
Division 2-1

Request:

Re: witness Nutile's Direct Testimony page 22 of 23, please provide monthly forecasted and actual throughput for each of the previous five years.

Response:

Attachment DIV 2-1 provides the actual and forecast throughput per rate class for each of the previous five years.

Prepared by or under the supervision of: Suhila Nouri Nutile

Actual Throughput

Line No.													
1	Total THROUGHPUT	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total Nov-Oct
2	Residential Non-Heating	40,798	63,453	80,291	77,880	71,380	60,827	42,710	35,440	29,795	25,513	28,158	28,795	585,039
3	Residential Non-Heating Low Income	1,398	2,777	3,680	3,784	3,139	2,654	1,609	945	705	596	638	667	22,592
4	Residential Heating	920,353	2,013,046	2,959,905	3,016,557	2,557,241	1,843,901	913,059	514,509	367,950	338,829	351,381	377,486	16,174,218
5	Residential Heating Low Income	104,771	205,482	294,768	304,459	263,112	220,131	115,189	71,759	51,639	42,811	45,777	48,508	1,768,404
6	Small C&I	115,197	292,499	487,812	495,049	407,231	275,546	123,393	68,788	54,697	46,827	46,018	47,648	2,460,705
7	Medium C&I	322,479	626,850	873,151	899,816	786,557	554,864	318,922	208,954	189,986	121,538	166,023	195,868	5,265,007
8	Large LLF	176,764	367,168	455,172	487,722	389,060	282,755	125,613	58,087	41,662	42,566	44,577	69,654	2,540,801
9	Large HLF	81,749	116,825	127,494	113,623	120,363	95,529	73,082	64,285	56,843	60,854	59,935	60,163	1,030,743
10	Extra Large LLF	90,335	184,501	173,230	177,020	139,442	117,347	52,426	16,660	15,713	18,268	21,217	46,703	1,052,861
11	Extra Large HLF	419,788	530,783	536,003	517,936	496,568	443,910	379,698	390,642	352,576	395,175	369,575	370,086	5,202,740
12	Default	6,488	8,866	9,625	7,820	7,946	6,143	3,930	1,961	4,023	1,378	1,818	2,170	62,168
13	Total Throughput	2,280,120	4,412,249	6,001,130	6,101,665	5,242,037	3,903,607	2,149,631	1,432,031	1,165,590	1,094,353	1,135,116	1,247,749	36,165,279

Source: GCR Deferred Filed Oct 11 -Docket No. 4199

14	Total THROUGHPUT	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total Nov-Oct
15	Residential Non-Heating	44,902	58,419	74,486	80,015	74,243	58,071	44,656	34,394	28,068	26,163	26,022	30,065	579,502
16	Residential Non-Heating Low Income	1,359	1,937	2,622	2,598	2,895	1,917	1,163	778	656	736	661	872	18,195
17	Residential Heating	960,000	1,459,048	2,163,628	2,410,188	2,120,996	1,370,734	837,999	497,026	368,362	341,313	331,780	434,145	13,295,220
18	Residential Heating Low Income	114,787	155,722	228,341	228,599	220,671	142,168	85,332	55,790	41,653	39,722	37,547	48,823	1,399,154
19	Small C&I	122,071	197,162	331,804	365,172	314,636	190,004	104,113	55,623	47,044	43,411	37,395	47,403	1,855,837
20	Medium C&I	354,746	479,700	662,670	792,433	628,082	468,331	262,106	144,216	174,869	152,213	151,656	200,672	4,471,693
21	Large LLF	209,947	279,896	367,039	494,826	347,270	217,441	111,848	64,048	28,500	38,057	41,427	64,497	2,264,794
22	Large HLF	79,582	84,517	95,169	108,139	95,733	77,086	64,492	62,286	53,390	47,435	67,858	67,115	902,801
23	Extra Large LLF	120,944	120,883	133,177	211,833	153,086	86,165	60,302	20,222	5,670	15,557	13,889	25,817	967,546
24	Extra Large HLF	431,555	445,798	463,288	581,948	472,111	422,375	376,980	375,871	380,328	379,943	410,312	363,453	5,103,962
25	Default	4,486	5,240	5,962	9,219	5,189	4,187	11,286	(4,444)	1,056	1,283	1,076	1,687	46,227
26	Total Throughput	2,444,380	3,288,323	4,528,185	5,284,970	4,434,912	3,038,478	1,960,277	1,305,809	1,129,595	1,085,833	1,119,620	1,284,548	30,904,930

Source: GCR Deferred Filed Oct 12 - Docket No. 4283

27	Total THROUGHPUT	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total Nov-Oct
28	Residential Non-Heating	45,986	78,983	98,907	109,290	100,574	85,531	54,040	36,130	28,862	27101.5	27610.2	30903.9	723,920
29	Residential Non-Heating Low Income	1,703	3,229	4,277	4,875	3,978	2,925	1,352	914	865	851.2	903.3	1087.6	26,961
30	Residential Heating	902,551	1,903,463	2,537,878	2,912,936	2,519,777	1,994,126	1,004,359	517,766	368,525	351754.2	355842.8	413994.1	15,782,971
31	Residential Heating Low Income	94,997	190,048	248,229	279,036	237,030	188,891	94,414	52,160	41,890	40616.8	40489.1	45534.6	1,553,337
32	Small C&I	106,317	269,726	399,055	480,777	383,824	278,735	128,656	49,170	40,658	44578.6	35651.1	49094.1	2,266,242
33	Medium C&I	290,265	651,514	762,706	903,074	782,902	588,764	325,217	187,113	158,376	162880.9	161806.7	196052.9	5,170,670
34	Large LLF	165,962	443,134	393,008	524,921	397,466	366,696	121,469	39,332	25,608	38823.8	45302.6	78374.5	2,640,097
35	Large HLF	79,960	115,555	121,058	134,042	113,580	113,111	69,178	68,502	71,204	63883.2	84826.5	84959.5	1,119,859
36	Extra Large LLF	95,882	201,014	187,246	316,328	97,718	300,780	(64,639)	(226)	(10,571)	12440.6	39524.5	40905.4	1,216,404
37	Extra Large HLF	437,237	550,319	518,236	633,997	460,632	561,744	351,363	281,695	477,302	397396.1	400826.2	365361.6	5,436,109
38	Default	1,820	8,109	7,008	9,834	5,832	6,429	1,890	(1,714)	1,457	1242	946.3	1264.5	44,117
39	Total Throughput	2,222,680	4,415,092	5,277,609	6,309,110	5,103,315	4,487,733	2,087,298	1,230,842	1,204,176	1,141,569	1,193,729	1,307,533	35,980,686

Source: GCR Deferred Filed Oct 13 for Nov 12 through Mar 13, GCR Annual Reconciliation Filing Filed July 14 for Apr through Oct 13- Docket No. 4346

Actual Throughput

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total Nov-Oct
40 Total THROUGHPUT													
41 Residential Non-Heating	52,939	103,262	141,802	141,832	138,940	103,094	65,116	37,167	29,077	27,531	27,601	33,761	902,122
42 Residential Non-Heating Low Income	2,401	5,198	6,878	6,529	6,217	4,678	3,213	1,508	1,202	1,113	1,130	1,382	41,448
43 Residential Heating	969,814	2,219,000	3,163,797	3,145,750	3,050,687	2,122,865	1,108,093	513,737	372,360	344,157	355,647	438,073	17,803,980
44 Residential Heating Low Income	99,566	219,809	302,587	289,373	283,752	210,481	123,623	57,730	44,605	41,177	41,359	48,984	1,763,045
45 Small C&I	115,595	324,268	517,511	521,961	496,004	313,467	141,840	58,923	44,241	41,469	43,864	56,088	2,675,230
46 Medium C&I	339,084	715,690	978,145	985,947	945,350	673,391	379,559	177,424	163,633	153,996	164,338	186,323	5,862,879
47 Large LLF	196,886	428,144	556,305	592,564	504,099	398,954	144,352	31,578	26,751	73,631	42,013	65,634	3,060,911
48 Large HLF	101,997	101,893	109,799	211,968	120,561	88,497	87,495	78,183	70,014	92,182	76,632	76,920	1,216,140
49 Extra Large LLF	106,115	238,139	242,187	250,714	181,749	191,500	37,882	1,542	(14,385)	18,428	18,660	26,186	1,298,718
50 Extra Large HLF	436,198	535,096	614,901	643,699	507,630	575,138	321,206	401,607	367,134	353,663	305,353	636,093	5,697,718
51 Default	2,475	7,881	7,468	49,428	3,273	65,503	(12,974)	71,604	(37,929)	1,961	646	79,279	238,615
52 Total Throughput	2,423,071	4,898,381	6,641,379	6,839,764	6,238,261	4,747,568	2,399,405	1,431,004	1,066,704	1,149,307	1,077,241	1,648,721	40,560,805

Source: GCR Deferred Filed October 14 - Docket No. 4436 (Note Nov 13 Total Throughput should have been 2,423,071 dth as reported in GCR Annual Reconciliation Filing Filed July 14.)

