Educational and Professional Experience

Mr. Wyatt has an educational background related to engineering, math and business studies, achieving an Associate in Engineering degree from New Hampshire Technical Institute and a Bachelor of Science undergraduate degree from Southern New Hampshire University (SNHU). It was during his time at SNHU that undergraduate degree requirements shifted more to business, where the emphasis was in accounting, finance, statistics and economics. He was accepted into an MBA graduate degree program at Southern New Hampshire University and completed one graduate course before withdrawing from the program to focus on his professional career.

Throughout his professional career, Mr. Wyatt has taken various professional development and computer software courses. In 2002 he completed professional development workshops for *Natural Gas Procurement and Hedging* and *The Basics, An Introductory Course on Rate Design* offered by the Center for Public Utilities at New Mexico State University. In 2004 Mr. Wyatt attended a two-day conference/workshop titled the *North American Natural Gas Supply Outlook* put together by EUCI (Electric Utility Consultants Inc.) in Denver. During the past ten years Mr. Wyatt has also attended several *The LDC Forum,* two-day conferences in Boston focusing on issues related to gas buyers and sellers.

In 1985, Mr. Wyatt worked for a two year period as a supervisor in the customer accounting department at EnergyNorth Natural Gas, Inc., a natural gas utility regulated by the New Hampshire Public Utilities Commission. It was in that supervisory position that he learned the intricacies of the customer assistance, meter reading, customer accounting, credit and billing functions of a regulated gas utility. He was also exposed to the conversion, employee training and implementation of the company's first customer information system. It was at this point in his career where he also became proficient at designing spreadsheets that he used as analytical tools.

In 1987, Mr. Wyatt transitioned briefly to a position as a gas dispatch supervisor in the gas supply department, a position in which he accepted as both a promotion and an opportunity to learn more about the operations functions of the company. In 1988, he was then promoted to a newly created gas supply analyst position for EnergyNorth.

Throughout his career, Mr. Wyatt has worked in various positions with a primary focus in the analyses of customer accounting, gas supply planning and end-use industrial energy budgeting and contracting. With 25 years of experience, including nearly 14 years working in the field of gas supply operations and planning. The position as a gas supply analyst provided Mr. Wyatt opportunities to learn and develop skills using a variety of forecast and statistical analysis software models to perform demand forecasting and analysis and least cost supply planning and analysis. In this position he also carried out supply related contract analysis, support functions for various state and federal regulatory filings and reporting plus other administrative and supervisory duties.

Beginning in 2000, Mr. Wyatt worked as an energy and raw materials analyst for Hitchiner Manufacturing Co., one of the largest natural gas and electric energy users in the State of New Hampshire at the time. While at Hitchiner his responsibilities included contracting for the company's natural gas requirements and energy consumption tracking, budgeting and analysis for its New Hampshire operations. He was a member of the company's energy efficiency committee which was tasked with finding ways to reduce the company's high energy consumption during a period of spiraling energy costs. While on that committee he worked with senior facilities engineers, process engineers and plant managers to learn the manufacturing processes that contributed to the company's high energy consumption. From that access he was able to develop a comprehensive energy consumption map summarizing usage and costs of all significant electric and gas powered equipment, by manufacturing process, for each of the company's facilities in New Hampshire. This analysis was then used by senior management in its long term strategic planning and decision making.

Since 2002, Mr. Wyatt has worked as a utility analyst for the New Hampshire Public Utilities Commission with a primary focus in matters related to the regulation of gas and steam utilities.

He is also responsible for the review of all cost of gas and cost of steam energy filings. He analyzes the utility filings, coordinates the discovery process, files testimony as needed and presents Staff's finding s to the Commission at hearings.

In 2006, Mr. Wyatt was the lead analyst in an investigation of thermal billing practices of one regulated gas utility in New Hampshire and discovered a seemingly insignificant change in billing methodology that resulted in the unauthorized over-billing of ratepayers. The discovery led to a significant refund to ratepayers and recognition from the Commission during public deliberations.

Attachment RJW-2

Cash Working Capital Requirements
12 Months Ended June 30, 2009

Notes: Non-Cash items removed from Staff calculation.
Interest on Customer Deposits excluded to be consistent with PMN calculation.

		Revenue Req Amount	Lead-Lag Days	Source	Weighted Amount
	A	B	C	D	E
1	**O&M Expense**				
3	Labor-Direct	$5,406,362	20.22	W/P Supporting pg 46, Ln 73	$109,316,640
4	Labor-Allocated	$4,575,008	65.21	See Note 2	$298,336,272
5	Employee Pensions & Benefits - Direct	$3,605,256	26.75	W/P Supporting pg 96, Ln 31	$96,440,598
6	Employee Pensions & Benefits - Allocated	$1,585,086	65.21	See Note 2	$103,363,458
8	Regulatory Commission Expense	$657,982	-89.00	W/P Supporting pg 120, Ln 5	-$58,560,398
9	Other O&M Expense - Direct	$3,410,580	34.50	W/P Supporting pg 121, Ln 27	$117,665,010
10	Other O&M Expense - Allocated	$4,194,137	65.21	See Note 2	$273,499,674
11	Total O&M Expense	$23,434,411			
12					
13	**Other Taxes**				
14	Other Taxes Excluding Property Taxes	$332,748	17.97	W/P Supporting pg 132, Ln 16	$5,979,482
15	Property Taxes	$4,457,169	-24.83	W/P Supporting pg 139, Ln 34	-$110,671,506
16	Total Other Taxes	$4,789,917			
17					
18	**Income Taxes**				
19	Federal Income Taxes	$3,687,983	30.00	W/P Supporting pg 172, Ln 13	$110,639,490
20	State Income Taxes	$928,128	30.00	W/P Supporting pg 173, Ln 13	$27,843,840
21	Total Income Taxes	$4,616,111			
22					
23	**Return**				
24	Interest on Long Term Debt	$5,898,313	91.25	W/P Supporting pg 174, Ln 5	$538,221,061
25	Interest on Short Term Debt	$344,791	45.66	W/P Supporting page 176	$15,743,157
26	Interest for Return	$0		Non-Cash Item	$0
27	Total Return	$6,243,104			
28					
29	**Total Delivery-Related Requirements**	$39,083,543	39.09	E29 / B29	$1,527,816,777
30	Revenue Lead Days		53.17	$8,738,385,241/$164,359,571	
31	Net Lag		14.08	C30 - C29	
32	Working Capital Percentage		3.8562%	C31 / 365 Days	
33	**Delivery Related Cash Working Capital**	**$1,507,149**		B29 x C32	
35	PMN-LL-2, page 1, line 44 column 5 result	$1,507,192			
36	Difference between Company & Staff	$43	0.003%		
38					
39	**Total Supply-Related Requirements**				
40	Purchased Gas	$112,156,611	38.89	W/P Supporting page 2	$4,361,770,602
41	Revenue Lead Days		53.17	$8,738,385,241/$164,359,571	
42	Net Lag		14.28	C30 - C29	
33	**Supply Related Cash Working Capital**	**$4,386,789**		B40 x (C42 / 365)	
35	PMN-LL-2, page 1, line 38 column 5 result	$4,385,813			
36	Difference between Company & Staff	-$976	-0.022%		

Table - 1
National Grid - New Hampshire
Marginal Cost Study

Production Investment Summary-Modified Peaker

Line No.	Description		Company Total	
	(1)		(2)	
	COST FOR REINFORCEMENT			
1				
2	Current Cost of Capacity Expansion	{1}	$1,596.52	
3				
4				
5				
6	First Year of Capacity Shortfall	{2}	2027	Adjusted
7				
8				
9	Base year of study		2008	
10				
11				
12	Years Before Additions	(6)-(9)	19	
13				
14	After Tax Cost of Capital	{3}	7.90%	
15	Inflation Rate	{6}	2.00%	
16			5.90%	
17				
18				
19	Present Worth of Capacity Cost			
20	(2)*[1+(15)]^(12)/[1+(14)]^(12)	{4}	$548.54	
21				
22	Percentage Related to Transportation	{5}	9.9%	
23				
24	**Transportation Related Investment**	(20)*(22)	**$54.39**	
25				
26	**Gas Supply Related Plant Investment**	(20)*[1-(22)]	**$494.15**	

