MEMORANDUM

TO: Rhode Island Public Utilities Commission

FROM: Bruce R. Oliver, Revilo Hill Associates, Inc.
Tim Oliver, Revilo Hill Associates, Inc.
On Behalf of the Division of Public Utilities and Carriers

DATE: October 16, 2017

SUBJECT: Review of National Grid's 2017 GCR Filing, Docket 4719.

This memorandum addresses the 2017 Annual Gas Cost Recovery ("GCR") filings by National Grid (hereinafter "National Grid" or "the Company"). National Grid's proposed GCR charges in this proceeding are supported by the September 1, 2017 Direct Testimony of Witnesses Nancy Culliford, Ann Leary, Theodore Poe, and John Protano, as subsequently modified by the Supplemental Direct Testimony and Schedules of witnesses Culliford, Leary and Stephen Greco. This memorandum first provides an overview of the Company's projected costs of gas and computed cost recovery requirements for the 2017-2018 GCR year, as well as the expected bill impacts of the Company's proposals in this proceeding. That overview is followed by discussion of GCR-related issues which focuses on three elements of National Grid's gas cost recovery request in this proceeding, as well as a concern of the Division regarding the manner in which the Company has been adjusting its forecasted sales volumes in monthly deferred gas cost reports. The final section of this memorandum summarizes the Division's findings and recommendations.

A. OVERVIEW

National Grid's 2017 GCR filing reflects an overall increase in its gas cost recovery requirements for the projected period from November 1, 2017 to October 31, 2018. As revised in the Company's September 29, 2017 Supplemental Direct Testimony, the Company's overall GCR cost recovery request is **$133.4 million**. That represents an increase of approximately $14.0 million or **11.7%** above the level of GCR cost recovery

approved by the Commission in Docket No. 4647 for National Grid's current GCR year (i.e., November 1, 2016 through October 31, 2017).[1] The Company's requested increase in GCR cost recovery, however, is not driven by gas cost increases. Rather, National Grid's total GCR Fixed and GCR Variable costs before adjustments are about $0.4 million or 0.3% below comparable measures in Docket No. 4647. The observed increase in National Grid's GCR cost recovery requirements is driven primarily by three factors. Those factors include:

- A $6.4 million reduction in Fixed Cost over-recoveries;
- A $5.5 million increase in Variable Cost under-recoveries; and
- A $2.8 million reduction in the NGMPM Customer Benefit.[2]

Attachment 1 to this memorandum shows the changes in GCR charges that would result from National Grid's proposals in this proceeding. For Residential Heating customers, Small C&I customers, Medium C&I customers, and low load factor Large and Extra Large C&I accounts, the charges set forth in Attachment AEL-1S, page 1 of 15, reflect an **11.8% increase** over the GCR levels currently in effect. The proposed increase in the GCR charges applicable to Residential Non-Heating customers and High Load Factor Large and Extra Large C&I accounts would be **8.0%**. Transportation customers would experience **decreases** in the FT-2 Marketer Demand Rate and the Storage and Peaking Charge of 9.6% and 3.8% respectively. However, those decreases would be countered by a **61.9% increase** in the Weighted Average Upstream Pipeline Transportation Charge.[3]

---

[1] National Grid's total gas cost recovery requirements for its 2016-2017 GCR year were $119.4 million.

[2] Attachment 2 shows the differences between the dollar amounts of adjustments and credits included in National Grid's GCR costs in this proceeding and the comparable adjustments included in National Grid's projected GCR costs in Docket No. 4647 for the Company's 2016-2017 GCR Year.

[3] The observed 61.9% increase in the Weighted Average Upstream Pipeline Transportation Charge equates to only about 20% of the delivered costs of gas for transportation service customers and is partially offset by decreases in the FT-2 Marketer Demand Charge and the Storage and Peaking Charge. In net, the average transportation service customer would likely see increases in their total charges for gas service roughly in the range of the proposed increases in GCR charges.

The combined bill impact of the Company's proposed GCR and DAC charges for Residential Heating customers range from 3.5% to 4.2%, with an average-use customer seeing approximately a 4.0% increase in their total annual charges for gas service. Residential Non-Heating customers would experience approximately 1.5% increases. C&I sales service customer bill impacts would range from about 3.1% to 5.1% for customers using High Load Factor service and from 3.6% to 7.5% for Low Load Factor service customers.