	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Total Nov-Oct
53 Total THROUGHPUT													
54 Residential Non-Heating	56,635	74,913	97,349	123,153	116,760	83,622	45,364	29,503	23,827				651,126
55 Residential Non-Heating Low Income	2,753	2,976	4,006	4,900	4,353	4,329	2,015	1,051	787				27,171
56 Residential Heating	954,909	2,132,202	2,877,504	3,747,011	3,449,650	2,298,799	1,005,002	502,341	400,977				17,368,393
57 Residential Heating Low Income	100,792	213,885	282,745	352,717	318,259	247,469	109,620	61,630	49,907				1,737,024
58 Small C&I	115,678	298,227	449,062	615,104	566,582	347,154	129,362	60,737	49,071				2,630,976
59 Medium C&I	357,629	677,643	900,081	1,127,548	1,064,830	714,720	337,898	192,267	165,473				5,538,090
60 Large LLF	199,207	424,741	519,005	653,341	564,137	314,850	145,774	77,015	40,575				2,938,645
61 Large HLF	94,200	88,389	140,338	147,390	155,847	129,368	76,319	84,416	70,262				986,528
62 Extra Large LLF	100,645	232,842	218,020	304,505	180,842	132,536	40,220	57,165	6,765				1,273,539
63 Extra Large HLF	248,997	703,937	611,829	1,190,838	276,281	660,386	405,351	464,398	475,385				5,037,401
64 Default	19,277	5,635	11,253	12,896	13,353	7,386	195	261	835				71,090
65 Total Throughput	2,250,721	4,855,391	6,111,192	8,279,403	6,710,893	4,940,618	2,297,118	1,530,785	1,283,863				38,259,983

Source: GCR Deferred Filed July 14 - Docket No. 4520

Forecasted Throughput

Line No.														
1	Total THROUGHPUT	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total Nov-Oct
2	Residential Non-Heating	54,674	70,653	82,003	87,827	78,867	70,493	60,870	46,251	39,370	33,934	33,888	39,380	698,210
3	Residential Heating	1,104,878	2,046,100	2,750,982	2,917,818	2,636,773	1,990,787	1,114,772	639,475	404,535	324,025	378,664	506,454	16,815,263
4	Small C&I	117,722	232,014	356,367	380,345	326,862	224,723	116,333	61,244	58,320	40,721	20,031	51,998	1,986,681
5	Medium C&I	360,318	470,932	716,407	756,775	662,446	445,309	294,061	202,007	149,943	139,727	129,491	186,498	4,513,915
6	Large LLF	174,826	311,925	394,697	409,350	378,527	288,000	136,863	72,453	36,018	37,131	30,799	77,599	2,348,189
7	Large HLF	78,177	96,473	108,659	99,221	103,174	98,094	69,605	66,704	48,898	58,178	66,847	73,523	967,552
8	Extra Large LLF	64,465	102,715	174,056	145,431	118,617	84,095	34,091	47,628	9,099	16,197	(1,106)	30,327	825,615
9	Extra Large HLF	313,556	354,899	390,788	385,607	382,070	389,009	287,285	282,978	263,168	272,408	311,008	295,370	3,928,147
10	Total Throughput	2,268,616	3,685,711	4,973,960	5,182,373	4,687,337	3,590,511	2,113,880	1,418,739	1,009,352	922,322	969,622	1,261,149	32,083,572

Source: GCR Filing Docket No. 4199

11	Total THROUGHPUT	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Total Nov-Oct
12	Residential Non-Heating	48,787	57,359	74,908	72,427	62,047	52,923	43,928	35,764	31,804	28,744	28,529	35,143	572,364
13	Residential Heating	1,028,594	2,284,131	3,445,597	3,365,922	2,511,707	1,705,118	1,081,596	473,491	422,847	362,367	345,116	409,966	17,436,451
14	Small C&I	154,145	306,277	491,295	478,896	407,036	252,709	122,112	47,649	42,243	34,558	49,280	80,503	2,466,704
15	Medium C&I	384,835	683,624	1,039,674	972,492	798,012	420,268	243,494	106,097	128,572	80,628	134,162	213,538	5,205,395
16	Large LLF	226,330	411,067	548,439	496,664	444,434	326,807	120,419	62,590	20,845	19,091	34,149	94,057	2,804,893
17	Large HLF	98,847	95,115	162,692	126,073	121,975	101,638	83,115	79,512	65,664	70,556	57,951	94,502	1,157,639
18	Extra Large LLF	87,436	161,401	189,233	161,912	141,003	80,652	32,713	23,350	12,130	8,024	16,500	37,324	951,676
19	Extra Large HLF	442,612	481,256	649,419	550,308	541,380	501,282	396,175	426,407	385,094	353,465	381,374	451,689	5,560,462
20	Total Throughput	2,471,585	4,480,229	6,601,257	6,224,693	5,027,594	3,441,397	2,123,550	1,254,861	1,109,199	957,434	1,047,061	1,416,722	36,155,583

Source: GCR Filing Docket No. 4283

21	Total THROUGHPUT	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Total Nov-Oct
22	Residential Non-Heating	39,952	59,594	78,573	77,377	66,696	52,095	46,325	34,178	29,995	27,280	27,901	28,447	568,413
23	Residential Heating	1,099,863	2,058,633	3,053,892	3,108,191	2,680,218	1,998,463	1,232,855	674,166	443,392	388,331	399,794	515,751	17,653,549
24	Small C&I	121,739	254,777	460,531	442,493	396,614	264,475	142,278	71,605	53,665	47,990	48,259	48,988	2,353,415
25	Medium C&I	364,651	585,632	838,975	891,201	766,750	540,515	358,911	226,708	183,310	172,711	188,419	212,996	5,330,780
26	Large LLF	222,164	350,835	475,113	467,179	415,605	308,325	143,544	88,793	53,607	46,769	54,797	98,791	2,725,521
27	Large HLF	78,431	92,901	99,967	103,872	103,826	81,907	74,577	60,247	55,624	59,555	62,527	58,297	931,731
28	Extra Large LLF	109,175	161,825	182,320	176,119	149,486	99,241	47,910	23,709	18,513	18,206	23,719	50,092	1,060,314
29	Extra Large HLF	394,798	490,008	441,981	425,484	388,437	340,930	390,126	372,971	371,195	379,890	396,990	371,180	4,763,990
30	Total Throughput	2,430,775	4,054,205	5,631,350	5,691,916	4,967,631	3,685,951	2,436,526	1,552,377	1,209,300	1,140,732	1,202,406	1,384,542	35,387,711

Source: GCR Filing Docket No. 4346

Forecasted Throughput

		Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total Nov-Oct
31	Total THROUGHPUT													
32	Residential Non-Heating	48,298	78,202	111,021	119,337	79,602	64,567	56,216	40,932	31,123	28,396	28,939	35,495	722,127
33	Residential Heating	1,055,948	2,069,091	3,227,307	3,227,172	2,949,996	2,054,509	1,275,453	688,829	437,527	393,560	433,919	517,838	18,331,149
34	Small C&I	127,131	235,525	446,056	416,921	377,264	270,238	159,950	84,920	60,020	57,753	67,751	67,154	2,370,683
35	Medium C&I	361,547	643,182	896,477	881,766	735,106	529,439	377,672	198,292	153,309	146,809	165,423	212,386	5,301,406
36	Large LLF	227,029	394,669	545,109	488,890	450,991	303,505	185,732	73,578	38,435	33,853	47,110	106,920	2,895,821
37	Large HLF	94,792	115,687	137,449	127,574	130,253	104,717	93,374	82,589	64,726	67,975	81,772	75,653	1,176,561
38	Extra Large LLF	166,990	247,809	283,538	273,641	281,556	132,298	72,001	19,075	13,411	13,105	21,219	80,389	1,605,030
39	Extra Large HLF	523,718	621,329	666,342	580,527	631,002	490,774	446,243	423,981	419,902	423,083	412,107	458,867	6,097,877
40	Total Throughput	2,605,454	4,405,494	6,313,298	6,115,828	5,635,770	3,950,046	2,666,640	1,612,196	1,218,453	1,164,534	1,258,241	1,554,701	38,500,653

Source: GCR Filing Docket No. 4436

		Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Total Nov-Oct
41	Total THROUGHPUT													
42	Residential Non-Heating	45,060	82,938	115,737	119,268	108,822	83,093	55,290	37,237	28,824	27,104	27,648	30,965	761,987
43	Residential Heating	1,044,744	2,226,624	3,239,393	3,325,991	2,989,103	2,151,864	1,342,728	702,519	482,963	461,730	466,391	539,594	18,973,642
44	Small C&I	111,924	292,538	478,552	500,985	439,148	285,357	169,179	63,729	51,244	56,204	44,858	61,560	2,555,277
45	Medium C&I	309,258	610,866	851,711	887,115	791,416	580,483	351,817	198,991	167,224	171,714	170,770	207,323	5,298,689
46	Large LLF	180,283	367,805	488,889	541,439	423,116	358,586	201,379	60,055	40,524	64,859	74,482	130,722	2,932,140
47	Large HLF	132,397	130,735	133,311	269,344	151,913	122,401	37,546	37,149	40,531	34,245	47,943	45,929	1,183,444
48	Extra Large LLF	55,948	120,466	132,332	139,838	99,538	99,898	113,255	43,717	37,340	38,593	82,408	95,275	1,058,607
49	Extra Large HLF	401,085	489,331	550,460	602,818	446,104	513,898	361,510	335,564	423,462	462,415	381,290	378,795	5,346,731
50	Total Throughput	2,280,698	4,321,303	5,990,384	6,386,798	5,449,161	4,195,580	2,632,704	1,478,960	1,272,113	1,316,865	1,295,789	1,490,163	38,110,517

Source: GCR Filing Docket No. 4520

Division 2-2

Request:

Re: witness Nutile's Direct Testimony at page 6 of 23, please provide a list of each described AGT project during the 2014-2015 period and for each project indicate:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes for the proposed facility;

c. Description of the advanced technology utilized;

d. The estimated amount of the rebate the Company would offer for the project and the basis for computing the estimated rebate;

e. The estimated in-service date for the proposed facility;

f. The anticipated schedule for payment of rebates;

g. The estimated rebate amount per vehicle for the Natural Gas Vehicle project.

Response:

Other than Toray Plastics (America), Inc., described on page 6 of the Direct Testimony, there were no other projects during the 2014-2015 period.

Division 2-3

Request:

Re: witness Nutile's Direct Testimony at page 6 of 23, please provide a list of each proposed AGT project the Company has identified for the 2015-2016 period, and for each project indicate:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes for the proposed facility;

c. Description of the advanced technology to be utilized;

d. The estimated amount of the rebate the Company would offer for the project and the basis for computing the estimated rebate;

e. The estimated in-service date for the proposed facility;

f. The anticipated schedule for payment of rebates.

Response:

There are presently no proposed projects that the Company has identified as being in-service for the 2015-2016 period.

Redacted

Division 2-4

Request:

Re: witness Nutile's Direct Testimony at pages 6 and 7 of 23, please provide a list of each project presently being considered by the Company for inclusion in the AGT program and provide:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes for the proposed facility;

c. The dollar amount of anticipated AGT funding for the project by year;

d. Description of the advanced technology proposed; and

e. Any workpapers, studies and analyses relied upon to support the Company's assessment of the proposed project.

