nationalgrid

Thomas R. Teehan
Senior Counsel

October 11, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4346 - 2012 Gas Cost Recovery Filing ("GCR")
<u>Responses to Division Data Requests – Set 2</u>

Dear Ms. Massaro:

Enclosed are National Grid's responses to the Division's Second Set of Data Requests issued in the above-referenced proceeding.

The Company is seeking protective treatment of the Excel version of Attachment DIV 2-1 as permitted by Commission Rule 1.2(g) and by R.I.G.L. § 38-2-2(5)(i)(B). The Company has submitted a Motion for Protective Treatment under separate cover along with one (1) copy of the confidential attachment on CD-ROM to the Commission pending a determination on the Company's Motion.

In addition, the Company is providing a copy of the confidential CD-ROM to the Division and its consultant, pursuant to a protective agreement between the parties.

Please be advised that the Company's response to Division 2-16 will be filed shortly.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7685.

Very truly yours,

Thomas R. Teehan

Enclosure

cc: Docket 4346 Service List
Leo Wold, Esq.
Steve Scialabba
Bruce Oliver

280 Melrose Street, Providence, RI 02907
T: (401) 784-7667 ■ F: (401) 784-4321 ■ thomas.teehan@us.ngrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically submitted to the individuals listed below. The Commission received hard copies of this transmittal.

Joanne M. Scanlon

October 11, 2012
Date

Docket No. 4346 – National Grid – 2012 Annual Gas Cost Recovery Filing ("GCR") - Service List as of 10/11/12

Name/Address	E-mail	Phone
Thomas R. Teehan, Esq. National Grid 280 Melrose St. Providence, RI 02907	Thomas.Teehan@nationalgrid.com Joanne.Scanlon@nationalgrid.com	401-784-7667
Ann E. Leary National Grid 40 Sylvan Road Waltham, MA 02541	Ann.Leary@nationalgrid.com	
Elizabeth D. Arangio National Grid 40 Sylvan Road Waltham, MA 02541	Elizabeth.Arangio@nationalgrid.com	
Stephen A. McCauley National Grid 40 Sylvan Road Waltham, MA 02541	Stephen.Mccauley@nationalgrid.com	
Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence RI 02903	Lwold@riag.ri.gov Sscialabba@ripuc.state.ri.us dmacrae@riag.ri.gov	401-222-2424
Bruce Oliver Revilo Hill Associates 7103 Laketree Drive Fairfax Station, VA 22039	Boliver.rha@verizon.net	703-569-6480
File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02888	Lmassaro@puc.state.ri.us Plucarelli@puc.state.ri.us Sccamara@puc.state.ri.us	401-780-2107 401-941-1691

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2012
Docket No. 4346

NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission ("Commission") provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.2(g) and R.I.G.L. § 38-2-2(5)(i)(B). National Grid also hereby requests that, pending entry of that finding, the Commission preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On October 11, 2012, National Grid filed with the Commission its responses to the Division of Public Utilities and Carriers' ("Division") second set of data requests in this docket. The attachment to Response 2-1 (Att. DIV 2-1) incorporates pricing information contained in the Distrigas contract and relative to forecasted basis numbers for which National Grid is requesting confidential treatment. The Company already requested confidential treatment for this information when it was originally submitted on

September 4, 2012 as part of Attachments EDA-2 and EDA-4 to the testimony of Elizabeth A. Arangio.

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(5)(i)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; <u>or</u> (2) to cause substantial harm to the competitive position of the person from whom the information

---

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

was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I.2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under that balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

II. BASIS FOR CONFIDENTIALITY

The Company seeks protective treatment for pricing information under its contract with Distrigas and for its basis number information, which provides price forecasts at specific points where gas is purchased. This basis information is assembled by a third-party and purchased by the Company subject to contractual agreement to maintain it as proprietary and confidential information. This type of pricing and basis information is proprietary, confidential, and not of a kind that the Company would customarily release to the public. Public disclosure of this information would prejudice the Company in its ability to obtain similar information in the future and would deter the Company's ability to obtain the lowest prices for its customers.

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to that portion of its data responses identified above.

Respectfully submitted,

NATIONAL GRID

By its attorney,

____

Thomas R. Teehan, Esq. (RI Bar #4698)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7667

Dated: October 11, 2012

Division 2-1

Request:

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Re: the September 4, 2012, Direct Testimony and Attachments of witness Ann E. Leary, please provide all workpapers (including electronic spreadsheet files), data, analyses, studies and other documents supporting development of witness Leary's Direct Testimony and Attachments.

Response:

The Company is providing the Excel version of Attachment DIV 2-1 on CD-ROM. Please be advised that the Company is seeking confidential treatment of this attachment as permitted by Commission Rule 1.2(g) and by R.I.G.L. §38-2-2(5)(i)(B). In addition, the CD-ROM containing the above-referenced attachment is also being provided to the Division and its consultant pursuant to a confidentiality agreement between the parties.

Division 2-2

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 5, lines 8-12, a quantitative demonstration of the manner in which the proposed changes in FT-2 Storage charges "will improve the alignment between how storage fixed costs are incurred and how they are recovered.

Response:

In accordance with the recent approval of the revised Marketer tariffs in Docket No. 4270, the Company bills Marketers for the storage and peaking demand costs based on a maximum daily contract quantity and no longer recovers these costs through a volumetric surcharge. This ensures that the Company will recover from Marketers their allocated portion of these fixed underground storage and peaking demand costs and will not be subject to over or under recovery of these charges due to volumetric changes. In addition, billing on a demand basis is consistent with the billing method used by the pipelines. For example, last year the Company forecasted the FT-2 volumes at 2,852,725 Dth and correspondingly designed the FT-2 Marketer rate at $0.3690/Dth. Therefore, the Company was anticipating collecting $1,052,656 from Marketers (2,852,725 * 0.3690). However, the actual/projected throughput for the period Nov 2011 – October 2012 is forecasted to be only 2,701,116 Dth and therefore the Company will only collect $996,712 from Marketers. With the implementation of the demand rate, the Marketers will pay their prorate share regardless of variances to throughput.

Division 2-3

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary, please provide quantitative analyses that demonstrate by C&I rate classification that the effective costs of capacity for C&I Sales service customers are comparable to the effective costs of capacity for FT-2 customers.

Response:

Please see attached analysis that compares the fixed gas costs that the FT-2 customers would pay if they were on the Company's GCR rates as compared to the fixed gas costs the Marketers pay under the FT-2 Demand rate and the Pipeline capacity costs. For comparison purposes, the Company removed from its Fixed GCR rates the prior period reconciliation, NGPMP credits, and the Marketer Reconciliation. Also the pipeline capacity costs were based on the overall system average costs of capacity as calculated in Attachment EDA-2 page 17. The FT-2 charges are approximately $230K greater than the $4.4M in C&I sales costs the marketers would have incurred if they purchased C&I sales service at the forecasted level of transportation 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	Nov-Oct
	FT-2 TRANSPORTATION THROUGHPUT -THERM													
1	FT-2 Medium	92,888	159,599	219,045	234,859	204,413	151,837	105,327	68,711	55,908	50,329	59,272	57,359	1,459,546
2	FT-2 Large LLF	60,687	110,429	167,936	167,051	155,037	122,409	66,369	40,157	19,655	15,980	19,047	29,944	974,700
3	FT-2 Large HLF	18,521	23,975	27,099	26,494	27,954	22,743	19,797	15,478	13,152	14,036	14,742	14,350	238,339
4	FT-2 Extra Large LLF	3,015	5,220	8,530	7,548	6,718	5,357	3,709	1,489	1,425	1,446	1,414	1,359	47,230
5	FT-2 Extra Large HLF	10,716	10,540	16,390	13,759	13,375	12,647	16,583	13,581	9,378	13,944	10,967	10,056	151,936
6	**Total FT-2 Transportation**	185,827	309,764	438,999	449,710	407,496	314,992	211,785	139,415	99,519	95,734	105,441	113,068	2,871,750
7														
8	GCR Filed Fixed Rate	$/therm												
9	HLF	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	1.3509	
10	LLF	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	1.8206	
11														
12	GCR Filed Fixed Rate excluding prior period reconciliation, NGPMP, and Marketer Reconciliation													
13	HLF	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	1.1785	
14	LLF	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	1.5883	
15														
16	**GCR Collections Assuming Transportation Customers Paid GCR Rates**													
17	FT-2 Medium	147,534	253,492	347,909	373,026	324,669	241,162	167,291	109,133	88,798	79,937	94,141	91,104	2,318,197
18	FT-2 Large LLF	96,389	175,395	266,732	265,327	246,245	194,422	105,413	63,782	31,218	25,381	30,252	47,560	1,548,116
19	FT-2 Large HLF	21,827	28,255	31,936	31,223	32,943	26,802	23,330	18,240	15,500	16,541	17,373	16,911	280,882
20	FT-2 Extra Large LLF	4,788	8,292	13,548	11,988	10,670	8,508	5,892	2,364	2,264	2,296	2,246	2,158	75,015
21	FT-2 Extra Large HLF	12,629	12,421	19,315	16,215	15,763	14,905	19,543	16,005	11,052	16,433	12,924	11,851	179,056
22														
23	**Total**	283,167	477,854	679,441	697,779	630,290	485,800	321,470	209,524	148,832	140,588	156,936	169,585	4,401,267
24														
25	**Marketer Rates**													
26														
27	FT-2 Demand													
28	MDCQ	13651	13651	13651	13651	13651	13651	13651	13651	13651	13651	13651	13651	163,812
29	Marketer FT-2 Rate	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	7.1955	86
30		98,226	98,226	98,226	98,226	98,226	98,226	98,226	98,226	98,226	98,226	98,226	98,226	1,178,709
31														
32	FT-2													
33	Pipeline	MDCQ												
34	Marketer A	2,229	2,229	2,229	2,229	2,229	2,229	2,229	2,229	2,229	2,229	2,229	2,229	
35	Marketer B	8,325	8,325	8,325	8,325	8,325	8,325	8,325	8,325	8,325	8,325	8,325	8,325	
36	Marketer C	785	785	785	785	785	785	785	785	785	785	785	785	
37	Marketer D	260	260	260	260	260	260	260	260	260	260	260	260	
38	Marketer E	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	
39	Marketer F	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	
40	Marketer G													
41	Total	16,928	16,928	16,928	16,928	16,928	16,928	16,928	16,928	16,928	16,928	16,928	16,928	
42														
43	System Average Pipeline cost	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	17.0071	
44														
45	No. Day													
46	Total Pipeline Capacity costs	287,894	287,894	287,894	287,894	287,894	287,894	287,894	287,894	287,894	287,894	287,894	287,894	3,454,731
47														
48	Total Marketer Costs	386,120	386,120	386,120	386,120	386,120	386,120	386,120	386,120	386,120	386,120	386,120	386,120	4,633,440
49														
50	**Variance**	(102,953)	91,734	293,321	311,659	244,170	99,680	(64,650)	(176,596)	(237,288)	(245,532)	(229,184)	(216,535)	(232,174)

