VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.80 per MMBtu** of Daily Imbalance Volumes

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

- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$17.27 per MMBtu** per MDPQ per month for November 2007 through April 2008.

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

III. Supplier Services and Associated Fees:

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

Issued: September 14, 2007
Effective: November 1, 2007

Issued by: *Stephen H. Bryant*
Title: President

Authorized by NHPUC Order No. in Docket No. DG 07- , dated

Calculation Steps for Supplier Balancing Charge

The Company has derived the Supplier Balancing Charge based on its daily dispatch activity for the twelve-month period May 1, 2000 through April 30, 2001.

The steps taken to calculate the balancing charge are as follows:

1. Actual Daily Sendout from Dispatch Center.

2. Base Load = July and August's Daily Sendout divided by 62 days.

3. Heating Load = Actual Sendout less Base Load.

4. Use per Degree Day ("UPDD") = Heating Load divided by Actual Effective Degree Days ("EDD").

5. Actual Swing = Actual EDD less Estimated EDD multiplied by UPDD.

6. Adjusted Swing = Actual Swing less 10% of Scheduled Deliveries.

7. % Allocated to Balancing for Firm Transportation ("FT") and Deliverability = Sum of Positive Swings divided by Total Withdrawals (November 2000 through April 2001).

8. % Allocated to Balancing for Space = Sum of Total Northern Utilities' Absolute Swings divided by Total Northern Utilities' Storage Capacity.

9. Billing Determinant = Sum of Absolute Value of All Swings plus 10% of Scheduled Deliveries on days of swings.

10. % Maximum Daily Quantity ("MDQ") = Maximum Swing divided by New Hampshire's MDQ (NH's MDQ is calculated by taking the total MDQ for Northern Utilities and multiplying by the Current Demand Allocator for NH).

11. Balancing Costs = % MDQ multiplied by NH's share of storage costs (NH's share of storage costs are calculated by taking total Northern Utilities' storage costs and multiplying by the Current Demand Allocator for NH).

12. Costs Allocated to Balancing = (a) FT (for storage) and Deliverability costs multiplied by the percentage derived per #7 above; or, (b) space/capacity costs multiplied by the percentage derived per #8 above.

Northern Utilities, Inc.-New Hampshire
Calculation of Balancing Charge

November 2007 through October 2008

	MDQ		Max Swing	% MDQ	
New Hampshire Underground	17,776		3,532	19.87%	
LNG	4,974		0	0.00%	
Propane	1,990		0	0.00%	

	% MDQ	Costs	Balancing Costs	% Allocated (to Balancing)	Allocated Costs
New Hampshire Underground					
Del., Res., and Transp.	19.87%	$6,579,391	$1,307,273	0.19%	$2,492
Capacity	19.87%	$1,580,618	$314,056	35.50%	$111,501
LNG	0.00%	$114,240	$0	138.63%	$0
Propane	0.00%	$124,831	$0	0.00%	$0
Total		$8,399,079	$1,621,329		$113,993
Annual Sum of Absolute Swings					142,624
Balancing Rate Per MMBtu Swing					**$0.80**

Northern Utilities, Inc.
Calculation of Balancing Charge
Allocation of Costs Between Balancing and Supply Functions

	Maximum Swing	Sum of Positive Swings	Total Utilization	Ratio Pos. Swings to Tot. Utilization	Sum of Absolute Swings	Total Capacity	Ratio Abs. Swings to Capacity
New Hampshire Underground	3,532	3,811	1,999,262	0.19%	36,518	146,796	24.88%
Maine Underground	7,580	1,635	2,020,164	0.08%	68,023	147,654	46.07%
Total Northern					104,540	294,450	**35.50%**
	Maximum Swing	Sum of Swings	Tank Capacity	Ratio Swings to Tank Capacity			
LNG	0	(26,271)	6,839	384.12%			
Propane	0	0	12,800	0.00%			

