Thomas R. Teehan
Senior Counsel

October 30, 2008

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02889

RE: Docket 3943 – National Grid Request for Change of Gas Distribution Rates Responses to Record Requests

Dear Ms. Massaro:

Enclosed please find eight (8) copies of National Grid's[1] responses to Record Requests RR-DIV-5 through RR-DIV-9, RR-DIV-11 and RR-DIV-13, as well as responses to RR-RIH-1 and RR-COMM-24 and RR-COMM-26. In addition, for assistance to the parties, the Company has included a listing of record requests (by the Company's count), which indicates the responses that have already been filed, that are included in today's filing and that remain outstanding as of this date.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 3943 Service List

[1] The Narragansett Electric Company d/b/a National Grid ("Company").

Request #	Record Request Description	Issue Date	Filing Status
AG-1	Show impact of excluding low-income customers from decoupling	9/12/2008	Filed
COMM-1	Schedule and workpapers for alternative merger-savings calculation	9/8/2008	Filed
COMM-2	Describe Pension and PBOP recovery in other NGRID jurisdictions	9/8/2008	Filed
COMM-3	Update Schedule NG-MDL-5	9/8/2008	Filed
COMM-4	Explain negative accrual rate for production plant (depreciation)	9/8/2008	Filed
COMM-5	Provide additional info on FAS112 expense adjustment		Filed
COMM-6	Provide comparative statistics on leak rates	9/9/2008	Filed
COMM-7	Provide elements of "Company Unaccounted For" gas volumes	9/9/2008	Filed
COMM-8	Data on productivity of RI workforce	9/9/2008	Filed
COMM-9	Verify total growth capital is accurate in Attachment NG-SLF-2.	9/9/2008	Filed
COMM-10	Line losses and Unaccounted For Gas	9/9/2008	Filed
COMM-11	Company's "wish list" of system projects	9/9/2008	Filed
COMM-12	System Integrity Report and Priority Report	9/9/2008	Filed
COMM-13	Ratio of in-house staff vs. outside contractors	9/9/2008	Filed
COMM-14	Cost/Benefit analysis for outside meter locations	9/9/2008	Filed
COMM-15	Calculation of return on equity and rate of return on rate base in UK	9/10/2008	Filed
COMM-16	Actual capital structure of Providence Gas Company	9/10/2008	Filed
COMM-17	ConEd decision setting ROE	9/10/2008	Filed
COMM-18	Support Beta of debt being zero	9/10/2008	Filed
COMM-19	Obligor on long-term debt for electric and gas operations	9/11/2008	Filed
COMM-20	Charitable contributions calculation	9/11/2008	Filed
COMM-21	Summary table showing total energy assistance funds for low income	9/11/2008	Filed
COMM-22	Revise decoupling example to show other scenarios	9/12/2008	Filed
COMM-23	Support increase of property value being $8,400 with gas conversion	10/20/2008	Outstanding
COMM-24	Proposed Calculation of ESM	10/21/2008	Included
COMM-25	Cost incurred to improve operations not included in rate case	10/22/2008	Outstanding
COMM-26	Expenditure of funds for Advanced Gas Technologies Program	10/22/2008	Included
DIV-1	Number of incidents where outside meter was struck or broken	9/26/2008	Outstanding
DIV-2	Locations where company has installed inside meter	9/26/2008	Outstanding
DIV-3	Calculate return on equity if decoupling was in place	9/26/2008	Filed
DIV-4	Certification required for burning alternative fuels	10/8/2008	Filed
DIV-5	Waste oil discount documentation	10/8/2008	Included
DIV-6	Number of non-firm customers unable to convert to firm service	10/8/2008	Included
DIV-7	Investment to convert non-firm customers	10/8/2008	Included
DIV-8	How is company capable to serve non-firm on year-round basis	10/8/2008	Included
DIV-9	Cost of LNG associated with moving customers to firm from non-firm	10/8/2008	Included
DIV-10	History of non-firm rate cap in New York	10/8/2008	Filed
DIV-11	Supply Guarantee of Satisfaction document for Gas Marketing Program	10/20/2008	Included
DIV-12	Cost for remediation of Mr. Murphy's conversion to natural gas	10/20/2008	Outstanding
DIV-13	Percent of customers that contract with National Grid Energy Services	10/20/2008	Included
DIV-14	Bulk purchases of heating equipment for Gas Marketing	10/20/2008	Outstanding
ENE-1	Calculation of customer charge if all revenue collected in customer charge	9/26/2008	Filed
OER-1	Outcome of NARUC resolution on decoupling	9/26/2008	Filed
RIH-1	Differences Between Exhibit NGRID 38 and NGRID 39 on non-firm cost	10/20/2008	Included
RIH-2	Allocated Cost of service study and workpapers for Exh. NGRID-39	10/20/2008	Filed
TEC-RI-1	Alternative allocation of recovery of low-income discount dollars	9/29/2008	Filed

Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically submitted, hand delivered and mailed to the individuals listed below.