NOTES:
1 Source: Table - 1, page 2.
2 Source: 2010 IRP Design Day Growth projected out to first year of resource shortfall
3 Source: Table - 8, page 1.
4 Cost in today's dollars sufficient to purchase the designated unit in the first year of capacity shortfall allowing for interest and price escalation.
5 Source: Table - 1, page 3.
6 Inflation Net of Technical Progress

Table - 1
National Grid - New Hampshire
Marginal Cost Study

Development of Marginal Production Plant Investment

Line No.	**Description**				**Costs**
	(1)				(2)
1	CONSTRUCTION OF PROPANE PROJECT ALTERNATIVE FACILITY				
2					
3	Addition of a New Facility:	{1}			
4	Storage Tanks				$8,340,000
5	Refrigeration Systems				1,970,000
6	Delivery Systems				4,010,000
7	Air Deliver Systems				2,560,000
8	Air Metering & Regulating (M&R) Station				1,370,000
9	Pipeline Connection to Project				1,000,000
10	Pipeline Connection from Project				2,500,000
11	Land Costs				3,520,000
12	Indirect Costs				5,950,000
13	Total Direct Costs				$31,220,000
14	KeySpan Overhead				6,650,000
15	Total Capital Costs				$37,870,000
16	O&M Costs				800,000
17	Total Project Costs				$38,670,000
18	Price escalation {2}	2.0%	2	years	4.0%
19					
20	Cost of Facility	(17)*[1+(18)]			$40,232,268
21					
22	Total Project Capacity	{1}			25,200
23					
24	Unit Cost of Expansion	(20)/(22)			$1,596.52
25					
26	Estimated Reserves for Supplemental Capacity	{3}			0%
27					
28	**Adj Cost of Production Capacity, $/Dt**	(24)*[1+(26)]			**$1,596.52**
29					
30	Percent Transportation-related	{4}			9.9% Adjusted
31					
32	Distribution related	(28)*(30)			$158.29
33	Production related	(28)-(32)			$1,438.23

NOTES:
1 Source: Prior Study
2 Escalation from 2006 to 2008
3 No allowance employed for planning purposes. Company plans for rating of the plant.
4 Table 1, page 3, line 20: Preassure support percentage of total production capacity

Table - 1
National Grid - New Hampshire
Marginal Cost Study

Development of Distribution-related Production Plant Investment

Line No.	Plant Name	Location	Type	Rating, mscfg	Heat Rate	Hours per Day	Design Day Dt
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Capacity of Down Stream Assets			{1}			
2							
3	38 Bridge St	Nashua	LP-Air	367	1,250	24	11,000
5	130 Elm St	Manchester	LP-Air	720	1,250	24	21,600
6	130 Elm St	Manchester	LNG	333	1,050	24	8,400
7	Broken Bridge	Concord	LNG	190	1,050	24	4,800
8	Tilton Plant	Tilton	LP-Air	67	1,250	24	2,000
9	Tilton Plant	Tilton	LNG	381	1,050	24	9,600
10	Total			2,058	1,162		57,400
11							
12	Production Requirements in lieu of Distribution investments						
13	Output Required for Pressure Support						
14							
15				{2}			
16	Tilton Plant	Tilton	LNG	271	1,050	20	5,691
17		Total		271			5,691
18							
19							
20	Production Allocated to Pressure Support Function				(17)/(10)	9.9%	
21							
22	Production Allocated to Supply Function				100%-(20)	90.1%	

NOTES:
1 Source: Company Distribution Engineering personnel.
2 Source: EN 2009 Data Source.xls - Stoner Pressure Support design hour
3 Stoner Pressure Support Design Hour x 20 Hours

This Table was revised in Staff DR 3-49.

Table - 4
National Grid - New Hampshire
Marginal Cost Study
Development of Capacity Related Production Expense

Line No.	Year	Total Capacity Related Expenses	Cost Index	Expense 2008 Dollars	Design Day Sendout, Dt	Average Cost per Design Day Dt
	(1)	(2)	(3)	(4)	(5)	(6)
		{1}				
1	1989	1,013,183	1.5605	$1,581,072	92,038	$17.18
2	1990	1,203,578	1.5025	1,808,401	94,799	19.08
3	1991	1,075,515	1.4511	1,560,651	95,896	16.27
4	1992	1,013,237	1.4175	1,436,238	98,274	14.61
5	1993	1,075,775	1.3868	1,491,892	101,510	14.70
6	1994	1,227,075	1.3582	1,666,619	102,395	16.28
7	1995	1,224,047	1.3305	1,628,563	105,007	15.51
8	1996	1,266,733	1.3056	1,653,876	107,684	15.36
9	1997	1,335,709	1.2830	1,713,669	112,869	15.18
10	1998	1,338,075	1.2686	1,697,536	119,052	14.26
11	1999	1,152,648	1.2502	1,441,095	120,233	11.99
12	2000	671,418	1.2238	821,654	128,617	6.39
13	2001	568,616	1.1967	680,475	124,000	5.49
14	2002	845,341	1.1777	995,522	122,483	8.13
15	2003	545,839	1.1528	629,266	116,027	5.42
16	2004	591,437	1.1210	663,014	128,044	5.18
17	2005	699,365	1.0848	758,688	136,000	5.58
18	2006	768,391	1.0506	807,272	138,746	5.82
19	2007	757,630	1.0214	773,817	142,000	5.45
20	2008	812,189	1.0000	812,189	146,900	5.53
21						
22						
23						
24	**REGRESSION RESULTS**				Expense (4)	Avg Cost (6)
25					vs Demand (5)	vs Year (1)
26	Slope =				-20.6132	-0.7965
27	Y Intercept =				3635171	1603
28	Coefficent of Determination (R**2)				61.13%	85.15%
29	t Value				(5.3)	(10.2)
30						
31	**MARGINAL COST ESTIMATES**					
32	Trended Cost Per Design Day Dt				($20.61)	
33	Time Series Predicted Avg Cost (2008*slope)+Intercept					$1.21
34						
35	Average Cost Per Design Day Dt					
36	1989-2008					$10.56
37	2000-2008					$5.87
38	2002-2008					$5.85
39	Current Average Cost per Design Day Dt					$5.53
40						
41	Assumed Marginal Cost			(35) {2}		$5.85
42						
43						
44	Percentage Related to Transportation				{3}	9.9%
45	Transportation Related Investment				(39)*(42)	$0.58
46	Gas Supply Related Investment				(39)*[1-(42)]	$5.27

NOTES:
1 Source: Booked maintenance and other expenses for Manufactured Gas, Accounts 1701, 1707, 1722, 1724 & 1725.
2 Post merger 2002-2008 average used for marginal cost.
3 Source: Table - 1, page 3.

Table - 7
National Grid - New Hampshire
Marginal Cost Study

Development of Miscellaneous Loading Factors

Line No.	Description		# #	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	Materials and Supplies and Prepayments Loader												
2	Materials and Supplies		[illegible]	3,171,473	3,759,164	6,009,797	9,804,208	10,148,000	9,443,673	9,397,268	10,278,497	10,579,101	10,889,994
3	Fuel Inventory (included above)		[illegible]	2,443,323	4,124,553	4,166,243	8,158,686	8,523,369	7,902,225	7,899,072	8,825,292	8,921,160	9,478,909
4	Prepayments		[illegible]	1,901,113	1,176,804	1,735,297	1,196,252	1,286,591	1,062,916	1,155,521	1,097,855	1,087,596	946,031
5	Fuel Related Prepayments		[illegible]	0	2,990	0	21,226	0	0	0	0	0	0
6	Total Utility Plant		[illegible]	90,119,090	95,467,319	106,202,255	113,423,806	118,656,821	124,120,897	129,472,654	135,806,318	146,866,629	156,424,246
7													
8	Non-Fuel Loader (2-3+4-5)/(6)	(1)	[illegible]	4.03%	2.42%	2.00%	2.54%	2.65%	2.10%	2.05%	1.80%	1.80%	1.50%
9	Average 2003 - 2008 = 0.13%												
10													
11													
12													
13	General Plant Loading Factor												
14	Total General Plant		[illegible]	5,933,583	6,503,724	6,849,445	7,659,250	7,970,207	8,364,746	8,221,795	8,878,155	9,203,222	9,478,301
15	Total Utility Plant		[illegible]	90,119,090	95,467,319	106,202,255	113,423,806	118,656,821	124,120,897	129,472,654	135,806,318	146,866,629	156,424,246
16													
17	Gen Plant Factor (14)/(15-14)	(1)	[illegible]	7.05%	7.00%	6.89%	7.21%	7.20%	7.24%	6.70%	6.99%	6.73%	6.45%
18	Average 2003 - 2008 = 4.78% (3)												
19													
20													
21													
22	Loss Factor												
23	Total Sendout		[illegible]	96,483,220	85,553,690	89,662,710	101,241,238	103,826,468	108,622,778	105,688,400	115,169,580	117,213,840	112,364,238
24	Total Sales		[illegible]	94,368,509	83,671,509	87,600,338	99,013,933	100,759,879	106,233,809	102,125,178	113,132,820	113,890,420	111,013,990
25													
26	Loss Factor (24)/(23)		[illegible]	97.80%	97.80%	97.80%	97.80%	97.80%	97.80%	97.57%	99.17%	97.17%	98.80%
27	Average 1989 - 2008= 97.54%												