Northern Utilities, Inc.
Calculation of Balancing Charge
Costs of Balancing Resources
November 2007 through October 2008

New Hampshire			
El Paso FS Storage	MMBtu	Rate	Costs
Capacity	128,994	$0.0185	$28,637
Deliverability	2,110	$1.1500	$29,124
Firm Transportation-Tenn	1,320	$5.8900	$93,269
Firm Transportation-GSGT	1,320	$1.2639	$20,014
Total			$171,045
Texas Eastern Storage	MMBtu	Rate	Costs
Space - SS-1	731	$0.1293	$95
Reservation - SS-1	10	$5.4760	$686
Space - FSS-1	159	$0.1293	$247
Reservation - FSS-1	32	$0.8950	$342
TETCO Reservation	32	$5.6560	$2,161
Firm Transportation-GSGT	32	$1.2639	$483
Firm Transportation-GSGT	10	$1.2639	$158
Total			$4,172
MCN Storage	MMBtu	Rate	Costs
MCN	16,912	$ 18.3500	$ 1,551,639
PNGTS	9,948	$ 49.1229	$ 2,443,374
PNGTS	6,466	$ 49.1229	$ 1,588,193
CoEnergy/Trans Canada	16,414	$ 10.9287	$ 2,152,635
Firm Transportation-GSGT	16,414	$ 1.2639	$ 248,951
Total			$ 7,984,792
Maine			
El Paso FS Storage	MMBtu	Rate	Costs
Capacity	130,343	$0.0185	$28,936
Deliverability	2,133	$1.1500	$29,429
Firm Transportation-Tenn	1,333	$5.8900	$94,245
Firm Transportation-GSGT	1,333	$1.2639	$20,223
Total			$172,833
Texas Eastern Storage			
Space - SS-1	62	$0.1293	$8
Reservation - SS-1	11	$5.4880	$695
Space - FSS-1	161	$0.1293	$250
Reservation - FSS-1	32	$0.8950	$345
TETCO Reservation	32	$5.6560	$2,183
Firm Transportation-GSGT	32	$1.2639	$488
Firm Transportation-GSGT	11	$1.2639	$160
Total			$4,129
MCN Storage	MMBtu	Rate	Costs
MCN	17,088	$ 18.3500	$ 1,567,861
PNGTS	10,052	$ 49.1229	$ 2,468,918
PNGTS	6,534	$ 49.1229	$ 1,604,797
CoEnergy/TransCanada	16,586	$ 10.9287	$ 2,175,139
Firm Transportation-GSGT	16,586	$ 1.2639	$ 251,554
Total			$ 8,068,268
LNG	MMBtu		Costs
Capacity	10,000		$229,674
Total			$229,674
Propane	MMBtu		Costs
Capacity	4,000		$250,967
Total			$250,967

Northern Utilities, Inc.
Calculation on Balancing Charge

Derivation of Absolute Swings
May 2000 through April 2001
Summary

	Sum Positive Swings		Sum Negative Swings		Sum LP / LNG Swings		ABS all Swings		Total
	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	Ports-NH	Port-Maine	ABS Swings
May	1,060	1,484	8,125	1,162	0	0	9,185	2,646	11,832
June	0	28	1,213	5,553	0	0	1,213	5,582	6,794
July	1,125	0	0	0	0	0	1,125	0	1,125
Aug	45	0	99	1,027	0	0	145	1,027	1,172
Sept	0	0	301	11,279	0	0	301	11,279	11,580
Oct	1,196	123	2,821	26,853	0	0	4,017	26,976	30,993
Nov	384	0	3,976	7,620	(2,382)	(2,539)	1,978	5,081	7,059
Dec	0	0	7,956	12,177	0	0	7,956	12,177	20,133
Jan	0	0	1,873	174	(423)	(13,355)	1,450	(13,181)	(11,731)
Feb	0	0	2,807	542	(4,431)	(4,339)	(1,623)	(3,797)	(5,420)
March	0	0	1,048	0	(2,245)	(6,038)	(1,197)	(6,038)	(7,235)
April	0	0	2,487	0	0	0	2,487	0	2,487
Total	3,811	1,635	32,707	66,387	(9,481)	(26,271)	45,999	94,294	140,292
			add back 10% of the scheduled deliveries=				96,625	97,195	193,819
					Total ABS Swings =		**142,624**	**191,488**	334,112

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2007 through October 31, 2008.

Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	18.55%	36.87%
Storage:	32.25%	25.00%
Peaking:	49.20%	38.14%

Description of Calculation of Capacity Allocators

This brief report summarizes the method used to assign capacity costs to customers migrating from bundled sales to delivery service. The method is designed to be consistent with the gas cost allocation method implicit in the Company's CGFC. This method is the basis for the development of the figures shown on Appendix C, Capacity Allocators, set out in Appendix C of the Delivery Service Terms and Conditions.

Pursuant to the partial unbundling and redesigning of the Company's rates in Docket No. 97-393, the Company implemented a gas cost recovery method that recovered seasonal gas costs from all classes using the Market Based Allocation method (MBA). Under this method capacity costs are assigned to classes on the basis of their contribution to the system's design day load. The assignment is performed in two steps:

> Design Day Base Use - Base use is defined as that portion of the class's load that exists throughout the year, as measured by the average daily load in the warmest months. Pipeline supplies are used to satisfy the base use portion of each class's design day demand.
>
> Design Day Remaining Use – Remaining use is defined as the total class design day demand less that portion served by base use supplies. Remaining use is served by a combination of pipeline, storage and peaking supplies. Capacity costs for these supplies are allocated on the basis of design day demand less base use demand.

The following pages of this Attachment detail the development of capacity assignment allocators. Page 2 of 3 lists the major assumptions behind the calculations and tabulates the input data. Base use and remaining design day demand are shown by class. Beginning on line 27, the system pipeline capacity is assigned to the base use and remaining categories using the class base use load data above. Then on line 34, the residential allocation of supplies is performed. Since this class is assigned average costs, their assignment is simply computed as their proportion of the design day demand, irrespective of the supplies used to serve their loads.

Page 3 of 3 develops the allocation of capacity costs for the commercial and industrial (C&I) rates and summarizes the results of the allocation process. On lines 1 through 6 the supplies for the C&I classes are calculated by subtracting those supplies assigned to residential from the system totals. Then on lines 9 to 22 the C&I supplies are allocated to high and low load factor classes. In each case, base use pipeline supplies are allocated in proportion to class base use demand, while all other supplies are allocated on the basis of remaining design day demands. Unit costs for each class are summarized on lines 25 to 30. Lines 34 to 39 show the percentage of each supply necessary to serve class loads. Finally, lines 42 to 46 show the distribution of supplies among classes.

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2007-2008
<u>Derivation of Class Assignments and Weightings</u>

Basic assumptions:

1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
   a The base use portion of the class design day demand based on base use
   b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

		Design Day Demand. Th	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	2,200	218	0.4%	50	168
2	RATE B-Resi Htg	211,900	20,979	36.1%	1,010	19,969
3	RATE G-40 (R)	123,300	12,207	21.0%	280	11,927
4	RATE G-50 (Q)	9,700	960	1.7%	460	500
5	RATE G-41 (T)	111,700	11,059	19.0%	450	10,609
6	RATE G-51 (S)	21,400	2,119	3.6%	770	1,349
7	RATE G-42 (V)	16,700	1,653	2.8%	250	1,403
8	RATE G-52a (U)	19,800	1,960	3.4%	290	1,670
9	Special Contract	-	-	0.0%	-	-
10	RATE T-40	7,600	752	1.3%	20	732
11	RATE T-50	2,100	208	0.4%	10	198
12	RATE T-41	38,000	3,762	6.5%	160	3,602
13	RATE T-51	6,400	634	1.1%	120	514
14	RATE T-42	14,700	1,455	2.5%	60	1,395
15	RATE T-52	900	89	0.2%	30	59
16	Total	586,400	58,056	100.0%	3,960	54,096
17						-
18	Residential Total	214,100	21,197	**36.5%**	1,060	20,137
19	LLF Total	312,000	30,889	53.2%	1,220	29,669
20	HLF Total	60,300	5,970	10.3%	1,680	4,290
21	Total	586,400	58,056	100.0%	3,960	54,096
22						
23						

