**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**
**OF THE**
**STATE OF RHODE ISLAND**
**AND PROVIDENCE PLANTATIONS**

**IN THE MATTER OF**

| | | |
|---|---|---|
| **The National Grid Annual** | ) | |
| **Gas Cost Recovery Charge** | ) | **Docket No. 4647** |
| **Filing** | ) | |

**DIRECT TESTIMONY OF WITNESS**
**BRUCE R. OLIVER**

On Behalf of

**The Division of Public Utilities and Carriers**

*October 7, 2016*

**TESTIMONY OF BRUCE R. OLIVER**
**Docket No. 4647**
*October 7, 2016*

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## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

**Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?**

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct the preparation and presentation of economic, utility planning, and regulatory policy analyses for our clients.

**Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?**

A. My testimony in this proceeding is presented on behalf of the Division of Public Utilities and Carriers (hereinafter "the Division").

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. This testimony addresses issues relating to the National Grid (or hereinafter “the Company”) Annual Gas Cost Recovery (GCR) filing. This testimony reviews and comments on the content of the September 1, 2016 direct testimony and attachments of witnesses Arangio, Leary, Poe and McCauley for National Grid, as well as the September 30, 2016 supplemental testimony of Witness McCauley regarding the Company's market area hedging plans and the revised exhibits of witnesses Arangio and Leary filed on October 3, 2016.

**Q. HAVE YOU PRESENTED TESTIMONY ON BEHALF OF THE DIVISION IN ANY PRIOR GCR PROCEEDINGS?**

A. Yes, I have participated in each annual gas cost proceeding for National Grid and its predecessor organizations for more than twenty years.

## II. SUMMARY

**Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR REVIEW OF NATIONAL GRID'S FILINGS IN THIS PROCEEDING?**

A. My review of the Company's filings in this proceeding yields the following findings:

1. National Grid's proposed GCR charges on average reflect roughly 14% reductions from the levels approved by this Commission in the Company's last GCR proceeding (Docket 4576).

2. The Company's GPIP and NGPMP incentive mechanisms continue to be productive in terms of lowering costs to Rhode Island gas customers.

3. National Grid's proposals for Market Area Hedging for the winter of 2016-17 are reasonable and consistent with the previously stated goal of this Commission to seek greater stability in the natural gas costs billed to Rhode Island consumers.

4. Two unexpected events have affected the Company's planning of gas supply resources for the winter of 2016-17, and certain elements of the Company's responses to those events should be questioned.

5. Numerous issues have been identified in the forecasts the Company has presented in this proceeding and in the analyses upon which National Grid is making important long-term gas supply planning decisions, and this Commission is encouraged to become more actively engaged in the exercise of oversight for those activities.

## III. OVERVIEW

**Q. CAN YOU PROVIDE AN OVERVIEW OF THE KEY ISSUES ON WHICH YOU BELIEVE THE COMMISSION SHOULD FOCUS IN THIS PROCEEDING?**

A. Yes. The Company's gas costs recovery requirements in this proceeding have declined by $24.9 million or 17.3%. The proposed GCR charges in this proceeding are the lowest GCR charges for Rhode Island gas customers since National Grid acquired the gas utility operations of Southern Union. The overall reduction in

National Grid's GRC cost recovery requirements combined with the Company's downward revision to its projected sales volumes yields decreases of approximately 14% in National Grid's proposed GCR charges for both High Load Factor and Low Load Factor customers. However, adjustments and credits to the Company's gas costs serve to obscure an increase of nearly $6.4 million or 22% National Grid's projected Fixed Supply Costs for 2016-17.

The Commission is cautioned that natural gas commodity prices appear to be at or near a market low, and increases in gas commodity prices should be anticipated as we move forward in time. As the Company's overall gas supply costs begin to rise once again, sensitivity to costs imposed by National Grid's planning of long-term gas supply resources will increase, and the acquisition of well-planned and cost-effective gas supply resources will become increasingly critical to the Company's ability to maintain affordable gas supply services. Since tomorrow's fixed costs are largely a product of current long-term planning decisions, the Division encourages this Commission to become more actively engaged in the oversight of the Company's methods, assumptions, and criteria that National Grid uses to guide its decisions regarding long-term commitments to gas supply resources.

Several of the gas supply planning considerations outlined in witness Arangio's testimony in this proceeding involve significant long-term financial commitments that could be reflected in GCR charges for Rhode Island's firm gas service customers well into the future (i.e., the next 20 years or longer). As fixed costs for gas supply resources are not part of the Company's base rate considerations, GCR proceedings are presently the primary forum, if not the only forum, in which the Commission has the opportunity to exercise oversight over fixed gas supply costs that National Grid incurs to serve its Rhode Island gas customers.

Although National Grid files Long-Range Gas Supply plans on a biennial basis, those filings have not been subject to any formal review process.[1] Thus, the current process for review of the Company's long-range forecasts and planning lacks relevance. A significant number of data requests the Division submitted to the Company regarding its March 10, 2016 Long-Range Resource and Requirements Plan ("LRP") have not been answered.[2] At this point the Division is not satisfied that the Company has reasonably assessed either its near-term or long-term gas supply requirements. The Division also has a number of questions regarding the economics of certain of the gas supply options that National Grid is pursuing.

This testimony demonstrates that the forecasts, analyses, and planning criteria upon which National Grid relies to support its long-term planning decisions warrant closer scrutiny. Many of the planning decisions that National Grid is now considering (or acting upon) involve significant long-term fixed cost commitments that may or may not be in the best interests of National Grid's Rhode Island ratepayers. Without timely review of the need for, and service reliability implications

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[1] This contrasts with the Division's understand that in Massachusetts National Grid to seek approval from the Massachusetts Department of Utilities before entering into gas capacity contracts with a term of more than one year.

[2] The September 1, 2016 testimony of National Grid witness Theodore Poe in this proceeding at page 12 recognizes that the Division's outstanding requests and indicates that the Company is "*in the process of completing its remaining responses to the Division's second set of data requests in that docket*." Yet, a month after that testimony was filed and more than six months after those requests were submitted to the Company no further responses have been received.

of those projects, this Commission cannot ensure that Rhode Island ratepayers will be protected from responsibility for unproductive and burdensome expenditures that could result from the Company's planning decisions.

The Division continues to have numerous concerns regarding the data, assumptions and methods that National Grid uses in the development of its forecasts of Rhode Island's gas service requirements. In this context, the Company is encouraged to refine the forecasts and forecasting methods that underlie both its annual GCR filings and its biennial presentation of long-range forecasts and resource plans. Moreover, the process and/or schedule for long-range plan filings needs to be revised, and greater structure needs to be developed for review of National Grid's long-range forecasts and resource planning analyses. The Division believes that ties between the Company's long-range forecasts and its decisions regarding commitments to long-term gas supply resources need to be more explicitly established with Commission oversight and input regarding the planning criteria that ultimately drive assessments of the need for, and economics of, gas supply capacity additions. The current GCR review process which allows only roughly five to six weeks for review and analysis of the Company's filings is inadequate to provide the Commission a well-developed record with respect to important forecasting and planning issues.

Finally, I note that in last year's Annual GCR review (i.e., Docket 4576), issues relating to the National Grid's proposal to allow Capacity Exempt customers[3] to transfer to Capacity Assigned service received considerable attention. At the conclusion of that proceeding, those issues were left unresolved. As of this date, the Division is aware of no further proposals from the Company for offering current Capacity Exempt customers the opportunity to revoke their past determination and request assignments of capacity resource from National Grid.