B. DISCUSSION OF GCR ISSUES

This review of National Grid's 2017 Annual GCR costs has identified three areas of specific concern. Those are: (1) the method that National Grid has used to transfer costs for maintenance of system pressures from the GCR to the DAC; and (2) the Company's proposed treatment of additional costs it now believes it will need to incur to purchase gas to meet design day requirements in the Cumberland area. In addition, the Division addresses matters relating to National Grid's adjustments to forecasted sales service volumes in its monthly GCR Deferred Balance reports.

1. Allocation of System Pressure Related Costs to DAC

The role of National Grid's System Pressure (SP) Factor in its Distribution Adjustment Clause ("DAC") is to transfer costs related to the maintenance of system pressure from the GCR costs to the DAC. That transfer of costs is intended to ensure that all customers who utilize the system for gas deliveries, and benefit from the Company's efforts to maintain system pressures, share responsibility for costs that are incurred for that purpose. Without this reassignment of costs to the DAC, all costs associated with National Grid's maintenance of system pressures would be considered borne exclusively by the Company's gas sales customers. Transportation service customers would be effectively exempted from responsibility for system pressure costs

even though the delivery of gas to those customers is likewise dependent upon National Grid's ability to maintain system pressures. In 2012 National Grid and the Division entered into a Settlement Agreement accepted by the Commission in Docket No. 4339 which set forth a methodology for determining the dollar amount of system pressure costs to be transferred from National Grid's GCR costs to the DAC. The methodology was premised on an allocation of 75.77% of the annual lease payments for the Providence LNG tank. That agreed upon methodology has been utilized since November 2012.

However, in the Company's current DAC proceeding (Docket No. 4708), the testimony of Ann Leary for National Grid indicates that the Company's reliance on LNG to maintain pressure in its distribution system has been eliminated by the completion and operation of the new Crary Street Gate Station which provides a high pressure feed into the Providence area on the Manchester Street lateral off of the Algonquin main line.[4] The Company suggests that its replacement of LNG use with high pressure gas delivered through the Crary Street Gate Station should be reflected through a modification of the 2012 Settlement Agreement. National Grid's proposal substitutes the pipeline demand charges for deliveries through the Crary Street Gate Station for Lease Payments associated with the Company's Providence LNG Tank, while maintaining the 75.77% allocation for the purpose of determining system pressure costs to be allocated to the DAC.

Based on discussions with the Company over the last couple years, the Division understood that the completion of the Crary Street Gate Station would alter the manner in which National Grid provided system pressure support in the Providence area, and that change might require modification of the methodology agreed upon in Docket No. 4339. However, the Division has two concerns regarding the modification National Grid's proposes in this proceeding. First, where the Company had previously indicated that only a portion of the capacity of the Providence LNG tank was used for system pressure

[4] See the and the September 1, 2017 Supplemental Direct Testimony of Witness Leary for National Grid in Docket No. 4708 at page 4, lines 13-14, and the September 1, 2017 testimony of Witness Culliford in Docket No. 4719 at page 11, lines 3-5, that indicates the Crary Street Gate Station was placed into service on July 17, 2017.

support, National Grid now indicates that "*100% of the contracted firm supply delivered at the Crary Street Gate Station is anticipated to be used for maintenance of system pressure*."[5] Second, the methodology agreed upon in Docket No. 4339 represented a compromise arrangement. Although that compromise methodology was premised on an allocation of lease costs associated with the Providence LNG tank, it was understood that LNG was also being used in other parts of the Company's system for pressure support purposes.[6] In that context, the agreed upon percentage of the Providence LNG Tank lease payments allocated to the DAC was viewed by the Division as a proxy measure that included consideration of all LNG use for pressure support on the Company's Rhode Island system, not just pressure support derived from Providence Tank LNG sendout.

For the forgoing reasons, we have reservations regarding the appropriateness of the modified system pressure factor determination that National Grid has relied upon in this proceeding. Based on the Company's responses to Division data requests in Docket No. 4708, it appears that a more appropriate approach to the determination of National Grid's system pressure costs would assign **100%** of the demand charges associated with deliveries to the Crary Street Gas Station to system pressure support, as the Company data response states that all gas flowing through the Crary Street Gate Station would be used for maintenance of system pressure. In addition, we believe that costs for LNG or other sources of gas supply that are used to provide system pressure support should also be included in the development of the Company's System Pressure (SP) Factor.