Response:

a. The names of the customers presently being considered by the Company for inclusion in the AGT program for the 2016-2017 period are shown in the table below.

b. The projected annual gas use volumes (in therms) for the proposed facilities are listed below:

[redacted]	1,148,198
[redacted]	145,305
[redacted]	TBD

Prepared by or under the supervision of: Suhila Nouri Nutile and Fred Paine

Redacted

Division 2-4, page 2

c. The estimated rebate that [redacted] would be eligible to receive is $330,000. The Company has not estimated the rebates for the other customers.

   The [redacted] estimated rebate is based on 75% of the net present value of the customer's estimated margin using the AGT screening tool.

d. The advanced technology to be utilized in all the potential projects is Combined Heat and Power System.

e. Attachment DIV 2-4-e provides the analysis relied upon to support the Company's assessment of the proposed project for [redacted].

[redacted]
East Providence, RI

Cogeneration Feasibility Assessment

TA Study Report – Final

17 July 2015

PREPARED FOR:

National Grid

PREPARED BY:

Andelman and Lelek Engineering, Inc.
1408 Providence Highway
Norwood, MA 02062
(781) 769-8773

PROJECT CONTACT INFORMATION

Customer's Facility/Project Location		
[redacted] East Providence, RI		
Customer's Consultants:		
Robert Rose	Consulting Engineer A/Z Corporation	860-445-3469 rrose@a-zcorp.com
National Grid		
Dinesh Patel	Principal Engineer, Technical Strategy and Policy	781-907-2250 Dinesh.Patel@nationalgrid.com
Jeffrey Dunham	Lead Strategic Sales	401-527-4055 Jeffrey.Dunham@nationalgrid.com
Gerald Ferris	Lead Technical Service Consultant	401-784-7364 Gerald.Ferris@nationalgrid.com
TA Study Consultants: Andelman and Lelek Engineering, Inc.		
Michael Andelman	Principal	781-769-8773 mike@andelmanlelek.com
Neil Sen	Project Engineer	781-769-8773 neil@andelmanlelek.com

Executive Summary

A/Z Corporation and National Grid retained Andelman and Lelek Engineering, Inc. (ALE) to perform a Technical Assistance (TA) study to assess cogeneration opportunities for [redacted] in East Providence, RI.

This report presents an analysis of the savings and costs associated with adding a natural gas engine generator cogeneration system for [redacted] The new cogeneration system would produce hot water via the engine's cooling circuits and via an engine exhaust heat exchanger. The option explored for this study was cogeneration system of approximately 1,275 kWe electric capacity. An energy analysis was performed using a custom spreadsheet calculation based on available usage records, manufacturers' performance data, and calculated values. A summary of the analysis results is shown in Table 1.

This report begins with a description of the existing facility equipment and operating sequences, followed by a general discussion of cogeneration requirements for the site. We then characterize the current electrical and thermal loads, and we present the evaluated cogeneration option along with its expected installed cost. The energy analysis calculation and important assumptions are then described.

Table 1: Savings and Costs Summary

Plant economics 1,275 kWe		
Useful electricity produced by new cogen	kWh/yr	9,946,930
Natural gas consumed by new cogen	therms/yr	972,905
Boiler fuel offset	therms/yr	501,499
Total increase in natural gas purchased	therms/yr	471,407
Total energy cost savings	$/yr	859,464
Approx. cost for complete system	$	3,600,000
Maintenance cost	$/yr	248,673
Total annual cost savings	$/yr	610,791
Simple payback (before incentives)	**yrs**	**5.9**
Annual Electrical Efficiency	**%**	**34.9**
Annual Thermal efficiency	**%**	**41.2**
Annual system efficiency	**%**	**76.1**

Facility Description

[redacted] in East Providence, RI produces industrial insulation. The manufacturing process is constant throughout the year.

Information used in this study was obtained from [redacted] personnel, from documentation provided by [redacted] and from power usage information obtained from NGrid.

Existing Cogeneration Equipment

[redacted] does not have any existing cogeneration equipment.

Facility Schedule

[redacted] operates 24 hours a day, 7 days a week. The facility shuts down for one shift every month for maintenance.

General Cogeneration Considerations

Gas-fired cogeneration systems typically contain either a turbine generator or an engine generator. In gas turbine systems, heat is recovered from the turbine exhaust gases; the exhaust gas temperature is sufficient to generate steam. Exhaust heat is captured in gas engine systems and can be used to produce steam, but a significant fraction of the recoverable energy is in the form of lower-grade heat from the engine jacket and other cooling systems. Jacket heat is not suitable for steam generation; to make full use of an engine cogeneration system, the facility must have suitable hot water loads (or other end-uses of low-grade heat).

The most suitable system depends on the balance between heating and electrical loads, but generally speaking, gas engine installations are less costly than gas turbines of similar size. Further economic benefits are often conferred by engines' higher electrical efficiency.

Installed cost per kW decreases as the size of the installation rises. It is therefore advantageous to select the largest unit that can currently be accommodated at the facility; however, oversizing the unit results in significant efficiency penalties because part load performance often drops rapidly below 50% loading. If electricity demands are not large enough to operate the unit close to capacity, or if a lack of heating demand forces the unit to operate at low part load (or to dump heat), energy savings will suffer.

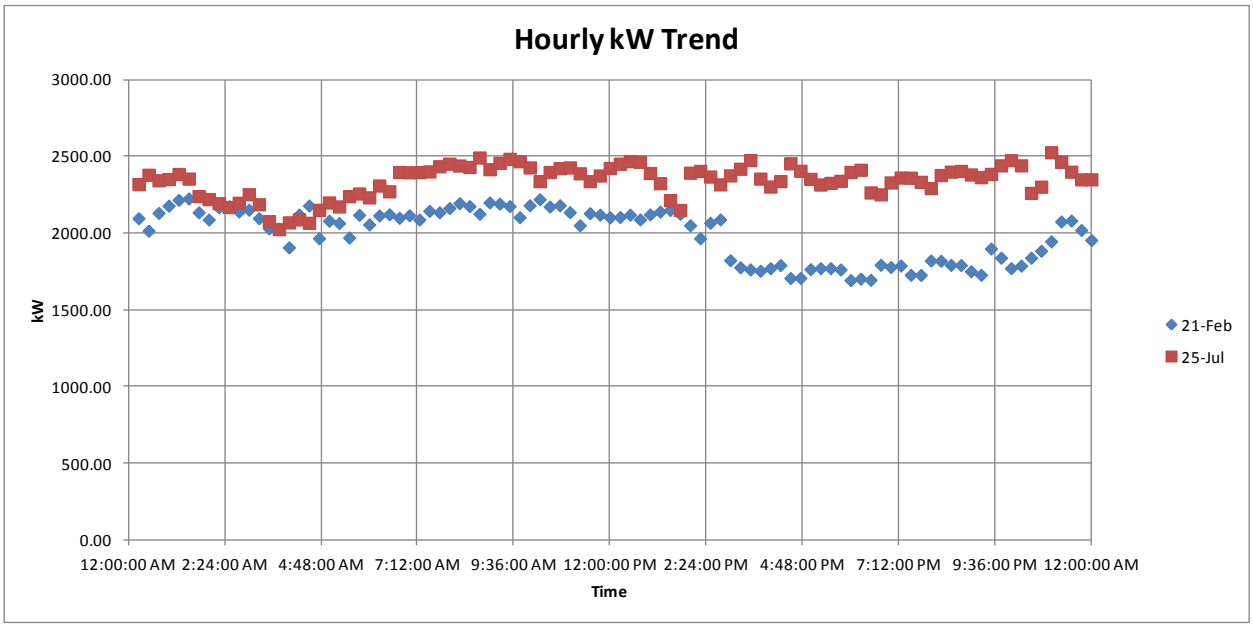
Load Characterization and System Sizing

The facility's electrical and thermal loads were characterized to determine the optimal sizing of the cogeneration system.

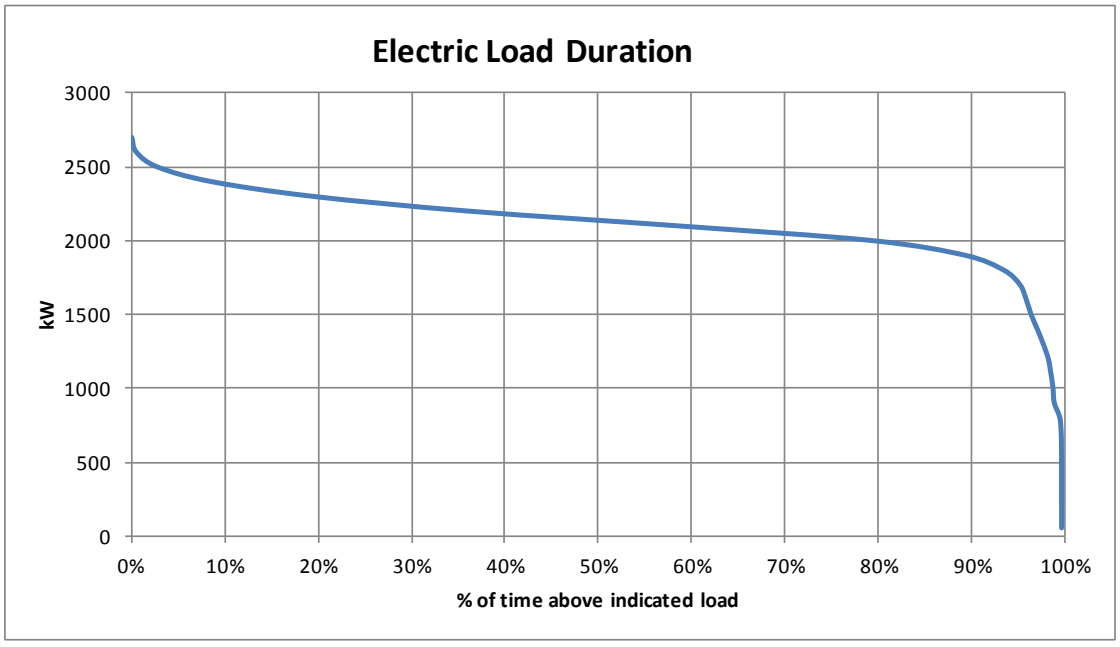
Electrical Loads

Hourly electrical data for [redacted] from 2014 were obtained from National Grid. Below is a graph showing the electrical usage for one day in the winter and one day in the summer.

Electrical consumption patterns do not vary significantly with season.



The electrical load duration curve for the facility is shown below.