Line No.	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	
1	Materials and Supplies and Prepayments Loader											
2	Materials and Supplies	10,988,064	8,252,716	9,726,073	6,879,583	12,264,675	14,721,037	18,472,896	20,753,378	17,891,289	21,471,774	
3	Fuel Inventory (included above)	9,482,667	7,191,792	8,926,722	6,141,837	12,252,987	14,714,963	18,472,896	20,753,378	17,891,289	21,471,774	
4	Prepayments	967,468	635,893	623,862	(349)	800	82,806	664,721	579,700	556,729	338,849	
5	Fuel Related Prepayments	0	0	0	0	0	0	0	0	0	0	
6	Total Utility Plant	166,482,099	174,018,261	189,363,169	202,252,941	227,692,187	239,474,276	242,115,491	263,405,595	288,967,870	298,931,540	
7												
8	Non-Fuel Loader (2-3+4-5)/(6)	1.40%	0.97%	0.75%	0.34%	0.05%	0.04%	0.19%	0.22%	0.20%	0.11%	
9	Average 2003 - 2008 = 0.13%											
10												
11												
12												
13	General Plant Loading Factor											
14	Total General Plant	11,244,509	7,255,965	8,348,042	11,173,887	11,582,178	10,899,392	10,220,862	11,333,343	12,889,178	15,897,759	(3)
15	Total Utility Plant	166,482,099	174,018,261	189,363,169	202,252,941	227,692,187	239,474,276	242,115,491	263,405,595	288,967,870	298,931,540	
16												
17	Gen Plant Factor (14)/(15-14)	7.23%	4.35%	4.61%	5.85%	5.36%	4.59%	4.41%	4.50%	4.50%	5.83%	
18	Average 2003 - 2008 = 4.78% (3)											
19												
20												
21												
22	Loss Factor											
23	Total Sendout	123,050,780	116,295,192	136,046,620	145,107,650	154,541,850	149,609,900	147,633,850	136,718,040	156,698,070	155,838,956	
24	Total Sales	116,256,180	114,313,111	133,840,578	139,804,882	152,009,238	144,710,278	143,418,868	136,709,736	148,740,142	150,190,486	
25												
26	Loss Factor (24)/(23)	94.40%	98.30%	98.30%	95.79%	98.40%	96.73%	97.14%	100.00%	94.93%	96.38%	
27	Average 1989 - 2008= 97.54%											

NOTES:
1 Used post merger data for Materials & Supplies and General Plant loading factors to eliminate effect of changes in accounting and recording overheads.
2 Loss factor has remained stable for entire study period.
3 Gen Plant loading factor changed as a result of DR Staff Tech 3-19 corrections to 2007 and 2008 Total General Plant amounts.

Table - 9
National Grid - New Hampshire
Marginal Cost Study

Summary of Marginal Capacity Costs

Line No.	Description	---- PRODUCTION ---- Supply Related	Transp. Related	----TRANS & DIST---- Mains Reinforce	Mains Extension	Total Dist	Total Prod & Dist
		(1)	(2)	(3)	(4)	(5)	(6)
	PLANT INVESTMENT						
1	Long-Run Unit Costs - $/Design Day Dt {1}	$494.15	$54.39	$226.85	$1,390.05	$1,616.90	$2,165.44
2	General Plant Loading Factor See DR Staff Tech 3-19	4.78%	4.78%	4.78%	4.78%		
3	Unit Costs + Loading Factor (1)+(1)*(2)	517.76	56.98	237.69	1,456.46	$1,694.15	$2,268.89
4							
5	Fixed Charge Rate	10.71%	10.71%	9.31%	9.31%		
6	A & G Exp Plant-Related Loading Factor	0.23%	0.23%	0.23%	0.23%		
7	Total Rate (5)+(6)	10.95%	10.95%	9.54%	9.54%		
8							
9	Annualized Cost (3)*(7)	$56.67	$6.24	$22.67	$138.94	$161.62	$224.52
10							
11	**OPERATING EXPENSES**						
12	Production capacity costs {2}	$5.27	$0.58				$5.85
13	Distribution capacity costs {3}			$0.00	$29.17	$29.17	$29.17
14	A&G Exp Non-Plant Loading Factor	63.40%	63.40%	63.40%	63.40%		
15	Total O&M Expense [(12)+(13)]*[1+(14)]	$8.61	$0.95	$0.00	$47.67	$47.67	$57.22
16							
17	**WORKING CAPITAL**						
18	Materials & Supplies + Prepayments Rate {4}	0.13%	0.13%	0.13%	0.13%		
19	M&S Cost (3)*(17)	0.66	0.07	0.30	1.85	$2.15	$2.88
20	Working Cash O&M Allowance {5} [(9)+(15)]*8.65%	5.65	0.62	1.96	16.14	$18.10	$24.37
21	Total Working Capital (19)+(20)	$6.30	$0.69	$2.26	$17.99	$20.26	$27.26
22							
23	Working Capital Rev. Req'd {6} (21)*13.18%	$0.83	$0.09	$0.30	$2.37	$2.67	$3.59
24							
25	System Seasonal Capacity Related Cost	{9}					
26	$/Design Day Dt (9)+(15)+(23)	$0.00	$7.28	$22.97	$188.98	$211.95	$219.23
27							
28	Loss Factor {7}	0.975	0.975	0.975	0.975	0.975	0.975
29	Inflation Adjustment {8}	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
30							
31	**Seasonal Capacity Cost (26)*[1+(28)]/(29)**	**$0.00**	**$7.93**	**$25.04**	**$206.02**	**$231.06**	**$238.99**

NOTES:

1 Sources: Production taken from Table - 1, Page 1. Distribution taken from Table - 2, page 1.
2 Source: Table - 4, page 2.
3 Source: Table - 5, page 1.
4 Source: Table - 7, page 2.
5 Working cash computed on the basis of previous study.
6 Revenue requirement for working cash computed as the after tax cost of capital, i.e. debt costs plus equity costs increased by taxes equals 13.18%.
7 Source: Table - 7 , page 2.
8 Inflation adjustment to restate marginal costs to rate year dollars.
9 Supply capacity costs set to zero since they are not applicable to delivery marginal costs.