To reflect the reconfiguration of National Grid's system pressure support activities and costs that have resulted from the addition of the Crary Street Gate Station, the Company's System Pressure Factor determination should reflect: (1) 100% of the Demand Charges associated with firm deliveries of gas to the Crary Street Gate Station; and (2) costs associated with the Company's maintenance of system pressures in other

---

[5] Docket No. 4708, National Grid's response to Division Data Request 3-2, part A.

[6] Docket No. 4708, National Grid's response to Division Data Request 3-3 states, "*The Company's distribution system will continue to utilize LNG to maintain system pressure in the Southern Rhode Island region (i.e., Washington County) from the Exeter LNG facility*." The Division further understands that some use of either LNG or other sources of gas supply for pressure support may be required in the Cumberland area.

parts of its Rhode Island system that are not supported by deliveries to the Crary Street Gate Station. The demand costs associated with the Crary Street deliveries of gas are readily identifiable at this time, but the Company has provided no quantification of the costs it expects to incur for maintenance of system pressures in other parts of its system. The Division is confident, however, that the demand charges for gas delivered to the Crary Street Gate Station represent the majority of costs appropriately allocated to the DAC for recovery as system pressure costs. Thus, for the purposes of this proceeding, the Division believes that the Commission should require the System Pressure Factor in the DAC to reflect 100% of the demand costs associated with Crary Street deliveries. Prior to the Company's next DAC filing, the Division would need further clarification of costs the Company incurs to maintain system pressure for other parts of its Rhode Island system and the extent to which those costs that warrant incorporation in System Pressure Factor determinations for subsequent proceedings.

2. Treatment of Incremental Cumberland Costs

On September 29, 2017 National Grid filed Supplemental Direct Testimony. That supplemental testimony requests a waiver of tariff provisions regarding the definition of supply-related local production and storage costs. The waiver is requested to facilitate recovery of additional costs that National Grid claims it will incur to meet peak day requirements during the winter of 2017-2018 in the Cumberland area of its Rhode Island system. In conjunction with that waiver request, National Grid asks for recovery of an additional $637,000 through its 2017-2018 GCR charges. The Company also asks that it be permitted to continue to recover those costs through its GCR until a long-term solution is found or until the Company no longer uses the proposed temporary solution meeting design day requirements in the Cumberland area.

Due to the late filing of this request for incremental cost recovery, the Division does not feel that it has had adequate time to investigate fully this additional cost recovery request. In the Supplemental Direct of Witness Leary, she explains that the amount of supply-related local production and storage costs recovered through the GCR has

typically been determined through a general rate case, but in this proceeding National Grid seeks a waiver of the tariff to permit an adjustment to the Commission's past determinations. However, that request fails to address National Grid's announced plans to file a general rate case in Rhode Island within the month of November 2017, (i.e., roughly one-month from now). With such a near term opportunity to review these costs, the appropriateness of the requested waiver appears unnecessary. Further, the Division discourages Commission action in the absence of more well-developed record regarding this matter. Although more time is needed to complete the Division's review of the Company's proposals, two potentially important observations have been made. First, National Grid's characterization of these incremental peak supply costs as "fixed cost" needs to be questioned. Second, the Company's support for its need to incur these incremental costs requires further development and clarification. Thus, the Commission should consider either directing the Company to address this matter within its forthcoming general base rate case or approving interim GCR rates while allowing additional time within this docket for further development of the record on this matter.

3. Recovery of Market Area Hedge Costs

The Company's request in its Supplemental Direct Testimony and Attachments for additional cost recovery relating to its Market Area Hedge plan for the winter of 2017-2018 closely parallel the plan that National Grid proposed and the Division Supported in National Grid's last GCR proceeding. The details of the Company's plan for winter of 2017-2018 have been reviewed with the Company and are found to once again provide a reasonable strategy for reducing exposure to large cost increases in the face of extreme cold weather and adverse market conditions. Recognizing that the Company's Market Area Hedge Plan is designed to operate in the context of uncertain future conditions, the Company has also demonstrated considerable effort to balance the costs of the program against its risks. In this context, the Commission approval of cost recovery for National Grid's Market Area Hedge Plan for the winter of 2017 and 2018 through the GCR is warranted. Although the Plan adds to the Company's overall gas supply costs, the plan

serves as insurance against considerably higher costs under colder than normal weather conditions.