Given that the Company does not plan its gas supply, storage and peaking resources to ensure the availability of capacity to serve the requirements of Capacity Exempt customers, a decision to allow current Capacity Exempt customers to return to Capacity Assigned status would have a direct impact of National Grid's near-term and long-term capacity requirements. It would also be expected to increase National Grid's overall capacity costs and/or decrease the reliability of service for the vast majority of customers who presently rely on National Grid for the planning and acquisition of capacity resources to meet their gas service customers. For these reasons, any future proposals for changes in regulations or policies that might allow existing Capacity Exempt customers to return to Capacity Assigned service must be considered in terms of the impacts of such changes on: (1) the adequacy of National

[3] Capacity Exempt customers (a.k.a., Zero Capacity customers) are firm service customers who have made an irrevocable one-time election to obtain any and all gas supply, storage or peaking capacity that their operations may require from sources other than National Grid. By electing not to receive an assignment of capacity from National Grid, a Capacity Exempt customer avoids all responsibility for contributing to the costs of gas supply capacity resources that National Grid acquires to ensure its ability to ensure its ability to reliably meet is firm gas service customers' requirements throughout the year.

Grid's gas supply resources and (2) the costs that the proposed changes may impose on the Company's other firm gas service customers.

## III. DISCUSSION OF ISSUES

### A. Changes in National Grid's GCR Charges and Gas Costs

**Q. WHAT ARE THE COMPANY'S PROPOSED CHANGES IN GCR CHARGES?**

A. National Grid's filing proposes significant reductions in its GCR charges for all firm gas sales service rate classifications. As shown in **Attachment BRO-1,** the Company's proposes to lower its GCR charges for Residential Heating customers, Small C&I customers, Medium C&I customers, Low Load Factor Large C&I customers, and Low Load Factor Extra Large C&I customers by 13.8% from $0.5530 per therm to $0.4766 per therm. The Company's September 1, 2016 filing in this proceeding also proposes a reduction of 14.0% in the GCR charges for High Load Factor gas sales service customers. As a result, GCR charges for those customers would decline from $0.5259 per therm to $0.4525 per therm.

For Marketer Transportation, National Grid computes that its Weighted Average Cost of Upstream Pipeline Transportation declines from $0.4219 per dekatherm ("Dth") to $0.3119 per Dth (i.e., a 26.1% reduction). In addition, the Company's computed FT-2 Demand Rate decreases 9.4% from $8.8817 per Dth to

$8.0484 per Dth, and the Storage and Peaking Charge for Transportation Marketers is reduced 2.1% from $0.6945 per Dth to $0.6802 per Dth.

**Q. DO THE PROPOSED REDUCTIONS IN NATIONAL GRID'S GCR CHARGES INDICATE THAT THE COMPANY'S GAS COSTS HAVE FALLEN BY APPROXIMATELY 15% SINCE LAST YEAR?**

A. No. Attachment BRO-2 demonstrates that the Company's overall costs of gas (including both Fixed and Variable gas cost components) prior to reconciliations, credits, and other adjustments have declined 8.1% or approximately $11.6 million from the levels projected in Docket 4576. This marks the fourth straight year in which the Company's total gas costs (prior to Adjustments and Reconciliations) have declined from the prior year's projections. These projected reductions in the Company's gas costs are driven primarily by three factors. Those are:

1. Lower overall market prices for natural gas;

2. A gas procurement program which continues to produce desired results; and

3. A productive asset management incentive structure that provides a substantial offset to National Grid's Fixed Gas Supply Costs.

However, as demonstrated in **Attachment BRO-1**, National Grid's proposed GRC charges are roughly 14% below the Company's currently effective GCR charges. The greater percentage reductions in the proposed GCR charges are primarily attributable to four factors:

- A $4.3 million increase in the NGPMP Customer Benefit (i.e., an increase from $9.4 million of $13.7 million);

- A $2.3 million increase in credits for Deferred Fixed Cost over-recoveries; and

- A $6.5 million decrease in Variable Cost Under-recoveries;

- A forecasted 4.0% reduction in annual sales volumes for firm service customers.[4]

The identified adjustments to gas costs essentially double the reduction in the dollar amount in the Company's GRC costs from $13 million to nearly a $26 million. That amplifies the percentage decrease in GCR cost recovery requirements from 9.4% to 17.3%.[5] However, the final reduction in GCR charges also reflects the 4.0% reduction in forecasted sales volumes which partially offsets the overall decrease in

[4] See Attachment BRO-2, page 2 of 3.
[5] See Attachment BRO-2, page 3 of 3.

gas cost recovery requirements when converted to dollars per therm charges. Thus, the net results (as shown in Attachment BRO-1) are roughly 14% reductions in the Company's proposed GCR charges for both high load factor and low load factor customers.

**B. GPIP Incentive Calculations**

**Q. DOES THE COMPANY SEEK APPROVAL OF A GAS PROCUREMENT INCENTIVE FOR THE 12 MONTH PERIOD ENDED JUNE 2015?**

A. Yes. The direct testimony of witness Stephen McCauley at page 4, lines 13-17, indicates that National Grid made 4,043,000 Dth of discretionary purchases for the twelve months ended June 30, 2016 and earned a net incentive of $167,963. According to the analysis presented in Attachment SAM-2, the average costs of discretionary hedges made by National Grid was $0.415 per Dth below the average cost of mandatory hedges.

**Q. DO YOU FIND ANY REASON TO QUESTION THE ACCURACY OF THE COMPANY'S GPIP INCENTIVE CALCULATIONS?**

A. No, I do not. The incentive calculations Witness McCauley presents for the twelve months ended June 2016 are well documented, accurately computed, and compliant with the with the terms of the Gas Procurement Incentive Plan (GPIP).

**Q. IS THE GPIP INCENTIVE MECHANISM CONTINUING TO FUNCTION IN A MANNER THAT BENEFITS THE COMPANY'S FIRM GAS SALES CUSTOMERS?**

A. Yes. The Company's discretionary hedges for the period from July 1, 2015 through June 30, 2016 produce an overall benefit of nearly $1.68 million dollars. After allowing for payment of the approved incentive for National Grid, the net benefit for Rhode Island ratepayers is 90% of the achieved savings or over $1.5 million. Thus, the resulting **9:1** ratio of benefits to cost for the Company's customers is quite favorable. Moreover, it is noteworthy that National Grid was able to achieve these results in the context of a market which the prices for volumes subject to mandatory hedging were already comparatively low.

**Q. SHOULD THE COMMISSION APPROVE NATIONAL GRID'S REQUESTED GPIP INCENTIVE PAYMENT FOR THE TWELVE MONTHS ENDED JUNE 2015?**

A. Yes. The Company has clearly embraced the incentives provided, and has produced results that easily justify the level incentive requested. Thus, I conclude that the Company has earned its requested GPIP incentive, and the Commission should authorize approval of National Grid's requested **$167,963** GPIP incentive as just and reasonable.

**<u>C. Natural Gas Portfolio Management Plan (NGPMP)</u>**

**Q. HAS NATIONAL GRID ALSO EARNED AN INCENTIVE PAYMENT UNDER THE PROVISIONS OF THE NGPMP?**

A. Yes. Attachment SAM-3 to the direct testimony of Witness McCauley in this proceeding provides extensive data and analyses that support the Company's achievement of over $15.1 million of gross asset management benefits for the twelve months ended March 31, 2016 from the release of unneeded capacity. From that amount of gross benefit, National Grid computes that it should be provided an incentive payment of **$2,822,632**. This requested $2.8 million incentive represents a substantial addition to earnings for National Grid's Rhode Island gas operations.