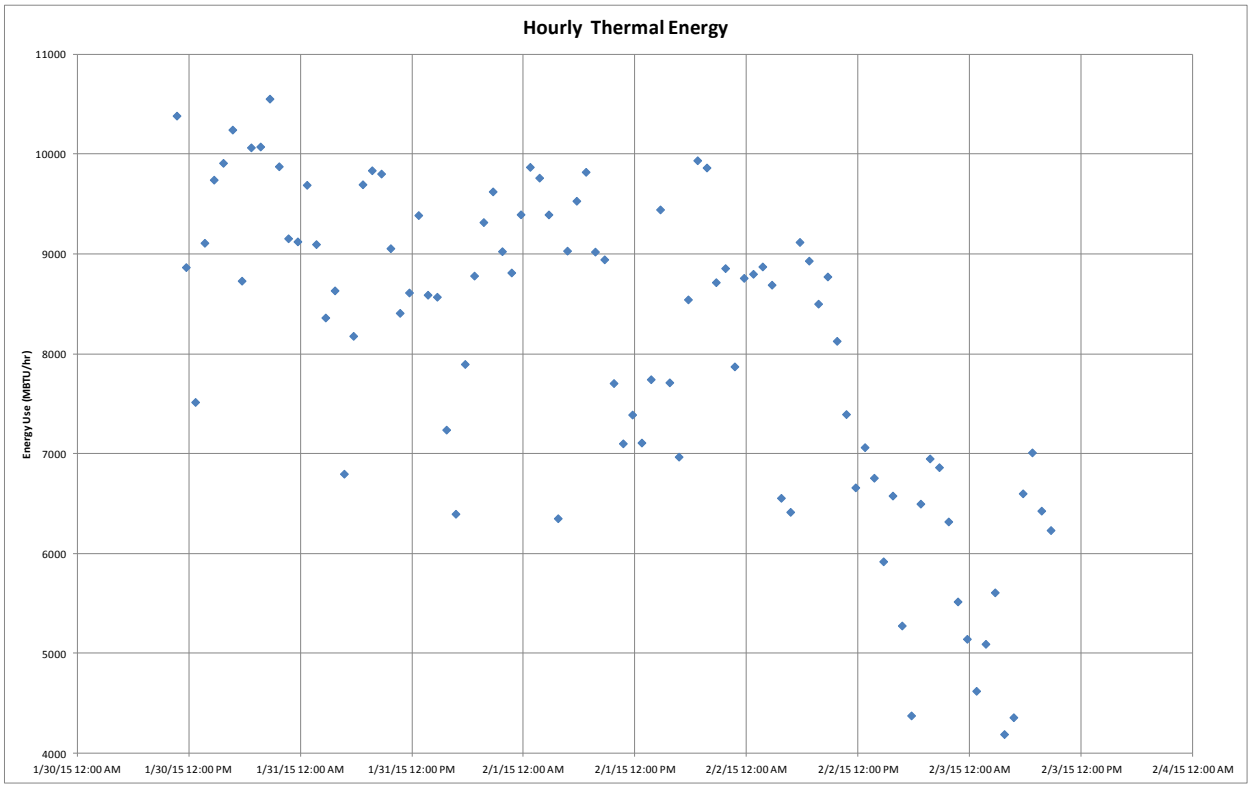


Based on the load duration curve, an approximately 1,275 kWe engine would be running at full load approximately 97% of the year.

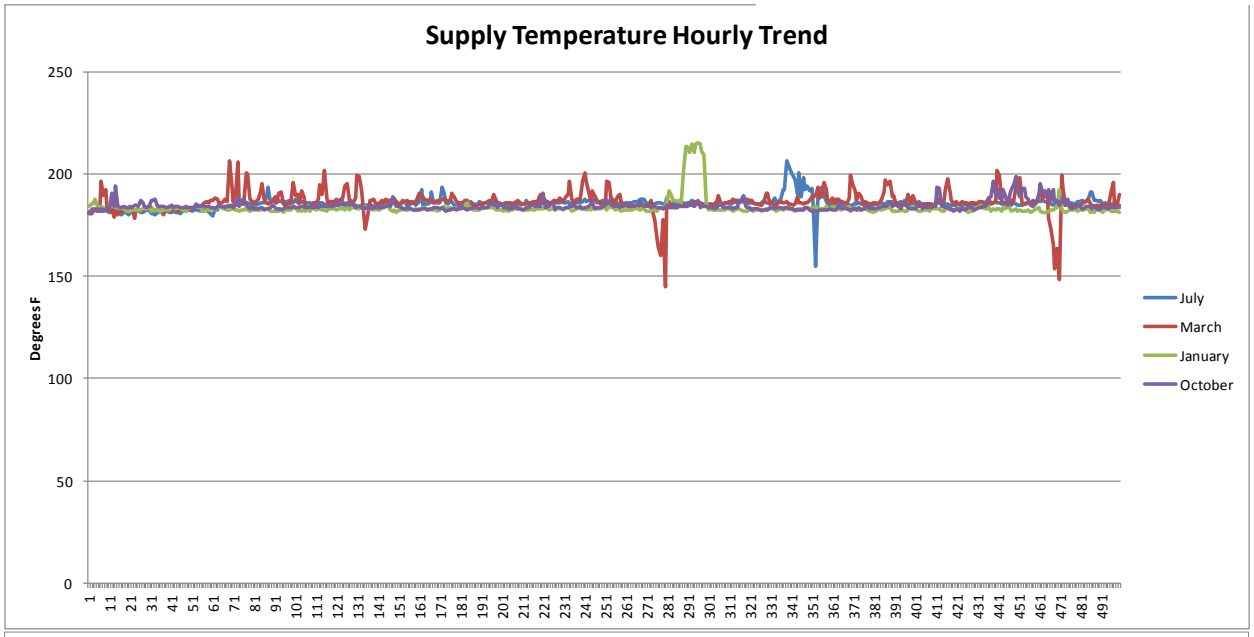
Existing Thermal Loads

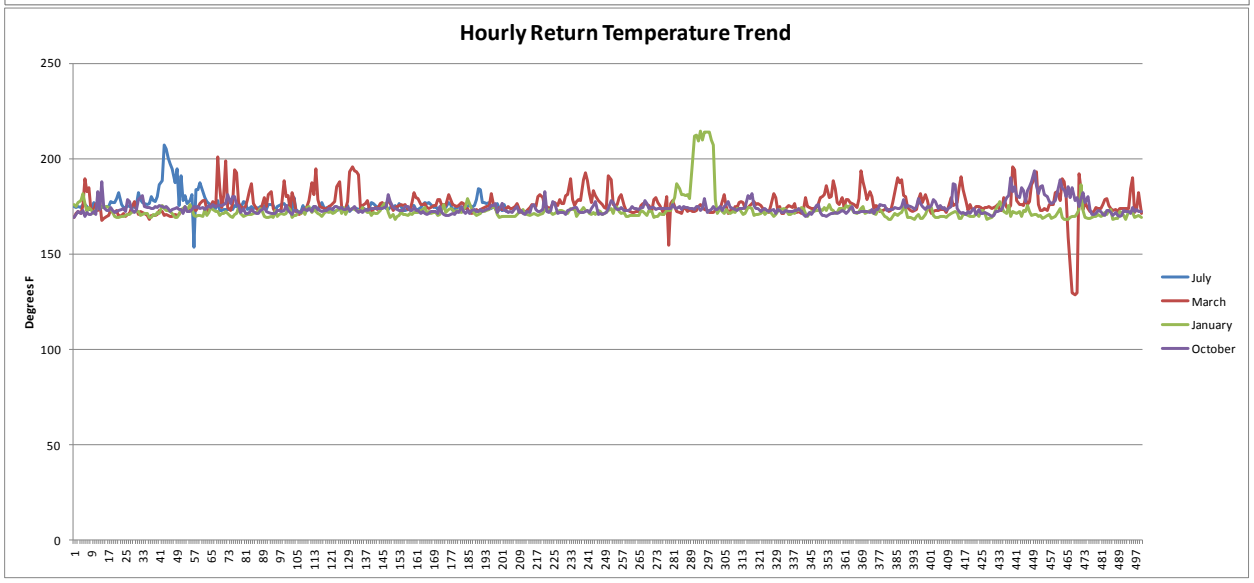
The CHP system will be used to offset loads on [redacted] hot water system, which provides heat to their manufacturing process. The hot water system includes three boilers, of which two are normally used. Their input ratings are 80 therms/hr and 120 therms/hr. [redacted] also has a flame burner with a maximum fuel firing rate of 60 therms/hr.

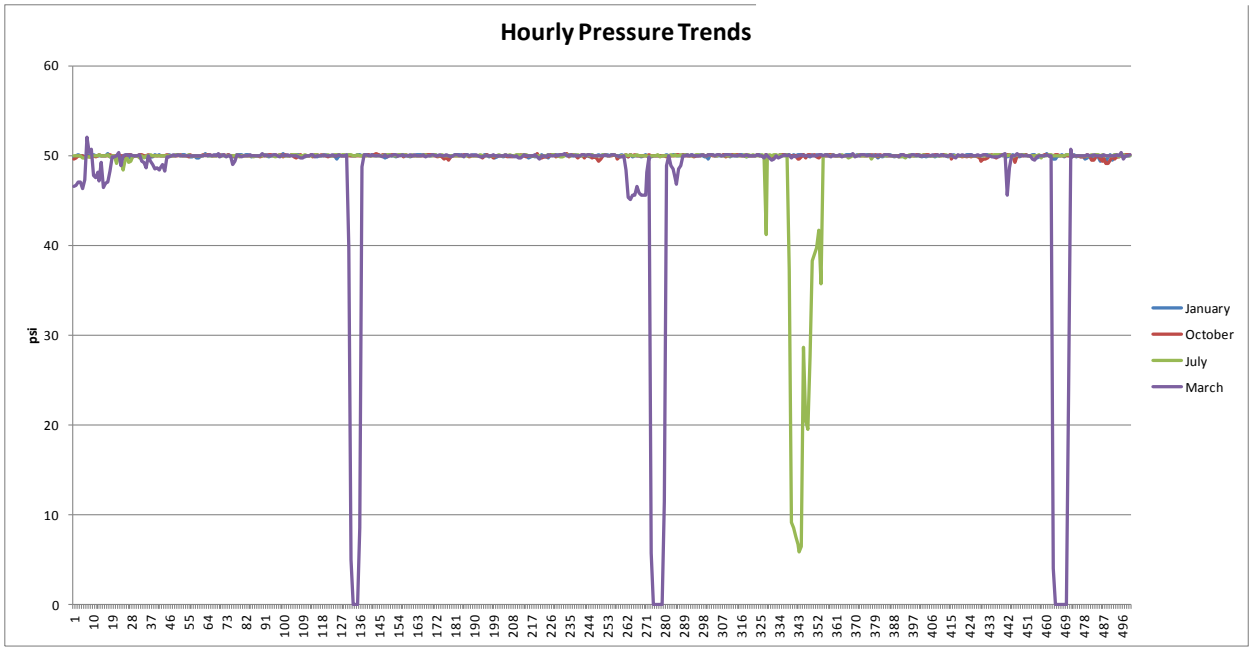
From field metering data of boiler plant hot water production using an ultrasonic BTU meter, the following process hot water load profile was constructed. At its lowest point, the thermal load was a little over 40 therms/hr. The CHP system's thermal capacity, including jacket water and exhaust, is 50 therms/hr and thus the thermal load would almost always be more than 80% of the CHP system's capacity.