Table - 11
National Grid - New Hampshire
Marginal Cost Study

Summary of Marginal Customer Costs

Line No.	Description	ResNonHt R-1	ResHt R-3&R-4	SmHiW G-41	SmLoW G-51	MdHiW G-42	MdLoW G-52	LgHiW G-43	LgLF<90 G-53	LgLF<110 G-54	LgLF>110 G-63
		--- Residential ---		--- Small C&I ---		--- Medium C&I ---		--- Large C&I ---			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	PLANT INVESTMENT										
1	Meters and Regulators {1}	$205.04	$205.04	$305.92	$305.92	$1,175.26	$1,175.26	$2,471.57	$2,471.57	$11,142.23	$11,142.23
2	General Plant Loading Factor {2} see DR Staff Tech 3-19	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%
3	Unit Costs + Loading Factor (1)+(1)*(2)	214.83	214.83	320.53	320.53	1,231.40	1,231.40	2,589.64	2,589.64	11,674.52	11,674.52
4	Fixed Charge Rate {3}	11.19%	11.19%	11.19%	11.19%	11.19%	11.19%	11.19%	11.19%	11.19%	11.19%
5	Meters Carrying Costs (3)*(4)	24.03	24.03	35.86	35.86	137.75	137.75	289.70	289.70	1,306.01	1,306.01
6	Services {1}	1,838.25	1,838.25	2,270.41	2,270.41	7,080.41	7,080.41	8,063.76	8,063.76	15,605.88	15,605.88
7	General Plant Loading Factor {2}	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%
8	Unit Costs + Loading Factor (6)+(6)*(7)	1,926.07	1,926.07	2,378.87	2,378.87	7,418.66	7,418.66	8,448.98	8,448.98	16,351.41	16,351.41
9	Fixed Charge Rate {3}	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
10	Services Carrying Costs (8)*(9)	185.08	185.08	228.60	228.60	712.89	712.89	811.90	811.90	1,571.28	1,571.28
11											
12	Total Plant Carrying Costs (5)+(10)	$209.12	$209.12	$264.45	$264.45	$850.65	$850.65	$1,101.60	$1,101.60	$2,877.29	$2,877.29
13											
14	A & G Exp Plant-Related Loading Factor {4}	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%
15											
16	Annualized Cost (100%+(14))*(12)	$209.60	$209.60	$265.07	$265.07	$852.62	$852.62	$1,104.16	$1,104.16	$2,883.98	$2,883.98
17											
18											
19	**OPERATING EXPENSES**										
20	Plant Related O&M $/Customer {5}	$29.29	$29.29	$36.93	$36.93	$118.33	$118.33	$151.00	$151.00	$383.38	$383.38
21	Customer Acctg & Mktg Expenses {6}	$40.88	$40.88	$40.88	$40.88	$40.88	$40.88	$40.88	$40.88	$40.88	$40.88
22	A&G Exp Non-Plant Loading Factor {4}	63.40%	63.40%	63.40%	63.40%	63.40%	63.40%	63.40%	63.40%	63.40%	63.40%
23	Total O&M Expense {20+21+[20+21]*22}	$114.65	$114.65	$127.14	$127.14	$260.14	$260.14	$313.53	$313.53	$693.22	$693.22
24											
25	**WORKING CAPITAL - $/Customer**										
26	Materials & Supplies + Prepayments Rate {3}	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%
27	M&S Cost [(3)+(8)]*(26)	2.72	2.72	3.43	3.43	11.00	11.00	14.03	14.03	35.63	35.63
28	Working Cash O&M Allowance {7} [(16)+(34)]*8.65%	28.05	28.05	33.93	33.93	96.25	96.25	122.63	122.63	309.43	309.43
29	Total Working Capital (27)+(28)	$30.77	$30.77	$37.36	$37.36	$107.25	$107.25	$136.66	$136.66	$345.06	$345.06
30	{8}										
31	Working Capital Rev. Requirement (29)* 13.18%	$4.05	$4.05	$4.92	$4.92	$14.13	$14.13	$18.01	$18.01	$45.47	$45.47
32											
33	Annual Customer Related Cost	$328.31	$328.31	$397.13	$397.13	$1,126.90	$1,126.90	$1,435.70	$1,435.70	$3,622.67	$3,622.67
34	$/Customer (16)+(23)+(31)										
35	Inflation Adjustment {9}	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
36											
37	**Annual Customer Related Cost (33)*[1+(35)]**	**$349.13**	**$349.13**	**$422.30**	**$422.30**	**$1,198.34**	**$1,198.34**	**$1,526.72**	**$1,526.72**	**$3,852.34**	**$3,852.34**

NOTES:

1 Meter investment from Table - 3, Page 1.
2 Source: Table - 7, page 2. See DR Staff Tech 3-19
3 Source: Table - 8, page 1.
4 Source: Table - 7, page 1.
5 Source: Table - 6, page 2.
6 Source: Table - 6, page 4.
7 Working cash computed on the basis of 31.57 days net lag.
8 Revenue requirement for working cash computed as tax rate divided by 1 minus tax rate multiplied by the cost of equity all added to the cost of capital.
9 Source: Price escalation to mid-point of rate year.

Table - 12
National Grid - New Hampshire
Marginal Cost Study

Attachment RJW-3
Page 8
Att. PMN-3, Page 35 of 38

Summary of Marginal Cost Estimates

Line No.	Description		Residential		Small C&I		Medium C&I		Large C&I					Total Company
			ResNonHt	ResHt	SmHiW	SmLoW	MdHiW	MdLoW	LgHiW	LgLF<90	LgLF<110	LgLF>110		
			R-1	R-3&R-4	G-41	G-51	G-42	G-52	G-43	G-53	G-54	G-63		
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)
1	**UNCOLLECTIBLE FACTOR Staff Adjustment to 0.0%**		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2														
3	**CUSTOMER CHARGE $'s per month**	{1}												
4	Customer Charge w/o Uncollectibles		$29.09	$29.09	$35.19	$35.19	$99.86	$99.86	$127.23	$127.23	$321.03	$321.03		
5	Adjustment for Uncollectibles	(1)*(4)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
6	Customer Charge Incl. Uncollectibles	(4)+(5)	$29.09	$29.09	$35.19	$35.19	$99.86	$99.86	$127.23	$127.23	$321.03	$321.03		
7														
8	**WINTER CHARGES**													
9	Gas Supply Demand Charge, Design Day, Dt	{3}	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
10	Delivery Demand Charge - Pressure Support	{2}	7.93	7.93	7.93	7.93	7.93	7.93	7.93	7.93	7.93	7.93		
11	Delivery Demand Charge - Reinforcements	{2}	25.04	25.04	25.04	25.04	25.04	25.04	25.04	25.04	25.04	25.04	Rev	
12	Delivery Demand Charge - Main Extensions	{2}	206.02	206.02	206.02	206.02	206.02	206.02	206.02	206.02	206.02	206.02		
13	Adjustment for Uncollectibles	[(9)+(10)+(11)+(12)]*(1)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
14	Winter Charges Incl. Uncollectibles	(13)+(14)	$238.99	$238.99	$238.99	$238.99	$238.99	$238.99	$238.99	$238.99	$238.99	$238.99	Rev	
15														
16	Supply Commodity Charge $'s per Dt	{3}	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
17	Adjustment for Uncollectibles	(1)*(16)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
18	Supply Commodity Charge Incl. Uncollectibles	(17)+(18)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
19														
20	**SUMMER CHARGES**													
21	Demand Charge $'s per Design Day Dt	{2}	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
22	Delivery Demand Charge		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
23	Adjustment for Uncollectibles	[(21)+(22)]*(1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
24	Summer Charges Incl. Uncollectibles		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
25														
26	Commodity Charge $'s per Dt	{3}	$0.00	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000		
27	Adjustment for Uncollectibles	(1)*(26)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
28	Commodity Charge Incl. Uncollectibles	(26)+(27)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
29														
30	**CALENDAR MONTH BILLING DETERMINANTS**	(2008)												
31	Customers		4,482	69,455	7,530	1,308	1,484	309	40	35	5	15		84,664
32	Design Day Dt -Sales & Transp		707	61,972	21,418	2,556	33,108	3,987	6,530	4,420	2,833	2,590		140,121
33	Winter Dt -Sales & Transp		694,780	45,906,857	15,717,608	2,454,019	24,799,619	4,155,286	5,702,562	5,254,414	3,411,445	4,382,964		112,479,555
34	Summer Dt -Sales & Transp		352,122	10,432,792	2,503,058	1,290,733	5,538,175	2,519,576	1,862,758	3,658,766	3,806,172	4,328,182		36,292,334
35														
36	**REVENUES RESULTING FROM FULL MARGINAL COST PRICING**													
37	Total Customer Related	(6)*(31)*12 Mos.	$1,564,937	$24,248,537	$3,179,849	$552,352	$1,778,068	$370,560	$61,149	$53,868	$20,610	$58,363		31,888,294
38														
39	Winter													
40	Winter Supply Capacity Cost	(1+(1))*(9)*(32)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
41	Winter Delivery Pressure Support	(1+(1))*(10)*(32	5,606	491,560	169,883	20,275	262,609	31,622	51,792	35,063	22,472	20,545	Rev	1,111,426
42	Winter Delivery Reinforcements	(1+(1))*(11)*(32	17,701	1,552,035	536,383	64,015	829,153	99,844	163,526	110,705	70,952	64,869		3,509,182
43	Winter Delivery Main Ext.	(1+(1))*(12)*(32	145,616	12,767,394	4,412,408	526,604	6,820,803	821,338	1,345,199	910,689	583,664	533,624		28,867,339
44	Winter Supply Commodity	(1+(1))*(16)*(33	0	0	0	0	0	0	0	0	0	0		0
45	Total Winter	(40)+(41)+(42)+(43)+(44)	$168,923	$14,810,988	$5,118,673	$610,894	$7,912,565	$952,804	$1,560,517	$1,056,457	$677,087	$619,038	Rev	$33,487,947
46														
47	Summer													
48	Summer Supply Demand	(1+(1))*(21)*(32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
49	Delivery Demand Charge	(1+(1))*(22)*(34	0	0	0	0	0	0	0	0	0	0		0
50	Summer Supply Commodity	(1+(1))*(26)*(34	0	0	0	0	0	0	0	0	0	0		0
51	Total Summer		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
52														
53	Customer Subtotal	(37)	1,564,937	24,248,537	3,179,849	552,352	1,778,068	370,560	61,149	53,868	20,610	58,363		$31,888,294
54	Supply Subtotal	(40)+(44)+(48)+(50)	0	0	0	0	0	0	0	0	0	0		0
55	Delivery Subtotal	(41)+(42)+(43)+(49)	168,923	14,810,988	5,118,673	610,894	7,912,565	952,804	1,560,517	1,056,457	677,087	619,038	Rev	33,487,947
56	**Total Marginal Annual Cost**		$1,733,861	$39,059,525	$8,298,522	$1,163,245	$9,690,633	$1,323,365	$1,621,666	$1,110,325	$697,697	$677,401	Rev	$65,376,241