4. Adjustments to Forecasted Monthly Sales Service Volumes in National Grid's Monthly Deferred Gas Balance Reports

Over the past several months, the Division has observed several instances in which National Grid's monthly GCR Deferred Balances reports have made noticeable adjustments to the forecasted sales volumes. The inclusion of adjustments to forecasted volumes has not traditionally been the Company's practice. Moreover, from the Division's perspective, unilateral changes in the forecasted volumes from those presented by National Grid in its Annual GCR filings are inappropriate and distort the interpretation of the computed end of October deferred balances which serve as a measure for assessing the need for interim GCR rate adjustments.

National Grid represents that its adjustments to sales volumes are intended to account for implied changes in Unaccounted for Gas ("UFG") volumes. However, UFG volumes have never been a focus of the Company's GCR reporting. Over more than a decade of reviewing GCR filings for the Division, we are aware of no precedent for the Company's recent adjustments to forecasted sales service volumes. This unilateral change in the Company's reporting practices appears unnecessary. Moreover, the Company's adjustments appear arbitrary in their determination and are inappropriately applied to just sales service rate classifications. Further, from the Division's perspective the Company's adjustments to sale service volumes are a distortion of historic cost recovery relationships that is confusing and counter-productive. We note that while Unaccounted For Gas considerations appear to be a key driver of the Company's sales forecast adjustments during the 2016-2017 GCR period, there is no discussion of the UFG issues anywhere in National Grid's testimony in this proceeding.

Each month, National Grid files a GCR Deferred Balances report with the Commission. Each report provides actual costs, service volumes, and revenues for the month just completed, and projects deferred gas cost balances through the end of the

current GCR period (i.e., through October 31 of the GCR year). Historically, the service volumes used to project the Company's expected end-of-period deferred GCR balances have been the forecasted normal weather volumes by rate classification that the Company relied upon in the preparation of its most recently approved Annual GCR filing.[7] However, within the current GCR period, the Division has observed several significant departures from the Company's past reporting practice.

For example, in the Company's April 20, 2017 filing of GCR Deferred Balances, National Grid provided actual results and actual GCR deferred balances through the end of March 2017. It also provided an updated projection of its end-of-October 2017 GCR deferred balances. However, as part of its projection of end-of-October 2017 GCR deferred balances, National Grid increased its projected April 2017 forecasted sales service volumes by **49.7%**. This dramatic one-time adjustment to the forecast of sales service volumes presented in its 2016 Annual GCR filings in Docket No. 4647 was noted in a footnote to the cover letter for its April 20, 2017 filing of GCR Deferred Balances as follows:

> *National Grid has adjusted the April 2017 billing sales so that the Unaccounted For Gas (UFG) percentage for the period of November 2016 through October 2017 is 3 percent. This adjustment results from March 2017 being colder than normal, with National Grid's billing of increased sales not yet completed by March 31, 2017 due to the manner by which the Company bills customers throughout a calendar month (over 20 billing cycles). Without this adjustment, the UFG based on actual sales and sendout for the period of November 2016 through March 2017 and forecasted sales and sendout for the period of April 2017 through October 2017 would be 8 percent. The high UFG is due to the lag in the billing of March deliveries resulting from the colder-than-normal weather. National Grid anticipates that April 2017 billed sales will be higher than originally forecasted, as the remaining March deliveries are billed in April.*

Yet, when the Company's monthly GCR Deferred Balances report of actual results for April 2017 were filed on May 20, 2017, the actual Sales Service volumes for the month of April 2017 were only about **15%** higher than the sales volume levels that served as the

[7] See, for example, Attachment AEL-1S, page 11 of 15, which accompanies the Supplemental Direct Testimony of National Grid Witness Leary in this proceeding.

basis for the development of National Grid's 2016 GCR charges. Thus, it appears that the forecast adjustment made in the Company's April 20, 2017 GCR Deferred Balances report represented a substantially inaccurate assessment of the magnitude of the volumes the Company would bill on a lagged basis.[8]

Additionally, the Division observes that the number of billing cycles used by National Grid to render bills to its Rhode Island customers has not changed, and lags in the billing of service volumes are common. While cold weather at the end of March may have resulted in a larger than usual amount of service being billed in the subsequent month, such lags have never been viewed as a significant problem in the past. Lags in the billing of late March 2017 usage volumes also do not explain the adjustments made by the Company to forecasted normal weather sales volumes for each month from January through August of 2017.