From temperature and pump discharge pressure data taken over three-week periods in January, March, July, and October, it is apparent that thermal loads do not vary significantly between seasons.


Supply Temperature Hourly Trend
250
200
150
100
50
0
DegreesF
July
March
January
October


Hourly Return Temperature Trend
250
200
150
100
50
0
DegreesF
July
March
January
October


Hourly Pressure Trends
psi
60
50
40
30
20
10
0
January
October
July
March

Proposed Cogeneration System

A final selection for the proposed CHP unit is a 1,275 kWe gas engine generator. The savings calculations presented here use data obtained for a 1,275 kWe gas engine generator with high electrical efficiency.

The proposed cogeneration system package contains the following main components:

- Gas engine generator: packaged system containing the gas engine, electrical generator, and heat recovery system to produce hot water from engine cooling circuits

Table 2: Summary of Cogeneration System Properties

Gas engine generator model	Dresser-Rand HGM 560
Nominal generator capacity (kWe)	1,275
Electrical generation efficiency (HHV)	36.0%
Hot water produced via engine cooling circuits	25 therms/hr

Sequence of Operation

The CHP unit would normally operate continuously in thermal and electrical-following mode, i.e. no excess electricity would be produced and no thermal dumping would occur. Hot water would be produced via the engine's cooling circuits. The CHP unit would be controlled to operate above a minimum of 50% turndown. Based on electric and thermal load data, the unit is expected to operate above 80% capacity all operational hours (analysis assumes 93% availability).

System Pricing

The cost of the new cogeneration system was estimated based on information received from the equipment vendor. Please note that this estimate is based on initial pricing from the owner's contractor; it does not represent a guaranteed maximum price, and is not associated with a specific detailed system design.

According to [redacted] consulting engineer, the packaged cogeneration system would have an installed cost of approximately $3,600,000.

Energy and Cost Savings Analysis

A custom cogeneration spreadsheet analysis was used to perform the energy analysis for this study. A summary of the analysis results is provided in Table 1 in the Executive Summary of this report. Details of the modeling methodology are presented below, along with information on the utility rates used in the analysis.

Calculation Methodology

The full calculation spreadsheet will be provided to National Grid for review. Notes on assumptions are provided below.

- The calculation used 15-minute interval electrical usage data for the entire year of 2014 and 1-minute interval thermal data for early 2015.
- Cogen thermal loads were determined from thermal data as described in the Load Characterization section of this report.
- For the four-week period from October 18 to November 19, adjacent days were used to approximate the hourly electrical interval data in that time as the original data were missing.
- Gas engine generator performance data (generation capacity, heat rate, thermal output, and part-load performance) were obtained from the technical properties document supplied by the vendor.
- System parasitic power (circulation pumps and radiator fan) was assumed to be 3% of full-load capacity.
- The cogeneration system was assumed have 93% availability throughout the year.
- Average electric and gas rates for 2014, which were $0.117/kWh and $0.656/therm, were used to calculate energy cost savings estimates. No additional demand charges were applied during outage periods.
- Existing boiler thermal efficiency was modeled as 80% at all times; no part load variations were modeled.
- The system was assumed to be in electrical and thermal load following mode, i.e. no excess electrical or thermal production was permitted.
- The minimum turndown for the cogen system was set to be 50%.
- Thermal process loads were assumed to be constant (24/7 schedule).

Tabulated below is the monthly increase in fuel consumption.

Table 3: Monthly Increase in Gas Usage

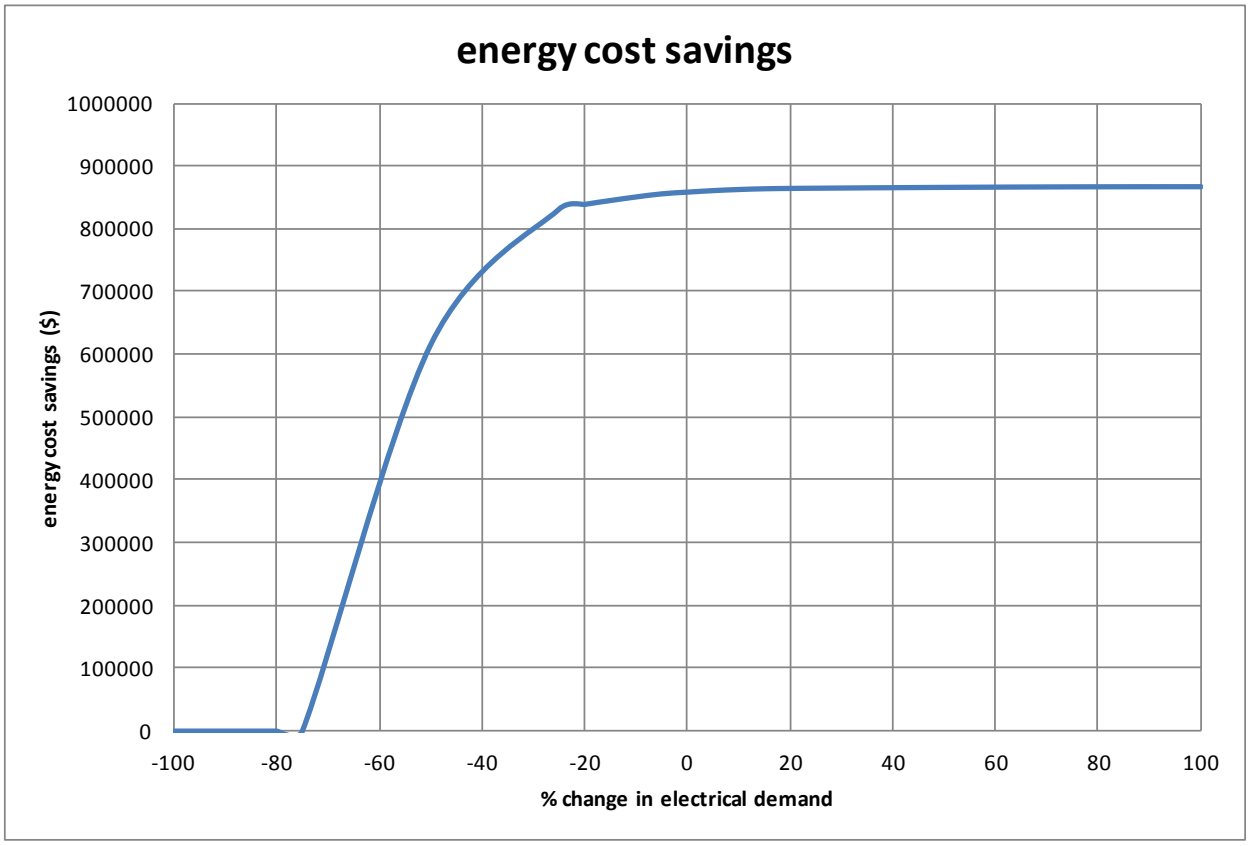
Month	Existing Load (Therms)	Generator Load (Therms)	Thermal Offset Recovery (Therms)	Increase in gas use (Therms)	Proposed Therms
January	59,834.8	89,370.4	46,045.9	40,291.8	100,126.5
February	54,235.3	80,833.5	41,647.0	36,443.4	90,678.8
March	59,893.9	89,449.5	46,080.7	40,333.0	100,226.9
April	58,385.6	85,784.6	44,228.8	38,646.9	97,032.5
May	59,922.3	88,437.2	45,616.2	39,823.5	99,745.9
June	58,033.5	86,702.2	44,663.8	39,095.8	97,129.3
July	60,245.9	89,581.5	46,147.8	40,393.4	100,639.3
August	59,922.3	89,536.9	46,128.4	40,369.9	100,292.2
September	58,033.5	84,558.7	43,673.0	38,023.7	96,057.3
October	60,245.9	88,340.4	45,511.0	39,831.4	100,077.3
November	57,833.0	85,428.6	44,012.6	38,516.8	96,349.8
December	60,174.4	88,111.5	45,490.7	39,637.3	99,811.7

The monthly increase in gas use is 93% of the difference between the monthly generator load and thermal offset recovery. The total proposed gas usage is the sum of the existing load and the increase in gas use. The months from May to September represent 42% of the increase in gas consumption after the installation of the CHP system.

Sensitivity Analysis

In this section, we explore the sensitivity of the results to changes in the facility's electrical demand.

Facility Thermal Demand



When the electrical demand decreases, it adopts three linear regimes from 0% to 25%, 25% to 45%, and 45% to 75%. The cost savings decrease more dramatically with each regime.

When the increase in energy demand exceeds 50%, the amount of money saved per year plateaus at about $868,000. On the other hand, if the percent decrease exceeds 75%, the savings sharply decrease until the savings approach $0.

Appendix

- HGM 560 Technical Description document
- Custom Cogen Calculation Spreadsheet
- Custom Screening Spreadsheet
- [redacted] MRD

Division 2-5

Request:

Re: witness Nutile's Direct Testimony at pages 6 and 7 of 23, please provide a list of each project during the last three years that have applied for but been denied rebates under the AGT program including:

a. The name of the customer (may be provided subject to confidentiality restrictions);

b. The projected annual gas use volumes for the proposed facility;

c. Description of the advanced technology proposed;

d. Reason for project denial;

e. Requested Rebate amount.