NOTES:
1 Source: Table 11, page 1, line (37)/12
2 Source: Table - 9, page 1.
3 Source: Table - 10, page 1."These values are zeroed out so production capacity costs that are recovered through the Cost of Gas Factor are excluded from delivery marginal costs.

Table - 13
National Grid - New Hampshire
Marginal Cost Study

Marginal Unit Costs per Dt

Line No.	Description	ResNonHt R-1	ResHt R-3&R-4	SmHiW G-41	SmLoW G-51	MdHiW G-42	MdLoW G-52	LgHiW G-43	LgLF<90 G-53	LgLF<110 G-54	LgLF>110 G-63	Total Company
		-------- Residential --------		---------- Small C&I ----------		-------- Medium C&I --------		------------ Large C&I ------------				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	CUSTOMER CHARGE											
2	Customer Charge (w/ Uncoll) $'s per Month	$29.094	$29.094	$35.192	$35.192	$99.862	$99.862	$127.226	$127.226	$321.028	$321.028	
3												
4												
5	WINTER CHARGES (1)											
6	Winter Supply Capacity Cost	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
7	Winter Delivery Pressure Support Revised	$0.0081	$0.0107	$0.0108	$0.0083	$0.0106	$0.0076	$0.0091	$0.0067	$0.0066	$0.0047	
8	Winter Delivery Reinforcements	$0.0255	$0.0338	$0.0341	$0.0261	$0.0334	$0.0240	$0.0287	$0.0211	$0.0208	$0.0148	
9	Winter Delivery Main Ext.	$0.2096	$0.2781	$0.2807	$0.2146	$0.2750	$0.1977	$0.2359	$0.1733	$0.1711	$0.1217	
10	Winter Supply Commodity	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
11												
12												
13	SUMMER CHARGES (1)											
14	Supply Demand Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
15	Delivery Demand Charge	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
16	Commodity Charge $'s per Dt	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
17												
18	**TOTAL CHARGES**											
19	Supply Costs											
20	Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
21	Winter, $/Dt	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
22	Summer, $/Dt	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
23	Annual Avg. $/Dt	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
24												
25	Delivery											
26	Customer (2)	$29.09	$29.09	$35.19	$35.19	$99.86	$99.86	$127.23	$127.23	$321.03	$321.03	
27	Winter, $/Dt (7)+(8)+(9) Revised	$0.2431	$0.3226	$0.3257	$0.2489	$0.3191	$0.2293	$0.2737	$0.2011	$0.1985	$0.1412	
28	Summer, $/Dt (15)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
29	Annual Avg. $/Dt Revised	$0.1614	$0.2629	$0.2809	$0.1631	$0.2608	$0.1427	$0.2063	$0.1185	$0.0938	$0.0711	
30												
31	TEST YEAR CALENDAR MONTH BILLING DETERMINANTS - SALES and TRANSPORTATION LOADS (All Firm Loads)											
32	Customers	4,482	69,455	7,530	1,308	1,484	309	40	35	5	15	84,664
33	Design Day Dt	707	61,972	21,418	2,556	33,108	3,987	6,530	4,420	2,833	2,590	140,121
34	Winter Dt	694,780	45,906,857	15,717,608	2,454,019	24,799,619	4,155,286	5,702,562	5,254,414	3,411,445	4,382,964	112,479,555
35	Summer Dt	352,122	10,432,792	2,503,058	1,290,733	5,538,175	2,519,576	1,862,758	3,658,766	3,806,172	4,328,182	36,292,334
36	Total Annual Dt	1,046,902	56,339,649	18,220,666	3,744,752	30,337,794	6,674,862	7,565,321	8,913,180	7,217,618	8,711,146	148,771,890

NOTES:
1 Source: Table - 12 revenues divided by billing month normalized determinants.

Table - 14
National Grid - New Hampshire
Marginal Cost Study

Derivation of Marginal Prices Equi-Porportionately Constrained by Embedded Costs

Line No.	Description		Residential		Small C&I		Medium C&I		Large C&I				
			ResNonHt R-1	ResHt R-3&R-4	SmHiW G-41	SmLoW G-51	MdHiW G-42	MdLoW G-52	LgHiW G-43	LgLF<90 G-53	LgLF<110 G-54	LgLF>110 G-63	Total Company
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Estimated Delivery Revenue Reqm'ts	(1)											$55,611,421
2	Total Marginal Annual Revenue Requirements	(2)	1,733,861	39,059,525	8,298,522	1,163,245	9,690,633	1,323,365	1,621,666	1,110,325	697,697	677,401	65,376,241
3	Difference	(1) - (2)											(9,764,820)
4	% Difference	(3)/(2)											-14.94%
5	Equi-proportional Adjustment	(2) x (4)	(258,975)	(5,834,065)	(1,239,496)	(173,746)	(1,447,426)	(197,662)	(242,218)	(165,842)	(104,210)	(101,179)	(9,764,820)
6	Marginal Cost Constained to Allowed Revenues	(2) + (5)	1,474,886	33,225,461	7,059,027	989,499	8,243,207	1,125,702	1,379,448	944,483	593,487	576,222	55,611,421
7													
8	Marginal Unit Prices	Unit Costs from											
9	Customer	Table 14 X	$24.75	$24.75	$29.94	$29.94	$84.95	$84.95	$108.22	$108.22	$273.08	$273.08	
10		[1+ (4)]											
11	WINTER CHARGES												
12	Winter Supply Capacity Cost		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
13	Winter Delivery Pressure Support		$0.0069	$0.0091	$0.0092	$0.0070	$0.0090	$0.0065	$0.0077	$0.0057	$0.0056	$0.0040	
14	Winter Delivery Reinforcements		$0.0217	$0.0288	$0.0290	$0.0222	$0.0284	$0.0204	$0.0244	$0.0179	$0.0177	$0.0126	
15	Winter Delivery Main Ext.		$0.1783	$0.2366	$0.2388	$0.1825	$0.2340	$0.1681	$0.2007	$0.1474	$0.1455	$0.1036	
16	Winter Supply Commodity		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
17			$0.2068	$0.2744	$0.2770	$0.2118	$0.2714	$0.1951	$0.2328	$0.1710	$0.1688	$0.1201	
18													
19	SUMMER CHARGES												
20	Supply Demand Charge		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
21	Delivery Demand Charge		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
22	Commodity Charge $'s per Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
23			$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
24	TOTAL CHARGES												
25	Supply Costs												
26	Customer		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
27	Winter, $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
28	Summer, $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
29	Annual Avg. $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
30													
31													
32	Delivery												
33	Customer Charges		$24.75	$24.75	$29.94	$29.94	$84.95	$84.95	$108.22	$108.22	$273.08	$273.08	
34	Winter, $/Dt		$0.2068	$0.2744	$0.2770	$0.2118	$0.2714	$0.1951	$0.2328	$0.1710	$0.1688	$0.1201	
35	Summer, $/Dt		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
36	Annual Avg. $/Dt		$0.1373	$0.2236	$0.2390	$0.1388	$0.2219	$0.1214	$0.1755	$0.1008	$0.0798	$0.0604	
37	or												
38	Facilities Charge, $/Month	(6) / Annual bi	$ 27.42	$ 39.86	$ 78.12	$ 63.04	$ 462.96	$ 303.36	$ 2,870.06	$ 2,230.71	$ 9,244.33	$ 3,169.54	