___/S/_______________________________ October 30, 2008
Linda Samuelian Date

National Grid (NGrid) – Request for Change in Gas Distribution Rates
Docket No. 3943 - Service List as of 9/15/08

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File original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02889	Lmassaro@puc.state.ri.us Tmassaro@puc.state.ri.us Anault@puc.state.ri.us	401-780-2107 401-941-1691

Division Record Request No. 5

Request:

Please provide information on the Company's assessment that waste oil is discounted from the price of No. 6 oil by 30-40 percent.

Response:

During the Company's investigation of available pricing information for waste oil, a company named Cycle Solve indicated that there is no published price for waste oil. However, Cycle Solve indicated that a reasonable pricing methodology would be to take the # 6 oil price as stated in "Platt's Oilgram" and use 69-79% of that price as a proxy, which represents a 21-31% discount off the # 6 oil price.

Prepared by or under the supervision of: Peter Czekanski

Division Record Request No. 6

Request:

Please provide information on the non-firm customers who are unable to convert to firm service because of distribution capacity issues. Also, please confirm the number of customers that are currently taking non-firm service.

Response:

A preliminary engineering review shows that the Company has a total of 12 non-firm service customers who are located in Westerly, Newport, South Kingstown, Warwick, Pawtucket, East Providence and Providence, Rhode Island where system enhancements would be required in order to provide firm service. The estimated costs associated with providing firm service to each customer ranges from $9,000 to $3 million, depending on the specific system upgrade that would be needed to bring a particular customer online on a firm basis.

As of September 1, 2008, there are 32 active non-firm service accounts.

Prepared by or under the supervision of: Peter Czekanski

Division Record Request No. 7

Request:

Please provide information that may exist about the investment that would be required to allow all non-firm customers to take firm service.

Response:

The Company has not undertaken a comprehensive engineering load and design study to quantify the total investment that would be needed to offer firm service to all existing non-firm customers. A preliminary review of several non-firm customers indicates that the costs would be at least $9 to $10 million.

Division Record Request No. 8

Request:

Please describe how the Company is capable of serving non-firm customers on a year-round basis if non-firm customers have to be interrupted periodically as a non-firm customer.

Response:

In considering whether the Company has the distribution capacity to serve a non-firm customer on an uninterrupted basis, the Company evaluates the converting non-firm customer as it would any new firm customer. Specifically, the Company obtains complete, up-to-date information on the customer's installed equipment and gas requirements and then performs a full engineering evaluation of the distribution system, delivery service, pressure regulator and metering needs. If the customer is in an area where the pipeline city gate has limited capability, the gate station capacity will also be evaluated.

If a converting customer happens to be located in an area where the capacity exists to serve them, then no upgrade is required and the conversion to firm service is accomplished. There is no incremental cost or burden to the system in extending firm service to these customers, except potentially in terms of a change in system pressure requirements. The Company uses LNG in winter periods to maintain adequate pressures across the system and the conversion of a non-firm customer to firm service may place a localized demand on the system in terms of maintaining adequate pressure (LNG used for pressure purposes is different from the LNG that is used as gas supply for sales service customers). As discussed in the response to RR-DIV-9, firm transportation customers are subject to the system pressure charges assessed as part of the Distribution Adjustment Charge when they become firm customers. Therefore, non-firm customers who convert to firm distribution service pay their proportional share of the system pressure charges arising from the need to use LNG to maintain adequate operating pressures in the winter period. Conversely, the Company does not incur system costs to maintain operating pressures for non-firm customers in the winter season, which is a major reason that non-firm customers are interrupted. Thus, the interruption of non-firm service does not necessarily indicate a lack of distribution capacity.

If the Company's evaluation indicates that additional facilities are needed, the Company identifies the cost of those upgrades for the customer so that the customer can determine whether it makes economic sense for them to pay for the upgrade in order to obtain firm service.