**Q. HOW DOES THE LEVEL OF THE COMPANY'S REQUESTED NGPMP INCENTIVE COMPARE WITH THE ASSET MANAGEMENT BENEFITS THAT FLOW TO RHODE ISLAND GAS USERS THROUGH THE NGPMP MECHANISM FOR THE TWELVE MONTHS ENDED MARCH 31, 2016 (i.e., FY 2016)?**

A. In this proceeding, the Company shows net asset management revenue under the NGPMP mechanism of more than $15,113,164.50 for the Company's 2016 fiscal year. Of that amount, **$12,290,531.60 million** (or 81.3% of the total) accrues to the benefit of the Company's ratepayers. This is the largest ratepayer benefit derived from the NGPMP program to date. The ratio of the benefits received by ratepayers to the cost of the incentive is **4.35:1**.

**Q. HOW DO THE LEVELS OF NET ASSET MANAGEMENT BENEFITS FOR RATEPAYERS ACHIEVED BY THE COMPANY AND THE COMPANY'S INCENTIVE FOR FY 2016 COMPARE WITH NGPMP RESULTS IN PRIOR YEARS?**

A. Table 1 below illustrates the significant increases in net asset management revenue, Ratepayer Benefits, and Company Incentives that National Grid has achieved since 2010. The Company's net asset management revenues and its Ratepayer Benefits for FY 2016 are more than **five times** the levels achieve in 2010. Moreover, in just the last two years, NGPMP Ratepayer Benefits have increased by about 80% while the Company's Incentives have nearly doubled.

**Table 1**
**Historical Sharing of NGPMP Benefits**

| Year | Total Net Asset Mgmt Revenue | Ratepayer Benefits | | Company Incentives | |
|---|---|---|---|---|---|
| | | $ | % of Total | $ | % of Total |
| 2010 | $ 2,876,378 | $2,501,102 | 87.0% | $ 375,276 | 13.0% |
| 2011 | $ 4,655,474 | $3,924,380 | 84.3% | $ 731,094 | 15.7% |
| 2012 | $ 5,498,991 | $4,599,192 | 83.6% | $ 899,798 | 16.4% |
| 2013 | $ 8,412,857 | $6,930,285 | 82.4% | $1,482,571 | 17.6% |
| 2014 | $ 8,370,836 | $6,896,669 | 82.4% | $1,474,167 | 17.6% |
| 2015 | $11,547,657 | $9,468,125 | 82.0% | $2,079,531 | 18.0% |
| 2016 | $15,113,164 | $12,290,532 | 81.3% | $2,822,633 | 18.7% |

**Q. IS NATIONAL GRID'S REQUESTED NGPMP INCENTIVE PROPERLY COMPUTED UNDER THE PROVISIONS OF THE NATURAL GAS PORTFOLIO MANAGEMENT PLAN (NGPMP)?**

A. Yes. Again, the information that National Grid presents in support of its computed incentive is extensive. The methods employed to determine the amount of the requested incentive conform to the provisions of the NGPMP that were in effect for the twelve month period ended March 31, 2016,[6] and the mathematical accuracy of the calculations used has been verified.

**Q. DO YOU FIND ANY CHALLENGE THE COMMISSION'S APPROVAL OF THE NGPMP INCENTIVE THAT NATIONAL GRID REQUESTS FOR FY 2016?**

A. No, I do not.

**Q. WHAT LEVEL OF NET ASSET MANAGEMENT REVENUE FROM THE NGPMP DOES THE COMPANY ASSUME IN THE DEVELOPMENT OF ITS PROPOSED 2016/17 GCR RATES?**

A. National Grid assumes that net asset management credits to ratepayers over the 2016/17 GCR year will equal $13.7 million.

[6] On March 3, 2016, National Grid, working cooperatively with the Division, proposed a modification of the NGPMP revenue sharing provisions. The modification eliminated the minimum ratepayer benefit guarantee, but increased customers' share of benefits as total capacity release revenues increase. The proposed modification was approved by the Commission and became effective as of April 1, 2016. See Commission Order No. 22418 in Docket 4038 issued on May 24, 2016.

**Q. WHY IS THE LEVEL OF NET ASSET MANAGEMENT REVENUE FROM THE NGPMP THAT NATIONAL GRID REFLECTS IN ITS COMPUTATION OF GCR CHARGES IN THIS PROCEEDING GREATER THAN THE APPROXIMATELY $12.2 MILLION OF CREDITS TO GAS COSTS FOR FIRM SERVICE CUSTOMERS ACTUALLY ACHIEVED THROUGH THE NGPMP FOR FY 2016?**

A. It is my understanding that the $13.7 million credit included in the Company's GCR calculations applies the modified NGPMP revenue sharing that this Commission approved in Order No. 22418 in Docket No. 4038 to the level of net asset management revenue achieved in FY 2016. Under the revised revenue sharing arrangement now in effect, the benefits for National Grid's Rhode Island customers will be enhanced.

**Q. IS THE LEVEL OF NGPMP CREDITS THAT THE COMPANY ASSUMES IN THE DEVELOPMENT OF ITS PROPOSED 2016/17 GCR CHARGES RESONABLE?**

A. There is no guarantee that level of net asset management revenue achieved in FY 2017 will equal or exceed the Company's actual results for FY 2016. However, given continued constraints on gas pipeline capacity into the New England market area and the lead times required to acquire or build new alternative sources of reliable gas supply, it is reasonable to expect that National Grid will be able to derive value through its asset management activities during FY 2017 that will be in the range of the value it during FY 2016. Thus, National Grid's assumption that ratepayer benefits for the 2016/17 GCR period will approximate $13.7 million for FY 2017 appears reasonable.

**D. National Grid's Market Area Hedging Proposal**

**Q. WHAT IS THE PURPOSE OF THE MARKET AREA HEDGING PROPOSALS THAT NATIONAL GRID WITNESS MCCAULEY SETS FORTH IN HIS SEPTEMBER 30, 2016 TESTIMONY?**

A. As explained in Witness McCauley's testimony, the Company's Market Area Hedging proposals are intended to mitigate a portion of the risk associated with market area purchases of natural gas for the November 2016 through March 2017 winter season.

During the winters of 2013-14 and 2014-15, large increases in gas purchase costs were experience by National Grid and other utilities in New England due to the combination of extreme weather and constraints on the availability of pipeline capacity into northeastern markets. In the winter of 2013-14, prolonged cold weather required the Company to make substantial purchases of incremental gas supplies at high market prices. That caused National Grid's deferred gas cost balances to soar to record levels, even though natural gas prices during non-peak periods generally continued to decline. After analyzing market conditions, the costs of hedges, the expected costs of unhedged gas purchase volumes, and uncertainties with respect to gas supply requirements in future winter period, the

Company developed a hedging strategy to address a portion of the risk that could be imposed by another period of severe winter weather.

**Q. HAS THE COMPANY PREVIOUSLY EMPLOYED SIMILAR MARKET AREA HEDGING STRATEGIES?**

A. Yes. Similar market area hedges were employed for each of the last two winters.

**Q. HOW DO THE MARKET AREA HEDGES THAT NATIONAL GRID PROPOSES IN THIS PROCEEDING DIFFER FROM THOSE THAT WERE EMPLOYED FOR THE WINTER OF 2015-16?**

A. Each year Witness McCauley performs analyses to assess the opportunities for market area hedges that are likely to provide favorable ratios of risk mitigation benefits to hedging costs. For the winter of 2016-17, the Company's hedging plan has been modified to adjust slightly the receipt points and months for which hedges are employed. Importantly, the hedges the Company proposes are focused on receipt points that are essentially baseloaded in each month for which hedges are used since receipt points that are not baseloaded tend to have greater risk that hedging costs will exceed realized benefits under warmer than normal weather conditions.