Table - 14
National Grid - New Hampshire
Marginal Cost Study

Derivation of Marginal Prices Inverse Elasticty Constrained by Embedded Costs

Line No.	Description		Residential ResNonHt R-1	Residential ResHt R-3&R-4	Small C&I SmHiW G-41	Small C&I SmLoW G-51	Medium C&I MdHiW G-42	Medium C&I MdLoW G-52	Large C&I LgHiW G-43	Large C&I LgLF<90 G-53	Large C&I LgLF<110 G-54	Large C&I LgLF>110 G-63	Total Company
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	MARGINAL COSTS												
1	Marginal Customer Related Costs	{2}	$1,564,937	$24,248,537	$3,179,849	$552,352	$1,778,068	$370,560	$61,149	$53,868	$20,610	$58,363	$31,888,294
2	Total Marginal Annual Revenue Requirements	{2}	1,733,861	39,059,525	8,298,522	1,163,245	9,690,633	1,323,365	1,621,666	1,110,325	697,697	677,401	$65,376,241
3	Non-Customer Costs	(2)-(1)	$168,923	$24,248,537	$3,179,849	$552,352	$1,778,068	$370,560	$61,149	$53,868	$20,610	$58,363	$30,492,280
4													
5	RECONCILIATION												
6	Total Estiimated Delivery Revenue Requirments												55,611,421
7	Customer Cost Adjusted to Meet Rev Req'd	(6)-(3)											25,119,142
8	Constrained Customer Revenues	(1)*(7)/(1)	1,232,737	19,101,130	2,504,840	435,100	1,400,625	291,899	48,169	42,433	16,235	45,974	
9													
10	CUSTOMER CHARGE (If allowed to be negative)												
11	Average Number of Monthly Bills		4,482	69,455	7,530	1,308	1,484	309	40	35	5	15	84,664
12	Customer Charge (w/ Uncoll) $'s per Month	(8)/(11)/12	$22.92	$22.92	$27.72	$27.72	$78.66	$78.66	$100.22	$100.22	$252.88	$252.88	$24.72
13													
14	CUSTOMER CHARGE (If constrained to be non-negative)		NOT APPLICABLE										
15	Customer Charge (w/ Uncoll) $'s per Month		$22.92	$22.92	$27.72	$27.72	$78.66	$78.66	$100.22	$100.22	$252.88	$252.88	$24.72
16	Customer-Related Revenue	(11)*(15)*12 Months	$1,232,737	$19,101,130	$2,504,840	$435,100	$1,400,625	$291,899	$48,169	$42,433	$16,235	$45,974	$25,119,142
17	Adjmt to Winter Demand Charge	(8)-(16) (4)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
18	Adjmt to Winter Demand Chrg $/Dt												
19													
20	WINTER CHARGES (Adjusted for Non-negative Customer Charge)												
21	Winter Billing Units		694,780	45,906,857	15,717,608	2,454,019	24,799,619	4,155,286	5,702,562	5,254,414	3,411,445	4,382,964	112,479,555
22	Marginal Winter Demand Charge Revenues (Unadjusted)		0	0	0	0	0	0	0	0	0	0	0
23	Adjusted Winter Demand Revenue	(33)+(37)	0	0	0	0	0	0	0	0	0	0	0
24	Adjusted Winter Demand Rate	(38)/(36)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
	Commodity Charge	(18)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
	Total Winter	(39)+(40)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000

NOTES:
1 Source: Company's Accounting Cost Study
2 Source: Table - 12.
3 Source: Table - 13.
4 Assumes the Demand Charge is the second least elastic component of rates.