Division 2-4

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 8, line 13, through page 9, please:

a. Document by marketer by month the amount of applicable Tennessee rates for the months of June 2011 through October 2011:

    1. Under the "final approved November 2011 Tennessee rates;
    2. Under the rates actually billed for the months of June 2011 through October 2011;

b. Document by marketer by month the amount of Tennessee Refunds "directly provided" to each marketer during the 2010-2011 reconciliation period;

Response:

a. Please see Attachment DIV 2-4 (a) 1 and 2.

b. Please see Attachment DIV 2-4 (b).

Final Approved Tennessee Rates

Month	Amerada Hess	Direct	Glacial	Global	Metromedia	Santa Buckley	Sprague
June-11	$6,030.26	$67,113.81	$8,351.27	$24,815.19	$27,071.12	$35,118.70	$37,569.85
July-11	$6,030.26	$67,092.12	$8,372.96	$24,815.19	$27,071.12	$35,118.70	$37,569.85
August-11	$6,030.26	$67,005.35	$8,459.72	$24,815.19	$27,071.12	$35,118.70	$37,569.85
September-11	$6,030.26	$67,005.35	$8,459.72	$24,815.19	$27,071.12	$35,118.70	$37,569.85
October-11	$6,030.26	$67,005.35	$8,459.72	$24,815.19	$27,071.12	$35,118.70	$37,569.85
Total	$30,151.32	$335,221.99	$42,103.40	$124,075.95	$135,355.58	$175,593.50	$187,849.26

Actual Billed Tennessee Rates

Month	Amerada Hess	Direct	Glacial	Global	Metromedia	Santa Buckley	Sprague
June-11	$8,192.02	$91,173.06	$11,345.06	$33,711.05	$36,775.69	$47,708.21	$51,038.06
July-11	$8,192.02	$91,143.60	$11,374.53	$33,711.05	$36,775.69	$47,708.21	$51,038.06
August-11	$8,192.02	$91,025.73	$11,492.40	$33,711.05	$36,775.69	$47,708.21	$51,038.06
September-11	$8,192.02	$91,025.73	$11,492.40	$33,711.05	$36,775.69	$47,708.21	$51,038.06
October-11	$8,192.02	$91,025.73	$11,492.40	$33,711.05	$36,775.69	$47,708.21	$51,038.06
Total	$40,960.10	$455,393.84	$57,196.81	$168,555.24	$183,878.45	$238,541.03	$255,190.28

Tennessee Refunds directly provided to each marketer

Month	Amerada Hess	Direct	Glacial	Global	Metromedia	Santa Buckley	Sprague	
June-11	$2,161.76	$24,059.25	$2,993.80	$8,895.86	$9,704.57	$12,589.51	$13,468.21	
July-11	$2,161.76	$24,051.48	$3,001.57	$8,895.86	$9,704.57	$12,589.51	$13,468.21	
August-11	$2,161.76	$24,020.37	$3,032.68	$8,895.86	$9,704.57	$12,589.51	$13,468.21	
September-11	$2,161.76	$24,020.37	$3,032.68	$8,895.86	$9,704.57	$12,589.51	$13,468.21	
October-11	$2,161.76	$24,020.37	$3,032.68	$8,895.86	$9,704.57	$12,589.51	$13,468.21	
Total Refund	$10,808.78	$120,171.85	$15,093.41	$44,479.29	$48,522.86	$62,947.53	$67,341.03	
Interest	$ 116.63	$ 1,296.85	$ 162.75	$ 479.96	$ 523.60	$ 679.25	$ 726.66	
Total Refund w/Interest	$10,925.41	$121,468.70	$15,256.16	$44,959.25	$49,046.46	$63,626.78	$68,067.68	$373,350.45

Division 2-5

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 9, lines 1-5, please

a. Explain when and in what form the calculated $375,462 amount will be billed to marketers; and

b. Provide the amount of the surcharge that will be applied to each marketer and provide supporting workpapers, data and calculations for the determination of each marketer's surcharge amount.

Response:

a. The calculated $374,462 amount will be billed to marketers from November 2012 to October 2013 through the surcharge/credit for the differential between the released pipeline path and the Weighted Average Upstream Pipeline Transportation Cost as calculated in Attachment EDA-4.

b. Each marketer will be accessed $0.0317 per dekatherm of released pipeline capacity. This surcharge is included in the Company's Weighted Average Upstream Pipeline Transportation Cost, thus increasing the surcharge, or decreasing the credit the marketer would pay/receive for the released pipeline path. This factor is derived by dividing the $374,462 by the Marketer demand volumes of 11,831,110 dekatherms. See Attachment EDA-4 page 10.

Prepared by or under the supervision of: Ann E. Leary

Division 2-6

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 9, lines 8-9, please provide the workpapers, data and calculations relied upon in the development of the Company's design winter sales and throughput projections.

Response:

As provided in response to Division 2-1, please refer to tabs "AEL-1 pg 11 (Forecast dth)" and "AEL-1 pg 12 (DesignWinter)" in the electronic workpapers provided on CD-ROM.

Division 2-7

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 9, line 14, please:

a. Provide the witness' definition of "balancing related LNG Costs;"

b. Explain how the costs that the witness references as "balancing related LNG Costs" costs relate to the "System Pressure Costs" referenced in the Company's DAC filing;

c. Explain the witness' understanding of the function System Pressure Costs support and how that function relates to "balancing."

Response:

The "balancing related LNG costs" are the LNG costs related to system pressure which the Company allocates to DAC.

Prepared by or under the supervision of: Ann E. Leary

Division 2-8

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 9, line 20, to page 10, line 7, please provide the workpapers, data and calculations relied upon in the development of the Company's design winter sales and throughput projections.

Corrected Request:

Re: the September 4, 2012, Direct Testimony of witness Ann E. Leary at page 9, line 20, to page 10, line 7, please provide the workpapers, data and calculations relied upon in the development of the Company's deferred gas cost balance.

Response:

Please see the electronic workpapers as provided in response to Division 2-1 for the Company's estimate of the deferred gas cost balance at the end of the current GCR period on October 31, 2012.

Division 2-9

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: Attachment AEL-1, please provide the workpapers, data, analyses, studies and other documents upon which the Company relies to demonstrate that the proposed design of GCR charges based on high load factor and low load factor categories of service properly assigns Storage Variable Non-Product Costs to FT-2 marketers.