**Q. ARE YOU SATISFIED THAT THE HEDGING PLAN WITNESS MCCAULEY OUTLINES FOR THE 2016-17 WINTER SEASON IS REASONABLE AND APPROPRIATE FOR APPROVAL BY THIS COMMISSION?**

A. I am. There no guarantees that the hedges proposed will lower the Company's gas costs for the coming winter. However, I am satisfied that the plan Witness McCauley presents has a high likelihood of producing positive benefits and reducing the potential impacts of extreme cold weather on the Company's gas costs.

**Q. DO YOU SUPPORT THE COMMISSION'S APPROVAL OF NATIONAL GRID'S MARKET AREA HEDGING PLAN IN THIS PROCEEDING?**

A. I do.

## <u>E. GCR Reconciliations</u>

**Q. HAVE YOU REVIEWED THE COMPANY'S RECONCILIATION OF GAS COSTS FOR THE TWELVE MONTHS ENDED JUNE 30, 2015?**

A. Yes, I have. The Company's gas cost reconciliation calculations are presented in the Company's "Annual Gas Cost Recovery Reconciliation Report." That report is provided in this docket as Attachment AEL-2 to the Direct Testimony of National Grid Witness Ann E. Leary that was filed on September 1, 2015. The Company's GCR reconciliation report details the Company's actual costs and revenue collections by month for each of the major components of its Gas Supply Costs for the twelve months ended March 31, 2016. I was also provided an electronic version of the Company's gas cost reconciliation analyses in advance of the Company's September 1, 2016 filing in this proceeding. With the aid of National Grid's electronic spreadsheet files, the full detail of the Company's FY 2016 GCR reconciliations have been examined.

**Q. WHAT ARE THE RESULTS OF NATIONAL GRID'S FILED GAS COST RECONCILIATION ANALYSES?**

A. The Company's gas cost reconciliations show an aggregate deferred gas cost balance as of March 31, 2016 of $3,197,068. That aggregate balance represents the net of a $17,436,635 under-recovery of Variable Costs and a $14,239,567 over-recovery of Fixed Costs.[7]

**Q. ARE THE COMPANY'S RECONCILIATIONS MATHEMATICALLY ACCURATE?**

A. Our review of National Grid's gas costs reconciliations has identified no errors in calculation or application of the Company's GCR-related tariff provisions. In addition, no cost or revenue entries were identified that appeared inconsistent with expectations or previously reported actual results. Our review, however, does not constitute a full audit of the Company's reported results.

**Q. HOW HAS THE COMPANY'S DEFERRED GCR BALANCE CHANGED SINCE THE END OF THE RECONCILIATION PERIOD ON MARCH 31, 2016?**

A. Since March 31, 2016, the Company's deferred gas cost balance has been essentially reversed. National Grid's most recent Deferred Gas Costs Balance

[7] See Attachment AEL-2, page 1 of 7, in this proceeding.

report, filed on September 20, 2016, presents actual results through August 2016. As shown in that report the Company's actual GCR Deferred Gas Cost Balance as of the end of August 2016 was a **net over-recovery balance of $2,861,157**. The Company's September 20, 2016 monthly report also projects an end of October 2016 **under-recovery balance of $1,604,807**. That projected end of October 2016 GCR deferred balance, aligns closely with and supports the reasonableness of the **$1,621,668 under-recovery balance** that is reflected in Witness Leary's development of the Company's proposed 2016-17 GCR charges.

**F. Current Gas Supply Portfolio Considerations**

**Q. WHAT CHANGES IN THE COMPANY'S PORTFOLIO OF GAS SUPPLY RESOURCES ARE DISCUSSED IN WITNESS ARANGIO'S SEPTEMBER 1, 2016 DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Witness Arangio's discussion of changes in the Company's gas supply portfolio constitutes the majority of her 23 page presentation. The implemented and proposed changes in the Company's gas supply portfolio include:

- The scheduled start-up of contracted Algonquin Incremental Market (AIM) Project capacity;

- The Company's response to two unforeseen events that have affected the Company's gas supply resource planning for the winter of 2016-17 and possibly longer;

- Two pending pipeline transportation service agreements;

- Two LNG Liquefaction Projects; and

- Replacement of capacity for the cancelled Northeast Energy Direct (NED) project.

Of the gas supply portfolio considerations identified in Witness Arangio's testimony, the schedule start-up of the AIM Project and the Company's responses to recent unforeseen events warrant particular focus in terms of their impacts on National Grid's gas supply costs for the 2016-17 GCR year.

### 1. <u>Scheduled Start-up of AIM Project Capacity</u>

**Q. DO YOU HAVE ANY COMMENTS REGARDING THE PLANNED START-UP OF THE AIM PROJECT CAPACITY FOR WHICH NATIONAL GRID HAS CON-TRACTED?**

A. I do. Although the specific cost of the AIM Project capacity is designated by the Company as Confidential, the Commission should note the rate National Grid will pay for that capacity is significantly above the pipeline capacity charges its pays under other pipeline transportation contracts. See the line labeled "Algonquin AIM Demand" in Confidential version of Attachment EDA-2, page 10 of 17. The incremental costs of AIM Project capacity[8] represent the major driver of the 22% increase in Supply Fixed costs that National Grid projects for its 2016-17 GCR year.

[8] The "incremental costs" of the AIM Project capacity are viewed as the costs of the AIM Project capacity less the costs of the HubLine and East-to-West Capacity on Algonquin that the AIM Project capacity is intended to replace.

It is understood that the AIM Project capacity is expected to provide National Grid greater operational flexibility and access to lower cost gas supplies. However, the Company offers no demonstration of the extent to which the AIM Project capacity has actually contributed to the Company's projected reduction in Variable Supply Costs. The Division's expectation is that the AIM Project capacity would serve to reduce National Grid's Variable Supply Costs, but no quantification of Variable Cost reductions resulting from the schedule start-up of AIM Project capacity is included in the Company's 2016-17 GCR filing. Such analyses would be instructive.

**Q. IS THERE ANY UNCERTAINTY REGARDING THE START-UP DATE FOR AIM PROJECT CAPACITY?**

A. Yes. National Grid's response to Division Data Request 2-2 notes that the November 1, 2016 start-up date referenced in Witness Arangio's direct testimony is now uncertain due to a construction problem that Texas Eastern has encountered.

**Q. IF THE AIM PROJECT START-UP DATE IS DELAYED, HOW WILL THE COMPANY'S ESTIMATED GAS COSTS FOR THE 2016-17 GCR YEAR BE AFFECTED?**

A. The Company indicates in its response to Division Data Request 2-2 that its existing HubLine agreements will remain in place until the AIM Project is operational, and the Company would continue to pay the lower HubLine demand charges until the AIM

Project is placed into service. National Grid also suggests that regardless of the status of AIM Project construction, it will have a plan in-place to ensure the adequacy of pipeline supplies. However, the Company offers no estimate of the impact of a delay in the completion of the AIM Project on its estimated gas purchase costs. Thus, a delay in the start-up of the AIM Project could lower the actual demand charges paid by the Company for the 2016-17 GCR year, but we have no indication of the extent to which any such capacity cost savings could be offset by increases in commodity purchase costs.