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**DG 10-017 MCS - Staff Peaker Adjustment**							**Revenue Requirement**				**Attachment RJW-4**	
2	**Propane Peakshaving Facility**							**30 Yr Analysis**				**Page 1**	
3						Assumptions							
4			Peaker Cost (Orig $)		$38,670,000	Match	Cost Estimate Year		2006				
5			Peaker Cost (Test Yr $)		$40,232,268	Match	Test Year		2008				
6			Peaker Cost in	2027	$58,610,818		Investment/In Service Year (Company)		2009				
7			Depreciable Basis		$58,610,818		Investment/In Service Year (Staff)		2027	2008	2009 PV		
8			Book Life		30		Unit Cost of Capacity Checks			$1,596.52	$1,509.22		
9			Capacity (Dth/d)		25,200		Present Worth (Invest Yr to Test Yr $/Dth)		$548.49				
10			Unit Cost/Dth in	2027	$2,325.83		After Tax Cost of Capital (Discount Rate)		7.90%				
11			Present Worth $/Dth	2027	$799.05		Depreciable Basis Adj		50.00%				
12			Net Inflation Rate		2.00%		Wtd Cost of Capital (Before Tax)		9.26%				
13			Inflation Rate		2.50%		Test Year to Invest/SvcYear		19		0.0375		
14			Technical Progress Adjustment		-0.50%		MACRS Life		20				
15			Price Escalation Years		2.00		Eff. Tax Rate (35% Federal, 7% State)		40.52%				
16	Revenue Requirements Analysis												
17			Rate Base	Rate Base	Rate Base	Return on	20 Yr Tax	Book	Tax Adj. Book	Deferred	Annual	PV	PV
18	Year		(BoY)	(EoY)	(Avg)	Rate Base	Depreciation	Depreciation Unadj	Depreciation	Tax	Rev Req	Factor	Rev Req
19													
20	19	2027	$58,610,818	$56,558,169	$57,584,493	$5,237,286	$2,197,906	$1,953,694	$1,953,694	$98,955	$7,190,980	0.235826	$1,695,824
21	20	2028	$56,558,169	$53,681,664	$55,119,917	$4,970,922	$4,231,115	$1,953,694	$1,953,694	$922,811	$6,924,616	0.218560	$1,513,446
22	21	2029	$53,681,664	$50,933,879	$52,307,772	$4,716,477	$3,913,444	$1,953,694	$1,953,694	$794,091	$6,670,171	0.202558	$1,351,097
23	22	2030	$50,933,879	$48,304,840	$49,619,360	$4,473,028	$3,620,390	$1,953,694	$1,953,694	$675,345	$6,426,722	0.187728	$1,206,473
24	23	2031	$48,304,840	$45,785,997	$47,045,418	$4,239,783	$3,348,436	$1,953,694	$1,953,694	$565,149	$6,193,477	0.173983	$1,077,560
25	24	2032	$45,785,997	$43,368,799	$44,577,398	$4,015,951	$3,097,582	$1,953,694	$1,953,694	$463,503	$5,969,645	0.161245	$962,573
26	25	2033	$43,368,799	$41,045,886	$42,207,343	$3,800,849	$2,864,897	$1,953,694	$1,953,694	$369,219	$5,754,543	0.149439	$859,953
27	26	2034	$41,045,886	$38,809,895	$39,927,890	$3,593,796	$2,650,381	$1,953,694	$1,953,694	$282,298	$5,547,490	0.138498	$768,314
28	27	2035	$38,809,895	$36,588,152	$37,699,023	$3,388,063	$2,615,215	$1,953,694	$1,953,694	$268,048	$5,341,757	0.128357	$685,654
29	28	2036	$36,588,152	$34,366,648	$35,477,400	$3,182,352	$2,614,629	$1,953,694	$1,953,694	$267,811	$5,136,045	0.118960	$610,982
30	29	2037	$34,366,648	$32,144,906	$33,255,777	$2,976,618	$2,615,215	$1,953,694	$1,953,694	$268,048	$4,930,312	0.110250	$543,566
31	30	2038	$32,144,906	$29,923,401	$31,034,153	$2,770,907	$2,614,629	$1,953,694	$1,953,694	$267,811	$4,724,601	0.102178	$482,749
32	31	2039	$29,923,401	$27,701,659	$28,812,530	$2,565,174	$2,615,215	$1,953,694	$1,953,694	$268,048	$4,518,868	0.094697	$427,922
33	32	2040	$27,701,659	$25,480,154	$26,590,907	$2,359,462	$2,614,629	$1,953,694	$1,953,694	$267,811	$4,313,156	0.087763	$378,538
34	33	2041	$25,480,154	$23,258,412	$24,369,283	$2,153,729	$2,615,215	$1,953,694	$1,953,694	$268,048	$4,107,423	0.081338	$334,089
35	34	2042	$23,258,412	$21,036,907	$22,147,660	$1,948,018	$2,614,629	$1,953,694	$1,953,694	$267,811	$3,901,712	0.075383	$294,121
36	35	2043	$21,036,907	$18,815,165	$19,926,036	$1,742,284	$2,615,215	$1,953,694	$1,953,694	$268,048	$3,695,978	0.069863	$258,213
37	36	2044	$18,815,165	$16,593,661	$17,704,413	$1,536,573	$2,614,629	$1,953,694	$1,953,694	$267,811	$3,490,267	0.064748	$225,989
38	37	2045	$16,593,661	$14,371,919	$15,482,790	$1,330,840	$2,615,215	$1,953,694	$1,953,694	$268,048	$3,284,534	0.060008	$197,097
39	38	2046	$14,371,919	$12,150,414	$13,261,166	$1,125,128	$2,614,629	$1,953,694	$1,953,694	$267,811	$3,078,822	0.055614	$171,226
40	39	2047	$12,150,414	$10,458,514	$11,304,464	$968,458	$1,307,607	$1,953,694	$1,953,694	($261,794)	$2,922,152	0.051542	$150,614
41	40	2048	$10,458,514	$9,296,457	$9,877,486	$860,852	$0	$1,953,694	$1,953,694	($791,637)	$2,814,546	0.047769	$134,447
42	41	2049	$9,296,457	$8,134,400	$8,715,429	$753,245	$0	$1,953,694	$1,953,694	($791,637)	$2,706,939	0.044271	$119,839
43	42	2050	$8,134,400	$6,972,343	$7,553,371	$645,639	$0	$1,953,694	$1,953,694	($791,637)	$2,599,333	0.041030	$106,650
44	43	2051	$6,972,343	$5,810,286	$6,391,314	$538,032	$0	$1,953,694	$1,953,694	($791,637)	$2,491,726	0.038026	$94,750
45	44	2052	$5,810,286	$4,648,229	$5,229,257	$430,426	$0	$1,953,694	$1,953,694	($791,637)	$2,384,120	0.035242	$84,020
46	45	2053	$4,648,229	$3,486,171	$4,067,200	$322,819	$0	$1,953,694	$1,953,694	($791,637)	$2,276,513	0.032661	$74,354
47	46	2054	$3,486,171	$2,324,114	$2,905,143	$215,213	$0	$1,953,694	$1,953,694	($791,637)	$2,168,907	0.030270	$65,653
48	47	2055	$2,324,114	$1,162,057	$1,743,086	$107,606	$0	$1,953,694	$1,953,694	($791,637)	$2,061,300	0.028054	$57,827
49	48	2056	$1,162,057	$0	$581,029	$0	$0	$1,953,694	$1,953,694	($791,637)	$1,953,694	0.026000	$50,796
50													
51						$66,969,533	$58,610,818	$58,610,818	$58,610,818	$0	$125,580,350		$14,984,338
52													
53													
54											Supply Related	Transp. Related	Total
55												Pressure Support	Peaker
56									Plant Capacity/Day				25,200
57									Allocation		90.1%	9.9%	100.0%
58									**Long Run Unit Cost/Dth**		**$535.75**	**$58.87**	$594.62

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
OCA's Data Requests – Set # 2

Date Received: June 18, 2010 | Date of Response: July 9, 2010
Request No.: OCA 2-7 | Witness: Paul M. Normand

REQUEST: Please provide the peak load forecast used to develop GLG-RD-3, page 6 in docket DG 08-009 and the peak load forecast used to develop PMN-3, page 6 in the instant docket.

RESPONSE: See Attachments OCA 2-7(a) and OCA 2-7(b). The peak load forecast used to develop GLG-RD-3, page 6 in docket DG 08-009, was based on Mr. Poe's 2007 Quarter 3 forecast. The peak load forecast used to develop PMN-3, page 6 in docket DG 10-017, was based on Mr. Poe's 2009 Quarter 3 forecast. Since both forecasts include only the usage associated with those customers who are assigned Company capacity, it was necessary to add to this forecast the usage associated with those transportation customers who are not assigned a portion of the Company's pipeline capacity. In addition, since the distribution reinforcement costs did not include any forecast for the Tilton line, the Company had to remove from both forecasts the load associated with Tilton.

UTILITY FORECAST
KEDNE-2008 Q3 5 Year DesignDay Forecast.xls

KED-NE 2007 Q3 Design Day Forecast

For All Customers Using Utility Capacity
('000 MMBtu/day)

Company	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**
Boston	910,600	921,200	932,000	944,200	955,500	966,000
Essex	75,500	76,400	77,300	78,500	79,800	80,800
Lowell	145,900	147,000	148,400	150,000	151,500	152,800
Cape	119,100	120,400	121,900	123,600	125,100	126,300
SubTotal MA	*1,251,100*	*1,265,000*	*1,279,600*	*1,296,300*	*1,311,900*	*1,325,900*
NH	138,500	142,700	146,900	150,900	154,800	158,400
TOTAL KED-NE	**1,389,600**	**1,407,700**	**1,426,500**	**1,447,200**	**1,466,700**	**1,484,300**

Note: Forecast received by Engineering on August 8, 2006

KED-NE 2008 Q3 Design Day Forecast

For All Customers Using Utility Capacity
('000 MMBtu/day)

Company	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**	**2012-2013**
Boston		933,109				
Essex		77,455				
Lowell		148,609				
Cape		122,934				
SubTotal MA	*0*	*1,282,107*	*0*	*0*	*0*	*0*
NH		145,100				
TOTAL KED-NE	**0**	**1,427,207**	**0**	**0**	**0**	**0**

Note: Forecast received by Engineering on August 21, 2008

Company	Prior Forecast Growth ı	Change from Prior Forecast	Annual Increase	% Change
Boston	1.2%	0.1%	1.3%	10.1%
Essex	1.2%	0.2%	1.4%	17.0%
Lowell	1.0%	0.1%	1.1%	14.8%
Cape	1.2%	0.8%	2.1%	68.1%
SubTotal MA	1.2%	0.2%	1.4%	17.0%
NH	2.9%	-1.2%	1.7%	-41.6%
TOTAL KED-NE	1.3%	0.0%	1.4%	3.7%

2009Q3 Comparison of ENGICustomer Requirements Forecasts
(MMBtu)