Prepared by or under the supervision of: Gary Beland

Division Record Request No. 9

Request:

If the Company is using more LNG to serve customers than it would be using if the former non-firm customers had not converted to firm service, please provide the cost that the Company has incurred in relation to that increased LNG use.

Response:

Please see the response to RR-DIV-8. The Company uses LNG in winter periods to maintain adequate pressures across the system and the conversion of a non-firm customer to firm service may place a demand on the system from a pressure perspective depending on the customer's location on the system.

Because customers who convert from non-firm to firm service are transportation-only customers, any increased use of LNG would be limited to the LNG needed to provide pressure support in the area of the distribution system on which the converting customer is located. Firm transportation customers pay their proportional share of the system pressure support cost through the Distribution Adjustment Charge (DAC). The system pressure charge of the DAC is specifically designed to recover the cost of pressure support to all customers on the system and is not designed to target specific customers or pressure-constrained areas. Thus, the cost of any incremental pressure requirements would be addressed through the DAC with the converting customer adding to the customer population responsible for paying the DAC (recovering not only the system pressure charge, but also other costs of running the system).

Prepared by or under the supervision of: Gary Beland

Division Record Request No. 11

Request:

Please provide a copy of the customer guaranty document that is provided to customers who complete a gas conversion through the Company's Gas Marketing Program.

Response:

Please see Attachment RR-DIV-11.

Prepared by or under the supervision of: Sean Mongan

CERTIFICATE OF Guaranteed Satisfaction

NATIONAL GRID GUARANTEES THAT YOU WILL BE COMPLETELY SATISFIED WITH NATURAL GAS HEAT.

If however, two years from the date of installation of your new natural gas heating equipment, you are not satisfied with natural gas and wish to switch to another fuel, National Grid will arrange for the removal of the gas heating equipment and will refund your equipment and installation costs to you.

To be eligible for a refund under this guarantee:

1. You must have the natural gas heating equipment installed by a qualified, licensed (where required) heating contractor;
2. You must have had the natural gas heating equipment in place and in use for two years;
3. Within the thirty (30) day period following the second anniversary of the equipment installation, you must make a written request to National Grid for equipment removal and refund; and
4. You must comply with the conditions on the reverse side of this certificate.

Name ______________________________

Address ______________________________

Installer ______________________ Date of Installation ______________________

nationalgrid

Conditions

This guarantee applies only to gas space heating equipment installations that replace a competitive fuel in owner-occupied, residential homes (as defined by the local National Grid Gas Tariff).

This guarantee is not transferable to subsequent homeowners.

The removed gas heating equipment must be replaced with heating equipment that is not fueled by natural gas. National Grid is not responsible for the storage or protection of the original heating equipment or for the installation of any new equipment to replace the removed gas heating equipment.

Customer's written request for equipment removal and refund must be accompanied by a copy of the equipment installation contract and supporting invoices. National Grid will refund all reasonable and customary charges for gas heat equipment installations.

In the event that the customer financed the installation of the gas heating equipment, National Grid reserves the right to pay any refund or portion thereof to the bank or financial institution financing the installation.

In the event the customer is in arrears in payment of customer's National Grid account, National Grid reserves the right to apply any refund due to customer's National Grid account.

It is understood that the cost of oil tank removal or abatement, extra radiation, system work, as well as ductwork is not included in the amount that National Grid will refund under the Guarantee of Satisfaction.

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Division Record Request No. 13

Request:

Based on the Company's experience in New York, New Hampshire and Massachusetts with the Gas Marketing Program, please provide the percentage of conversions handled by National Grid Energy Services through the Value Plus Installer referral program.

Response:

Please see Attachment RR-DIV-13.

Prepared by or under the supervision of: Sean Mongan

January 2008 - September 2008

Leads Assigned to National Grid Energy Services through VPI

	Total VPI Appointments Sold by VPI Installers			NGES Sold With VPI Appointment			NGES % vs. Total Sold		
	NY	**LI**	**NE**	**NY**	**LI**	**NE**	**NY**	**LI**	**NE**
2008	814	1,574	1,295	47	35	101	6%	2%	8%

Average Number of VPI Conversions Handled By NGES 5%

Rhode Island Hospital Record Request No. 1

Request:

Please isolate the differences in the assumptions used to develop the Company's analysis in Exhibits NGRID-38 and NGRID-39.

Response:

Please see Attachment RR-RIH-1 for the summary schedule relative to Exhibit NGRID-39, which was developed based on the Company's "as filed" revenue requirement.