As shown in Table 1 below, the Company has made upward adjustments to its normal weather sales forecast for every month from January 2017 through August 2017. For the months of January through March, those upward adjustments were roughly in the range of 6%. However, in subsequent months, the Company's upward adjustments have ranged from 13.5% to 49.7%. Some of those adjustments have been referenced in footnotes to the cover letters for monthly GCR Deferred Balance filings, but nowhere is the methodology for determining the magnitude of those adjustments clearly documented.

Table 1

[8] Without information regarding the variations from normal weather degree days for the months of March and April 2017, a more detailed assessment of the drivers of the observed differences between actual and forecasted volumes by rate class is not possible.

National Grid Adjustments to Monthly Normal Weather
Sales Service Volume Forecasts *(Dth)*

Month/Year	2016 Annual GCR Filing Forecast Docket 4647	National Grid Revised Forecast	National Grid Forecast Adjustment	% Adjustment
Nov 2016	2,035,708	NA		
Dec 2016	3,354,779	3,354,779	0	0.0%
Jan 2017	4,378,071	4,668,170	290,099	6.6%
Feb 2017	4,497,543	4,781,404	283,861	6.3%
Mar 2017	3,869,298	4,099,004	229,706	5.9%
Apr 2017	2,899,229	4,339,249	1,440,020	49.7%
May 2017	1,721,774	2,268,616	546,842	31.8%
Jun 2017	860,026	975,755	115,729	13.5%
Jul 2017	476,936	611,798	137,862	29.1%
Aug 2017	419,850	487,578	67,728	16.1%
Sep 2017	476,163	476,163	0	0.0%
Oct 2017	943,610	NA		

NA indicates "not available."

Furthermore, with one identified exception, all of the Company's adjustments to forecasted monthly volumes have been applied exclusively to Sale Service volumes. This implicitly suggests that Transportation Service customers have no responsibility for variations in Unaccounted for Gas. Yet, no analytic support for the application of those adjustments only to Sales Service has been presented. Any assignment of upward adjustments to Transportation Service volumes, rather than solely Sales Service volumes, could directly impact National Grid's estimates of GCR costs and revenues, and alter the Company's estimated end-of-October deferred balances.

The Division finds no compelling justification for the adjustments to monthly Sales Service volumes that National Grid has applied in its monthly GCR Deferred Balances reporting. We also find that the adjustment to Sales Service volumes that Company has employed improperly distort assessments of end-of-period GCR balances. Such distortion impede the ability of the Commission and the Division to understand a basic measure of gas cost recoveries that has been relied upon for years as a guide for

assessing when interim adjustments to National Grid's GCR charges may need to be considered. The Company's unilateral application of adjustments to forecasted monthly sales volumes, thus, erodes the transparency of a well-established process for reporting of GCR Deferred Balances.

C. SUMMARY OF DIVISION FINDINGS & RECOMMENDATIONS

Overall, National Grid's initial presentation in its September 1, 2017 testimony and Attachments for this proceeding appears reasonable and appropriate. No reason to question the volumes or costs presented in Witness Culliford's testimony has been identified. A similar statement can be made with respect to most of Witness Leary's testimony and attachments, with one minor exception. That problem was noted by the Division in discovery, verified by the Company in response to Division Data Request DIV 2-5, and corrected in Witness Leary's supplemental schedules.