		Capacity Cost	MDQ, Dt	$/Dt-Mo.
24		Capacity Cost	MDQ, Dt	$/Dt-Mo.
25	Pipeline	2,659,880	12,440	17.82
26	Storage	8,283,970	18,061	38.22
27	Peaking	2,766,343	27,555	8.37
28	Total	13,710,193	58,056	19.68
29				
30				
31				
32		Capacity Cost	MDQ, Dt	$/Dt-Mo.
33	Pipeline - Baseload	846,698	3,960	17.82
34	Pipeline - Remaining	1,813,182	8,480	17.82
35	Storage	8,283,970	18,061	38.22
36	Peaking	2,766,343	27,555	8.37
37	Total	13,710,193	58,056	19.68
38				
39				

			Capacity Cost	MDQ, Dt	$/Dt-Mo.
40	Residential Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.
41	Pipeline - Base	**36.5%**	309,137	1,446	17.82
42	Pipeline - Remaining	**36.5%**	662,009	3,096	17.82
43	Storage	**36.5%**	3,024,553	6,594	38.22
44	Peaking	**36.5%**	1,010,017	10,061	8.37
45	Total	**36.5%**	5,005,717	21,197	19.68

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2007-2008
Derivation of Class Assignments and Weightings

1	C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
2	Pipeline - Base		537,561	2,514	17.82	
3	Pipeline - Remaining		1,151,173	5,384	17.82	
4	Storage		5,259,417	11,467	38.22	
5	Peaking		1,756,326	17,494	8.37	
6	Total	**63.5%**	8,704,476	36,859	19.68	
7						
8						
9	LLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
10	Pipeline - Base		226,146	1,058	17.82	
11	Pipeline - Remaining		1,005,749	4,704	17.82	
12	Storage		4,595,012	10,018	38.22	
13	Peaking		1,534,455	15,284	8.37	
14	Total	**53.7%**	7,361,363	31,064	**19.75**	
15						
16						
17	HLF - C&I Allocation		Capacity Cost	MDQ, Dt	$/Dt-Mo.	
18	Pipeline - Base		311,414	1,456	17.82	
19	Pipeline - Remaining		145,424	680	17.82	
20	Storage		664,405	1,449	38.22	
21	Peaking		221,871	2,210	8.37	
22	Total	**9.8%**	1,343,114	5,795	**19.31**	
23						
24						
25	Unit Cost		Residential	LLF C&I	HLF C&I	
26						
27	Pipeline		$ 17.82	$ 17.82	$ 17.82	
28	Storage		$ 38.22	$ 38.22	$ 38.22	
29	Peaking		$ 8.37	$ 8.37	$ 8.37	
30	Total		$ 19.68	$ 19.75	$ 19.31	
31	Checktotal		$ 19.68	$ 19.75	$ 19.31	
32						
33						
34	Load Makeup		Residential	**LLF C&I**	**HLF C&I**	
35						
36	Pipeline		21.43%	**18.55%**	**36.87%**	
37	Storage		31.11%	**32.25%**	**25.00%**	$234.000000
38	Peaking		47.46%	**49.20%**	**38.14%**	
39	Total		100.00%	**100.00%**	**100.00%**	
40						
41						
42	Supply Makeup		Residential	LLF C&I	HLF C&I	Total
43						
44	Pipeline		36.51%	46.31%	17.18%	100.00%
45	Storage		36.51%	55.47%	8.02%	100.00%
46	Peaking		36.51%	55.47%	8.02%	100.00%