	2009Q3 Forecast								Avg PerAnnum Growth
Normal Year	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	
2009Q3 (v_tp)	#N/A	#N/A	12,871,013	12,721,418	12,706,443	12,872,348	13,079,927	13,255,312	0.59%
2008Q3	#N/A	12,936,501	13,246,148	13,463,079	13,854,423	14,206,555	#N/A	#N/A	2.37%
2007Q3	13,196,013	13,611,157	14,029,851	14,435,346	#N/A	#N/A	#N/A	#N/A	3.03%
DY Using NY Coeffs	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	
2009Q3 (v_tp)	#N/A	#N/A	13,642,758	13,484,936	13,469,137	13,644,166	13,863,162	14,048,194	0.59%
2008Q3	#N/A	13,705,671	14,030,913	14,258,716	14,669,656	15,039,238	#N/A	#N/A	2.35%
2007Q3	13,977,080	14,422,054	14,870,625	15,305,262	#N/A	#N/A	#N/A	#N/A	3.07%
DY Using DY Coeffs	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	
2009Q3 (v_tp)	#N/A	#N/A	15,561,472	15,403,622	15,387,820	15,562,880	15,781,913	15,966,977	0.52%
2008Q3	#N/A	15,236,179	15,561,472	15,789,302	16,200,242	16,569,823	#N/A	#N/A	2.12%
2007Q3	14,791,151	15,236,179	15,684,750	16,119,387	#N/A	#N/A	#N/A	#N/A	2.90%
DY Using Blended Coeffs	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	
2009Q3 (v_tp)	#N/A	#N/A	13,911,718	13,753,895	#N/A	#N/A	#N/A	#N/A	
2008Q3	#N/A	13,945,999	14,271,240	#N/A	#N/A	#N/A	#N/A	#N/A	
2007Q3	14,464,055	14,844,912	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	
DD Using NY Coeffs	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	
2009Q3 (v_tp)	#N/A	#N/A	111,466	110,402	110,296	111,475	112,952	114,199	0.49%
2008Q3	#N/A	128,893	131,319	133,012	136,061	138,785	#N/A	#N/A	1.87%
2007Q3	130,665	134,816	138,976	143,025	#N/A	#N/A	#N/A	#N/A	3.06%
DD Using DY Coeffs	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	
2009Q3 (v_tp)	#N/A	#N/A	145,125	143,883	143,758	145,136	146,860	148,316	0.44%
2008Q3	#N/A	142,699	145,125	146,818	149,867	152,591	#N/A	#N/A	1.69%
2007Q3	138,548	142,699	146,859	150,908	#N/A	#N/A	#N/A	#N/A	2.89%

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 11, 2010 | Date of Response: June 1, 2010
Request No.: Staff 1-171 | Witness: Paul M. Normand

REQUEST: Ref. Attachment PMN-3, page 11 of 38, Table 4.

a. Explain why design day sendout in this Table is not consistent with what is used in the analysis in Table 2, on pages 7 and 8 of 38 or in Table 5, on page 12 of 38. If this is in error, please recalculate where appropriate.

b. Lines 19 and 20 reflect equal capacity related expenses for 2007 and 2008. Is the 2008 expense an estimate?

c. Line 33 describes the time series predicted average cost as (2008 * slope) + intercept, which does not seem to calculate. Show how the figure ($2.72) was derived.

d. What percentage of expenses booked to Accounts 1707, 1722, 1724 and 1725 are currently collected through the COG rate?

e. What percentage of the investment cost in LNG and LP-Air facilities is currently collected through the COG rate?

f. What percentage of O&M expenses associated with LNG and LP-Air facilities is currently collected through the COG rate?

RESPONSE: :a. The analysis in Table 4 originally used the primary estimate of design day demand, the estimate made in that year. However, when the regression was weak, an alternate measure of design day demand was evaluated, the prior year's estimate of the current year's design day. However, as shown on this table, the alternate analysis was also statistically invalid. While the time series regression showed promise, a discussion with ENGI staff revealed that some manufactured gas plants were retired over the period of analysis making the data internally inconsistent. Consequently, the regressions were ignored and a current average cost was used to estimate future unit costs.

b. This is a cell reference error and will be corrected in the next version of the MCS.

c. The value was shown for the rate year on line 33 computed as (2011*slope + intercept). The calculation should be (test year * slope + intercept). Even though this figure is not used in the computation of marginal costs, it will be corrected in the next version of the MCS.

d. For account 1707, 87.6% is collected through the COG rate. For account 1722, 81.2% is booked in the COG rate. The other two accounts--1724 and 1725--have a zero balance.

e. In the last rate case, 12.4% of the manufactured gas plant-related costs were assigned to the distribution function, since they were used to provide pressure support. Consequently, 87.6% of the test year manufactured gas costs were included for recovery in the COG.

f. 30% is currently collected through the COG rate.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 11, 2010 | Date of Response: June 2, 2010
Request No.: Staff 1-183 | Witness: Paul M. Normand

REQUEST: Ref. Attachment PMN-3, Table 1 and PMN-5, page 15-16 of 27. Section PMN-5 discusses the peaker method used in Table 1 of the marginal cost study on distribution-related production plant investment.

a. What were the other specific alternatives analyzed in this study?

b. Please provide support for the statement in PMN-5 that the peaker method identifies the least capital intensive capacity source that can be added to the Company's resources to meet peaks of short duration.

c. Does Mr. Normand believe it is necessary that the peaker analysis must pass a reasonableness standard where only operationally viable options are considered for the distribution system in need of the new capacity resources?

RESPONSE: a. There were none as we only considered the peaker analysis as explained on page 15 of Attachment PMN-5 for the on-system supply for the delivery system.

b. This statement refers to on-system capability as explained on page 15 of Attachment PMN-5. The Tilton plant was considered as the economic alternative for capacity expansion.

c. Yes. The Tilton plant estimate was considered as an operationally viable alternative for on-system peaking supply for the Company's delivery system.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Data Requests – Set #3

Date Received: August 24, 2010
Request No.: Staff 3-49

Date of Response: September 14, 2010
Witness: Paul Normand

REQUEST: Reference Table 4, page 2, column 2, line 19 or 20.
Response to Staff 1-171 b notes a cell reference error that will be corrected in the revised MCS. Please provide the corrected values and include the correction(s) in the updated the MCS.

RESPONSE: See Attachment Staff 3-49. While making the correction another cell reference error was noticed in column 2. The error was from the years 2002 to the present. The attached file has these corrections included.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Technical Session Data Requests – Set # 3

Date Received: September 22, 2010 | Date of Response: October 1, 2010
Request No.: Staff Tech 3-19 | Witness: Paul Normand

REQUEST: Re. MCS Table 7, page 2 of 2, line 14. Response Staff 1-176 notes Total General Plant expenses for 2007 and 2008 will be corrected. This was still an issue at the last tech session.

a. What are the Total General Plant correct expense figures for 2007 and 2008?

b. What was the impact on the General Plant loading factor when the correct figures were inserted into the spreadsheet?

c. Was there any impact on the other loading factors in Table 7 as a result of this correction?

RESPONSE: a. The Total General Plant figures should be $12,089,175 for 2007, and $15,097,759 for 2008.

b. The result is a decrease in the 2007 percentage from 8.94% to 4.5%, and a decrease in the 2008 percentage from 9.7% to 5.32%. This change decreases the 2003-2008 average from 6.25% to 4.78%.

c. There was no impact on any other loading factors in Table 7.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-017

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 11, 2010
Request No.: Staff 1-185

Date of Response: June 1, 2010
Witness: Paul M. Normand

REQUEST: Provide a table that shows the forecast design day demand requirement for the Tilton distribution system over the next ten years. Include the natural gas pipeline design day capacity available from the Company's Tilton high line at the Tilton plant.

RESPONSE: The following table reflects the projected design day requirements for the Tilton distribution system over the next ten years as identified by Gas Reliability Planning based on the August 2009 design day forecast.

Forecast Winter Period	Calculated Design Day Demand Through High Line (Dth/day)	Calculated Design Day Tilton Plant Demand (Dth/day)	Total Projected Design Day Demand for Tilton System (Dth/day)
2010-11	4,920	5,680	10,600
2011-12	4,920	5,820	10,740
2012-13	4,920	6,020	10,940
2013-14	4,920	6,180	11,100
2014-15	4,920	6,340	11,260
2019-20	4,920	7,140	12,060

Notes:

1. Calculated based on peak hour model (assumed 5% of total design day sendout) converted to an equivalent daily sendout.
2. Forecast analysis for the 6-10 year period is based on the growth in the forecast from year 4 to year 5.