Likewise, the Company's GCR reconciliations appear accurate. However, there are a couple of elements of the Company's reported gas cost reconciliation filing with which the Division has concerns and warrants for further investigation. One concern relates to a significant increase observed in the Company's reported actual Variable Gas Supply Costs for the month of March 2017 (i.e., the last month of the reconciliation period). The Division understands that an unusually cold period for late March was experienced, but the observed $5.5 million or 52% increase in reported gas costs over the Company's prior projections for the month of March does not appear well explained. The second concern involves extremely low throughput volumes that are reported for FT-1 Extra Large High Load Factor ("XL HLF") service for the month of November 2016. As shown in Exhibit AEL-2, page 7 of 7, line 38, the reported XL HLF volumes for November 2016 were 26,686 Dth. For all other months of the reconciliation period that class has reported actual volumes between roughly 400,000 Dth and 560,000 Dth. In the prior reconciliation year, the volumes for FT-1 XL HLF service varied between 400,000 and 600,000 Dth. Thus, the very small volumes reported for that class for November 2016 need further explanation and documentation.

With respect to the content of National Grid's September 1, 2017 filing, the only substantive concern relates to the amount of costs assigned to the DAC for maintenance of system pressure. This matter is also addressed in the Division DAC memorandum submitted in Docket No. 4708. As explained in that memorandum, the Division is recommending that an additional **$764,118** be shifted from National Grid's GCR to the DAC to more accurately reflect the Company's representation of the determinants of its costs for maintaining system pressure.

However, National Grid's Supplemental Direct Testimony and attachments raise some additional considerations. As explained in Witness Leary's Supplemental Direct Testimony at page 2, lines 14-21, two adjustments are made in the Company's Supplemental testimony and attachments which further increase the total costs that National Grid seeks to recover from Rhode Island ratepayers. The added considerations arising from National Grid's September 29, 2017 Supplemental Direct Testimony include: (1) the Company's request for a waiver of its tariff provision that defines supply-related local production and storage costs; and (2) National Grid's request for recovery of incremental costs associated with National Grid's Market Area Hedging activities.. The Division has supported National Grid's Market Area Hedging Plan for the winter of 2017-2018 and thereby also supports the Company's request for recovery of costs associated with implementing that plan. On the other hand, the Division believes that more time is needed to consider the appropriate treatment of costs associated with National Grid's plan for meeting peak day supply requirements in the Cumberland area. The Division also notes that consideration of the Cumberland LNG related costs for which National Grid seek recovery may be more appropriate in the context of the upcoming National Grid base rate proceeding. Lacking sufficient information at this time to address the additional Cumberland LNG costs for which National Grid seeks recovery for the first time in its Supplemental Direct Testimony, the Division recommends that any GCR rates approved by the Commission at this time should exclude those costs with the understanding that once the appropriate treatment of those costs is determined, the Commission could allow

an appropriate portion of those costs to be reflected in the Company's GCR Deferred cost balance.

Attachment DIV GCR–3 depicts the changes in National Grid's GCR costs and proposed charges that the Division recommends. Attachment DIV GCR–3, page 2 of 2, shows the impact of the Division's recommendation on the fixed cost recovery requirements for the 2017-2018 GCR year. These changes reflect the allocation of 100% of the Crary Street Gate Station Costs that the Division recommends be allocated to the DAC and removal, for now, of the Cumberland Portable LNG costs. Page 1 of 2, of Attachment DIV GCR–3 illustrates the impact of the Division's recommendations on the Company's proposed GCR charges. The Division's recommended GCR charges are **$0.4851** for High Load Factor classes and **$0.5279** for Low Load Factor classes. The Division's recommendations reduce the Company's proposed GCR charges by 1.0% (i.e., 100 basis points) for Residential Heating customers and Low Load Factor C&I customers. They also lower the Company's proposed charges for High Load Factor C&I customers and Residential Non-Heating customers by 0.8% (i.e., 80 basis points).

