Robert J. Humm
Senior Counsel

February 16, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4719 - 2017 Gas Cost Recovery Interim Filing
Responses to PUC Data Requests – Set 1

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] responses to the first set of data requests issued by the Rhode Island Public Utilities Commission in the above-referenced docket.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosures

cc: Docket 4719 Service List
Leo Wold, Esq.
Al Mancini, Division
Bruce Oliver, Division
Tim Oliver, Division

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

280 Melrose Street, Providence, RI 02907
T: 401-784-7415 ■ robert.humm@nationalgrid.com ■ www.nationalgrid.com

PUC 1-1

Request:

Has the company met both its purchase and storage targets for the GCR period?

Response:

The Company does not have "purchase" targets. The Company does, however, maintain storage "targets", otherwise known as storage rule curves.[1] With respect to underground storage, the Company has been at or above its underground storage rule curve throughout the 2017/2018 peak season. With respect to liquefied natural gas (LNG) storage, during the extreme cold LNG inventory levels dropped below the LNG rule curve. At the end of December 2017, the Company's LNG storage inventory balance was 67 percent full, below the design season rule curve level of 95 percent. The LNG inventory levels continued to decrease throughout the month to a level of approximately 33% full, until the Company executed the agreement for additional liquid with ENGIE and trucking commenced mid-month allowing the inventory levels to be replenished to rule curve levels. As of February 8, 2018, the LNG inventory balance is 39.5 percent full, above the LNG rule curve level of 26 percent full.

Please see the table below for both underground storage inventory levels and LNG from December 1, 2017 through February 8, 2018.

Underground Storage Inventory

Date	Sum of Capacity	Sum of Balance	% Full	Rule Curve
December 1, 2018	4,731,591	4,295,103	91%	91%
January 1, 2018	4,731,591	3,680,137	78%	73%
February 1, 2018	4,731,591	2,784,837	59%	51%
February 8, 2018	4,731,591	2,559,277	54%	46%

LNG Inventory

Date	Sum of Capacity	Sum of Balance	% Full	Rule Curve
December 1, 2018	749,117	745,362	99%	98%
January 1, 2018	748,506	497,909	67%	95%
February 1, 2018	745,707	297,972	40%	33%
February 8, 2018	745,707	294,397	39%	26%

[1] Design rule curve levels indicate the level of inventory that is needed in order to meet design season requirements for each day remaining in the winter period.

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-2

Request:

Please provide the Company's actual net NGPMP revenues for the months of November, 2017, December, 2017 and January 2018. Also provide actual net NGPMP revenues for the month of February 2018 as soon as that data becomes available.

Response:

The actual net Natural Gas Portfolio Management Plan (NGPMP) realized and unrealized revenues for November 2017 was $153,071 and for December 2017 was $258,554. Invoicing is not final until the 25th day of the next calendar month, or if the 25th day falls on a weekend, then the next business day. Therefore, January 2018 revenues will not be available until February 26. January and February revenues will be final and provided as soon as possible after February 26 and March 26, respectively.

Prepared by or under the supervision of: Stephen A. McCauley

PUC 1-3

Request:

Please provide a table indicating actual volumes (both contracted for and dispatched) and the percentage each contract represents in relation to the Company's total sendout by month.

Response:

Please see the tables below showing the actual volumes transported on each of the Company's Algonquin, Tennessee, and National Grid LNG contracts, as well as the percentage each contract represents in relation to the Company's total sendout by month.[1]

	Volumes By Contract		
Algonquin	November 2017	December 2017	January 2018
9001	185,010	230,852	306,797
90106	369,609	480,110	501,970
90107	188,338	749,152	706,418
933005	24,110	49,792	65,960
93001ESC	382,702	596,197	710,381
93011E	61,830	61,137	61,830
93401S	3,350	7,035	10,019
96004SC	40,064	46,598	51,463
9B105	196,227	264,657	261,223
9S100S	1,374	3,927	5,610
9W009E	104,008	201,433	193,775
510801	277,985	433,663	464,509
Tennessee			
1597	128,329	150,000	151,929
8516	109,694	155,000	153,585
10807	99,081	242,130	231,338
39173	21,331	32,010	32,006
62857	231,758	288,821	288,655
62930	-	4,001	-
64025	156,600	161,819	161,817
64026	191,400	197,780	197,780
95345	15,036	31,000	31,000
322983	-	168,595	89,444
National Grid LNG			
LNG003	11,376	199,941	211,234
Total Sendout	4,284,080	7,052,796	7,722,998

[1] Total Sendout volume includes firm sales and transportation load (including capacity exempt customer load).

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-3, page 2

	Percent of Sendout By Contract		
Algonquin	November 2017	December 2017	January 2018
9001	4.32%	3.27%	3.97%
90106	8.63%	6.81%	6.50%
90107	4.40%	10.62%	9.15%
933005	0.56%	0.71%	0.85%
93001ESC	8.93%	8.45%	9.20%
93011E	1.44%	0.87%	0.80%
93401S	0.08%	0.10%	0.13%
96004SC	0.94%	0.66%	0.67%
9B105	4.58%	3.75%	3.38%
9S100S	0.03%	0.06%	0.07%
9W009E	2.43%	2.86%	2.51%
510801	6.49%	6.15%	6.01%
Tennessee			
1597	3.00%	2.13%	1.97%
8516	2.56%	2.20%	1.99%
10807	2.31%	3.43%	3.00%
39173	0.50%	0.45%	0.41%
62857	5.41%	4.10%	3.74%
62930	0.00%	0.06%	0.00%
64025	3.66%	2.29%	2.10%
64026	4.47%	2.80%	2.56%
95345	0.35%	0.44%	0.40%
322983	0.00%	2.39%	1.16%
National Grid LNG			
LNG003	0.27%	2.83%	2.74%
Total Sendout	100%	100.00%	100.00%

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-4

Request:

State whether the Company uses a daily dispatch model. Please explain.

Response:

Yes, the Company uses a daily dispatch model. Provided in this response are three documents that are used to plan the gas supply requirements for each new gas day, and contain examples of the information the Company uses to plan its gas supply requirements for each new day. They do not constitute an exhaustive list. For illustrative purposes, please refer to Wednesday, December 6, 2017.

Daily Game Plan

The first document used is the Daily Game Plan (Attachment PUC 1-4-1). The Daily Game Plan is designed to balance the demand requirements of the overall system for the current day with scheduled supply volumes, and projects a six-day supply/demand forecast. The left-hand side of the worksheet represents demand while the right-hand side represents supply.