Originally, Exhibit NGRID-38 was developed using the following assumptions:

- As filed revenue requirement;
- Actual interruptible volumes for the 12-months ending June 2007, excluding any customers who were assumed to go to firm service in the rate filing;
- Former interruptible customers who have switched to firm service will remain on firm service;
- All interruptible volumes were included in the RSUM allocation factor;
- Meter costs were assigned based on the average cost of the interruptible meters from the meter study;
- Service costs were allocated using the same weighting factor as large C&I customers (2.31);
- No LNG or propane costs were allocated to the interruptible class;
- Interruptible customers were included in the customer allocation factor; and
- Interruptible customers were included in the allocation of Account 903 (Collections and Customer Records).

Originally, Exhibit NGRID-39 was developed using the following assumptions:

- Company rebuttal revenue requirement;
- Actual interruptible volumes for the 12-months ending June 2007, excluding any customers who were assumed to go to firm service in the rate filing;
- 18 former interruptible customers who had switched to firm service were assumed to return to interruptible service;
- Firm service volumes were reduced by 1,374,772 dth and revenues were reduced by $1,220,605 for the 18 customers returning to interruptible service;

Rhode Island Hospital Record Request No. 1 (cont.)

- Interruptible volumes were increased by 942,928 dth to account for the customers assumed to be returning to interruptible service. These volumes were based on the customers last 12 months of actual throughput as an interruptible customer. Since this assumes a historical level of interruptions the volumes are less than the volume amount removed from firm service;
- All interruptible volumes were included in the RSUM allocation factor;
- Meter costs from the Company's original meter study were adjusted to account for the transfer of customers from the firm to interruptible classes. Firm class meter costs were reduced by the number of customers leaving the class times the average meter cost for the class. These firm meter cost reductions were added to the interruptible class meter costs;
- Service costs were allocated using the same weighting factor as large C&I customers (2.31);
- No LNG or propane costs were allocated to the interruptible class;
- Interruptible customers were included in the customer allocation factor; and
- Interruptible customers were included in the allocation of Account 903 (Collections and Customer Records).

National Grid RI Gas
Docket No. ________
Class Cost of Service Study - Summary
Filed Revenue Requirement Including Interruptible as Class with Transfer from Firm