Response:

During the last three years, there were no projects that applied for but were denied rebates under the AGT program.

Division 2-6

Request:

Re: footnote 1 on page 9 of 23, please provide:

a. The annually funded amounts for the LIHEAP program collected through surcharges for each of the last three years;

b. The annually funded amounts estimated for 2015-2016 period for the LIHEAP program collected through surcharges.

Response:

a. Attachment DIV 2-6-a provides the annually funded amounts for the both the LIHEAP enhancement program which is funded through the per-customer monthly surcharge and the Low Income Assistance Program (LIAP) which is funded through base rates, for each of the last three years. The amounts reflected for the LIHEAP enhancement program pertain only to funding provided by the Company's gas customers.

b. Attachment DIV 2-6-b provides the annual estimate for funding during the 2015-2016 period for the LIHEAP enhancement program and the LIAP. The estimated funding for the LIHEAP enhancement program pertain only to funding provided by the Company's gas customers.

Actuals

LIHEAP Enhancement Revenue

Line No.		October	November	December	January	February	March	April	May	June	July	August	September	Total
1	2012-2013	$208,023	$209,316	$212,019	$212,794	$213,949	$213,403	$214,248	$214,726	$212,023	$211,009	$211,070	$210,999	$2,543,580
2	2013-2014	$210,396	$212,467	$214,092	$192,263	$189,462	$190,926	$190,176	$190,306	$187,973	$187,361	$186,785	$186,395	$2,338,602
3	2014-2015	$186,918	$187,276	$189,328	$191,205	$192,753	$192,340	$192,610	$192,722	$191,210				$1,716,362

*Filed for the annual period of October through November.

LIAP - Base Rates Revenue

		April	May	June	July	August	September	October	November	December	January	February	March	Total
4	LIAP Factor	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	
	Throughput (dth)													
5	2012-2013	3,038,478	1,960,277	1,305,809	1,129,595	1,085,833	1,119,620	1,284,548	2,222,680	4,415,092	5,277,609	6,309,110	5,103,315	34,251,967
6	2013-2014	4,486,226	2,151,794	1,354,405	1,331,548	1,273,742	1,325,817	1,431,941	2,423,071	4,898,381	6,641,379	6,839,764	6,238,261	40,396,327
7	2014-2015	4,747,568	2,399,405	1,431,004	1,066,704	1,149,307	1,077,241	1,648,721	2,250,721	4,855,391	6,111,192	8,279,403	6,710,893	41,727,549
	Revenue													
8	2012-2013	$134,908	$87,036	$57,978	$50,154	$48,211	$49,711	$57,034	$98,687	$196,030	$234,326	$280,125	$226,587	$1,520,787
9	2013-2014	$199,188	$95,540	$60,136	$59,121	$56,554	$58,866	$63,578	$107,584	$217,488	$294,877	$303,686	$276,979	$1,793,597
10	2014-2015	$210,792	$106,534	$63,537	$47,362	$51,029	$47,829	$73,203	$99,932	$215,579	$271,337	$367,605	$297,964	$1,852,703

*Based on the annual period ending March 31st.

1 LIHEAP Ehancement Plan Reconciliation Filed Oct 13 -Docket No. 4290
2 LIHEAP Ehancement Plan Reconciliation Filed Oct 14 -Docket No. 4290
3 LIHEAP Ehancement Plan Reconciliation Filed Jul 15 -Docket No. 4290
4 LIAP base rate factor, not including Low Income Weatherization. Approved $1,585,000 funding divided by the rate year forecast (Feb 13-Jan 14) of 35,678,072 dth.
5 Apr 2012-Oct 2012 based on actual throughput as filed in November 2012 in Docket No. 4283, Nov 2012-March 2013 based on actual throughput filed in Nov 2013 in Docket No. 4346.
6 Apr 2013-Oct 2013 based on actual throughput as filed in November 2013 in Docket No. 4346, Nov 2013-March 2014 based on actual throughput filed in Nov 2013 in Docket No. 4436.
7 Apr 2014-Oct 2014 based on actual throughput as filed in November 2014 in Docket No. 4436, Nov 2014-March 2015 based on actual throughput filed in Jul 15 in Docket No. 4520.
8 Line 4 * Line 5
9 Line 4 * Line 6
10 Line 4 * Line 7

Forecast

LIHEAP Enhancement Revenue

Line No.		October	November	December	January	February	March	April	May	June	July	August	September	Total
	2015-2016													
1	Customer count	261,479	261,804	262,672	263,988	264,984	265,765	265,673	265,476	265,111	264,616	264,187	263,688	3,169,443
2	Revenue	$190,880	$191,117	$191,751	$192,712	$193,438	$194,009	$193,941	$193,797	$193,531	$193,170	$192,856	$192,492	$2,313,694

LIAP - Base Rates Revenue

		April	May	June	July	August	September	October	November	December	January	February	March	Total
	2015-2016													
3	LIAP Factor	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	$0.0444	
4	Foreacast (dth)	4,101,788	2,635,524	1,750,213	1,285,422	1,199,637	1,292,583	1,717,475	3,165,312	5,035,687	6,060,918	6,097,869	5,462,856	39,805,284
5	Revenue	$182,119	$117,017	$77,709	$57,073	$53,264	$57,391	$76,256	$140,540	$223,585	$269,105	$270,745	$242,551	$1,767,355

1 The Company forecast from the 2015-2016 Gas Cost Recovery filing.
2 Line 1 * $0.73 (assumes a LIHEAP Ehancement surcharge of $0.73 for Oct 15 - Sep 16).
3 Page 1, Line 4.
4 The Company forecast from the 2015-2016 Gas Cost Recovery filing.
5 Line 3 * Line 4.

Division 2-7

Request:

Re: footnote 2 on page 12 of 23, please provide:

a. The workpapers and documents relied upon that details the updated On-System Margin threshold;

b. The workpapers and documents relied upon to determine the impact of the migration of six Non-Firm customers to firm transportation on the On-System Margin threshold;

c. Any instances of similar customer migration from Non-Firm to Firm Transportation during the period April 1st, 2014 to March 31st, 2015. Including any workpapers and documents used to determine the number of customer migrations and the assessment of their impacts on the determination of the On-System Margin threshold.

Response:

a-b. Schedule YC-6 from Docket No. 4514 documented the adjustment to the On-System Margin threshold as noted in footnote 2 on page 12 of 23 and is provided in Attachment DIV 2-7-a-b.

c. Customer migration from Non-Firm to Firm Transportation during the period April 1, 2014 to March 31, 2015 is provided in Attachment DIV 2-7-c-1. The electronic spreadsheet file of Schedule SLN-6 which fully documents the details of the migrations is provided as Attachment DIV 2-9.

National Grid - RI Gas
On-System Margin Threshold Adjustment

Customers moving from Non-firm to Firm service per Settlement Agreement of Docket No. 4323

Line No.	(a) Assigned #	(b) Test year usage (therm)	(c) Distribution rate approved in Dkt 4323 (per therm)	(d) Calculated annual margin (b) * (c)
	(i) July 2012 - January 2013			
1	3	249,841	$0.0912	$22,786
2	21	800,376	$0.0733	$58,668
3	38	742,357	$0.0912	$67,703
4	Sub-total			$149,156
	(ii) February 2013 - March 2013			
5	45	39,646	$0.1436	$5,693
6	Sub-total			$5,693
	(iii) April 2013 - March 2014			
7	25	500,891	$0.0733	$36,715
8	33	18,144	$0.2206	$4,003
9	Sub-total			$40,718
10	Total			$195,567

Calculation of Adjustment to On-System Margin Theshold Approved in Docket No. 4323

	(e) Annual Non-firm Threshold per Dkt 4323	(f) Adjustment to Non-firm Threshold (d), line 10	(g) Adjusted Annual Non-firm Threshold (e) - (f)
11	$1,800,000	$195,567	$1,604,433

National Grid - RI Gas
On-System Margin Threshold Adjustment

Customers moving from Non-firm to Firm service per Settlement Agreement of Docket No. 4323

Line No.	(a) Assigned #	(b) Test year usage for Nov 2011-Mar 2011 (therm)	(c) Distribution rate approved in Dkt 4323 (per therm)	(d) Calculated annual margin (b) * (c)
	April 2014 - March 2015			
1	5	263,379	$0.0733	$19,306
2	15	671,609	$0.0912	$61,251
3	Total			$80,556

Calculation of Adjustment to On-System Margin Threshold Approved in Docket No. 4323

	(e) Annual Non-firm Threshold per Dkt 4514	(f) Adjustment to Non-firm Threshold (d), line 3	(g) Adjusted Annual Non-firm Threshold (e) - (f)
4	$1,604,433	$80,556	$1,523,876

Column (e), Line 4, per Docket No. 4514, YC-6S, page 3, Line 11.
Column (b), Customers 5 and 15 transferred to firm service as of November 2014.

Division 2-8

Request:

Re: witness Nutile's Direct Testimony page 11 of 23 please provide:

a. The monthly throughput data used for the 12-month period to derive the PBOP Factor;

b. The analysis performed to determine the associated carrying charges.

Response:

a. The table below contains the monthly throughput data used for the 12-month period to derive the PBOP factor.

	Monthly throughput (dekatherm)
Nov-15	3,108,633
Dec-15	4,962,185
Jan-16	6,231,217
Feb-16	6,108,262
Mar-16	5,504,103
Apr-16	4,101,788
May-16	2,635,524
Jun-16	1,750,213
Jul-16	1,285,422
Aug-16	1,199,637
Sep-16	1,292,583
Oct-16	1,717,475
Total	39,897,042

b. The analysis performed to determine the associated carrying charges was provided in the Supplemental DAC filing submitted September 1, 2015 in Schedule WRR-3, Pages 3-4, and is provided in Attachment DIV 2-8-b.