Response:

Please see the electronic workpapers as provided in response to Division 2-1. With the consolidation of the GCR from five to two buckets, the Company no longer separately identifies the Storage Variable Non-Product costs (which are costs associated with transporting gas from storage to the Company's city gate, injection and withdrawal cost from storage, and fuel costs associated with storage). In prior filings, these costs were separately identified and developed into a separate component so that the Company could bill the FT-2 Marketers this factor. However, with the recent changes in the Marketer Terms and Conditions approved in Docket No. 4270, FT-2 marketers now pay monthly charges for the underground storage and peaking gas that they use. This monthly price will be based on the monthly inventory price plus the price for transporting gas from Storage to the Company's city gate, injection and withdrawal costs from storage, and fuel costs. As a result, these Storage Variable Non-Product costs that were previously included in the monthly FT-2 Marketer rate will now be recovered through the monthly pricing storage charge.

Division 2-10

Request:

Re: Attachment AEL-1, page 1 of 7, please provide the forecasted sales and throughput volumes upon which the forecasted costs and deferred balances are premised for the months of August 2012, September 2012 and October 2012.

Response:

Please see Attachment DIV 2-10 for the forecasted sales and throughput volumes in Attachment AEL-1, page 7 and 8 of 12 for the months of August 2012, September 2012 and October 2012.

Prepared by or under the supervision of: Ann E. Leary

	Aug-12 Dth	Sep-12 Dth	Oct-12 Dth
Residential Non-Heating	34,708	37,693	38,187
Residential Heating	437,553	455,959	445,472
Small C&I	41,729	65,108	87,476
Medium C&I	46,772	99,025	115,761
Large LLF	7,432	16,702	26,476
Large HLF	19,037	21,264	22,386
Extra Large LLF	-	199	83
Extra Large HLF	16,451	17,771	19,230
Forecasted Sales	603,682	713,721	755,071
Sendout	615,100	675,400	1,255,800

Division 2-11

Request:

Re: Attachment AEL-1, page 11 of 12, please provide:

a. The Company's projections of the numbers of Small C&I customers that will migrate from Sales service to FT-2 Transportation Service in each month of the 2012-2013 GCR period.

b. The Company's projections of the Small C&I customer volumes that will migrate from Sales service to FT-2 Transportation Service in each month of the 2012-2013 GCR period.

c. The number of Small C&I customers and associated annual normal weather volumes that have migrated from Sales service to FT-2 Transportation Service to date.

Response:

a. The Company does not have projections of the numbers of Small C&I customers that will migrate from Sales Service to FT-2 Transportation Service for two reasons. First, the Company's forecasts of customer counts do not distinguish which customers are projected to transfer from one specific rate class to another specific rate class. The forecasts only show the net change in customer counts for each C&I rate class. Second, the Company prepared its forecast before the Commission issued its order in Docket No. 4270 (August 1, 2012) that allows Small C&I sales customers to migrate to transportation service.

b. Please see the response above.

c. No small C&I customers have migrated to FT-2 service as of September 2012.

Division 2-12

Request:

Re: Attachment AEL-1, pages 6 of 12 and 7 of 12, please:

a. Provide the Company's actual Supply Fixed Costs, Storage Fixed Costs, Variable Supply Costs, and Storage Variable Costs for the months of November 2011 through July 2012 and forecasted Supply Fixed Costs, Storage Fixed Costs, Variable Supply Costs, and Storage Variable Costs for the months of August 2012 through October 2012 by pipeline or supplier in a format comparable to that used in Attachment AEL-1, pages 4 and 5;

b. Explain why the LNG Demand to DAC costs shown on page 6, line 15, for the forecasted months (i.e., Aug-12 through Oct-12) decline noticeably from the levels shown for each of the actual months.

c. Explain and document numerically the factors that cause "Supply Related LNG to DAC" to be a positive number for March 2012 and negative for all other months shown.

Response:

a. Please see Attachment DIV 2-12 (a).

b. The LNG Demand to DAC costs shown on page 6, line 15, for the forecasted months (i.e., Aug-12 through Oct-12) is based on the last year's GCR filing, Docket No. 4283. At the time of the filing, the Company had not yet finalized the Distrigas contract for GCR 2011/12 year. Therefore, the LNG Demand to DAC costs did not include the costs related to Distrigas contract in the forecast.

c. The reason "Supply Related LNG to DAC" was a positive number for March 2012 is that the LNG withdrawal costs for February 2012 were over-accrued. Each month, the Company books an accrual for the current month's gas cost and the net variance between the prior month's accrual and prior month's actual gas cost. Therefore, March's LNG gas cost includes the net variance between February's accrual and actual LNG costs. The reversal of February's LNG gas cost accrual resulted in March's LNG gas cost being negative. Since Supply Related LNG to DAC represents the reallocation of LNG costs from the GCR to the DAC, this negative adjustment appeared as a positive in the GCR Filing. Please see the details in Attachment DIV 2-12 (c).

Prepared by or under the supervision of: Ann E. Leary

Projected Gas Costs using 08-15-12 NYMEX

	Nov-11 actual	Dec-11 actual	Jan-12 actual	Feb-12 actual	Mar-12 actual	Apr-12 actual	May-12 actual	Jun-12 actual	Jul-12 actual	Aug-12 fcst	Sep-12 fcst	Oct-12 fcst	Nov-Oct
SUPPLY FIXED COSTS - Pipeline Delivery													
Algonquin	872,052	1,037,363	991,108	949,100	725,335	854,731	714,262	213,577	902,244	650,451	650,451	650,451	9,211,124
Alberta Northeast		526	526	474	(51)	539	516	495	499				3,525
Texas Eastern	765,159	903,311	819,999	862,839	875,989	762,149	781,929	940,981	716,124	211,880	211,880	211,880	8,064,119
TETCO	0	0	0	0	0	0	0	0	0	528,382	528,382	528,382	1,585,145
Tennessee	1,028,887	891,113	1,140,018	1,085,702	941,329	984,807	1,116,884	530,724	976,370	1,285,834	1,285,834	1,285,834	12,553,335
NETNE										10,792	10,792	10,792	32,377
Iroquois	6,676	6,676	0	6,676	6,676	6,676	0	6,066	6,676	6,676	6,676	6,676	66,153
Union	2,530	(71)	(780)	2,479	2,519	2,528	2,529	2,485	2,444	2,701	2,614	2,701	24,677
Transcanada										11,583	11,209	11,583	34,374
Dominion	34,096	34,959	34,096	36,625	123,304	2,311	2,311	85,698	0	2,313	2,313	2,313	360,341
Transco	1,289	6,625	6,625	6,282	6,625	22,766	(9,708)	6,552	6,432	6,625	6,412	6,625	73,153
National Fuel	4,184	4,184	4,199	4,214	0	4,182	4,182	4,663	5,143	4,184	4,184	4,184	47,503
Columbia	315,540	265,769	321,915	302,332	319,604	306,213	302,680	203,707	288,676	287,672	287,672	287,672	3,489,453
Hubline										74,203	74,203	74,203	222,609
Westerly Lateral	57,637	57,485	57,010	55,011	44,628	56,324	56,324	53,326	56,326	56,324	56,324	56,324	663,041
BG LNG Energy	11,968	88,542	12,247	38,823	62,958	38,924	11,475	38,924	(27,045)				276,815
NJR Energy								208,759	0				208,759
Louis Dreyfus Energy								1,063,471	0				1,063,471
GDF Seuz						0	0	0	0				0
East to West										84,341	84,341	84,341	253,023
Less Credits from Mkter Releases	735,836	766,383	755,856	599,667	688,082	866,752	682,156	756,911	733,023	586,787	586,787	586,787	8,345,026
TOTAL SUPPLY FIXED COSTS - Pipeline	2,364,181	2,530,100	2,631,108	2,750,889	2,420,835	2,175,399	2,301,228	2,602,517	2,200,867	2,637,174	2,636,499	2,637,174	29,887,971
Supplier													
Distrigas FCS													
Total Supply Fixed (Pipeline & Supplier)	2,364,181	2,530,100	2,631,108	2,750,889	2,420,835	2,175,399	2,301,228	2,602,517	2,200,867	2,637,174	2,636,499	2,637,174	29,887,971
STORAGE FIXED COSTS - Facilities													
Texas Eastern SS-1 Demand	87,194	(268)	0	0	0	88,182	(296)	0	87,781	81,796	81,796	81,796	507,981
Texas Eastern SS-1 Capacity										13,361	13,361	13,361	40,084
Texas Eastern FSS-1 Demand										845	845	845	2,535
Texas Eastern FSS-1 Capacity										610	610	610	1,831
Dominion GSS Demand	83,387	86,440	83,387	84,978	(0)	83,283	100,500	0	83,387	21,543	21,543	21,543	669,989
Dominion GSS Capiacity										15,070	15,070	15,070	45,210
Dominion GSS-TE Demand										27,085	27,085	27,085	81,256
Dominion GSS-TE Capacity										19,957	19,957	19,957	59,870
Tennessee FSMA Demand	49,804	43,128	56,480	49,804	32,600	49,804	43,128	54,891	49,804	38,316	38,316	38,316	544,390
Tennessee FSMA Capacity										20,384	20,384	20,384	61,151
Columbia FSS Demand		24,720	0	0	0	0	0	0	8,775	3,830	3,830	3,830	44,985
Columbia FSS Capacity										5,894	5,894	5,894	17,683
Iroquois		6,676	112	0	0	0	(11,046)	0	(614)				(4,872)
Repsol	8,333	0	0	0	0	0	0	0	0				8,333
Keyspan LNG Tank Lease Payment	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	163,740	1,964,880
STORAGE FACILITIES FIXED COST $	392,459	324,436	303,719	298,522	196,340	385,009	296,024	218,631	392,872	412,431	412,431	412,431	4,045,306
STORAGE FIXED COSTS - Delivery													
Algonquin for TETCO SS-1	145,543	91,424	158,405	156,758	275,688	137,174	197,016	0	67,083	84,498	84,498	84,498	1,482,585
Algonquin delivery for FSS										5,642	5,642	5,642	16,927
TETCO delivery for FSS										4,985	4,985	4,985	14,956
Algonquin SCT for SS-1										1,590	1,590	1,590	4,770
Algonquin delivery for GSS, GSS-TE,										70,165	70,165	70,165	210,496
Algonquin SCT delivery for GSS-TE										447	447	447	1,341
Algonquin delivery for GSS Conv										20,168	20,168	20,168	60,503
Tennessee delivery for GSS	118,854	66,208	91,993	91,993	92,038	91,993	91,993	91,993	91,993	81,830	81,830	81,830	1,074,551
Tennessee delivery for FSMA										50,023	50,023	50,023	150,069
TETCO delivery for GSS	86,162	53,593	53,593	21,023	53,679	42,962	64,310	0	42,962	34,117	34,117	34,117	520,635
TETCO delivery for GSS-TE										3,538	3,538	3,538	10,614
TETCO delivery for GSS-TE										34,396	34,396	34,396	103,187
TETCO delivery for GSS Conv										10,674	10,674	10,674	32,022
Dominion delivery for GSS Conv										22,933	22,933	22,933	68,799
Dominion delivery for GSS										8,878	8,878	8,878	26,633
Algonquin delivery for FSS										15,212	15,212	15,212	45,635
Columbia Delivery for FSS									7,514	14,995	14,995	14,995	52,499
Distrigas FLS call payment		148,438	148,438	148,438	148,438	125,383	125,383	125,383	125,383	0	0	0	1,095,282
National Fuel					4,206								4,206
VPEM			(303)	0	0	0	0	0	0				(303)
STORAGE DELIVERY FIXED COST $	350,558	359,662	452,125	418,212	574,049	397,512	478,702	217,376	334,935	464,091	464,091	464,091	4,975,406
TOTAL STORAGE FIXED	743,017	684,098	755,845	716,734	770,389	782,521	774,727	436,007	727,807	876,522	876,522	876,522	9,020,712
TOTAL FIXED COSTS	3,107,198	3,214,198	3,386,953	3,467,623	3,191,224	2,957,921	3,075,955	3,038,524	2,928,674	3,513,696	3,513,021	3,513,696	38,908,683