Line No.	Description	System Total	Residential Non-Heating	Residential Heating	Small Commercial General	Medium Commerical General	Large Low Load Factor	Large High Load Factor	Extra Large Low Load Factor	Extra Large High Load Factor	Interruptible
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Rate Base										
1	Plant in Service	$ 589,768,961	$ 37,270,192	$ 379,540,748	$ 49,221,357	$ 65,421,109	$ 27,982,233	$ 8,751,316	$ 4,328,681	$ 11,367,491	$ 5,885,835
2	Accumulated Reserve	(284,401,644)	(21,976,616)	(190,814,685)	(22,722,290)	(26,106,850)	(10,301,112)	(3,048,068)	(2,487,225)	(4,809,506)	(2,135,292)
3	Other Rate Base Items	(20,125,855)	(965,200)	(10,239,116)	(3,241,954)	(3,814,821)	(1,095,868)	(426,506)	(125,577)	(159,163)	(57,649)
4	Total Rate Base	$ 285,241,462	$ 14,328,375	$ 178,486,947	$ 23,257,114	$ 35,499,438	$ 16,585,253	$ 5,276,741	$ 1,715,879	$ 6,398,822	$ 3,692,894
	Revenue at Current Rates										
5	Sales Revenue	$ 113,817,712	$ 5,133,293	$ 82,183,208	$ 10,513,902	$ 11,494,239	$ 3,228,223	$ 832,757	$ 162,535	$ 269,555	$ -
6	Transport Revenue	12,168,395	-	-	-	3,156,002	3,441,781	967,289	532,975	2,470,348	1,600,000
7	Other Revenues	2,642,480	28,960	893,796	313,178	649,888	293,695	64,479	150,686	193,132	54,666
8	Total Revenues	$ 128,628,587	$ 5,162,253	$ 83,077,004	$ 10,827,080	$ 15,300,129	$ 6,963,699	$ 1,864,525	$ 846,196	$ 2,933,035	$ 1,654,666
	Expenses at Current Rates										
9	Purchased Gas Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other Operation and Maintenance	83,291,079	5,161,565	53,555,763	7,686,704	7,806,698	3,117,764	1,044,376	781,005	2,682,297	1,454,907
11	Depreciation Expense	21,609,815	1,375,070	13,873,414	1,730,400	2,334,676	1,010,535	322,863	170,154	510,453	282,250
11	Taxes Other Than Income	10,021,018	616,727	6,369,563	888,302	1,119,327	473,193	149,143	78,843	213,514	112,406
12	Income Taxes	761,275	(903,186)	719,957	(151,232)	917,153	596,382	48,495	(89,157)	(256,597)	(120,539)
13	Total Expenses - Current	$ 115,683,187	$ 6,250,176	$ 74,518,696	$ 10,154,175	$ 12,177,853	$ 5,197,873	$ 1,564,877	$ 940,845	$ 3,149,667	$ 1,729,024
14	Operating Income - Current	12,945,400	(1,087,923)	8,558,308	672,905	3,122,276	1,765,826	299,648	(94,650)	(216,632)	(74,358)
15	Current Rate of Return	4.54%	-7.59%	4.79%	2.89%	8.80%	10.65%	5.68%	-5.52%	-3.39%	-2.01%
	Revenue Requirement at Equal Rates of Return										
16	Required Return	9.27%	9.27%	9.27%	9.27%	9.27%	9.27%	9.27%	9.27%	9.27%	9.27%
17	Required Operating Income	26,441,884	1,328,240	16,545,740	2,155,934	3,290,798	1,537,453	489,154	159,062	593,171	342,331
18	Operating Income (Deficiency)/Surplus	(13,496,483)	(2,416,163)	(7,987,432)	(1,483,029)	(168,522)	228,373	(189,506)	(253,712)	(809,803)	(416,689)
	Expenses at Required Return										
19	Purchased Gas Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Other Operation and Maintenance	83,783,967	5,185,703	53,982,459	7,711,327	7,817,615	3,117,764	1,047,642	781,005	2,685,545	1,454,907
21	Depreciation Expense	21,609,815	1,375,070	13,873,414	1,730,400	2,334,676	1,010,535	322,863	170,154	510,453	282,250
22	Taxes Other Than Income	10,021,018	616,727	6,369,563	888,302	1,119,327	473,193	149,143	78,843	213,514	112,406
23	Income Taxes	8,028,612	397,825	5,020,882	647,322	1,007,896	473,412	150,536	47,457	179,451	103,832
24	Total Expenses - Required	$ 123,443,412	$ 7,575,326	$ 79,246,317	$ 10,977,351	$ 12,279,513	$ 5,074,903	$ 1,670,184	$ 1,077,459	$ 3,588,963	$ 1,953,395
25	Revenue Requirement at Equal Rates of Return	$ 149,885,296	$ 8,903,566	$ 95,792,057	$ 13,133,286	$ 15,570,311	$ 6,612,356	$ 2,159,338	$ 1,236,521	$ 4,182,134	$ 2,295,727
26	Revenue (Deficiency) / Surplus	$ (21,256,709)	$ (3,741,313)	$ (12,715,053)	$ (2,306,206)	$ (270,182)	$ 351,343	$ (294,813)	$ (390,326)	$ (1,249,099)	$ (641,061)
	Revenue Requirement at Proposed Rates										
27	Proposed Revenue Increase	$ 20,599,969	$ 1,107,327	$ 12,727,473	$ 2,152,065	$ 1,825,097	$ 844,121	$ 282,144	$ 258,864	$ 839,012	$ 563,866
28	Rate Schedule Revenue as Proposed	146,586,076	6,240,620	94,910,681	12,665,967	16,475,338	7,514,125	2,082,190	954,374	3,578,915	2,163,866
29	Other Revenue	2,642,480	28,960	893,796	313,178	649,888	293,695	64,479	150,686	193,132	54,666
30	Total Revenues as Proposed	$ 149,228,556	$ 6,269,580	$ 95,804,477	$ 12,979,145	$ 17,125,226	$ 7,807,820	$ 2,146,669	$ 1,105,060	$ 3,772,047	$ 2,218,532
31	Expenses (excluding Income Taxes)	$ 115,414,800	$ 7,177,500	$ 74,225,435	$ 10,330,029	$ 11,271,617	$ 4,601,492	$ 1,519,648	$ 1,030,002	$ 3,409,512	$ 1,849,563
32	Interest Expense	10,782,127	541,613	6,746,807	879,119	1,341,879	626,923	199,461	64,860	241,875	139,591
33	Taxable Income	23,031,629	(1,449,533)	14,832,235	1,769,997	4,511,730	2,579,406	427,560	10,198	120,660	229,378
34	Income Taxes	7,798,754	(524,070)	5,025,229	593,373	1,552,116	891,824	146,102	1,446	35,921	76,814
35	Operating Income as Proposed	$ 26,015,003	$ (383,850)	$ 16,553,813	$ 2,055,743	$ 4,301,493	$ 2,314,504	$ 480,919	$ 73,612	$ 326,615	$ 292,155
36	Return at Proposed Rates	9.12%	-2.68%	9.27%	8.84%	12.12%	13.96%	9.11%	4.29%	5.10%	7.91%