The daily process of obtaining sufficient resources to meet predicted customer needs requires a level of coordination between the Company's Gas Control New England (NE), Gas Supply Planning NE, and Gas Trading departments. Each day, Gas Control NE provides Gas Supply Planning NE with projected sendout requirements that are developed based upon the results of the demand-forecasting process. A conference call is held each weekday morning at 8:15 a.m. between Gas Supply Planning NE and Gas Control NE to discuss the projected sendout requirements as well as any pipeline or distribution system issues. Gas Supply Planning NE then coordinates with Gas Trading to determine the availability of supply and pricing information in order to satisfy the predicted customer loads, following the order of the dispatch established by the Company's Natural Gas Portfolio Management Plan (NGPMP).

Daily Request Sheet

The second document the Company uses to plan is the Daily Request Sheet (Attachment PUC 1-4-2). After the 8:15 a.m. conference call is complete, Gas Supply Planning NE prepares the total requirements by pipeline via inputs to the Daily Request Sheet. The Daily Request Sheet is a worksheet that represents the supplies for the next gas day. In addition, the worksheet shows the availability of baseload, swing, storage, and peaking assets needed to meet customer requirements. Finally, the worksheet also provides the remaining assets available for intraday nomination changes. Once the worksheet is completed, it is sent to various groups within the

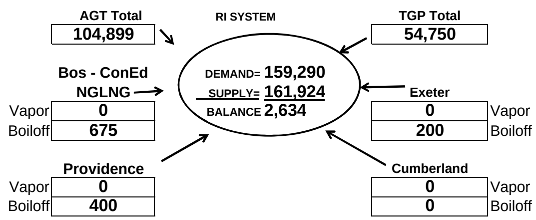
Company (Gas Supply Planning NE, Gas Control NE, Gas Trading/Scheduling, Wholesale Electric Supply, and U.S. Commodity Hedging).

Monthly Set Up Sheet

The third document the Company uses to plan is the Monthly Set Up Sheet (Attachment PUC 1-4-3). The Monthly Set Up Sheet is a worksheet that identifies all of the Company's assets by pipeline and underground storage fields. The worksheet is a mix of transportation and storage assets. The projected baseload and swing load requirements are selected using a least cost dispatch of flowing supplies available from the Company's supply portfolio. This is further detailed in the Company's NGPMP (see Attachment PUC 1-6).

Prepared by or under the supervision of: Nancy G. Culliford

h	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY	MONDAY	TUESDAY
DAY OF WEEK:	3	4	5	6	7	1	2
DATE:	06-Dec-17	07-Dec-17	08-Dec-17	09-Dec-17	10-Dec-17	11-Dec-17	12-Dec-17
PROVIDENCE AVG TEMP	40	37	36	32	30	34	32
DEGREE DAYS	25	28	29	33	35	31	33
DAY	0	1	2	3	4	5	6
PROVIDENCE EDD	27	30	31	34	38	33	35
Providence Sendout	128,250	142,000	143,750	158,740	167,300	154,180	161,740
Cumberland Sendout	31,550	34,932	35,363	39,050	41,156	37,928	39,788
Bristol-Warren	4,417	4,890	4,951	5,467	5,762	5,310	5,570
Sendout Subtotal	164,217	181,822	184,064	203,257	214,218	197,418	207,098
Cold Weather Factor	-0.03	0.02	0.00	0.00	0.00	0.00	0.00
Total Firm Sendout	308,931	355,980	353,417	321,134	266,203	303,669	366,741
Pawtucket Power	0	0	0	0	0	0	0
Total Thruput	159,290	185,458	184,064	203,257	214,218	197,418	207,098
	164,217						



Algonquin	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY	MONDAY	TUESDAY
AGT Baseload	40,000	40,000	40,000	40,000	40,000	40,000	40,000
AGT Swing	34,000	34,000	34,000	34,000	34,000	34,000	34,000
AGT Storage	0	0	0	0	0	0	0
City Gate Purchases	0	0	0	0	0	0	0
AGT FT	31,573	31,573	31,573	31,573	31,573	31,573	31,573
UGI Payback	0	0	0	0	0	0	0
OBA Scheduled	0	0	0	0	0	0	0
Total AGT Supply	105,573	105,573	105,573	105,573	105,573	105,573	105,573
Boston Gas LNG Backoff	0	0	0	0	0	0	0
Con Edison LNG Backoff	0	0	0	0	0	0	0
Boston Gas Boiloff	(521)	(521)	(521)	(521)	(521)	(521)	(521)
ConEd Boiloff	(154)	(154)	(154)	(154)	(154)	(154)	(154)
UGI Payback	0	0	0	0	0	0	0
FINAL AGT SUPPLY	104,898	104,898	104,898	104,898	104,898	104,898	104,898
Montville Delivery	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Tennessee							
TGP Baseload	23,000	23,000	23,000	23,000	23,000	23,000	23,000
TGP Swing	10,502	10,502	10,502	10,502	10,502	10,502	10,502
TGP Storage	0	0	0	0	0	0	0
City Gate Purchases	0	0	0	0	0	0	0
TGP FT	21,248	21,248	21,248	21,248	21,248	21,248	21,248
Pawtuckett Power	0	0	0	0	0	0	0
OBA Scheduled	0	0	0	0	0	0	0
Total TGP Supply	54,750	54,750	54,750	54,750	54,750	54,750	54,750
TGP (9500)	0	0	0	0	0	0	0
FINAL TGP SUPPLY	54,750	54,750	54,750	54,750	54,750	54,750	54,750
Total Pipeline Supply	160,649	160,649	160,649	160,649	160,649	160,649	160,649
NGLNG							
Boston Gas LNG	0	0	0	0	0	0	0
UGI (ConEd) LNG	0	0	0	0	0	0	0
Total Pipeline and NGLNG	160,649	160,649	160,649	160,649	160,649	160,649	160,649
Pipeline Imbalance	1,359	(24,809)	(23,415)	(42,608)	(53,569)	(36,769)	(46,449)
Rhode Island Production							
Providence - Narragansett	0	0	0	0	0	0	0
Cumberland	0	0	0	0	0	0	0
Exeter	0	0	0	0	0	0	0
Total Production	0	0	0	0	0	0	0
Boiloff							
Providence - Boston Gas	521	521	521	521	521	521	521
Providence - ConEd-UGI	154	154	154	154	154	154	154
Providence - Narragansett	400	400	400	400	400	400	400
Scott Rd	0	0	0	0	0	0	0
Exeter	200	200	200	200	200	200	200
Total Boiloff	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Total Supply	161,924	161,924	161,924	161,924	161,924	161,924	161,924
System Balance	2,634	(23,534)	(22,140)	(41,333)	(52,294)	(35,494)	(45,174)
	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY	MONDAY	TUESDAY
Average Temp	40	37	36	32	30	34	32
AGT Pipe Estimate	104,898	104,898	104,898	104,898	104,898	104,898	104,898
TGP Pipe Estimate	54,750	54,750	54,750	54,750	54,750	54,750	54,750
Total Pipe	160,649	160,649	160,649	160,649	160,649	160,649	160,649
LNG	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Total Supply	161,924	161,924	161,924	161,924	161,924	161,924	161,924
AGT	65%	65%	65%	65%	65%	65%	65%
TGT	34%	34%	34%	34%	34%	34%	34%