National Grid- RI Gas

Docket No. 4719 - 2017 Annual GRC Proceeding

National Grid's Proposed Changes in GCR Charges by Rate Class

Rate Classification	Current GCR Rate 1/ ($/Therm)	NGrid Proposed GCR Rate 1/ ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$ 0.4525	$ 0.4888	$0.0363	8.0%
Low Income- Non Heating	$ 0.4525	$ 0.4888	$0.0363	8.0%
Heating	$ 0.4766	$ 0.5329	$0.0563	11.8%
Low income- Heating	$ 0.4766	$ 0.5329	$0.0563	11.8%
Commercial & Industrial				
Small	$ 0.4766	$ 0.5329	$0.0563	11.8%
Medium	$ 0.4766	$ 0.5329	$0.0563	11.8%
Large Low Load Factor	$ 0.4766	$ 0.5329	$0.0563	11.8%
Large High Load Factor	$ 0.4525	$ 0.4888	$0.0363	8.0%
Extra Large Low Load Factor	$ 0.4766	$ 0.5329	$0.0563	11.8%
Extra Large High Load Factor	$ 0.4525	$ 0.4888	$0.0363	8.0%
FT-2 Marketer Demand Rate	$ 8.8817	$ 8.0328	($0.8489)	-9.6%
Storage and Peaking Charge	$ 0.6945	$ 0.6682	($0.0263)	-3.8%
Wtd Avg Upstream Pipeline Transportation Charge	$ 0.4219	$ 0.6831	$0.2612	61.9%

1/ Residential and Commercial and Industrial charges from Attachment AEL-1S, page 1. The proposed FT-2 Marketer Demand Rate, Storage and Peaking Charge and Weighted Average Upstream Upstream Transportation Charge are from Attachment AEL-5S, page 1 of 3.

National Grid- RI Gas

Docket No. 4719 - 2017 Annual GRC Proceeding

Changes in Forecasted Gas Costs by GCR Cost Component

Without Adjustments and Reconciliations

GCR Cost Component	Dkt 4719 Forecasted Annual Cost 2017-18 1/	Dkt 4647 Forecasted Annual Cost 2016-17 2/	Dkt 4576 Forecasted Annual Cost 2015-16 3/	Change 2016-17 to 2017-18 $	Change 2016-17 to 2017-18 %	2-Year Change 2014-15 to 2016-17 $	2-Year Change 2014-15 to 2016-17 %
Supply Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Storage Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Supply Variable Costs	$ 67,590,607	$ 68,304,529	$ 82,733,795	$ (713,922)	-1.0%	$ (15,143,188)	-22.2%
Storage Variable Costs	$ 10,739,066	$ 13,008,462	$ 15,653,838	$ (2,269,396)	-17.4%	$ (4,914,772)	-37.8%
TOTAL	$ 131,621,957	$ 132,058,629	$ 143,669,875	$ (436,672)	-0.3%	$ (12,047,918)	-9.1%
Total Fixed Costs	$ 53,292,284	$ 50,745,638	$ 45,282,242	$ 2,546,646	5.0%	$ 8,010,042	15.8%
Total Variable Costs	$ 78,329,673	$ 81,312,991	$ 98,387,633	$ (2,983,318)	-3.7%	$ (20,057,960)	-24.7%

1/ Source: Docket No. 4719, Attachment AEL-1S, September 29, 2017, pages 2-5.
2/ Source: Docket No. 4647, Attachment AEL-1, REVISED October 3, 2016, pages 2-5.
3/ Source: Docket No. 4576, Attachment AEL-1, September 1, 2015, pages 2-5.