National Grid RI Gas
Docket No. ________
Class Cost of Service - Functional Rate Base
Filed Revenue Requirement Including Interruptible as Class with Transfer from Firm

	System Total	Residential Non-Heating	Residential Heating	Small Commercial General	Medium Commerical General	Large Low Load Factor	Large High Load Factor	Extra Large Low Load Factor	Extra Large High Load Factor	Interruptible
Propane										
Demand	$ (1,650,208)	$ (18,783)	$ (836,358)	$ (115,186)	$ (230,717)	$ (133,848)	$ (9,134)	$ (167,870)	$ (138,312)	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (1,650,208)*	*$ (18,783)*	*$ (836,358)*	*$ (115,186)*	*$ (230,717)*	*$ (133,848)*	*$ (9,134)*	*$ (167,870)*	*$ (138,312)*	*$ -*
LNG										
Demand	$ 2,647,389	$ 30,134	$ 1,341,749	$ 184,790	$ 370,134	$ 214,729	$ 14,654	$ 269,310	$ 221,891	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 2,647,389*	*$ 30,134*	*$ 1,341,749*	*$ 184,790*	*$ 370,134*	*$ 214,729*	*$ 14,654*	*$ 269,310*	*$ 221,891*	*$ -*
Distribution										
Demand	$ 178,191,065	$ 2,758,368	$ 102,005,735	$ 13,775,402	$ 29,093,213	$ 15,144,385	$ 4,945,333	$ 1,417,589	$ 5,911,298	$ 3,139,740
Customer	$ 105,298,661	$ 11,547,089	$ 75,611,389	$ 9,364,253	$ 6,160,125	$ 1,306,714	$ 305,109	$ 180,634	$ 322,842	$ 500,507
Commodity	$ 754,554	$ 11,568	$ 364,432	$ 47,855	$ 106,683	$ 53,272	$ 20,780	$ 16,216	$ 81,103	$ 52,647
Sub-total	*$ 284,244,281*	*$ 14,317,025*	*$ 177,981,555*	*$ 23,187,510*	*$ 35,360,021*	*$ 16,504,372*	*$ 5,271,222*	*$ 1,614,439*	*$ 6,315,243*	*$ 3,692,894*
TOTAL										
Demand	$ 179,188,247	$ 2,769,719	$ 102,511,126	$ 13,845,006	$ 29,232,630	$ 15,225,267	$ 4,950,853	$ 1,519,029	$ 5,994,877	$ 3,139,740
Customer	$ 105,298,661	$ 11,547,089	$ 75,611,389	$ 9,364,253	$ 6,160,125	$ 1,306,714	$ 305,109	$ 180,634	$ 322,842	$ 500,507
Commodity	$ 754,554	$ 11,568	$ 364,432	$ 47,855	$ 106,683	$ 53,272	$ 20,780	$ 16,216	$ 81,103	$ 52,647
TOTAL RATE BASE	***$ 285,241,462***	***$ 14,328,375***	***$ 178,486,947***	***$ 23,257,114***	***$ 35,499,438***	***$ 16,585,253***	***$ 5,276,741***	***$ 1,715,879***	***$ 6,398,822***	***$ 3,692,894***

National Grid RI Gas
Docket No. ________
Class Cost of Service - Functional Revenue Requirement
Filed Revenue Requirement Including Interruptible as Class with Transfer from Firm