SAVE

Please do not erase		
		103.543%
Sendout Report Factor	1.126	-1.04
Months Running Ave Variance	1.069	

AGT Supply Balance
TGT Supply Balance

TO: ETO — 12/05/17
FROM: National Grid - Brian Spencer (781) 907-1642 / Nancy Culliford (781) 907-1638
RE: Daily Requirements Confirmation for Narragansett Electric Company
PHONE: 508-421-7590 or 508-421-7591 is 24 hr. Northborough Gas Control

Total TGP and AGT Requirements - Rhode Island — Effective for Gas Day: Wednesday 12/06/17

TGP	AGT	TOTAL	
32,502	**75,000**	107,502	**OK**

Rhode Island

	TGP	AGT
Baseload	22,000	40,000
Swing	**10,502**	**34,000**
Storage	**-**	**-**

TGP		AGT	
GSS 300168	-	GSS-TE 600045	-
GSS 300170	-	GSS 300169	-
FSMA 62918	-	GSS 300171	-
FSMA 501	-	TCO-FSS 9630	-
		FSS-1 400515	-
		SS-1 400185	-
		SS-1 400221	-
		Yankee -- Montville	**1,000**
TOTAL	**32,502**		**75,000**

VOLUMES COMING TO THE GATE IN ADDITION TO ABOVE VOLUMES:

	Call Volume	Gate Volume	
Dawn AMA Call (BP Canada)	*1,029*	**1,000**	*Baseload for Dec*
Dracut Supply Call (Freepoint)	-	**-**	

Remaining Storage: TGP **10,836** — AGT **28,082**

	Remaining		Remaining	
GSS 300168:	1,385	GSS-TE 600045:	5,489	
GSS 300170:	5,161	GSS 300169:	1,999	
FSMA 62918:	10,133	GSS 300171:	2,555	
FSMA 501:	10,797	TCO-FSS 7980:	2,482	*Not available for Intraday
		FSS-1 400515:	915	
		SS-1 400185:	658	
		SS-1 400221:	13,984	

Remaining Intraday Available:	**10,836**	**25,600**

ALGONQUIN

Path	Receipt Point	Receipt Volumes	M2	M3	City Gate Capacity	Net CG Deliveries	Baseload	Available Swing
Transco Leidy->AGT	Transco	73		**73**	72	72	72	0
Transco Leidy->AGT SCT	Transco	1,172		**1,167**	1,154	1,154	1,154	0
DTI->TETCO FTS->AGT	Dom SP	548		**530**	524	524	524	0
TETCO Leidy-Dominion	Leidy-Dom	3,851		**3,801**	3,760	3,760	3,760	0
TETCO->AGT	M2	27,340	27,340	**26,684**	26,396	26,396	26,396	0
AGT	M3	2,980		2,980	**2,948**	2,948	2,948	0
RAMAPO->AGT	RAMAPO	18,688		18,688	**18,000**	18,000	5,146	12,854
TCO->AGT	Eagle	3,652		**3,600**	3,561	3,561	0	3,561
Remaining AGT (SCT)	M3 (SCT)	3,485		3,485	**3,447**	3,447	0	3,447
TCO->AGT	Maumee	28,326		**27,920**	27,618	27,618	0	27,618
TCO->AGT	Broad Run	10,145		**10,000**	9,892	9,892	0	9,892
TCO->AGT	Downingtown	3,489		**3,439**	3,402	3,402	0	3,402
				Transport	100,774	100,774	40,000	60,774

AGT Storage

Path	Receipt Point	In-Hole WDs	MDWQ	M3	Storage Capacity	
GSS-TE 600045	DTI GSS-TE	5,636	5,636	**5,549**	5,489	GSS-TE withdrawal only 5,549 @M3
GSS 300169	DTI GSS	2,061	**2,061**	2,021	1,999	
GSS 300171	DTI GSS	2,617	**2,617**	2,583	2,555	
FSS 9630	TCO FSS	2,545	**2,545**	2,509	2,482	
FSS-1 400515	TETCO FSS	948	**944**	925	915	
SS-1 400185	TETCO SS1	676	**665**	665	658	
SS-1 400221	TETCO SS1	14,370	**14,137**	14,137	13,984	
				Storage	28,082	
				Total	128,856	Available AGT Swing 60,774

TENNESSEE

Path	Receipt Point	Receipt Volumes	TGP Waddy	TGP Zone4	City Gate Capacity	Net CG Deliveries	Baseload	Available Swing
Union>TrCan>IGT>TGP	Dawn	1,029	1,009		**1,000**	1,000	1,000	0
TGP ConnXion 4 --> 6	Z4 CXN	11,733		*11,733*	**11,600**	11,600	11,600	0
TGP 4 --> 6	Z4	19,859		*19,859*	**19,635**	19,635	10,400	9,235
TGP 1 --> 6	800 Leg	208			**200**	200	0	200
TGP 5 --> 6	Niagara	1,076			**1,067**	1,067	0	1,067
TGP 6 --> 6	Dracut	38,772			**38,768**	38,768	0	38,768
				Transport	71,270	71,270	22,000	49,270

TGP Storage

Path	Receipt Point	In-Hole WDs	MDWQ		City Gate Deliveries	
GSS 300168	DTI GSS	1,401	**1,401**		1,385	
GSS 300170	DTI GSS	5,324	**5,324**		5,161	
FSMA 62918	TGP FSMA	10,249	**10,249**		10,133	
FSMA 501	TGP FSMA	10,920	**10,920**		10,797	
				Storage	*10,836*	
				Total	82,106	Available TGP Swing 49,270

Total Transport	172,044	172,044	62,000		
Total Storage	38,918				
Total Citygate	210,962			Total Available Swing	110,044

PUC 1-5

Request:

Please describe the Company's daily and monthly dispatch practices in procuring supplies via the long-haul pipeline capacity, storage gas, and online peaking resources.