Projected Gas Costs using 08-15-12 NYMEX

	Nov-11 actual	Dec-11 actual	Jan-12 actual	Feb-12 actual	Mar-12 actual	Apr-12 actual	May-12 actual	Jun-12 actual	Jul-12 actual	Aug-12 fcst	Sep-12 fcst	Oct-12 fcst	Nov-Oct
VARIABLE SUPPLY COSTS (Includes Injections)													
Total Pipeline Commodity Charges	6,107,083	10,722,952	11,589,916	10,008,590	5,338,209	3,482,661	1,887,875	1,283,682	1,462,174	1,943,693	3,160,965	3,621,597	60,609,397
Hedging	6,136,997	8,090,460	9,471,036	9,242,977	9,248,290	5,188,071	3,003,155	1,626,411	1,325,002	1,651,690	1,620,290	1,747,120	58,351,500
Costs of Injections										177,979	1,971,087	71,291	2,220,358
Refunds (Tennessee)			(406,764)		(1,548,477)								(1,955,240)
TOTAL VARIABLE SUPPLY COSTS	12,244,080	18,813,413	20,654,189	19,251,567	13,038,022	8,670,731	4,891,030	2,910,093	2,787,176	3,417,404	2,810,168	5,297,426	114,785,299
VARIABLE STORAGE COSTS													
Underground Storage	1,325,294	2,695,451	5,034,774	6,013,275	(985,495)	325,885	1,758,812	(1,105,519)	400,356	0	0	0	15,462,834
LNG Withdrawals and Trucking	132,967	217,371	1,534,727	301,350	415,824	81,388	73,019	96,291	117,174	116,130	111,839	116,274	3,314,354
TOTAL VARIABLE STORAGE COSTS	1,458,261	2,912,822	6,569,501	6,314,625	(569,671)	407,273	1,831,831	(1,009,228)	517,530	116,130	111,839	116,274	18,777,188
TOTAL VARIABLE COSTS	13,702,342	21,726,235	27,223,690	25,566,192	12,468,351	9,078,004	6,722,861	1,900,864	3,304,706	3,533,534	2,922,007	5,413,700	133,562,486
TOTAL SUPPLY COSTS	16,809,540	24,940,433	30,610,643	29,033,815	15,659,575	12,035,925	9,798,816	4,939,388	6,233,380	7,047,230	6,435,029	8,927,396	172,471,170
Storage Costs for FT-2 Calculation													
Storage Fixed Costs - Facilities	392,459	324,436	303,719	298,522	196,340	385,009	296,024	218,631	392,872	412,431	412,431	412,431	4,045,306
Storage Fixed Costs - Deliveries	350,558	359,662	452,125	418,212	574,049	397,512	478,702	217,376	334,935	464,091	464,091	464,091	4,975,406
Variable Delivery Costs	6,444	8,970	16,879	23,794	10,262	1,764	1,716	2,756	2,196	0	0	0	74,782
Variable Injection/withdrawal Costs	1,853	3,279	5,466	1,177	6,736	6,359	9,612	5,558	4,822	611	10,518	392	56,382
Fuel Costs Allocated to Storage	3,956	8,572	12,446	2,680	11,789	10,078	14,899	9,989	9,500	2,412	26,551	1,780	114,653
Total Storage Costs	755,270	704,920	790,636	744,385	799,176	800,722	800,954	454,311	744,325	879,545	913,592	878,694	9,266,530
Pipeline Variable	$12,244,080	$18,813,413	$20,654,189	$19,251,567	$13,038,022	$8,670,731	$4,891,030	$2,910,093	$2,787,176	$3,417,404	$2,810,168	$5,297,426	114,785,299
Less Non-firm Gas Costs	$232,486	$380,432	$178,276	$133,990	$109,223	$95,772	$64,990	$57,189	$51,245				
Less Company Use	$28,957	$33,795	$43,404	$42,370	$52,075	$21,768	$10,900	$20,735	$4,074				
Less Manchester St Balancing	$13,030	$19,304	$43,830	$43,830	$18,401	$36,338	$12,562	$9,044	$9,100				
Plus Cashout													
Less Mkter Over-takes	$140,012	$6,885	$28,950	$25,058	$0	$0	$0	$0	$0				
Less Mkter W/drawals	($223,162)	($148,276)	$22,939	$184,448	$64,311	($69,479)	($552,280)	($181,095)	($202,999)				
Plus Mkter Undertakes	($10,599)	$72,692	$68,739	$52,947	$52,607	$31,598	$227,657	$42,380	$21,460				
Plus Mkter Injections	$0												
Storage Service Charge													
Plus Pipeline Srchg/Credit	$128,303	$174,654	$178,133	$176,730	$168,518	$179,580	$171,321	$176,338	$170,369				
TOTAL FIRM COMMODITY COSTS	$12,170,461	$18,768,619	$20,583,663	$19,051,547	$13,015,136	$8,797,510	$5,753,837	$3,222,939	$3,117,585	$3,417,404	$2,810,168	$5,297,426	116,006,293

Supply Related LNG to DAC

LNG Withdrawals		
Feb Accrual Reversal	$	(294,464)
Feb Actuals	$	152,906
March Accrual	$	104,039
Total	$	(37,520)
System Pressure factor		18.12%
Supply Related LNG to DAC	$	(6,799)

Division 2-13

Request:

Re: Attachment AEL-1, page 8 of 12, please document the source and derivation of the amounts shown by month for:

a. "LNG Demand to DAC" on line 2;
b. "Supply Related LNG O&M Costs" on line 4.

Response:

a. The LNG Demand to DAC is based on 18.12% of the forecasted LNG-related demand costs in the GCR filing dated September 4, 2012, Attachment EDA-2. Due to the confidential nature of these materials, please refer to the electronic workpapers included in response to DIV 2-1.

b. Supply Related LNG O&M Costs are based on the Supply Related LNG O&M Fixed Costs of $618,591 annually, as approved in the last rate case Docket No. 3943.