**Q. WHAT ARE THE TWO UNFORESEEN EVENTS THE COMPANY HAS ENCOUNTERED THAT WILL AFFECT ITS GAS SUPPLY PORTFOLIO FOR THE WINTER OF 2016-17?**

A. One is an incident on the Texas Eastern system in Pennsylvania which has restricted the Company's access to certain lower cost gas supplies. The other is an anomaly discovered at the bottom of the Cumberland LNG tank that has led to a decision by National Grid to take the facility out of service for the 2016-17 winter season.

**<u>2. The Texas Eastern Supply Restriction</u>**

**Q. HOW HAS THE RESTRICTION ON TEXAS EASTERN SYSTEM IN PENNSYLVANIA AFFECTED NATIONAL GRID'S GAS SUPPLY PLANNING?**

A. The Company's response to Division Data Request 2-1 indicates gas sourced from Texas Eastern (Tetco) M-2 purchase locations was the least expensive gas available during the current GCR year. The restriction on the Texas Eastern system in Pennsylvania has limited the Company's access to Tetco M-2 purchase locations. If that restriction continues beyond November 1, 2016, National Grid anticipates that it will need to purchase greater amounts of gas from more expensive locations. To address the potential that the restriction on the Texas Eastern system in Pennsylvania may not be eliminated for some or all of the winter of 2016-17, Witness Arangio explains that National Grid has issued an RFP to secure the option, but not the obligation, to call on gas supplies at Texas Eastern/M-3 (i.e., down-stream of the facilities subject to restriction. The call options that National Grid has sought to contract are for the months of December 2016, January 2017, and February 2017.

**Q. ARE THE COSTS OF THE REFERENCED CALL OPTIONS INCLUDED IN THE COMPANY'S PROJECTED 2016-17 GAS COSTS?**

A. Given that Witness Arangio's testimony indicates that the Company was in the process of finalizing contracts with suppliers for the referenced Supply Call options at the time her testimony was prepared, it does not appear that the costs of those options have been included in the Company's filed GCR costs.

**Q. IF THE RESTRICTION ON THE TEXAS EASTERN CAPACITY IS LIFTED FOR SOME OR ALL OF THE MONTHS OF DECEMBER 2016, JANUARY 2017, AND FEBRUARY 2017 WILL NATIONAL GRID BE ABLE TO AVOID SOME OR ALL OF THE COSTS OF THE REFERENCED SUPPLY CALL OPTIONS?**

A. Most likely no, but that will depend on market conditions at the time National Grid concludes that the call options are no longer required.

**Q. DO YOU HAVE ANY CONCERNS REGARDING THE MANNER IN WHICH NATIONAL GRID HAS APPROACHED ITS CONTRACTING FOR SUPPLY CALL OPTIONS?**

A. Yes, I do. The Company's use of Supply Call Options represents a form of commodity price hedging. Yet, unlike other commodity price hedging activities in which the Company engages, the Company appears to be pursuing these hedges outside of its GPIP and without the analytical rigor utilized in evaluating Market Area Hedging opportunities. Witness McCauley's testimony regarding the Company's Market Area Hedging proposal for the winter of 2016-17 employs risk versus reward considerations when evaluating hedging opportunities that could be useful in efforts to ensure the productivity of expenditures for Supply Call Options, but no evidence of the use of such analyses is offered for the options associated with the Texas Eastern capacity restriction.

**Q. DO YOU OFFER A RECOMMENDATION REGARDING THE RATE TREATMENT OF THE SUPPLY CALL OPTIONS THAT WITNESS ARANGIO DISCUSSES IN HER PRE-FILED TESTIMONY IN THIS PROCEEDING?**

A. I do. I recommend that in the absence of more rigorous quantitative assessment of the expected costs and benefits associated with those options, no costs for such options should be permitted in either the Company's GCR rates or its deferred gas cost balances.

**<u>3. The Cumberland LNG Tank Removal from Service</u>**

**Q. HOW HAS NATIONAL GRID ADJUSTED ITS GAS SUPPLY PLANS FOR THE WINTER OF 2016-17 TO ACCOUNT FOR THE CLOSING OF ITS CUMBERLAND LNG TANK?**

A. Witness Arangio's testimony explains that the Company has undertaken two strategies to replace the Cumberland LNG Tank capacity. Base on a representation that the Cumberland LNG Tank "*has historically provided up to 30,000 Dth per day and 80,000 Dth per season*," National Grid has:

(1) Contracted for 24,000 Dth per day of additional Tennessee Gas Pipeline capacity at Dracut;[9] and

[9] The fact that the incremental capacity at Dracut that National Grid has arranged as part of its plan to replace Cumberland LNG Tank capacity equals the amount of capacity it had planned to add at Dracut as part of the now cancelled NED project may suggests that National Grid has greater plans for that capacity.

(2) Initiated the process for securing up to seven 6,000 Dth per day of truckloads of LNG liquid service and up to 22 truckloads for the winter season to support the use portable LNG operations at the Cumberland site.

**Q. DO YOU FIND THAT THE COMPANY'S PLANS FOR REPLACEMENT OF THE CUMBERLAND TANK CAPACITY ARE REAONABLE?**

A. No. Despite experiencing two severely cold winters in the last three years, the Company's response to Division Data Request 1-1 identifies no day in the last three winters in which the Company utilized as much as 50% of the daily sendout capacity that it plans to acquire to replace the Cumberland Tank. In fact, withdrawals from the Cumberland Tank are reported for only 23 days in the last three winters, and the average withdrawal per day was only 3,892 Dth. Moreover, many of the days for which withdrawals are reported were not peak demand days for either the Company's overall system or the Cumberland System. Further, little correlation is found between Cumberland Tank withdrawals and recorded degree days or between Cumberland Tank withdrawals and reported total system sendout. In the winter of 2015-16, the highest level of withdrawals from the Cumberland Tank was 9,950 Dth on a day for which National Grid reports only 35 degree days, and it's total system sendout was only 266,967 Dth or about 73% of its peak sendout for that winter.

Considering the foregoing, the Commission should question the amount of capacity that National Grid has planned as replacement for the Cumberland LNG tank and the costs of that capacity. Nothing in National Grid's presentations in this proceeding provide a compelling case for the level of annual fixed cost for Dracut capacity that National Grid has apparently contracted. Recognizing uncertainties regarding the degree day requirements that may be encountered and the demands that will need to be served, this appears to be a situation in which further use of the types of risk and reward analyses used by Witness McCauley may be productive. In the absence of the presentation of greater analytic support for the costs that National Grid proposes to incur for capacity to replace the Cumberland LNG tank, recovery of those costs through the Company's GCR is inappropriate.

**Q. ARE THERE ANY OTHER MATTERS RELATING TO THE COMPANY'S REMOVAL OF THE CUMBERLAND LNG TANK FROM SERVICE THAT SHOULD BE ADDRESSED?**

A. Yes. Witness Leary's development of the Company's proposed GCR rates in Attachment AEL-1 at page 2, line (8), and page 3, line (7), includes recognition of costs for "Supply Related LNG O&M." With the Company's removal of the Cumberland Tank from service some adjustment for that known and measurable change in circumstances would appear appropriate. Yet, nothing in the Company's presentation in this proceeding addresses the impact of removing the Cumberland Tank from service on the LNG O&M costs included in its proposed GCR rates.

## G. Forecasting and Planning Issues

### 1. Forecasting Issues

**Q. WHAT IS THE RELEVANCE OF FORECASTS IN THE COMPANY'S DEVELOPMENT OF ITS GCR FILINGS?**

A. Forecasts of normal weather, design winter and design day requirements serve two key roles in the development of National Grid's GCR filings.