Response:

The following presents and discusses the steps in the Company's process regarding daily and monthly procurement of gas supply:

1. Every month, the Company's Gas Supply Planning group hosts a Planning Meeting attended by other groups within the Company's Energy Procurement organization, including Wholesale Gas Supply (Gas Trading, Gas Scheduling); Origination and Price Volatility Management; FERC Compliance and Contracting; and Customer Choice. One of the purposes of the meeting is to discuss assets available in the portfolio and to establish a least-cost dispatch.

   The December 2017 Monthly Set Up Sheet is described in the Company's response to PUC 1-4 and provided at Attachment PUC 1-4. This Monthly Set Up Sheet is a worksheet that follows the dispatch order of the proxy (as detailed in the Company's Natural Gas Portfolio Management Plan, provided at Attachment PUC 1-6) and identifies all of the Company's assets by pipeline as well as underground storage fields. This least cost dispatch order, set in the Monthly Planning Meeting, is used to determine the price of supplies base-loaded and delivered to the Company's Algonquin Gas Transmission and Tennessee Gas Pipeline city gates. Incremental swing supplies needed each day, as described in step 3 (see Attachment PUC 1-4), are priced at the next available least-cost supplies listed in the proxy dispatch order for both pipeline and storage paths.

2. Gas Control determines the total gas system sendout requirements based on forecasted weather conditions. The total gas system sendout includes the requirements for the firm sales customers and customer choice (transportation) customers. Gas Control compares the total gas system sendout requirements with the gas supplies delivered from the previous day to determine the amount of gas supply that must be either added or subtracted to balance the system for the new day.

3. Gas Supply Planning utilizes the information provided by Gas Control to develop the customer requirements for the new day. The details of these requirements include the incremental swing supply volumes needed over and above the volumes baseloaded for the month, storage, and peaking supplies required on the Tennessee Gas Pipeline and/or Algonquin Gas Transmission System. Gas Supply Planning provides the customer gas supply requirements via email to Wholesale Gas Supply (Gas Trading and Gas Scheduling).

4. Gas Trading then analyzes the available pipeline capacity and storage assets and gas pricing available by utilizing the Intercontinental Exchange (ICE) and by contacting a number of active counterparties to determine the appropriate mix of assets available to be called upon to meet customer requirements. Gas Trading executes the necessary gas supply purchases consistent with a least-cost dispatch of all required assets.

   To fill this incremental daily need, the Company will dispatch supply from any or any combination of the available sources below:

   a. Transportation capacity – The Company nominates volumes from the remaining transportation capacity at each pipeline citygate. This volume is priced to the Company's customers based on the next available asset path under a least-cost dispatch.

   b. Storage – The Company may nominate supply from each storage facility subject to contractual limitations. Intraday injections or withdrawals will be subject to the remaining capabilities of each storage facility and may be affected by certain pipeline and/or storage facility restrictions.

   c. Citygate purchases – At times, the Company may nominate volumes to be purchased at its citygates. This gas is be priced at the actual purchase price.

   d. Additional Company Assets – The Company may nominate volumes from any other available asset at its disposal. These include, but are not limited to, peaking supplies or any liquid/vapor contracts. This gas will be priced at the actual contract price or inventory cost plus variable transportation costs.

5. Upon completion of meeting customer requirements for the next gas day, Gas Trading identifies the remaining available pipeline capacity and attempts to re-market this capacity via bundled gas off-system sales in the day-ahead gas market.

    a. The Company will dedicate the resources to recognize and realize arbitrage and optimization opportunities by structuring a combination of transactions using the portfolio of assets and its flexibility to take advantage of opportunities that arise in the marketplace to reduce gas costs.

6. Gas Scheduling nominates/schedules all gas supplies purchased to meet the customer requirements and any bundled gas off-system sales executed in the secondary market in accordance with Eastern Standard Time for the Timely Cycle (2:00 p.m.), and updated nominations as needed for the Evening Cycle (7:00 p.m.), Intraday 1 (ID1), (11:00 a.m.), Intraday 2 (ID2) (3:30 p.m.), and Intraday 3 (ID3) (8:00 p.m.) cycles.

7. In accordance with Eastern Standard Time, during the peak season, Gas Supply Planning and/or Gas Trading contacts Gas Control in the afternoon (2:00 p.m.), evening (9:00 p.m.), and early morning (7:00 a.m.) to determine if any intra-day gas supply adjustments are required to meet the customer gas supply requirements. Intra-day adjustments are caused by a number of factors, including, but not limited to, customer load increases or decreases, changes in weather, delivery volumes of third-party marketers under the Company's Customer Choice Program, upstream pipeline operations, and on-system distribution operations. Gas Trading coordinates any intra-day gas supply adjustments with Gas Scheduling.

8. Throughout the day, Gas Trading will evaluate any requests for intra-day gas off-system sales received from counterparties and will execute those sales via bundled gas off-system sales in the intra-day market provided that the Company maintains adequate gas supplies to meet any fluctuations in customer requirements as well as the need to balance the overall system.

Prepared by or under the supervision of: Nancy G. Culliford and Stephen A. McCauley

PUC 1-6

Request:

Please explain how the Company calculates its daily base load volumes and selects the mix of supply resources to meet the projected daily base load requirements and swing load requirements.

Response:

Prior to the start of each month, both forecasted and historical customer requirements are reviewed to determine the monthly base load requirement (i.e., the forecasted minimum requirement on any day during the month). The Company would then purchase supplies prior to the month to fill that minimum requirement and lock in the base load supply for every day of the month.

The mix of supply resources to meet the projected daily base load and swing load requirements are selected using a least-cost dispatch of flowing supplies available from the Company's supply portfolio. This is further detailed in the Company's Natural Gas Portfolio Management Plan (NGPMP). Please see Attachment PUC 1-6 for a copy of the current NGPMP.

Prepared by or under the supervision of: Nancy G. Culliford and Stephen A. McCauley

National Grid
Natural Gas Portfolio Management Plan

Effective April 1, 2016

I. Objectives

To encourage the Company to minimize gas costs to customers by coupling a least-cost dispatch with an asset optimization program designed to obtain the maximum value from the gas supply portfolio resources.

II. Structure of the Incentive Plan (Plan)

A. This Plan will become effective April 1, 2016. It will be reviewed with each Gas Cost Recovery (GCR) filing. The Company will file its Report on the Plan on June 1st each year showing the results of the Plan for the prior year, April 1 to March 31.

B. Under this Plan, the Company will discontinue contracting with an asset manager as a full outsource supplier and will undertake the functions previously performed by the asset manager using Company resources.

C. To measure the Company's performance under the Plan and the benefits to customers, the Company will operate under the Plan in a way that parallels previous asset management contracts with outsource suppliers (*e.g.*, Merrill Lynch, ConocoPhillips).