	System Total	Residential Non-Heating	Residential Heating	Small Commercial General	Medium Commerical General	Large Low Load Factor	Large High Load Factor	Extra Large Low Load Factor	Extra Large High Load Factor	Interruptible
Propane										
Demand	$ 250,692	$ 2,853	$ 127,055	$ 17,498	$ 35,049	$ 20,334	$ 1,388	$ 25,502	$ 21,012	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 250,692*	*$ 2,853*	*$ 127,055*	*$ 17,498*	*$ 35,049*	*$ 20,334*	*$ 1,388*	*$ 25,502*	*$ 21,012*	*$ -*
LNG										
Demand	$ 2,396,287	$ 27,276	$ 1,214,485	$ 167,263	$ 335,027	$ 194,362	$ 13,264	$ 243,766	$ 200,845	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 2,396,287*	*$ 27,276*	*$ 1,214,485*	*$ 167,263*	*$ 335,027*	*$ 194,362*	*$ 13,264*	*$ 243,766*	*$ 200,845*	*$ -*
Distribution										
Demand	$ 63,673,957	$ 956,359	$ 35,304,483	$ 4,766,489	$ 10,072,157	$ 5,241,021	$ 1,714,779	$ 759,864	$ 3,171,827	$ 1,686,977
Customer	$ 76,909,271	$ 7,771,891	$ 55,644,193	$ 7,725,944	$ 4,229,774	$ 716,776	$ 269,136	$ 91,488	$ 218,734	$ 241,335
Commodity	$ 6,655,090	$ 145,187	$ 3,501,841	$ 456,092	$ 898,303	$ 439,864	$ 160,771	$ 115,902	$ 569,716	$ 367,414
Sub-total	*$ 147,238,317*	*$ 8,873,437*	*$ 94,450,517*	*$ 12,948,525*	*$ 15,200,235*	*$ 6,397,661*	*$ 2,144,687*	*$ 967,253*	*$ 3,960,277*	*$ 2,295,727*
TOTAL										
Demand	$ 66,320,935	$ 986,488	$ 36,646,023	$ 4,951,250	$ 10,442,234	$ 5,455,716	$ 1,729,431	$ 1,029,132	$ 3,393,684	$ 1,686,977
Customer	$ 76,909,271	$ 7,771,891	$ 55,644,193	$ 7,725,944	$ 4,229,774	$ 716,776	$ 269,136	$ 91,488	$ 218,734	$ 241,335
Commodity	$ 6,655,090	$ 145,187	$ 3,501,841	$ 456,092	$ 898,303	$ 439,864	$ 160,771	$ 115,902	$ 569,716	$ 367,414
Total Revenue Requirement	***$ 149,885,296***	***$ 8,903,566***	***$ 95,792,057***	***$ 13,133,286***	***$ 15,570,311***	***$ 6,612,356***	***$ 2,159,338***	***$ 1,236,521***	***$ 4,182,134***	***$ 2,295,727***

National Grid RI Gas
Docket No. ________
Class Cost of Service - Unit Costs
Filed Revenue Requirement Including Interruptible as Class with Transfer from Firm

	System Total	Residential Non-Heating	Residential Heating	Small Commercial General	Medium Commerical General	Large Low Load Factor	Large High Load Factor	Extra Large Low Load Factor	Extra Large High Load Factor	Interruptible
Propane										
Demand	$ 0.0067	$ 0.0050	$ 0.0071	$ 0.0074	$ 0.0066	$ 0.0077	$ 0.0014	$ 0.0318	$ 0.0052	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG										
Demand	$ 0.0643	$ 0.0477	$ 0.0674	$ 0.0707	$ 0.0635	$ 0.0738	$ 0.0129	$ 0.3041	$ 0.0501	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution										
Demand	$ 1.7074	$ 1.6727	$ 1.9601	$ 2.0153	$ 1.9102	$ 1.9906	$ 1.6696	$ 0.9481	$ 0.7913	$ 0.6483
Customer	$ 25.6364	$ 21.4525	$ 23.6643	$ 34.6348	$ 78.0300	$ 136.6849	$ 138.4444	$ 231.0292	$ 276.1797	$ 359.1297
Commodity	$ 0.1785	$ 0.2539	$ 0.1944	$ 0.1928	$ 0.1704	$ 0.1671	$ 0.1565	$ 0.1446	$ 0.1421	$ 0.1412
TOTAL										
Demand	$ 1.7784	$ 1.7254	$ 2.0345	$ 2.0934	$ 1.9804	$ 2.0721	$ 1.6839	$ 1.2841	$ 0.8466	$ 0.6483
Customer	$ 25.6364	$ 21.4525	$ 23.6643	$ 34.6348	$ 78.0300	$ 136.6849	$ 138.4444	$ 231.0292	$ 276.1797	$ 359.1297
Commodity	$ 0.1785	$ 0.2539	$ 0.1944	$ 0.1928	$ 0.1704	$ 0.1671	$ 0.1565	$ 0.1446	$ 0.1421	$ 0.1412
Total Throughput (dth)	*37,293,494*	*571,735*	*18,011,881*	*2,365,191*	*5,272,745*	*2,632,936*	*1,027,033*	*801,470*	*4,008,472*	*2,602,032*
All Customers	*250,000*	*30,190*	*195,950*	*18,589*	*4,517*	*437*	*162*	*33*	*66*	*56*
Total Throughput (dth)	*37,293,494*	*571,735*	*18,011,881*	*2,365,191*	*5,272,745*	*2,632,936*	*1,027,033*	*801,470*	*4,008,472*	*2,602,032*