National Grid- RI Gas

Docket No. 4719 - 2017 Annual GRC Proceeding

Computed Changes in Adjustments to GCR Fixed and Variable Costs

Ln No	Description	Dkt 4719 Forecasted Annual Cost 2016-17	Dkt 4647 Forecasted Annual Cost 2015-16	Change 2016-17 to 2017-18 $	Change 2016-17 to 2017-18 %
	Adjustments to Fixed Gas Costs				
1	NGPMP Customer Benefit	$ 10,900,000	$ 13,700,000	$ (2,800,000)	-20.4%
2	FT-2 Storage Demand Costs	$ 1,851,536	$ 1,821,075	$ 30,461	1.7%
3	LNG Demand to DAC	$ 2,389,483	$ 1,488,790	$ 900,693	60.5%
4	Supply Related LNG O&M Costs	$ (575,581)	$ (575,581)	$ -	0.0%
4a	Portable LNG Storage Cost	$ (637,000)	NA	$ (637,000)	NA
5	Working Capital Requirement	$ (293,378)	$ (283,602)	$ (9,776)	3.4%
6	Deferred Fixed Cost Over-Recovery	$ (1,169,851)	$ 5,220,624	$ (6,390,475)	-122.4%
7	Reconciliation Amount from Fixed Costs - Marketer	$ (36,098)	$ 37,411	$ (73,509)	-196.5%
8	Total Fixed Cost Adjustments	$ 12,429,111	$ 21,408,717	$ (8,979,606)	-41.9%
	Adjustments to Variable Costs				
9	Working Capital	$ 445,011	$ 468,168	$ (23,157)	-4.9%
10	Def Variable Cost Under-Recoveries	$ 12,377,603	$ 6,842,292	$ 5,535,311	80.9%
11	Supply Related LNG O&M	$ 572,694	$ 572,694	$ -	0.0%
12	Inventory Financing - LNG	$ 212,808	$ 248,872	$ (36,064)	-14.5%
13	Inventory Financing - Storage	$ 600,752	$ 632,657	$ (31,905)	-5.0%
14	Total Variable Cost Adjustments	$ 14,208,868	$ 8,764,683	$ 5,444,185	62.1%
15	Total Adjustments to Gas Costs	$ 26,637,979	$ 30,173,400	$ (3,535,421)	
	Summary of National Grid's Requested Gas Cost Recovery				
16	Annual Fixed Costs	$ 53,292,284	$ 50,745,638	$ 2,546,646	5.0%
17	Net Credits to Fixed Costs	$ (12,429,111)	$ (21,408,717)	$ 8,979,606	-41.9%
18	Adjusted Annual Fixed Costs	$ 40,863,173	$ 29,336,921	$ 11,526,252	**39.3%**
19	Annual Variable Costs	$ 78,329,673	$ 81,312,991	$ (2,983,318)	-3.7%
20	Additions to Variable Costs	$ 14,208,868	$ 8,764,683	$ 5,444,185	62.1%
21	Adjusted Annual Variable Cost	$ 92,538,541	$ 90,077,674	$ 2,460,867	**2.7%**
22	Total Required Gas Cost Recovery	$ 133,401,714	$ 119,414,595	$ 13,987,119	11.7%
23	Annual Sales Volumes (Dth)	25,914,442	25,929,986	(15,544)	-0.1%

National Grid- RI Gas

Docket No. 4719 - 2017 Annual GRC Proceeding

Division's Proposed Changes in GCR Charges by Cost Factor

Description	High Load[1]	Low Load[2]
Fixed Cost Factor - $/dktherm	$1.1259	$1.5404
Variable Cost Factor -$/dktherm	$3.5711	$3.5711
Total Gas Cost Recovery Charge- $/dktherm	$4.6970	$5.1115
Uncollectible %	3.18%	3.18%
Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	$4.8512	$5.2793
GCR Charge on a per therm basis	**$0.4851**	**$0.5279**
Current rate effective 11/01/16* - $/therm	$0.4525	$0.4766
Increase- $/therm	$0.0326	$0.0513
Percent Increase	7.2%	10.8%

* GCR rates approved with the Revised GCR filing per Docket 4647 filed on October 03, 2016

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load

[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

National Grid- RI Gas

Docket No. 4719 - 2017 Annual GRC Proceeding

Division's Proposed Changes to Fixed GCR Costs

Description	Amount	High Load Factor Total	Low Load Factor Total
Fixed Costs (net of Cap Rel to marketers)	$53,292,283		
Less:			
NGPMP Customer Benefit	($10,900,000)		
Interruptible Costs	$0		
FT-2 Storage Demand Costs	($1,699,721)		
Systeme Pressure to DAC[1]	**($3,153,600)**		
Refunds	$0		
Total Credits	($15,753,321)		
Plus:			
Supply Related LNG O&M Costs	$575,581		
Portable LNG Storage Cost[2]	**$0**		
Working Capital Requirement	$288,974		
Deferred Fixed Cost Under-recovered	$1,169,851		
Reconciliation Amount from Fixed costs- Marketers	$36,098		
Total Additions	$2,070,504		
Total Fixed Costs	$39,609,466		
Design Winter Sales Percentage		2.12%	97.88%
Allocated Supply Fixed Costs		$840,526	$38,768,940
Sales (Dt) Nov 2017 - Oct 2018	25,914,442	746,482	25,167,960
Fixed Factor		$1.1259	$1.5404

Notes:
[1] 100% of Crary Street Station Costs to DAC
[2] Removal of Columbia LNG Costs