D. The starting point for the measurement of the optimization benefits will be based on a least cost dispatch order of the available resources in the supply portfolio coupled with a one-seventh ratable storage refill plan. The Company will receive a sharing of the benefits under this incentive plan to the extent it reduces costs below the level obtainable through purchasing under the least cost purchase dispatch order and ratable storage fill plan.

E. This Plan will not be affected by or interact with the Gas Purchase Incentive Plan (GPIP) in any way. Because GPIP utilizes the purchase of future contracts for hedging, the GPIP does not affect the direct purchasing of supplies or the use of storage in any way, making the two plans entirely independent. The Company will operate under the Plan in a way that parallels the current practice; therefore the effectiveness of the GPIP will not be affected in any way.

III. Revenue Sharing

A. Rhode Island Customer Threshold

The Rhode Island customers will receive 100% of the first $2,000,000 of annual gas cost optimization benefits. If the total annual gas cost optimization benefits do not exceed $2,000,000 then the Rhode Island customers will only receive 100% of the actual total benefit.

B. Sharing of Net Proceeds between $2,000,000 and $5,000,000

Rhode Island customers will receive 80% of all net proceeds between $2,000,000 and $5,000,000 and the Company will receive 20% of the net proceeds between $2,000,000 and $5,000,000.

C. Sharing of Net Proceeds between $5,000,000 and $10,000,000

Rhode Island customers will receive 90% of all net proceeds between $5,000,000 and $10,000,000 and the Company will receive 10% of the net proceeds between $5,000,000 and $10,000,000.

D. Sharing of Net Proceeds above $10,000,000

Rhode Island customers will receive 94% of all net proceeds above the $10,000,000 and the Company will receive 6% of the net proceeds above $10,000,000.

E. Calculation of Optimization Benefits

The optimization benefit will be calculated annually for the optimization activity executed during the year. The optimization benefit for revenue sharing will be calculated as the positive value of; the revenue from sales to the Rhode Island customers at the citygate and storage facilities, plus the revenue from sales to third parties, less the costs to procure all supplies as well as all variable costs associated with the purchase, delivery and storage.

IV. Description of the Least Cost Dispatch Order

A. The least cost dispatch order, by which natural gas will be priced for Rhode Island customers for baseload and daily nominations will be based on published index prices. An index price is a published price for gas supply at a particular location, in this case, the point of receipt for the Company's pipeline capacity where it purchases supply to transport on its pipeline transportation capacity. Each year, the Company will analyze the historic and forward reference index price for each receipt point and each asset path's delivered price to the citygate. Based on these historical and forward index prices and the delivered cost of each path, the Company will establish an order from the least cost to the highest cost path. To establish a least cost dispatch, the Company will match the index price order with the available assets for each month. This process will be performed more frequently if changes occur to the portfolio (*e.g.*, new pipeline services are added to the portfolio) or changes occur in the wholesale market that would impact the least cost dispatch. The Company will notify the Division of the least cost dispatch order prior to the start of the year and inform it of any changes during the year.

B. An index price formula will not be used in non-standard transactions. Examples of non-standard transactions are intraday purchases, non-ratable weekend purchases, fixed price, fixed basis transactions at a location that does not have a published index, or other Additional Company Assets described below in section VI. For non-standard transactions, the actual purchase price, plus variable costs to deliver, will be charged to the Rhode Island customers.

C. The Index Pricing formula uses Platts "Inside FERC's Gas Market Report, Prices of Spot Gas Delivered to Pipelines", for baseload gas purchases for any month (FOM). The Index Pricing formula uses Platts "Gas Daily, Daily price survey", Midpoint prices for gas purchased for next day or ratable deliveries over the weekend (Gas Daily).

V. Baseload and Daily Nominations

A. Baseload Nominations - Each month, at least six business days prior to the start of the month of flow, the Company will nominate a separate baseload volume for deliveries at the Tennessee Gas Pipeline citygates and the Algonquin Gas Transmission citygates as under the current practice. This volume will be priced to the Rhode Island customers based on the least cost dispatch as described above in Section IV.

B. Daily Nominations – Each day, prior to 8:30AM EST, the Company will nominate a separate, incremental daily volume for deliveries at the Tennessee Gas Pipeline (TGP) citygates and the Algonquin Gas Transmission (AGT) citygates as under the current practice. To fill this incremental daily need, the Company will dispatch supply from any or any combination of the available sources below:

a. Transportation capacity – The Company nominates volumes from the remaining transportation capacity at each pipeline citygate. This volume is priced to the Rhode Island customers based on the next available asset path under a least cost dispatch as described in Section IV.

b. Storage – The Company may nominate supply from each storage facility subject to contractual limitations. Intraday injections or withdrawals will be subjected to the remaining capabilities of each storage facility and may be affected by certain pipeline and/or storage facility restrictions;

c. Citygate purchases – At times, the Company may nominate volumes to be purchased at its citygates. This volume will be priced to the Rhode Island customers based on the actual purchase price and will be a direct pass through; and

d. Additional Company Assets – The Company may nominate volumes from any other available asset at its disposal. These include, but are are not limited to peaking supplies or any liquid/vapor contracts. This volume will be priced to the Rhode Island customers based on the actual contract price or inventory cost plus variable delivery costs.

C. Storage Injections

a. During the months of April through and including October, Storage injection quantities will be calculated as 97% of the total storage Maximum Storage Quantity (MSQ), less the ending inventory on March 31. As is the practice today, this quantity will be deemed to be injected ratably over the seven month period. Any Rhode Island customer withdrawals in April will be deemed to be injected ratably over the next six months, May through October period; and

b. The price of the April through October injections is set in accordance with the Index Pricing formula using the FOM index pricing for each of the seven injection months.

VI. The Company as Gas Portfolio Manager

A. Optimizing the Gas Portfolio

As asset manager, the Company will dedicate the resources to recognize and realize arbitrage and optimization opportunities by structuring a combination of transactions using the portfolio of assets and its flexibility to take advantage of opportunities that arise in the marketplace to reduce gas costs. Optimization of the assets will be performed as a secondary process after the Company has met the load requirements of the Rhode Island customers through the least cost dispatch of all required assets.

B. Typical optimization strategies are:

a. Transportation capacity – the Company will lock-in the price difference between two locations with the use of temporarily idle transportation capacity;

b. Citygate exchanges – the Company will use its citygate receipt flexibility to capture price differences between the two delivering upstream pipelines, Tennessee Gas Pipeline and Algonquin Gas Transmission;

c. Storage – The Company will use the temporarily idle capacity, injections or withdrawal rights to capture the price difference between two time periods; and

d. Purchase Replacement – The Company will look to resource purchase obligations to effectuate a lower delivered price.