First, the Company's forecasts for the coming GCR year provide the foundation on which National Grid assesses its gas supply and capacity requirements for the coming GCR year and directly impact the Company's estimates of the costs that it will need to recover through it proposed GCR rates. The Company's forecasts of requirements for the coming GCR year also provide the units of gas consumption over which projected gas costs are spread to compute the Company's proposed GCR charges. In other words, National Grid's near-term forecasts affect both the magnitude of projected gas costs for the coming GCR year and the estimates of numbers of therms over which projected gas costs for the GCR year are assumed to be recovered.

Second, the Company's longer-term forecasts (i.e., its forecasts for periods beyond the year for which GRC rates are determined in this case) guide National Grid's decisions regarding financial commitments for the acquisition of gas supply resources. Since the acquisition of gas supply resources often involves multi-year lead times and long-term cost commitments, the Company's longer-term forecasts become major drivers of the fixed costs that National Grid will seek to recover through future GCR proceedings.

**Q. IS IT TRUE THAT FORECASTING ERRORS ARE OF LIMITED IMPORTANCE IN THE CONTEXT OF A RECONCILING GAS COST RECOVERY MECHANISM?**

A. No. While it is understood that load forecasts simply represent estimates of future service requirements, any representation that forecasts are unimportant in the context of a reconciling gas cost recovery mechanism reflects a myopic view of the GCR process.

In the near-term, differences between forecasted annual gas use and actual annual gas use as well as differences between projected gas costs and actual gas costs are subject to reconciliation. However, reconciliations do not address the impacts that the Company's forecasts of design winter, design day, and cold snap requirements can have on costs associated with the loads that the Company must be prepared to serve under extreme weather conditions. If design winter or design day requirements are significantly over-estimated, the Company will be compelled to incur costs for loads that have little or no likelihood of occurrence. In addition, since the costs of incremental supply resources tend to be much higher during periods of high demand, over-estimation of design day and/or design winter requirements will generally cause the Company to incur greater than average costs per therm to be prepared to serve such incremental requirements. On the other hand, if the Company's forecasts of design day or design winter requirements are under-stated, the Company and its ratepayers may be exposed to substantially above average costs to serve actual loads that exceed forecasted requirements.

Longer-term forecasts (e.g., the ten-year forecasts presented in the Company's annual LRP filings) are used primarily to guide the planning of capacity resources. The Company's decisions regarding capacity additions have a direct impact on the Company's future fixed and variable GCR costs. There is no reconcilable mechanism through which errors in long-term forecasts and/or use of inappropriate long-term planning criteria may be corrected. Yet, the impacts of long-term planning decisions on gas utilities' costs of gas are significant. Only through engagement in long-term forecasting and planning issues can regulators exercise necessary and appropriate oversight with respect to the criteria and decisions that will establish both the levels of fixed costs and sources of and costs of gas supply that will determine the levels of gas costs that must be recovered through future rates.

**Q. HAVE YOU FOUND SUBSTANTIAL REASONS TO QUESTION THE ACCURACY AND RELIABILITY OF THE FORECASTS OF NORMAL WEATHER, DESIGN WINTER, AND DESIGN DAY GAS SERVICE REQUIREMENTS THAT NATIONAL GRID PRESENTS IN THIS PROCEEDING?**

A. I have. Within the limited time we have to review the Company's filing in this proceeding, numerous errors and inconsistencies in the Company's forecasts have been identified. Several become evident by simply comparing forecast information in this proceeding with comparable estimates presented in past proceeding. From this I conclude that National Grid's forecasting process and results require greater review and oversight both from within the Company and by its regulators. Among the problems I have identified to date in forecasted data presented in the current GCR filing are:[10]

1. An error in the identification and use of measures of baseload gas use for the Small C&I Sales service;

2. An erroneous projection of gas use for the Residential Non-Heating class;

3. Use of inconsistent and irrational representations of gas use per degree day (i.e., "heat factors") by month for numerous service classifications;

4. Unexplained increases in forecasted design peak day requirements despite forecasted decreases in both normal weather and design winter volumes.

[10] The problems identified herein are not intended to constitute a comprehensive list of all problems found in the Company's forecasts. Rather, the items listed represent those that can be documented in a manner that may be understandable for persons having less familiarity with forecasting data and methods.

5. Large unexplained shifts in the distribution of gas use across months in both the Company's forecasts of normal weather and design winter requirements.

**Q. PLEASE EXPLAIN THE ERROR YOU HAVE IDENTIFIED IN THE COMPANY'S FORECAST OF SMALL C&I CUSTOMER GAS USE?**

A. In my initial review of the Company's September 1, 2016 filing in this proceeding, I identified anomalies in the forecasted **normal weather** volumes for **Small C&I Sales Service** customers in Attachment AEL-1, page 11. The forecasted volumes for that class for the months of July 2017, August 2017, and September 2017 were 28, 25, and 28 Dth respectively. In the Company's two prior GCR filings (Dockets 4520 and 4576) the monthly normal weather volumes for that class were in all months greater than 40,000 Dth. An additional check was made against the actual volumes presented in Schedule 6 of the Company's GCR Reconciliation which is provided as Attachment AEL-2. That also shows Small C&I sales volumes for all months of the reconciliation period (i.e., the twelve months ended March 2016) as being greater than 40,000 therms for all months of the year with the highest winter months having volumes in excess of 400,000 Dth.

I immediately communicated this possible error in the Company's normal weather forecast to Witness Leary who sponsored the referenced exhibit to afford the Company an opportunity to make any necessary corrections. Witness Leary, responded saying she had forwarded the inquiry to Witness Poe who was responsible for preparation of the forecast. More than three weeks later an e-mail response was received from Witness Poe indicating that "*a minor error was found in the historical data for Rate Code 404 during the off-peak period of 2015*," and that the sales and transportation volumes for the Small C&I class were being revised upward by 126,402 Dth or 0.3%. However, once I had an opportunity to review Witness Poe's response in greater depth, the problem was found to be more extensive. In fact, the "baseload" volumes for the C&I Sales class found in Attachment AEL-1, page 13, line 20, were substantially understated for all months of the forecasted GCR year. For the Small C&I class no month was shown to have baseload gas volumes of greater than 27 Dth and the total baseload volumes for the class for the year were only 317 Dth. That contrasts with information found in the comparable schedule in Docket 4576 which shows all months having baseload volumes for the Small C&I Sales class in excess of 44,000 Dth and total annual baseload requirements for that class (i.e., without consideration of any weather or degree day sensitive requirements) or 582,779 Dth.

The difference in the Company's assessment of baseload volumes for Small C&I Sales service customers in this case and comparable volumes from Docket 4576 suggests the need for a noticeably larger correction to the Company's normal weather Small C&I Sales volumes. A more appropriate revision to forecasted Small C&I Sales volumes in this proceeding would be in the range of 500,000 Dth or roughly 4 times the magnitude of the revision suggested by Witness Poe.

**Q. CAN YOU BRIEFLY SUMMARIZE THE BASIS FOR YOUR FINDING THAT THE COMPANY'S PROJECTIONS OF RESIDENTIAL NON-HEATING CLASS SALES VOLUMES ARE ERRONEOUS?**

A. In the Company's recent Revenue Decoupling Mechanism (RDM) and Distribution Adjustment Clause (DAC) filings, witness Nutile has discussed at length the steps the Company has taken to transfer customers to Residential Heating service who had been improperly included in the Residential Non-Heating class. Over the last couple of years roughly **20 percent** of the customers who had been included in the Residential Non-Heating class were **moved to Residential Heating service**. Yet, despite a sharp decline in the numbers of Residential Non-Heating customers, the Company's forecasted normal weather volumes for that class are **7.4% greater** in this case than National Grid forecasted in Docket 4576.