Division 2-14

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: Attachment AEL-1, page 10 of 12, please provide the workpapers, data, analyses, studies and other documents upon which the Company relies to derive the projected monthly dollar amounts for:

a. Storage Inventory Balance on line 1,
b. LNG Inventory Balance on line 13.

Response:

a-b. Please see the electronic workpapers in response to Division 2-1.

Division 2-15

Request:

Re: Attachment AEL-1, page 12 of 12, please provide the Company's projections of the Small C&I customer design winter volumes that will migrate from Sales service to FT-2 Transportation Service in each month of the 2012-2013 GCR period.

Response:

Please see the Company's response to Division 2-11a. The Company does not have projections of the numbers of Small C&I customers that will migrate from Sales Service to FT-2 Transportation Service for two reasons. First, the Company's forecasts of customer counts and volumes do not distinguish which customers are projected to transfer from one specific rate class to another specific rate class. The forecasts only show the net change in customer counts for each C&I rate class. Second, the Company prepared its forecast before the Commission issued its order in Docket No. 4270 (August 1, 2012) that allows Small C&I sales customers to migrate to transportation service.

Division 2-17

Request:

Re: Attachment AEL-2, page 9 of 15, please:

a. Fully document the derivation of the dollar amounts shown by month for each line item under the sub-heading "Pipeline Variable;"

b. Reconcile the "Non-firm Gas Costs" shown for the month of October 2011 with the "Non-Firm Gas Costs" for the same month shown on Attachment MCS-7, page 10 of 15 in the Company's August 1, 2012 DAC filing.

Response:

a. The "Pipeline Variable" costs that come from accounting include all the gas costs incurred for the month. Since only the gas costs associated with Firm customers should be recovered through the GCR, the Non-firm gas costs, Company Use, Manchester St. Balancing, and Marketer related costs supplied by accounting are subtracted out from the total gas costs.

b. The Non-firm Gas Cost for the month of October 2011 is $114,078 as reported on Attachment MCS-7, page 10 of 15 in the Company's August 1, 2012 DAC filing. In reviewing the Company's Gas cost reconciliation, a discrepancy was identified between the non firm gas costs embedded in the total commodity costs and the non firm gas costs used to derive the firm gas costs (Total commodity costs less non firm gas costs = Firm gas costs) in the amount of $9,109. To correct this discrepancy, the Company increased up the non-firm gas costs by $9,109, from $114,078 to a total of $123,187. As an alternative, the Company could have reduced the total commodity cost by $9,109 and reflected the non-firm gas cost of $114,078 to agree with the DAC filing.

Division 2-18

Request:

Re: Attachment AEL-4, please provide:

a. Versions of the bill impact analyses that reflect the Company's projected "Average Customer" consumption for each rate class:

   1. For the 2012-2013 GCR period,
   2. For the rate year in Docket 4323;

b. Please provide the high, low and median use per customer for each rate class that the Company actually experienced in each of its last three most recently completed GCR periods.

Response:

a. 1. Please see Attachment DIV 2-18 (a)1.
   2. Please see Attachment DIV 2-18 (a)2.

b. Please see Attachment DIV 2-18 (b).

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with 2012-13 GCR period Average Customer Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

Residential Heating:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: DAC	DAC: ISR	EnergyEff
	573	$814	$858	($45)	-5.2%	$0	($70)	$25	$0	($107)
	631	$881	$930	($49)	-5.3%	$0	($77)	$28	$0	$0
	691	$951	$1,005	($54)	-5.4%	$0	($84)	$30	$0	$0
	756	$1,024	$1,083	($59)	-5.5%	$0	($92)	$33	$0	$0
	816	$1,091	$1,155	($64)	-5.5%	$0	($100)	$36	$0	$0
Average Customer	**878**	**$1,158**	**$1,227**	**($69)**	**-5.6%**	**$0**	**($107)**	**$39**	**$0**	**$0**
	940	$1,226	$1,299	($74)	-5.7%	$0	($115)	$41	$0	$0
	1,000	$1,291	$1,369	($78)	-5.7%	$0	($122)	$44	$0	$0
	1,062	$1,358	$1,441	($83)	-5.8%	$0	($130)	$47	$0	$0
	1,123	$1,423	$1,511	($88)	-5.8%	$0	($137)	$49	$0	$0
	1,186	$1,489	$1,582	($93)	-5.9%	$0	($145)	$52	$0	$0

Residential Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EnergyEff
	573	$777	$822	($45)	-5.4%	$0	($70)	$25	$0	$0
	631	$842	$892	($49)	-5.5%	$0	($77)	$28	$0	$0
	691	$910	$964	($54)	-5.6%	$0	($84)	$30	$0	$0
	756	$981	$1,040	($59)	-5.7%	$0	($92)	$33	$0	$0
	816	$1,046	$1,109	($64)	-5.7%	$0	($100)	$36	$0	$0
Average Customer	**878**	**$1,111**	**$1,180**	**($69)**	**-5.8%**	**$0**	**($107)**	**$39**	**$0**	**$0**
	940	$1,177	$1,250	($74)	-5.9%	$0	($115)	$41	$0	$0
	1,000	$1,240	$1,318	($78)	-5.9%	$0	($122)	$44	$0	$0
	1,062	$1,306	$1,389	($83)	-6.0%	$0	($130)	$47	$0	$0
	1,123	$1,369	$1,457	($88)	-6.0%	$0	($137)	$49	$0	$0
	1,186	$1,433	$1,526	($93)	-6.1%	$0	($145)	$52	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with 2012-13 GCR period Average Customer Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

Residential Non-Heating:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: DAC	DAC: ISR	EnergyEff
	145	$291	$303	($12)	-3.8%	$0	($18)	$7	$0	$0
	162	$311	$324	($13)	-4.0%	$0	($21)	$8	$0	$0
	180	$333	$347	($14)	-4.2%	$0	($23)	$8	$0	$0
	195	$350	$366	($16)	-4.3%	$0	($25)	$9	$0	$0
	210	$368	$385	($17)	-4.4%	$0	($27)	$10	$0	$0
Average Customer	**226**	**$387**	**$405**	**($18)**	**-4.5%**	**$0**	**($29)**	**$11**	**$0**	**$0**
	242	$406	$425	($19)	-4.6%	$0	($31)	$11	$0	$0
	258	$425	$446	($21)	-4.6%	$0	($33)	$12	$0	$0
	272	$441	$463	($22)	-4.7%	$0	($35)	$13	$0	$0
	287	$459	$482	($23)	-4.8%	$0	($36)	$13	$0	$0
	304	$479	$504	($24)	-4.8%	$0	($39)	$14	$0	$0

Residential Non-Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	Difference due to: GCR	DAC: DAC	DAC: ISR	EnergyEff
	145	$274	$285	($12)	-4.1%	$0	($18)	$7	$10	$0
	162	$293	$306	($13)	-4.3%	$0	($21)	$8	$11	$0
	180	$313	$328	($14)	-4.4%	$0	($23)	$8	$12	$0
	195	$331	$346	($16)	-4.5%	$0	($25)	$9	$13	$0
	210	$348	$364	($17)	-4.6%	$0	($27)	$10	$14	$0
Average Customer	**226**	**$365**	**$384**	**($18)**	**-4.7%**	**$0**	**($29)**	**$11**	**$15**	**$0**
	242	$384	$404	($19)	-4.8%	$0	($31)	$11	$16	$0
	258	$402	$423	($21)	-4.9%	$0	($33)	$12	$18	$0
	272	$418	$440	($22)	-5.0%	$0	($35)	$13	$18	$0
	287	$436	$459	($23)	-5.0%	$0	($36)	$13	$20	$0
	304	$455	$479	($24)	-5.1%	$0	($39)	$14	$21	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with 2012-13 GCR period Average Customer Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

C & I Small:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	828	$1,241	$1,307	($65)	-5.0%	$0	($101)	$36	$0	$0
	915	$1,336	$1,408	($72)	-5.1%	$0	($112)	$39	$0	$0
	1,006	$1,435	$1,514	($79)	-5.2%	$0	($123)	$43	$0	$0
	1,093	$1,529	$1,615	($86)	-5.3%	$0	($133)	$47	$0	$0
	1,183	$1,623	$1,717	($93)	-5.4%	$0	($144)	$51	$0	$0
Average Customer	**1,272**	**$1,715**	**$1,815**	**($100)**	**-5.5%**	**$0**	**($155)**	**$55**	**$0**	**$0**
	1,359	$1,802	$1,909	($107)	-5.6%	$0	($166)	$59	$0	$0
	1,451	$1,895	$2,010	($115)	-5.7%	$0	($177)	$63	$0	$0
	1,539	$1,983	$2,105	($122)	-5.8%	$0	($188)	$66	$0	$0
	1,627	$2,070	$2,199	($129)	-5.8%	$0	($199)	$70	$0	$0
	1,717	$2,160	$2,296	($136)	-5.9%	$0	($210)	$74	$0	$0