VII. Reporting Requirements

A. Quarterly reports – The Company will provide quarterly reports showing the realized and unrealized margins associated with the portfolio optimization value. Reports will be provided on the first business day in the second month following the end of each fiscal quarter.

B. Annual Report – The Company will provide an annual report showing the total realized and unrealized margins generated through portfolio optimization in addition to the distribution of the sharing between the Rhode Island customers and National Grid. This report will be provided on the first business day following June 1 of each year.

PUC 1-7

Request:

For each month from November 1, 2017 through February 1, 2018, please provide the first of the month prices at Henry Hub and any other receipt points used by the Company.

Response:

Provided below are the first of month prices at Henry Hub and any other receipt points used by the Company for each month from November 2017 through February 2018.

	November 2017	**December 2017**	**January 2018**	**February 2018**
Henry Hub, NYMEX close	$2.752	$3.074	$2.738	$3.631
Algonquin, city-gates	$2.650	$5.800	$12.250	$13.340
Columbia Gas, App.	$2.440	$2.910	$2.520	$3.340
Dawn, Ontario	$2.730	$3.250	$3.000	$4.130
Dominion, Appalachia	$1.570	$2.500	$2.290	$2.890
Iroquois, receipts	$2.790	$3.950	$5.390	$6.630
Leidy Hub	$1.700	$2.670	$2.440	$3.040
Niagara	$2.180	$2.970	$3.330	$4.580
Tennessee, Louisiana, 500 Leg	$2.660	$3.010	$2.670	$3.590
Tennessee, Louisiana, 800 Leg	$2.650	$2.980	$2.650	$3.540
Tennessee, zone 0	$2.610	$2.920	$2.620	$3.510
Tennessee, zone 4-200 leg	$1.960	$2.750	$2.540	$3.460
Tennessee, zone 6 del.	$2.700	$6.410	$12.240	$13.520
Texas Eastern, M-2 receipts	$1.510	$2.510	$2.270	$3.020
Texas Eastern, M-3	$1.800	$3.200	$5.180	$8.330
Transco, Leidy Line receipts	$1.390	$2.390	$2.240	$2.790
Transco, zone 6 non-N.Y. North	$2.590	$3.730	$5.580	$9.820

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-8

Request:

Please indicate if the proposed interim GCR factor includes any offsets due to an increase in Off-System Sales credits or incremental GCR revenues.

Response:

The $34.5 million projected deferred balance includes the Natural Gas Portfolio Management Plan (NGPMP) credits reflected in the Company's approved 2017-18 Gas Cost Recovery (GCR) filing in Docket No. 4719. The Company did not adjust the amount it reflected in its initial GCR filing.

The Company updated the January 2018 forecasted GCR revenue to (1) reflect colder than normal weather experienced during the first 16 days in January that was not reflected in the initial January revenue forecast, which was based on normal weather; and (2) reflect an estimate of the billing for usage in the month of December 2017 that would be billed in January 2018. As shown in Attachment AEL-5 to the pre-filed direct testimony of Ann E. Leary in the Company's Interim GCR Filing submitted on January 29, 2018, the Company increased January 2018 billings by 2,505,371 dekatherms. This adjustment increased January GCR revenue by approximately $12.8 million.

PUC 1-9

Request:

Please indicate whether the Company has entered into any asset management arrangement (AMA) for the 2017/2018 peak period. If yes, please list each AMA and which resources have been assigned. Please indicate any resources that the Company plans to manage in-house.

Response:

For the 2017/2018 peak period, the Company entered into an asset management arrangement with BP Energy Canadian affiliates BP Canada Energy Marketing Corp and BP Canada Energy Group ULC to provide supply at Waddington, New York into Iroquois through the management of the Company's transportation agreements on Union and TransCanada. All other resources are presently being managed in-house by the Company. Please see Attachment PUC 1-9.

NATIONAL GRID - RHODE ISLAND ASSETS

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Manage in House
Narragansett Electric	Algonquin	9001	AFT1FT3	11,063	Yes
Narragansett Electric	Algonquin	90106	AFT-14	19,465	Yes
Narragansett Electric	Algonquin	90107	AFT-1W	26,129	Yes
Narragansett Electric	Algonquin	933005	AFT-1P	2,061	Yes
Narragansett Electric	Algonquin	93001ESC	AFT-ES1	2,384	Yes
Narragansett Electric	Algonquin	93011E	AFT-E1	56,035	Yes
Narragansett Electric	Algonquin	93401S	AFT-1S4	335	Yes
Narragansett Electric	Algonquin	96004SC	AFT-1S3	1,695	Yes
Narragansett Electric	Algonquin	9B105	AFT-1B	8,539	Yes
Narragansett Electric	Algonquin	9S100S	AFT-1SX	187	Yes
Narragansett Electric	Algonquin	9W009E	AFT-EW	6,812	Yes
Narragansett Electric	Algonquin AIM	510801	AFT1-H	18,000	Yes
Narragansett Electric	Algonquin	510985	AFT-CLMS	96,000	Yes
Narragansett Electric	Columbia	31520	FTS	3,855	Yes
Narragansett Electric	Columbia	31522	FTS	3,600	Yes
Narragansett Electric	Columbia	31523	FTS	10,000	Yes

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Manage in House
Narragansett Electric	Columbia	31524	FTS	30,000	Yes
Narragansett Electric	Columbia	9631	SST	2,545	Yes
Narragansett Electric	Dominion	100118	FTNN	537	Yes
Narragansett Electric	Dominion	700086	FTGSS	2,061	Yes
Narragansett Electric	Dominion	700087	FTGSS	5,324	Yes
Narragansett Electric	Iroquois	50001	RTS-1	1,012	Yes
Narragansett Electric	National Fuel	E11395	EFT	1,177	Yes
Narragansett Electric	Tennessee	1597	FT-A	5,000	Yes
Narragansett Electric	Tennessee	8516	FT-A	5,000	Yes
Narragansett Electric	Tennessee	10807	FT-A	10,836	Yes
Narragansett Electric	Tennessee	39173	FT-A	1,067	Yes
Narragansett Electric	Tennessee	62857	FT-A	19,335	Yes
Narragansett Electric	Tennessee	62930	FT-A	15,000	Yes
Narragansett Electric	Tennessee	64025	FT-A	5,220	Yes
Narragansett Electric	Tennessee	64026	FT-A	6,380	Yes
Narragansett Electric	Tennessee	95345	FT-A	1,000	Yes
Narragansett Electric	Tennessee	322983	FT-A	24,000	Yes