The Company's forecasted growth in Residential Non-Heating Sales service volumes appears even more questionable in the context of evidence that the customers transferred to Residential Heating service had an average use per customer nearly three time greater than the average use per customer for the Residential Non-Heating class prior to the Company's transfer of misclassified customers.[11] This suggests that the average use per customer for the Residential Non-Heating class after the transfers that have been implemented should be less than the average use per customer for that class prior to the transfers.[12] Moreover,

[11] See the Direct Testimony of Bruce R. Oliver at page 32 in Docket 4576.

[12] Attachment BRO-3 illustrates the changes in Residential Non-Heating class gas use per customer that result from National Grid's 2015 Q2 and 2016 Q2 forecasts. It also compares those use per customer results

the combination of the reduction in numbers of Residential Non-Heating customers and the reduction in usage per customer should necessarily yield an overall reduction in forecasted normal weather Residential Non-Heating Sales that is greater than the percentage reduction in numbers of customers. Thus, the Company's forecast of Residential Non-Heating class sales appears out of touch with what is actually happening within the Company's operations.

**Q. WHAT IS THE BASIS FOR YOUR ASSERTION THAT THE COMPANY'S ESTMATED "HEAT FACTORS" BY RATE CLASS ARE IRRATIONAL AND INCONSISTENT?**

A. Again my conclusion is premised on comparisons of the forecast data the Company has presented in this proceeding and in its last GCR proceeding (Docket 4576), as well as observations regarding differences in the "**Heat Factors**" by rate class across the months of the year in each of those proceedings. To illustrate, Attachment AEL-1, page 14, in this proceeding shows the "Heat Factors" used by the Company for each rate class where the reported "Heat Factors" are used to assess the sensitivity of gas use to changes in degree day assumptions. For classes having large numbers of customers, it should be anticipated that changes in

against the Residential Non-Heating Class use per customer that is reflected in the bill impact analyses presented in Witness Leary's Attachment AEL-4, page 2 of 5. Although the Company's forecasts appear to recognize customer transfers from Residential Non-Heating to Residential Heating service, the Company offsets reductions in the numbers of Residential Non-Heating customers with in explicable large increases in forecasted Residential Non-Heating use per customer that clearly ignore the fact that customers transferred to Residential Heating service were documented by the Company as having substantially greater than average use for the Residential Non-Heating class.

the applicable Heat Factor (i.e., usage per degree day) for a month would not vary significantly from one year to the next. Likewise, large differences in gas use per degree day would not be expected across the months of the year, except perhaps where usage per degree day increases as actual conditions approach design winter conditions. Yet, neither of those relationships is exhibited in the "Heat Factors" that National Grid presents in this proceeding.

For example, the "Heat Factor" shown in Attachment AEL-1, page 14, for the Residential Heating class for January 2017 is 2,585 Dth, while the Heat Factor for the same class for the month of July is 10,762 Dth. This implies that gas use in July has roughly four times the sensitivity to temperature fluctuations than gas use January. I have never seen such a relationship for other gas distribution utilities. Furthermore, in Docket 4576 the Company presented a July "Heat Factor" for the Residential Heating class of 27,643 Dth which is roughly nine times greater than the January Heat Factor for the same class in Docket 4576.

I also observe that for the C&I Extra Large Low Load Factor class, the Heat Factor used by the Company in this proceeding for the month of February is 190 Dth while the February Heat Factor for the same class in Docket 4576 is 159. That represents an increase of nearly 20% in the degree day sensitivity of usage for the C&I Extra Large Low Load Factor. Conversely, the November Heat Factor the Company presents in this docket for the C&I Extra Large Low Load Factor class is 23% lower than the November Heat Factor for the same class in Docket 4576. Similar, observations of inexplicable differences in Heat Factors between years and across month of a years can be made for several other classes of service, including Extra Large High Load Factor Transportation service, Medium C&I Sales service, Medium C&I Transportation service, and Residential Non-Heating service.[13]

**Q. WHY ARE THE OBSERVATIONS REGARDING FLUCTUATIONS IN HEAT FACTORS RELEVANT TO ASSESSMENTS OF THE RELIABILITY OF THE COMPANY'S FORECASTS IN THIS PROCEEDING?**

A. These observations are important for two reasons. First, there is no reason to expect significant year-to-year fluctuations in the distribution of "**normal weather**" sales and throughput by month for most rate classes. When such results are observed in forecasts, it should be the responsibility of the forecaster to explain the factors that contribute to such results. Second, the distribution of gas use across the months of the year can impact the Company's estimation of requirements under Design Winter, and possibly Cold Snap, planning scenarios.[14]

**Q. WHEN THE COMPANY'S FORECASTS OF TOTAL THROUGHPUT, TOTAL SALES VOLUMES, DESIGN WINTER SALES, AND DESIGN PEAK DAY**

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[13] A comparison of the "Heat Factors" by rate class by month that National Grid presents in this proceeding in Attachment AEL-1, page 14, with the comparable "Heat Factors" presented in Attachment AEL-1, page 14 in Docket 4576 can be found in Attachment BRO-4.

[14] For a comparison of National Grid's Forecasted Normal Weather by rate class by month as filed in this proceeding and the Normal Weather Sales by rate class by month the Company forecasted in Docket No. 4576, see Attachment BRO-5. Attachment BRO-6 provides a similar comparison of the Company's Design Winter Sales Forecast from Docket 4576 with its Design Winter Sales Forecast by rate class by month in this proceeding.

**REQUIREMENTS ARE COMPARED BETWEEN THIS CASE AND DOCKET 4576 ARE THE FORECASTED CHANGES CONSISTENT IN DIRECTION?**

A. No. As shown in Attachment BRO-7, the Company's forecast of total annual sales volumes for the 2016-17 GCR year in this case reflects a 4.0% decline from the level of total annual sales that National Grid projected in Docket 4576 for its 2015-16 GCR year. However, the Company's projected design day sendout requirements for 2016-17 (as presented at the bottom of page 12 of Attachment AEL-1) are **4.7% higher** than the Company's comparable forecast in Docket 4576. Considering that the Company's Sales Service comprises primarily weather sensitive customer loads, it is difficult to rationalize positive growth in Design Day Peak requirements when annual sales show a noticeable decline.

**2. Long-Term Planning Issues**

**Q. WHAT ARE THE LONG-TERM PLANNING ISSUES THAT THIS COMMISSION NEEDS TO ADDRESS?**

A. As previously discussed, the current LRP process lack relevance. The Company's LRP is filed biennially near the end of National Grid's an annual forecasting cycle. As a result, the LRP is provided to this Commission after planning decisions have been made rather than earlier in the cycle when the Commission could potentially have influence on the criteria and analyses the Company relies upon to make important long-term decisions. Thus, there are not direct ties between the content of the LRP studies filed with the Commission and planning decisions made by the Company.

This is particularly important in the context of the Company's plans to add new pipeline capacity commitments and LNG liquefaction capacity. These projects can add significant costs to the Company's GCR filings and may also introduce significant risk for ratepayers. Service reliability and the Company's ability to serve peak requirements are important, but other factors must also be weighed in the planning process. Included among such other factors are: (1) access to potential commodity cost savings; (2) changing sources of supply; (3) access to storage resources; and (4) the potential imposition of unnecessary financial burdens and risks on ratepayers. The Company's LRP filings have been essentially devoid of detail regarding these other considerations.