C & I Medium:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	7,035	$7,902	$8,461	($559)	-6.6%	$0	($859)	$300	$0	$0
	7,791	$8,674	$9,293	($619)	-6.7%	$0	($951)	$333	$0	$0
	8,549	$9,448	$10,127	($679)	-6.7%	$0	($1,044)	$365	$0	$0
	9,306	$10,221	$10,960	($739)	-6.7%	$0	($1,136)	$397	$0	$0
	10,066	$10,997	$11,796	($799)	-6.8%	$0	($1,229)	$430	$0	$0
Average Customer	**10,822**	**$11,769**	**$12,628**	**($859)**	**-6.8%**	**$0**	**($1,321)**	**$462**	**$0**	**$0**
	11,579	$12,542	$13,461	($919)	-6.8%	$0	($1,414)	$494	$0	$0
	12,338	$13,316	$14,296	($980)	-6.9%	$0	($1,506)	$527	$0	$0
	13,094	$14,088	$15,128	($1,040)	-6.9%	$0	($1,599)	$559	$0	$0
	13,852	$14,862	$15,962	($1,100)	-6.9%	$0	($1,691)	$592	$0	$0
	14,610	$15,636	$16,796	($1,160)	-6.9%	$0	($1,784)	$624	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with 2012-13 GCR period Average Customer Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

C & I LLF Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	36,332	$37,301	$41,661	($4,360)	-10.5%	$0	($4,436)	$76	$0	$0
	40,245	$41,163	$45,992	($4,829)	-10.5%	$0	($4,914)	$85	$0	$0
	44,159	$45,026	$50,325	($5,299)	-10.5%	$0	($5,392)	$93	$0	$0
	48,073	$48,889	$54,658	($5,769)	-10.6%	$0	($5,870)	$101	$0	$0
	51,986	$52,751	$58,989	($6,238)	-10.6%	$0	($6,347)	$109	$0	$0
Average Customer	**55,899**	**$56,613**	**$63,321**	**($6,708)**	**-10.6%**	**$0**	**($6,825)**	**$117**	**$0**	**$0**
	59,813	$60,477	$67,654	($7,178)	-10.6%	$0	($7,303)	$126	$0	$0
	63,725	$64,338	$71,985	($7,647)	-10.6%	$0	($7,781)	$134	$0	$0
	67,636	$68,198	$76,315	($8,116)	-10.6%	$0	($8,258)	$142	$0	$0
	71,550	$72,061	$80,647	($8,586)	-10.6%	$0	($8,736)	$150	$0	$0
	75,461	$75,922	$84,977	($9,055)	-10.7%	$0	($9,214)	$158	$0	$0

C & I HLF Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	33,902	$30,080	$34,311	($4,231)	-12.3%	$7,091	($4,309)	$78	$0	$0
	37,553	$33,165	$37,852	($4,687)	-12.4%	$7,700	($4,773)	$86	$0	$0
	41,204	$36,249	$41,392	($5,142)	-12.4%	$8,309	($5,237)	$95	$0	$0
	44,855	$39,334	$44,931	($5,598)	-12.5%	$8,917	($5,701)	$103	$0	$0
	48,507	$42,419	$48,472	($6,054)	-12.5%	$9,526	($6,165)	$112	$0	$0
Average Customer	**52,156**	**$45,502**	**$52,011**	**($6,509)**	**-12.5%**	**$10,135**	**($6,629)**	**$120**	**$0**	**$0**
	55,807	$48,586	$55,551	($6,965)	-12.5%	$10,743	($7,093)	$128	$0	$0
	59,458	$51,670	$59,091	($7,420)	-12.6%	$11,352	($7,557)	$137	$0	$0
	63,109	$54,755	$62,631	($7,876)	-12.6%	$11,960	($8,021)	$145	$0	$0
	66,759	$57,838	$66,170	($8,332)	-12.6%	$12,569	($8,485)	$154	$0	$0
	70,411	$60,924	$69,711	($8,787)	-12.6%	$13,178	($8,949)	$162	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with 2012-13 GCR period Average Customer Consumption:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

C & I LLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	84,970	$74,768	$85,024	($10,256)	-12.1%	$0	($10,375)	$119	$0	$0
	94,121	$82,432	$93,792	($11,360)	-12.1%	$0	($11,492)	$132	$0	$0
	103,271	$90,096	$102,560	($12,465)	-12.2%	$0	($12,609)	$145	$0	$0
	112,421	$97,759	$111,329	($13,569)	-12.2%	$0	($13,727)	$157	$0	$0
	121,571	$105,423	$120,097	($14,674)	-12.2%	$0	($14,844)	$170	$0	$0
Average Customer	**130,723**	**$113,088**	**$128,867**	**($15,778)**	**-12.2%**	**$0**	**($15,961)**	**$183**	**$0**	**$0**
	139,874	$120,753	$137,636	($16,883)	-12.3%	$0	($17,079)	$196	$0	$0
	149,025	$128,418	$146,405	($17,987)	-12.3%	$0	($18,196)	$209	$0	$0
	158,176	$136,082	$155,174	($19,092)	-12.3%	$0	($19,313)	$221	$0	$0
	167,325	$143,745	$163,941	($20,196)	-12.3%	$0	($20,430)	$234	$0	$0
	176,476	$151,409	$172,710	($21,301)	-12.3%	$0	($21,548)	$247	$0	$0

C & I HLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	164,545	$130,141	$150,841	($20,700)	-13.7%	$0	($20,914)	$214	$0	$0
	182,265	$143,769	$166,697	($22,929)	-13.8%	$0	($23,166)	$237	$0	$0
	199,985	$157,396	$182,554	($25,158)	-13.8%	$0	($25,418)	$260	$0	$0
	217,706	$171,023	$198,411	($27,387)	-13.8%	$0	($27,670)	$283	$0	$0
	235,424	$184,650	$214,266	($29,616)	-13.8%	$0	($29,922)	$306	$0	$0
Average Customer	**253,146**	**$198,279**	**$230,124**	**($31,846)**	**-13.8%**	**$0**	**($32,175)**	**$329**	**$0**	**$0**
	270,868	$211,907	$245,983	($34,075)	-13.9%	$0	($34,427)	$352	$0	$0
	288,587	$225,534	$261,838	($36,304)	-13.9%	$0	($36,679)	$375	$0	$0
	306,306	$239,160	$277,694	($38,533)	-13.9%	$0	($38,931)	$398	$0	$0
	324,026	$252,788	$293,550	($40,762)	-13.9%	$0	($41,184)	$421	$0	$0
	341,747	$266,416	$309,408	($42,992)	-13.9%	$0	($43,436)	$444	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Rate Year Average Customer Consumption in Docket 4323:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

Residential Heating:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	550	$788	$831	($43)	-5.2%	$0	($67)	$24	$0	($103)
	608	$855	$903	($48)	-5.3%	$0	($74)	$27	$0	$0
	667	$924	$976	($52)	-5.3%	$0	($81)	$29	$0	$0
	727	$992	$1,049	($57)	-5.4%	$0	($89)	$32	$0	$0
	788	$1,060	$1,122	($62)	-5.5%	$0	($96)	$35	$0	$0
Average Customer	**846**	**$1,123**	**$1,189**	**($66)**	**-5.6%**	**$0**	**($103)**	**$37**	**$0**	**$0**
	904	$1,186	$1,257	($71)	-5.6%	$0	($110)	$40	$0	$0
	966	$1,254	$1,329	($76)	-5.7%	$0	($118)	$42	$0	$0
	1,023	$1,316	$1,396	($80)	-5.7%	$0	($125)	$45	$0	$0
	1,081	$1,378	$1,463	($85)	-5.8%	$0	($132)	$47	$0	$0
	1,145	$1,446	$1,536	($90)	-5.8%	$0	($140)	$50	$0	$0

Residential Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EnergyEff
	550	$752	$795	($43)	-5.4%	$0	($67)	$24	$0	$0
	608	$817	$865	($48)	-5.5%	$0	($74)	$27	$0	$0
	667	$883	$936	($52)	-5.6%	$0	($81)	$29	$0	$0
	727	$950	$1,007	($57)	-5.6%	$0	($89)	$32	$0	$0
	788	$1,016	$1,077	($62)	-5.7%	$0	($96)	$35	$0	$0
Average Customer	**846**	**$1,077**	**$1,143**	**($66)**	**-5.8%**	**$0**	**($103)**	**$37**	**$0**	**$0**
	904	$1,139	$1,209	($71)	-5.8%	$0	($110)	$40	$0	$0
	966	$1,204	$1,280	($76)	-5.9%	$0	($118)	$42	$0	$0
	1,023	$1,264	$1,344	($80)	-6.0%	$0	($125)	$45	$0	$0
	1,081	$1,325	$1,410	($85)	-6.0%	$0	($132)	$47	$0	$0
	1,145	$1,391	$1,481	($90)	-6.0%	$0	($140)	$50	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Rate Year Average Customer Consumption in Docket 4323:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