Prepared by or under the supervision of: Suhila Nouri Nutile

Narragansett Electric - Gas Operations
Pension Costs
12 Months Ended March 31, 2015

Line No.		April 2014 thru March 2015
1	Rate Allowance:	
2	National Grid - RI Gas Pension Costs Allowance	$4,702,324
3	National Grid - Service Company Allocated Pension Costs Allowance	$2,977,528
4	Total Pension Costs in Base Rates	$7,679,852
5	Expense Reconciliation:	
6	Current Year actual Pension Expense Direct	$3,226,141
7	Current Year actual Service Company Allocated Pension Expense	$2,477,492
8	Current Year actual Affiliated Allocated Pension Expense	$64,557
9	Total Current Year Pension Expense Including Service Company-Allocated Expense	$5,768,191
10	Rate Allowance	$7,679,852
11	**Current Year Pension Expense Reconciliation**	($1,911,662)
12	**Funding Carrying Charge**	($351,075)

Line Notes:
2 Docket No. 4323 Attachment MDL-3-GAS page 36 of 65 Line 1 (e)
3 Docket No. 4323 Attachment MDL-3-GAS page 36 of 65 sum of Lines 2 (e) through 5 (e)
4 Line 2 plus Line 3
6-8 Per Company Books
9 Sum of Lines 6 through 8
10 Line 4
11 Line 4 minus Line 10
12 Minus Page 3 of 4 Line 18

Narragansett Electric - Gas Operations
Post-Retirement Benefits Other Than Pension (PBOP) Costs
12 Months Ended March 31, 2015

Line No.		April 2014 thru March 2015
1	Rate Allowance	
2	National Grid - RI Gas PBOP Costs Allowance	$2,470,365
3	National Grid - Service Company Allocated PBOP Costs Allowance	1,852,439
4	Total PBOP Costs	$4,322,804
5	Expense Reconciliation	
6	Current Year actual PBOP Expense Direct	$942,676
7	Current Year actual Service Company Allocated PBOP Expense	$916,550
8	Current Year actual Affiliated Allocated PBOP Expense	$71,065
9	Total Current Year PBOP Expense Including Service Company-Allocated Expense	$1,930,290
10	Rate Allowance	$4,322,804
11	**Current Year PBOP Expense Reconciliation**	($2,392,514)
12	Funding Carrying Charge - Current Year	($356,375)
13	Funding Carrying Charge - Prior Year Correction	$93,085
14	**Total Funding Carrying Charge**	($263,290)

Line Notes:
2 Docket No. 4323 Attachment MDL-3-GAS page 35 of 65 Line 1 (e)
3 Docket No. 4323 Attachment MDL-3-GAS page 35 of 65 sum of Lines 2 (e) thru 5 (e)
4 Line 2 plus Line 3
6-8 Per Company Books
9 Sum of Lines 6 through 8
10 Line 4
11 Line 9 minus Line 10
12 Minus Page 4 of 4 Line 18
13 WRR-4 Page 4 of 6 Line 30 (g)
14 Line 12 plus Line 13

Narragansett Electric - Gas Operations
Pension Funding Carrying Charges
12 Months Ended March 31, 2015

		(a)	(b)	(c)	(d)	(e)	(f)
	Customer Funding	Dkt 4323	Mar-2014	Jun-2014	Sep-2014	Dec-2014	Mar-2015
1	Base Rate Recovery:						
2	Direct	$4,702,324	$1,175,581	$1,175,581	$1,175,581	$1,175,581	$1,175,581
3	Servco	$2,977,528	$744,382	$744,382	$744,382	$744,382	$744,382
4	PAM Surcharge Recovery:		465,084	465,084	465,084	$128,376	($39,978)
5	Pension Capitalized Amount:						
6	Direct		$940,193	$462,848	$610,211	$849,645	$1,107,413
7	Servco/Other Affiliates		$178,520	$174,602	$209,526	$274,591	$290,571
8	Total Customer Funding:		$3,503,760	$3,022,498	$3,204,784	$3,172,575	$3,277,969
9	**Company Contributions**[1]		Jun-2014	Sep-2014	Dec-2014	Mar-2015	Jun-2015
10	Pension		$2,066,500	$2,066,500	$4,133,000	$0	9,138,750
11	Service Company Allocated Costs		$922,902	$918,984	$953,908	$1,018,973	$1,034,953
12	**Total Contributions**		$2,989,402	$2,985,484	$5,086,908	$1,018,973	$10,173,703
13	Under/(Over) Funding		$514,358	$37,014	($1,882,124)	$2,153,602	($6,895,734)
14	Cumulative Under/(Over) Funding		$5,110,651	$5,147,665	$3,265,541	$5,419,142	($1,476,592)
15	Five Quarter Average						$3,493,281
16	Base for Carrying Charge (greater of line 22 or zero)						$3,493,281
17	Pre-tax WACC						10.05%
18	Carrying Charge						$351,075

Company Contributions[1]-This amount represents dollars funded in the subsequent quarter

Line Notes

2(a)	Docket No. 4323 Attachment MDL-3-GAS page 36 of 65 line 1 (e)
2(b) - 2(f)	Line 2 (a) divided by 12 times 3
3(a)	Docket No. 4323 Attachment MDL-3-GAS page 36 of 65 sum of lines 2 (e) through 5 (e)
3(b) - 3(f)	Line 3 (a) divided by 12 times 3
4(b) - 4(d)	Docket No. 4431 Schedule WRR-1S, page 1 of 6, Line 14 divided by 12 times 3
4(e)	Docket No. 4431 Schedule WRR-1S, page 1 of 6, Line 14 divided by 12 times 1 plus Docket No. 4514 Schedule WRR-1, page 1 of 6, Line 9 divided by 12 times 2
4(f)	Docket No. 4514 Schedule WRR-1, page 1 of 6, Line 9 divided by 12 times 3
6(b) - 6(f)	Per Company Books
7(b) - 7(f)	Per Company Books
8(b) - 8(f)	Sum of Line 2 through Line 7
10	Per Company Books
11	Line 3 plus line 7
12	Line 10 plus Line 11
13	Line 8 minus Line 12
14	Current year Line 13 plus prior year Line 14
15	Average of column (b) through column (e)
16	If Line 15 is greater than zero, Line 15 if not, zero
17	Docket No 4323
18	Line 16 times Line 17

Narragansett Electric - Gas Operations
PBOP Funding - Carrying Charges
12 Months Ended March 31, 2015

		(a)	(b)	(c)	(d)	(e)	(f)
	Customer Funding	Dkt 4323	Mar-2014	Jun-2014	Sep-2014	Dec-2014	Mar-2015
1	Base Rate Recovery:						
2	Direct	$2,470,365	$617,591	$617,591	$617,591	$617,591	$617,591
3	Servco	$1,852,439	$463,110	$463,110	$463,110	$463,110	$463,110
4	PAM Surcharge Recovery:		($143,009)	($143,009)	($143,009)	($205,720)	($237,076)
5	PBOP Capitalized Amount:						
6	Direct		$411,931	$127,798	$202,047	$304,113	$254,064
7	Servco/Other Affiliates		$72,342	$64,793	$100,159	$138,261	$104,122
8	Total Customer Funding:		$1,421,965	$1,130,283	$1,239,897	$1,317,355	$1,201,812
9	**Company Contributions**[1]		Jun-2014	Sep-2014	Dec-2014	Mar-2015	Jun-2015
10	PBOP		$764,266	$764,176	$764,099	$764,120	$8,060,500
11	Service Company Allocated Costs		535,452	527,903	563,268	601,370	567,232
12			$1,299,718	$1,292,079	$1,327,367	$1,365,490	$8,627,732
13	Under/(Over) Funding		$122,247	($161,796)	($87,470)	($48,136)	($7,425,920)
14	Cumulative Funding Under/(Over) Funding		$5,232,382	$5,070,586	$4,983,116	$4,934,980	($2,490,940)
15	Five Quarter Average						$3,546,025
16	Base for Carrying Charge (greater of line 22 or zero)						$3,546,025
17	Pre-tax WACC						10.05%
18	Carrying Charge						$356,375

Company Contributions[1]-This amount represents dollars funded in the subsequent quarter

Line Notes

2(a)	Docket No. 4323 Attachment MDL-3-GAS page 36 of 65 line 1 (e)
2(b) - 2(f)	Line 2 (a) divided by 12 times 3
3(a)	Docket No. 4323 Attachment MDL-3-GAS page 36 of 65 sum of lines 2 (e) thru 5 (e)
3(b) - 3(f)	Line 3 (a) divided by 12 times 3
4(b) - 4(d)	Docket No. 4431 Schedule WRR-1S, page 2 of 6, Line 14 divided by 12 times 3
4(e)	Docket No. 4431 Schedule WRR-1S, page 2 of 6, Line 14 divided by 12 times 1 plus Docket No. 4514 Schedule WRR-1, page 2 of 6, Line 9 divided by 12 times 2
4(f)	Docket No. 4514 Schedule WRR-1, page 2 of 6, Line 9 divided by 12 times 3
6(b) - 6(f)	Per Company Books
7(b) - 7(f)	Per Company Books
8 (b) - 8(f)	Sum of Line 2 through Line 7
10	Per Company Books
11	Line 3 plus line 7
12	Line 10 plus Line 11
13	Line 8 minus Line 12
14	Current year Line 13 plus prior year Line 14
15	Average of column (b) through column (e)
16	If Line 15 is greater than zero, Line 15 if not, zero
17	Docket No 4323
18	Line 16 times Line 17

Division 2-9

Request:

Re: witness Nutile's Attachment SLN-6, please provide electronic spreadsheet file which fully documents the derivation of the detail on pages 4 through 7 for the monthly totals shown for:

a. Firm (dth)

b. Firm Revenue

c. Firm Revenue less GET

d. Total Gas Costs

e. Energy Efficiency Surcharges

f. Other charges

Response:

The electronic spreadsheet that supports the details of Schedule SLN-6 is being provided on a CD-ROM as Attachment DIV 2-9.

Consistent with the methodology used in prior DAC filings, the monthly totals for Non-firm Usage (dth), Non-firm Revenue, Non-firm Revenue subject to Margin Sharing, Total Gas Costs, Energy Efficiency Surcharges, and Other charges were derived based on the customers' actual billing information.

a. Non-firm Usage (dth) – this is the total billed volume in dekatherms from all the active Non-firm customers in a given month.
b. Non-firm Revenue – this is the total billed revenue from all the active Non-firm customers in a given month.
c. Non-firm Revenue subject to Margin Sharing – this is the total billed revenue excluding Sales tax, Gross Earnings Tax, Energy Efficiency Surcharge, and other charges indicated below from all the active Non-firm customers in a given month.
d. Total Gas Costs – this is the total billed gas charges from all the active Non-firm customers in a given month.
e. Energy Efficiency Surcharges – this is the total billed energy efficiency surcharges from all the active Non-firm customers in a given month.

