$43	0	\$0
Aug-20	1,025	\$42	0	\$0
Sep-20	1,169	\$47	0	\$0
Oct-20	3,077	\$125	0	\$0
Nov-20	4,860	\$86	0	\$0
Dec-20	12,779	\$15	0	\$0
Jan-21	16,710	\$20	0	\$0
Feb-21	23,305	\$28	0	\$0
Mar-21	24,188	\$29	0	\$0
Apr-21	11,950	\$14	0	\$0
May-21	0	\$0		
Jun-21	529	\$1	0	\$0
Jul-21	866	\$1	0	\$0
Total	102,688	\$499	0	\$0