Residential Non-Heating:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC DAC	DAC ISR	EnergyEff
	140	$285	$297	($11)	-3.8%	$0	($18)	$7	$0	$0
	155	$303	$316	($12)	-3.9%	$0	($20)	$7	$0	$0
	171	$322	$336	($14)	-4.1%	$0	($22)	$8	$0	$0
	184	$337	$352	($15)	-4.2%	$0	($23)	$9	$0	$0
	198	$354	$370	($16)	-4.3%	$0	($25)	$9	$0	$0
Average Customer	**214**	**$372**	**$390**	**($17)**	**-4.4%**	**$0**	**($27)**	**$10**	**$0**	**$0**
	228	$389	$408	($18)	-4.5%	$0	($29)	$11	$0	$0
	244	$408	$428	($20)	-4.6%	$0	($31)	$11	$0	$0
	258	$425	$446	($21)	-4.6%	$0	($33)	$12	$0	$0
	275	$445	$467	($22)	-4.7%	$0	($35)	$13	$0	$0
	288	$460	$483	($23)	-4.8%	$0	($37)	$14	$0	$0

Residential Non-Heating Low Income:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC DAC	DAC ISR	EnergyEff
	140	$268	$279	($11)	-4.0%	$0	($18)	$7	$10	$0
	155	$285	$297	($12)	-4.2%	$0	($20)	$7	$11	$0
	171	$303	$317	($14)	-4.3%	$0	($22)	$8	$12	$0
	184	$318	$333	($15)	-4.4%	$0	($23)	$9	$12	$0
	198	$334	$350	($16)	-4.5%	$0	($25)	$9	$13	$0
Average Customer	**214**	**$352**	**$369**	**($17)**	**-4.6%**	**$0**	**($27)**	**$10**	**$15**	**$0**
	228	$368	$386	($18)	-4.7%	$0	($29)	$11	$15	$0
	244	$386	$406	($20)	-4.8%	$0	($31)	$11	$17	$0
	258	$403	$423	($21)	-4.9%	$0	($33)	$12	$18	$0
	275	$422	$444	($22)	-5.0%	$0	($35)	$13	$19	$0
	288	$437	$460	($23)	-5.0%	$0	($37)	$14	$20	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Rate Year Average Customer Consumption in Docket 4323:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

C & I Small:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	880	$1,298	$1,368	($69)	-5.1%	$0	($107)	$38	$0	$0
	973	$1,400	$1,477	($77)	-5.2%	$0	($119)	$42	$0	$0
	1,067	$1,502	$1,586	($84)	-5.3%	$0	($130)	$46	$0	$0
	1,162	$1,603	$1,695	($92)	-5.4%	$0	($142)	$50	$0	$0
	1,258	$1,700	$1,799	($99)	-5.5%	$0	($154)	$54	$0	$0
Average Customer	**1,352**	**$1,794**	**$1,901**	**($107)**	**-5.6%**	**$0**	**($165)**	**$58**	**$0**	**$0**
	1,446	$1,889	$2,003	($114)	-5.7%	$0	($177)	$62	$0	$0
	1,542	$1,985	$2,107	($122)	-5.8%	$0	($188)	$66	$0	$0
	1,635	$2,079	$2,208	($129)	-5.8%	$0	($200)	$70	$0	$0
	1,730	$2,173	$2,310	($137)	-5.9%	$0	($211)	$75	$0	$0
	1,825	$2,268	$2,412	($144)	-6.0%	$0	($223)	$79	$0	$0

C & I Medium:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	7,262	$8,126	$8,702	($577)	-6.6%	$0	($887)	$310	$0	$0
	8,044	$8,923	$9,562	($639)	-6.7%	$0	($982)	$343	$0	$0
	8,827	$9,722	$10,423	($701)	-6.7%	$0	($1,078)	$377	$0	$0
	9,610	$10,520	$11,283	($763)	-6.8%	$0	($1,173)	$410	$0	$0
	10,390	$11,316	$12,141	($825)	-6.8%	$0	($1,269)	$444	$0	$0
Average Customer	**11,173**	**$12,114**	**$13,002**	**($887)**	**-6.8%**	**$0**	**($1,364)**	**$477**	**$0**	**$0**
	11,957	$12,914	$13,863	($949)	-6.8%	$0	($1,460)	$511	$0	$0
	12,737	$13,709	$14,720	($1,011)	-6.9%	$0	($1,555)	$544	$0	$0
	13,520	$14,508	$15,581	($1,073)	-6.9%	$0	($1,651)	$577	$0	$0
	14,303	$15,306	$16,442	($1,136)	-6.9%	$0	($1,746)	$611	$0	$0
	15,083	$16,101	$17,299	($1,198)	-6.9%	$0	($1,842)	$644	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Rate Year Average Customer Consumption in Docket 4323:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

C & I LLF Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	37,337	$38,178	$42,658	($4,480)	-10.5%	$0	($4,559)	$78	$0	$0
	41,359	$42,135	$47,098	($4,963)	-10.5%	$0	($5,050)	$87	$0	$0
	45,378	$46,090	$51,535	($5,445)	-10.6%	$0	($5,541)	$95	$0	$0
	49,400	$50,047	$55,975	($5,928)	-10.6%	$0	($6,032)	$104	$0	$0
	53,420	$54,003	$60,413	($6,410)	-10.6%	$0	($6,523)	$112	$0	$0
Average Customer	**57,442**	**$57,960**	**$64,854**	**($6,893)**	**-10.6%**	**$0**	**($7,014)**	**$121**	**$0**	**$0**
	61,464	$61,917	$69,293	($7,376)	-10.6%	$0	($7,505)	$129	$0	$0
	65,483	$65,872	$73,730	($7,858)	-10.7%	$0	($7,995)	$138	$0	$0
	69,506	$69,830	$78,171	($8,341)	-10.7%	$0	($8,487)	$146	$0	$0
	73,527	$73,787	$82,610	($8,823)	-10.7%	$0	($8,978)	$154	$0	$0
	77,547	$77,743	$87,048	($9,306)	-10.7%	$0	($9,468)	$163	$0	$0

C & I HLF Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	38,954	$34,802	$39,663	($4,861)	-12.3%	$8,387	($4,951)	$90	$0	$0
	43,152	$38,397	$43,783	($5,385)	-12.3%	$9,136	($5,485)	$99	$0	$0
	47,346	$41,989	$47,898	($5,909)	-12.3%	$9,884	($6,018)	$109	$0	$0
	51,542	$45,583	$52,015	($6,432)	-12.4%	$10,632	($6,551)	$119	$0	$0
	55,736	$49,175	$56,131	($6,956)	-12.4%	$11,381	($7,084)	$128	$0	$0
Average Customer	**59,932**	**$52,768**	**$60,248**	**($7,479)**	**-12.4%**	**$12,129**	**($7,617)**	**$138**	**$0**	**$0**
	64,127	$56,362	$64,365	($8,003)	-12.4%	$12,877	($8,151)	$148	$0	$0
	68,323	$59,955	$68,482	($8,527)	-12.5%	$13,625	($8,684)	$157	$0	$0
	72,518	$63,548	$72,598	($9,050)	-12.5%	$14,374	($9,217)	$167	$0	$0
	76,712	$67,140	$76,713	($9,574)	-12.5%	$15,121	($9,750)	$176	$0	$0
	80,908	$70,734	$80,831	($10,097)	-12.5%	$15,870	($10,283)	$186	$0	$0

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Rate Year Average Customer Consumption in Docket 4323:
Current Distribution, GCR, DAC, and ISR Rates thru October 2013

C & I LLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	125,447	$107,971	$123,112	($15,141)	-12.3%	$0	($15,317)	$176	$0	$0
	138,956	$119,210	$135,982	($16,772)	-12.3%	$0	($16,967)	$195	$0	$0
	152,467	$130,451	$148,854	($18,403)	-12.4%	$0	($18,616)	$213	$0	$0
	165,977	$141,691	$161,724	($20,033)	-12.4%	$0	($20,266)	$232	$0	$0
	179,483	$152,928	$174,591	($21,664)	-12.4%	$0	($21,915)	$251	$0	$0
Average Customer	**192,995**	**$164,170**	**$187,465**	**($23,295)**	**-12.4%**	**$0**	**($23,565)**	**$270**	**$0**	**$0**
	206,505	$175,410	$200,335	($24,925)	-12.4%	$0	($25,214)	$289	$0	$0
	220,016	$186,651	$213,207	($26,556)	-12.5%	$0	($26,864)	$308	$0	$0
	233,524	$197,889	$226,076	($28,186)	-12.5%	$0	($28,513)	$327	$0	$0
	247,035	$209,130	$238,948	($29,817)	-12.5%	$0	($30,163)	$346	$0	$0
	260,543	$220,369	$251,816	($31,448)	-12.5%	$0	($31,812)	$365	$0	$0