Prepared by or under the supervision of: Suhila Nouri Nutile

Division 2-9, page 2

f. Other charges – this includes the total billed late payment interest charges, LIHEAP Enhancement charge, and deposit installments from all the active Non-firm customers in a given month.

Division 2-10

Request:

Re: witness Nutile's Attachment SLN-6, please:

a. Document all curtailment and interruptions of service for individual non-firm customers during period April 1, 2014 through March 31, 2015 and for each curtailment:

   i. Provide the start and stop dates and times for the curtailment or service interruption;

   ii. Detail the methods and calculations used to computed curtailed therms of gas use;

   iii. Provide the computation of any and all penalties or excess use charges for unauthorized gas use for each customer during each period of service curtailment or interruption;

   iv. Provide the reasons for each curtailment or interruption of service;

   v. Identify the dollar amounts by customer by month of any and all charges for unauthorized or excess gas use that were waived or forgiven by the Company, as well as the reasons for the Company's waiver or forgiveness of the subject charges.

b. Document all billing adjustments for individual customers in excess of $10,000 and provide all workpapers, data, and assumptions relied upon to support those adjustments, as well as the Company's reasons and rationales for those adjustments.

Response:

a. i. During the period April 1, 2014 through March 31, 2015, the start and stop dates and times for the curtailment or service interruption were:

January 6, 2015 10:00 am to January 11, 2015 10:00 am
January 13, 2015 10:00 am to January 17, 2015 10:00 am
January 25, 2015 10:00 am to February 7, 2015 10:00 am

Prepared by or under the supervision of: Suhila Nouri Nutile

February 9, 2015 10:00 am to February 21, 2015 10:00 am
February 23, 2015 10:00 am to March 1, 2015 10:00 am
March 5, 2015 10:00 am to March 7, 2015 10:00 am

ii. Non-Firm customers are required to have phone lines that transmit gas usage via telemetered devices. During the winter curtailment season, the devices must call in every day and technicians are dispatched to collect the usage if a device does not call in. The Company's Meter Data Services Department collects gas usage in an hourly format in the Company's MV90 system and provides a query for the daily usage for each curtailment period to the Company's Special Billing Department. Special Billing then multiplies the ccfs by the therm conversion factor and adjusts for the fuel allowance to arrive at the therms to bill the customer. The Energy Efficiency Program Charge is then added.

iii. Attachment DIV 2-10-a contains the computation of all penalties or excess use charges that have been billed for unauthorized gas use for each customer during service curtailments or interruptions. As approved in the Tariff Advice Filing in Docket No. 4514, distribution and Energy Efficiency Program charges are included in the calculations of penalty charges. For purposes of confidentiality, the customer names have been replaced with their assigned customer number.

iv. All the curtailment or interruptions of service were due to the forecasted cold weather and LNG use.

v. There were no charges waived for unauthorized or excess gas use during this period.

b. Attachment DIV 2-10-b contains the details on all billing adjustments in excess of $10,000 for individual Non-Firm customers.

Curtailment Period 2014-2015

Assigned #	Curtailment Date	Curtailment Use (ccf)	Curtailment Use (therm)	Curtailment Use Billed (therm)	Pipeline	Daily Index (per Dth)	Penalty Multiplier	Penalty Rate (per therm)	Distribution Charge (per therm)	Energy Efficiency Charge (per therm)	Curtailment Penalty Charge	Distribution Charge	Total Curtailment Charge
	(a)	(b)	(c) (b) * 1.029	(d) (c) * 1.0352	(e)	(f)	(g)	(h) [(f)*(g)] / 10	(i)	(j)	(k) (d) * (h)	(l) (d) * (i)	(n) (k)+(l)+(m)
67	2/26/2015	603	620	642	TGP	$25.11	5	$12.56	$0.0733	$0.0637	$8,067.64	$47.08	$8,155.64
67 Total		603	620	642							$8,067.64	$47.08	$8,155.64
20	2/6/2015	37	38	39	TGP	$11.05	5	$5.53	$0.0733	$0.0637	$217.95	$2.89	$223.35
20	2/9/2015	70	72	75	TGP	$8.30	5	$4.15	$0.0733	$0.0637	$309.45	$5.47	$319.66
20	2/28/2015	92	95	98	TGP	$20.01	5	$10.00	$0.0733	$0.0637	$980.00	$7.18	$993.43
20	3/6/2005	32	33	34	TGP	$13.59	5	$6.80	$0.0733	$0.0637	$231.79	$2.50	$236.46
20 Total		231	238	246							$1,739.20	$18.04	$1,772.91
14	2/1/2015	30	31	32	AGT	$12.91	5	$6.46	$0.0912	$0.0637	$206.44	$2.91	$211.39
14	2/26/2015	160	165	170	AGT	$24.56	5	$12.28	$0.0912	$0.0637	$2,092.95	$15.54	$2,119.35
14 Total		190	196	202							$2,299.39	$18.46	$2,330.74
Total:		1,024	1,054	1,091							$12,106.22	$83.58	$12,259.28

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4573
2015 Distribution Adjustment Charge Filing
Responses to Division's Second Set of Data Requests
Attachment DIV 2-10-a
Page 1 of 1

Assigned #	Month Charges Apply To	Bill Date mo/yr	Sales or Trans	Customer Charge	Usage (therms)	Commodity charge	Commodity rate (per therm)	Distribution charge	Distribution rate	Sales tax	GET	Energy Efficiency Surcharge	Paperless credit	Other charges	Curtailments - Distribution	Curtailments - Commodity Charge	Total Bill	Revenue subject to Margin Sharing	Total Gas Cost (Col g + Col q)	Total Margin	Comment	Adjustment Details
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
17	Dec-13	May-14	Trans	($485)	(18,752)	$0	$0.7305	($1,337)	$0.0733	$0	$0	($760)	$0	($1)		($13,698)	($16,281)	($15,520)	($13,698)	($1,822)	Adj. for Dec'13	This reflects the canceled gas charges for November 30, 2013 - December 31, 2013
19	Nov-13	May-14	Trans	($715)	(79,692)	$0	$0.0813	($5,813)	$0.0733	$0	$0	($3,307)	$0	($1)		($6,477)	($16,312)	($13,004)	($6,477)	($6,528)	Adj. for Nov'13	This reflects the canceled gas charges for October 31, 2013 - November 30, 2013
19	Nov-13	May-14	Trans	$715	79,692	$0	$6.0444	$5,812	$0.0733	$0	$0	$3,306	$0	$1		$2,454	$12,288	$8,981	$2,454	$6,527	Curtailment 406 therms	This was for a curtailment on November 24, 2013 which was later cancelled and rebilled in May 2014. The original amount billed was $6,477 and the rebilled amount was $2,454.
16	Jan-14	Jun-14	Trans	$715	196,626	$0	$19.4330	$17,873	$0.0912	$0	$0	$9,642	$0	$1		$12,748	$40,978	$31,336	$12,748	$18,588	Curtailment 656 therms	This was for a curtailment on December 31, 2013 and January 1-8 and 21-29, 2014.
16	Feb-14	Jun-14	Trans	$715	246,111	$0	$13.9541	$22,423	$0.0912	$0	$0	$12,097	$0	$1		$3,419	$38,654	$26,557	$3,419	$23,138	Curtailment 245 therms	This was for a curtailment on February 6-28, 2014 and March 1-5, 2014.
36	Dec-13	Jun-14	Trans	($715)	(81,115)	$0	$0.0998	($5,923)	$0.0733	$0	($560)	($3,370)	$0	($1)		($8,092)	($18,661)	($14,731)	($8,092)	($6,638)	Adj. for Dec'13	This reflects the canceled gas charges for November 30, 2013 - December 31, 2013
36	Dec-13	Jun-14	Sales	$715	81,115	$0	$13.2516	$5,923	$0.0733	$0	$439	$3,369	$0	($244)		$4,201	$14,403	$10,838	$4,201	$6,638	Curtailment 317 therms	This was for a curtailment on December 12-19, 2013 which was later cancelled and rebilled in June 2014. The original amount billed was $6,638 and the rebilled amount was $4,201.
55	Dec-13	Jun-14	Trans	($715)	(22,035)	$0		($1,615)	$0.0733	$0	($92)	($919)	$0	($1)		($56,465)	($59,808)	($58,796)	($56,465)	($2,330)	Curtailment 2420 therms	This reflects the canceled gas charges for November 30, 2013 - December 31, 2013
55	Dec-13	Jun-14	Trans	$715	24,455	$0	$11.5349	$1,609	$0.0733	$0	$50	$915	$0	$82		$28,964	$32,334	$31,288	$28,964	$2,324	Curtailment 2511 therms	This was for a curtailment on December 12-19, 2013 which was later cancelled and rebilled in June 2014. The original amount billed was $56,465 and the rebilled amount was $28,964.
8	Dec-13	Jul-14	Sales	($715)	517,610	$0	($0.0011)	($37,939)	$0.0733	$0	($1,880)	($21,583)	$0	($77)		($549)	($62,744)	($39,203)	($549)	($38,654)	Adj. for Dec'13	This reflects the canceled gas charges for November 30, 2013 - December 31, 2013
8	Dec-13	Jul-14	Sales	$715	517,610	$0	$13.5524	$37,939	$0.0733	$0	$1,872	$21,583	$0	$1		$285	$62,395	$38,939	$285	$38,654	Curtailment 21 therms	This was for a curtailment on December 12-19, 2013 which was later cancelled and rebilled in July 2014. The original amount billed was $549 and the rebilled amount was $285.
17	Jan-14	Sep-14	Trans	$485	2,244	$0	$17.4934	$60	$0.0733	$0	$0	$40	$0	($439)		$24,928	$25,075	$25,473	$24,928	$545	Curtailment 1425 therms	This was for a curtailment on January 1-4 and 6-9 and 21-29, 2014.

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4573
2015 Distribution Adjustment Charge Filing
Responses to Division's Second Set of Data Requests
Attachment DIV 2-10-b
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