Shipper	Pipeline Company	Contract No.	Rate Schedule	City Gate MDQ	Manage in House
Narragansett Electric	Texas Eastern	330844	FTS	6,377	Yes
Narragansett Electric	Texas Eastern	330845	FTS	537	Yes
Narragansett Electric	Texas Eastern	330867	FTS-5	813	Yes
Narragansett Electric	Texas Eastern	330870	FTS-5	1,000	Yes
Narragansett Electric	Texas Eastern	330907	FTS-5	248	Yes
Narragansett Electric	Texas Eastern	331722	FTS-7	538	Yes
Narragansett Electric	Texas Eastern	331801	FTS-8	79	Yes
Narragansett Electric	Texas Eastern	331802	FTS-8	187	Yes
Narragansett Electric	Texas Eastern	331819	FTS-8	4,745	Yes
Narragansett Electric	Texas Eastern	800156	SCT	2,099	Yes
Narragansett Electric	Texas Eastern	800303	CDS	45,934	Yes
Narragansett Electric	Texas Eastern	800440	CDS	944	Yes
Narragansett Electric	TransCanada	42386	FT	1,012	No
Narragansett Electric	Transco	9081767	FT	1,240	Yes
Narragansett Electric	Union Gas	M12164	FT	1,025	No
Narragansett	Columbia	9630	FSS	2,545	Yes
Narragansett Electric	Dominion	300168	GSS	1,401	Yes

PUC 1-10

Request:

Please explain how an AMA is consistent with providing customers with the most reliable resource at the lowest possible cost.

Response:

The Company is obligated to plan for and procure a resource portfolio that will assure reliable, least-cost service to customers on a design day and design season basis. The Public Utilities Commission (PUC) has determined that a supply planning process is critical in enabling a gas company to formulate a resource plan that achieves an adequate, least-cost supply for its customers. Further, the Company is required to file a Long Range Resource and Requirements Plan every two years. This plan documents both the Company's forecast and planning processes and makes a demonstration to the PUC that the Company's resource portfolio is sufficient to meet the Company's projected sendout under several weather scenarios. An asset management agreement (AMA) affords the opportunity to place firm pipeline capacity into the control of a party that may be better able to manage the assets without compromising access to liquid and reliable resources to the firm gas customer. The only assets being managed under an AMA are the Company's Canadian transportation contracts on Union and TransCanada. The third party managing these assets is far more active in the Canadian markets and able to provide value to the Company's firm customers for the opportunity to manage the assets.

Prepared by or under the supervision of: Stephen A. McCauley

PUC 1-11

Request:

Describe the factors (i.e., weather, forecasted loads, previous day's sendout, supply requirements, etc.) that the Company takes into account in arriving at the daily nomination amounts.

Response:

Daily nomination decisions are based primarily on forecasted sendout requirements. These sendout forecasts are driven by ambient temperatures as reported to National Grid by a contracted professional weather service company. Daily average temperatures are used to determine the Heating Degree Day (HDD). As the daily average temperature lowers, the sendout forecast will increase. This is determined by applying heating increments for each effective degree day greater than zero, and adding this value to a baseload volume. This sendout forecast is slightly influenced by the previous day's observed conditions, as the Company attempts to buffer the swings in temperature from one day to the next, as well as day of the week (on weekends and holidays, the sendout volume is typically lower than what it would be on a weekday).

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-12

Request:

Please explain what communications take place between the Company and its asset managers for the process of daily nominations. Indicate if the Company is solely responsible for the changes in daily nominations. If not, describe the role of the asset manager as it pertains to the adjustments in daily nominations.

Response:

The Company has an asset management arrangement in place for the period November 1, 2017 through October 31, 2018 to manage the Company's Canadian capacity on Union and TransCanada, which provides 1,012 dekatherms per day of supply at Waddington, New York. The asset management arrangement provides the Company with baseload supply for the period December 1, 2017 through February 28, 2018, and a daily call on supply during the months of November 2017 and March 2018. For the daily call on supply in November 2017 and March 2018, the Company must notify the asset manager prior to 9:45 a.m. Eastern Time on the business day prior to the day of gas flow on which delivery of gas is requested. Nominations for the daily call on supply for the weekend must be made on Friday for Saturday through Monday (ratably).

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-13

Request:

Please indicate when is the last opportunity for the Company to make nomination adjustments prior to the end of the gas day. Indicate whether, after this last adjustment occurs, there would still be opportunity for the unused resource to be released to the market.

Response:

The two major interstate pipelines that deliver gas to the Company's service territory are Tennessee Gas Pipeline Company and Algonquin Gas Transmission, LLC. Since both of these pipelines accept hourly nominations, the Company can make nomination adjustments up to one hour prior to the end of the gas day (9:00 a.m. Eastern Time). At this time, it would no longer be possible to release any unutilized capacity to the market. The Company could execute a bundled sale to a third party in the marketplace one hour prior to the end of the gas day; however, such opportunities are rare and usually do not occur.

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-14

Request:

Please provide documentation detailing how the Company used liquefied natural gas to meet customer requirements when pipeline supplies were exhausted.

Response:

During the cold spell, the Company used liquefied natural gas (LNG) to meet the customer requirements when it had exhausted the portfolio of pipeline and storage supplies and could not obtain additional citygate supplies from third parties. Please see the table below for the volume of LNG utilized during the extreme cold period.

LNG Vaporization during Extreme Cold Period

	*Cumberland Lng	Exeter LNG	Providence LNG	Exeter Boiloff	Providence Boiloff	
26-Dec-17	-	93	24,292	93	292	
27-Dec-17	-	124	9,283	124	399	
28-Dec-17	580	235	43,655	235	407	
29-Dec-17	-	342	28,660	342	576	
30-Dec-17	-	348	16,411	348	657	
31-Dec-17	-	274	47,480	274	242	
Total	**580**	**1,416**	**169,781**	**1,416**	**2,573**	**175,766**
	***Cumberland Lng**	**Exeter LNG**	**Providence LNG**	**Exeter Boiloff**	**Providence Boiloff**	
1-Jan-18	-	7,682	53,793	260	222	
2-Jan-18	-	4,911	25,813	286	317	
3-Jan-18	-	-	28	318	423	
4-Jan-18	-	910	834	394	583	
5-Jan-18	-	7,237	46,826	129	261	
6-Jan-18	2,651	9,247	49,135	108	175	
7-Jan-18	455	3,630	10,514	230	226	
8-Jan-18	-	-	25	278	297	
Total	**3,106**	**33,617**	**186,968**	**2,003**	**2,504**	**228,198**

*Portable Cumberland LNG site

At the end of December 2017, the Company's LNG storage inventory balance was 67 percent full, below the design season rule curve level of 95 percent full.[1] The LNG inventory levels continued to decrease, and by January 8, the Company's available LNG inventories were at 36 percent full.