C & I HLF Extra-Large:

	Nov - Oct Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: DAC	DAC: ISR	EnergyEff
	199,103	$161,682	$186,730	($25,047)	-13.4%	$0	($25,306)	$259	$0	$0
	220,544	$178,706	$206,451	($27,744)	-13.4%	$0	($28,031)	$287	$0	$0
	241,984	$195,729	$226,170	($30,442)	-13.5%	$0	($30,756)	$315	$0	$0
	263,427	$212,754	$245,893	($33,139)	-13.5%	$0	($33,482)	$342	$0	$0
	284,866	$229,776	$265,612	($35,836)	-13.5%	$0	($36,206)	$370	$0	$0
Average Customer	**306,310**	**$246,802**	**$285,336**	**($38,534)**	**-13.5%**	**$0**	**($38,932)**	**$398**	**$0**	**$0**
	327,752	$263,826	$305,058	($41,231)	-13.5%	$0	($41,657)	$426	$0	$0
	349,194	$280,851	$324,780	($43,929)	-13.5%	$0	($44,383)	$454	$0	$0
	370,634	$297,873	$344,499	($46,626)	-13.5%	$0	($47,108)	$482	$0	$0
	392,076	$314,898	$364,221	($49,323)	-13.5%	$0	($49,833)	$510	$0	$0
	413,518	$331,922	$383,943	($52,021)	-13.5%	$0	($52,558)	$538	$0	$0

	Nov '08-Oct '09	Nov '09-Oct '10	Nov '10-Oct '11
Use (therm) per customer- Low (65% of Average)			
Residential Non-Heating	504	520	568
Residential Heating	1,148	1,080	1,147
Small C&I	844	796	870
Medium C&I	6,980	6,725	7,139
Large LLF	37,047	35,244	34,389
Large HLF	35,725	37,481	33,612
Extra Large LLF	185,230	137,011	76,902
Extra Large HLF	207,020	183,000	202,093
Total Sales	474,498	401,857	356,720
Use (therm) per customer- Median (100% of Average)			
Residential Non-Heating	775	800	874
Residential Heating	1,766	1,661	1,764
Small C&I	1,298	1,224	1,339
Medium C&I	10,738	10,346	10,983
Large LLF	56,996	54,222	52,907
Large HLF	54,961	57,663	51,711
Extra Large LLF	284,969	210,786	118,310
Extra Large HLF	318,493	281,538	310,912
Total Sales	729,996	618,242	548,799
Use (therm) per customer- High (135% of Average)			
Residential Non-Heating	1,047	1,081	1,180
Residential Heating	2,384	2,243	2,382
Small C&I	1,753	1,653	1,807
Medium C&I	14,496	13,967	14,826
Large LLF	76,944	73,200	71,424
Large HLF	74,198	77,846	69,810
Extra Large LLF	384,708	284,561	159,719
Extra Large HLF	429,965	380,077	419,731
Total Sales	985,495	834,626	740,879

Division 2-19

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: Attachment AEL-5, page 3 of 3, please provide:

a. The referenced "Mkter MDQ Forecast,"

b. The workpapers, data, analyses, studies and other documents upon which the Company relies to derive the referenced "Mkter MDQ Forecast"

c. Forecasted Marketer MDQ billing units by month for the 2012-2013 GCR year.

Response:

a-c. The Company relied on individual customer's most recent May to April load and the calculated capacity allocators for the "Mkter MDQ Forecast" on an annual basis. Please see the electronic workpapers as provided in response to Division 2-1.

Prepared by or under the supervision of: Ann E. Leary

Division 2-20

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: Attachment AEL-6, page 1 of 1, please provide the workpapers, data, analyses, studies and other documents relied upon to develop:

a. The percentages shown by rate class for "% of Peak Day Requirement" for Pipeline, Storage, and Peaking;

b. The percentages shown by rate class for "% of Total Capacity for Pipeline, Storage, and Peaking;

c. The percentages shown for "% of Peak Day Requirement" for Pipeline, Storage, and Peaking for the HLF and LLF classifications;

d. The percentages shown by rate class for "% of Total Capacity for Pipeline, Storage, and Peaking for the HLF and LLF classifications.

Response:

a-d. The electronic version of Attachment DIV 2-20 is being provided on CD-ROM. Please see the electronic workpapers in response to Division 2-20.

Prepared by or under the supervision of: Ann E. Leary

Division 2-21

Instruction: Each request for workpapers should be understood to include a request for all electronic spreadsheet files with all cell formulas and cell references in tact.

Request:

Re: Attachment AEL-7, page 1 of 1, please provide:

a. The workpapers, data, analyses, studies and other documents relied upon to compute the "Revised System Average" cost for 2010/2011;

b. The workpapers, data, analyses, studies and other documents relied upon to compute the "Revised System Average" cost for 2011/2012;

c. The Revised cost for each path for 2010/2011;

d. The Revised cost for each path for 2011/2012;

e. The "Annual MDCQ" for 2010/2011;

f. The "Annual MDCQ" for 2011/2012;

Response:

a. & b. Please see the Excel version of Attachment DIV 2-21 provided on CD-ROM.

c. & d. Please see Attachment DIV 2-21 (c) and (d).

e. The "Annual MDCQ" for 2010/2011 is 11,328,150 dekatherms.

f. The "Annual MDCQ" for 2011/2012 is 11,688,187 dekatherms.

2010/11 & 2011/2012 Annual Marketer Reconciliation

	Tetco ELA/Algonquin	Tetco WLA/Algonquin	Tennessee Zone 1 to NEGC	Tetco STX/Algonquin	Algonquin @ Lambertville, NJ	Columbia (Maumee/Downington)
2010-2011 Revised Path	$1.1331	$1.2065	$1.1003	$1.3396	$0.7824	$0.6862
2011-2012 Revised Path	$0.9604	$1.1578	$1.0205	$1.3399	$0.8669	$0.6425

Division 2-22

Request:

Re: the September 4, 2012, Direct Testimony and Attachments of witness Stephen A McCauley, please provide all workpapers (including electronic spreadsheet files), data, analyses, studies and other documents supporting development of witness McCauley's Direct Testimony and Attachments.

Response:

All required work papers for the GPIP and NGPMP are being provided electronically on a CD ROM. The file name for the GPIP backup is Attachment DIV 2-22-1 and the file name for the NGPMP backup is Attachment DIV 2-22-2. The PDF versions of these attachments were provided in the annual NGPMP report filed on June 1, 2012 and the semi-annual GPIP report filed on August 1, 2012.

Division 2-23

Request:

Re: The September 4, 2012, Direct Testimony of witness Stephen A McCauley at page 3, line 17, through page 4, line 10, please document and explain the manner in which the two exceptions referenced are reflected in the determination of the Company's computed incentive of $355,884 for the twelve months ended June 30, 2012.

Response:

The two exceptions referenced in this request pertain to transactions that were used to calculate the 20 percent or 5 percent GPIP incentive. In Attachment DIV 2-22-1, the Company provided the transaction details and the incentive calculation for all transactions separated by the three different incentive categories. As approved in the Commission's GCR proceeding, Docket No. 4283, the Company earns an incentive of 20 percent if the discretionary transaction is executed at least eight months prior to the month of gas flow and the unit cost savings is greater than 50 cents per dekatherm below the average mandatory price. If a discretionary transaction is executed in the four months prior to the month of flow, then the Company can earn a maximum incentive of 5 percent. For all other discretionary transactions, the Company earns a 10 percent incentive.

Prepared by or under the supervision of: Elizabeth D. Arangio

---

Division 2-24

Request:

Re: The September 4, 2012, Direct Testimony of witness Stephen A McCauley at page 63, lines 7-9, please explain how the Company achieves 'savings to its customers at levels that would be comparable to or that exceed those from a third-party asset manager for assets the witness Arrangio testifies were managed by a third-party. (See the September 4, 2012 Direct Testimony of witness Arrangio at pages 12-14).

Response:

The Natural Gas Portfolio Management Plan ("NGPMP") is an asset optimization program designed to obtain the maximum value from the Rhode Island gas supply portfolio resources. Prior to the April 1, 2009 implementation of the NGPMP, the total gas supply assets were managed by a third-party manager under contract. With the implementation of the NGPMP, the Company discontinued contracting the entire portfolio with an asset manager as a full asset supplier. Instead, the Company took control of Company's the gas portfolio assets in order to actively manage and optimize the value of that portfolio. The Company considers outsourcing a small slice of the portfolio to third-party asset manager as actively managing the portfolio. The Company believes that there are periods in which an individual piece of the portfolio released on an ad hoc basis can generate equal or greater value and that when it is advantageous the Company should use that approach in its overall management of the portfolio assets. The two asset management agreements referred to in witness Arangio's testimony are examples of discreet situations where the Company is seeks to generate savings through managing individual slices of the portfolio using a third-party asset manager.

Prepared by or under the supervision of: Stephen A. Mc Cauley