Commission Record Request No. 24

Request:

The Company is proposing to maintain its current earnings sharing mechanism. How would the adoption of the Company's proposed decoupling mechanism impact the earnings sharing mechanism and formula as currently in place?

Response:

In Docket 3401, the Commission approved an earnings sharing mechanism and sharing formula to be in effect through June 30, 2010. In this proceeding, the Company is proposing to keep this mechanism in effect until the effective date of the rates in the Company's next base-rate filing, which may or may not be later than June 30, 2010.

The earnings sharing mechanism approved in the Docket 3401 Settlement calculates the Company's actual earned return on equity for the twelve month period ended June 30th of each year, and shares earnings above the Commission approved return on equity allowance. The current return on equity allowance is 11.25%, as previously established by the Commission, and, for future periods, will be replaced with the return on equity allowance as established in this proceeding. This mechanism and sharing formula is unaffected by the adoption of the Company's proposed decoupling mechanism. Assuming the Company's proposed decoupling mechanism is approved; the Company will calculate the class revenue per customer adjustments on a monthly basis and will accrue the aggregate of the adjustments to revenue monthly. This ensures that the decoupling adjustments are included in earnings in the periods that they are generated as opposed to the periods in which they are ultimately billed or credited to customers. Earnings up to 100 basis points above the allowed return on equity as established in this proceeding would be shared 50/50 between customers and the Company. Incremental earnings of more than 100 basis points above the allowed return on equity as established in this proceeding would be shared 75/25 between customers and the Company.

Prepared by or under the supervision of: Mike Laflamme and David Effron

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Commission Record Request No. 26

Request:

Please describe the purpose of the Advanced Gas Technology program and what the funding would be used for in the future. Will the funding be used primarily to promote energy efficiency technology, research and development projects or some other type of activity? Is the Company planning on putting this money to use in the next 12 months?

Response:

The Advanced Gas Technology (AGT) program is funded through base rates in the amount of $300,000 annually and the current balance of the fund is $700,000.

Historically, the funds were available for rebates associated with installation of projects that add load to the system primarily in the off-peak period. The project must have a better load profile than the gas system in total so that it benefits all customers. The objective is to promote natural gas technology where normally natural gas might not be the customer's first choice because of a relatively high initial cost. For example, the program would enable the installation of a gas chiller rather than an electric chiller, or a cogeneration unit rather than electric service, or encourage the use of natural gas vehicles rather than gasoline-fueled vehicles. The amount of the rebate is calculated to be based on the least of three amounts, which are: (1) 75% of net present value of the project's lifetime margin; (2) 75% of the difference between the base and alternate capital cost for the project, and (3) an amount resulting in simple payback of 1.5 years.

Currently, there are three major AGT projects in various stages of discussions with customers. All three projects are cogen applications with the largest sized at 10 megawatts ("MW") and the other two tentatively sized at 6 MW and 1 MW. Two of the projects would be undertaken in coordination with universities and the other project with the State of Rhode Island. In one case, the customer has already contracted for an engineering assessment of the project. If either of the two larger projects is implemented, the Company would anticipate that the rebate would be in the range of $500,000 to $600,000. Given the size and complexity of these projects, implementation is not expected to occur before October 2009. However, under the terms of the AGT Program, a commitment letter would be issued prior to implementation requiring the commitment of rebate funds to those projects.

Prepared by or under the supervision of: Nick Stavropoulos and Peter Czekanski

Commission Record Request No. 26 (cont.)

In addition, the Company is in the process of identifying other technology initiatives that would be undertaken from a research and development standpoint with the objective of improving system utilization and operation. As stated by Mr. Stavropoulos, some of these projects may fall within the parameters of the AGT Program, in which case the Company anticipates that it would make a proposal to the Commission and the Division for funding consideration.

Prepared by or under the supervision of: Nick Stavropoulos and Peter Czekanski