[1] Design rule curve levels indicate the level of inventory that is needed in order to meet design season requirements for each day remaining in the winter period.

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-15

Request:

Please explain the Company's reliance on spot purchases made from December 11, 2017 to January 16, 2018. For each day, provide the total volume purchased under spot pricing.

Response:

The Company relies on spot purchases when all of the supplies in the Company's portfolio have been exhausted and the Company needs additional supply at its city gates. The Company would need additional supply either to meet a large customer demand or to manage adequate liquefied natural gas (LNG) inventory levels. In order to ensure the Company has a reliable amount of LNG in its inventory, the Company must follow a rule curve. Design rule curve levels indicate the level of inventory that is needed in order to meet design season requirements for each day remaining in the winter period.

Provided below are all of the daily spot purchases the Company made from December 11, 2017 to January 16, 2018 to be delivered to one of the Company's Tennessee or Algonquin city gates.

Date	Tennessee City Gate	Algonquin City Gate	TOTAL
December 11, 2017	0	0	0
December 12, 2017	0	0	0
December 13, 2017	0	0	0
December 14, 2017	0	0	0
December 15, 2017	0	0	0
December 16, 2017	0	0	0
December 17, 2017	0	0	0
December 18, 2017	0	0	0
December 19, 2017	0	0	0
December 20, 2017	0	0	0
December 21, 2017	0	0	0
December 22, 2017	0	0	0
December 23, 2017	0	0	0
December 24, 2017	0	0	0
December 25, 2017	0	0	0
December 26, 2017	15,000	0	15,000
December 27, 2017	10,000	0	10,000

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December 28, 2017	10,000	0	10,000
December 29, 2017	15,000	8,000	23,000
December 30, 2017	10,000	0	10,000
December 31, 2017	10,000	0	10,000
January 1, 2018	20,000	0	20,000
January 2, 2018	20,000	0	20,000
January 3, 2018	0	0	0
January 4, 2018	10,000	0	10,000
January 5, 2018	19,794	15,000	34,794
January 6, 2018	20,500	13,300	33,800
January 7, 2018	20,500	15,000	35,500
January 8, 2018	10,000	0	10,000
January 9, 2018	0	0	0
January 10, 2018	0	0	0
January 11, 2018	0	0	0
January 12, 2018	0	0	0
January 13, 2018	0	0	0
January 14, 2018	0	707	707
January 15, 2018	5,000	5,000	10,000
January 16, 2018	0	0	0

Prepared by or under the supervision of: Nancy G. Culliford

PUC 1-16

Request:

Is it the Company's opinion to recover the incremental gas costs through a surcharge on all customers' bills because it is believed that those customers were responsible for the increase and not to defer recovery to future customers? If so, please explain how non heating customers contributed to the increase in gas costs during periods of severe weather.

Response:

As shown in the pre-filed direct testimony of Ann E. Leary at Attachment AEL-2, page 1, the $34.5 deferred balance is comprised of a $1.5 million under-recovery of fixed gas costs (as shown on Line 17) and a $32.8 million under-recovery of variable gas costs (as shown on Line 34).

Since the Company is proposing to recover only $22.8 million of the projected $34.5 million deferred balance during the period March 2018 through October 2018, and the $22.8 million is less than the variable deferred balance of $32.8 million, the Company assigned the entire incremental recovery to the variable component of the Gas Cost Recovery (GCR). All customers, both high load factor customers (which include the Residential Non Heating customers) and low load factor customers, pay the same variable component of the GCR factor in accordance with the Company's GCR provision of its tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A. The fixed demand component of the GCR factor is differentiated between high and low load factor, and the Company is not proposing to recover the estimated $1.5 million under-recovery through the proposed increase to the GCR factors.

PUC 1-17

Request:

Please explain how the Company's hedging strategies mitigate risk during times of volatile gas pricing. Indicate other mitigation plans the Company has put into place to reduce risk in the future.

Response:

As described in the Company's Gas Procurement Incentive Plan (GPIP) filed each year in the Gas Cost Recovery (GCR) filing, the Company hedges, on average, a minimum of 74 percent of the forecasted normal weather requirements in November through March. The hedges are a combination of financial transactions, which hedge the physical purchases at the start of the month, and fixed price storage withdrawals during the month. Financial fixed price transactions are executed during the 24 month period prior to the month of delivery. Any price movement leading up to the month of the forecasted future physical purchase after the execution of a financial transaction is offset by an equal but opposite change in value of the financial transaction for the volume executed, thereby mitigating the price volatility for that portion of the forecasted purchases. These financial transactions hedge the price volatility leading up to the month of physical delivery, and not the volatility within the month associated with the swing purchases.

As a result of the high costs of swing purchases after the 2013-14 winter season, the Company recommended a Market Area Hedging strategy to mitigate a portion of the potential swing purchases. As described in detail in the Market Area Hedge strategy, filed on September 20, 2017, the Company can only hedge forecasted purchases that it expects to use under normal weather conditions. In the Market Area Hedge strategy, the Company describes the costs and risks associated with hedging the swing purchases under normal and design weather scenarios. In the Market Area Hedge strategy, the Company recommended and executed hedges to mitigate approximately one-third of the forecasted price risk by fixing the price and base loading a portion of what is typically swing purchases. By baseloading market area purchases instead of waiting until the day before the supply is needed, it eliminates the daily purchase at the daily price.

To help mitigate risks in the future, the Company is the process of contracting for additional pipeline capacity which will move the purchase risk from the market area to less volatile supply area receipt points in Pennsylvania and Canada. The Company expects an in-service date of November 2018 for 9,000 dekatherms (dt) per day of capacity on the Millennium Pipeline, which moves 9,000 dt per day of the total 18,000 dt per day of capacity on the Algonquin Incremental Market (AIM) contract from Texas Eastern M3 to Millennium East Pool receipt points.

Prepared by or under the supervision of: Stephen A. McCauley

PUC 1-17, page 2

Additionally, the Company is in the process of contracting for pipeline capacity, which will move the price risk of 29,000 dt per day from Tennessee Gas Pipeline Zone 6 at Dracut to Dawn, Canada. The pipeline capacity will phase in from 2018 to 2023. The Company will modify its Market Area Hedge strategy each year to adjust for the incremental pipeline capacity before each winter season.

Prepared by or under the supervision of: Stephen A. McCauley

PUC 1-18

Request:

Please provide documentation to support the update of the corporate federal income tax rate change from 35% to 21% in the working capital and inventory finance calculations.

Response:

The Company updated the federal tax rate from 35% to 21% in its working capital and inventory finance calculations in accordance with the recently enacted federal Tax Cuts and Jobs Act of 2017.