For example, this Commission must act to ensure that National Grid's plans to acquire or construct LNG liquefaction capacity are in the best interests of Rhode Island gas customers prior to allowing recovery of any costs associated with such facilities. The history of the natural gas industry is littered with examples of LNG facilities that were planned or constructed at considerable expense only to have the economic foundation for those investments eroded by unanticipated changes in market conditions well before the facilities reach the end of their useful lives. The prospect of being able to liquefy low cost gas from the Marcellus Shale formation and re-gasify it in winter months to meet winter peak requirement may appear attractive today. However, without contacts for natural gas supplies that lock-in access to natural gas supplies at prices that assure the on-going economic viability of liquefaction for the full expected life of the LNG facility, the risk that changes in market conditions will render those facilities uneconomic cannot be ignored.

A key to ensuring the long-term economic viability of LNG facilities is to obtain up-front commitments of affordable gas supply of natural gas supplies to serve as input for liquefaction processes. However, to date the Division is unaware of any proposed contract to lock-in or economically hedge future pricing of gas supply inputs for proposed LNG liquefaction activities. Thus, Rhode Island ratepayers could be exposed to having to pay above market costs for peaking supply services from otherwise uneconomic facilities. They could also be required to continue to bear the fixed costs for facilities that are abandoned for economic reasons and are no longer used and useful while also having to bear the costs of replacement capacity and/or replacement gas supplies. This Commission needs to protect Rhode Island ratepayers against well intended, but potentially ill-advised, commitments to capital-intensive LNG liquefaction facilities without a demonstration that the Company has obtained long-term supply commitments for either all or a substantial portion of the projected input requirements of such facilities.[15]

Concerns regarding National Grid's planning of capacity resources also extend to criteria and analyses that the Company uses in the preparation of its

[15] The foregoing discussion focuses on the Company's planning of LNG liquefaction capacity simply as an example of the types of issues that warrant this Commission involvement. No bias for or against LNG liquefaction alternatives is intended. It is anticipated that other proposals for long-term additions or expansion of capacity resources could also engender economic and service reliability issues that significantly impact the costs and/or quality of service for Rhode Island gas customers.

planning studies. At present certain of the Company's planning criteria appear either inappropriate or inconsistent and may produce results that overstate the amounts of capacity the Company requires to provide reliable service to its Rhode Island gas customers.

For example, National Grid uses a degree day measure with a frequency of **one occurrence in 98.86 years** to depict the "Design Day" conditions used in its planning. National Grid bases its assessment of the frequency of a design day event on weather data from Providence (T.F. Green) Airport. NSTAR has also used weather data from the Providence Airport in planning studies for its New Bedford Division. However, NStar's design day planning criteria reflects an event with an occurrence **once in 50 years**. Unitil (Northern Utilities, Inc.) in a 2015 LRP prepared for its New Hampshire and Maine divisions used a design day event with a frequency of **once in 33 years** to define its Design Day standard. Even National Grid in a 2013 LRP filed Massachusetts used **once in 35.9 years** frequency of occurrence as its design day standard. The differences between once in 33 years, once in 35.9 years or once in 50 years and National Grid's RI planning criteria of once in 98.86 years is substantial in terms of the incremental Design Day sendout for which National Grid must plan.

The Commission must also be cognizant of the fact that excess capacity can be an economic burden for ratepayers, but in the context of asset management incentive programs, it may represent financial opportunities for utilities. Under-standing that some measure of excess capacity is necessary in all but perhaps the most extreme circumstances, costs for capacity with low levels of utilization must be minimized. Although asset management activities may provide a measure of compensation for the costs of capacity that is not fully utilized throughout the year, rarely if ever, do ratepayer benefits from asset management activities fully compensate for the costs of excess capacity included in gas customers' rates. Thus, the Commission should act to ensure a reasonable balance between service reliability consideration and costs borne by ratepayers. Such a balance is only achievable through on-going oversight of utility capacity planning activities. The current absence of a structured process for Commission engagement in National Grids planning processes needs to be remedied.

**Q. DO YOU HAVE A RECOMMENDATION FOR IMPROVING THE CURRENT APPROACH TO CAPACITY PLANNING IN RHODE ISLAND?**

A. Yes. One approach might be to bi-furcate the GCR process. The current Annual GCR review process would be limited to reconciliation and review of variable costs, previously approved fixed costs, and pass through of increases in FERC approved rates. Any request for recovery of new fixed Supply or Storage costs would be addressed in phase 2 proceedings in which more time would be provided for discovery, analysis of proposals, and development of record evidence. Furthermore, the current schedule for LRP filings would be amended to provide for the submission of those filing in late spring or early summer to enable the details of the studies to be more thoroughly examined and better understood prior to the filing of gas cost recovery requests.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

# National Grid- RI Gas

*Docket No. 4647 - 2016 Annual GRC Proceeding*

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

| Rate Classification | Current GCR Rate 1/ ($/Therm) | NGrid Proposed GCR Rate 2/ ($/Therm) | Increase (Decrease) $ ($/Therm) | Increase (Decrease) % |
|---|---|---|---|---|
| **Residential** | | | | |
| Non-Heating | $ 0.5259 | $ 0.4525 | ($0.0734) | -14.0% |
| Low Income- Non Heating | $ 0.5259 | $ 0.4525 | ($0.0734) | -14.0% |
| Heating | $ 0.5530 | $ 0.4766 | ($0.0764) | -13.8% |
| Low income- Heating | $ 0.5530 | $ 0.4766 | ($0.0764) | -13.8% |
| **Commercial & Industrail** | | | | |
| Small | $ 0.5530 | $ 0.4766 | ($0.0764) | -13.8% |
| Medium | $ 0.5530 | $ 0.4766 | ($0.0764) | -13.8% |
| Large Low Load Factor | $ 0.5530 | $ 0.4766 | ($0.0764) | -13.8% |
| Large High Load Factor | $ 0.5259 | $ 0.4525 | ($0.0734) | -14.0% |
| Extra Large Low Load Factor | $ 0.5530 | $ 0.4766 | ($0.0764) | -13.8% |
| Extra Large High Load Factor | $ 0.5259 | $ 0.4525 | ($0.0734) | -14.0% |
| FT-2 Marketer Demand Rate | $ 8.8817 | $ 8.0484 | ($0.8333) | -9.4% |
| Storage and Peaking Charge | $ 0.6945 | $ 0.6802 | ($0.0143) | -2.1% |
| Wtd Avg Upstream Pipeline Transportation Charge | $ 0.4219 | $ 0.3766 | ($0.0453) | -10.7% |

1/ GCR charges effective November 1, 2015 as set forth in the Commissions Report and Order dated November 30, 2015.

2/ From Attachment AEL-1, page 1, REVISED filed 10/3/16.

# National Grid- RI Gas

*Docket No. 4647 - 2016 Annual GRC Proceeding*

## Changes in Forecasted Gas Costs by GCR Cost Component

*Without Adjustments and Reconciliations*

| GCR Cost Component | Dkt 4647 Forecasted Annual Cost 2016-17 1/ | Dkt 4576 Forecasted Annual Cost 2015-16 2/ | Dkt 4520 Forecasted Annual Cost 2014-15 3/ | Change 2015-16 to 2016-17 $ | Change 2015-16 to 2016-17 % | 2-Year Change 2014-15 to 2016-17 $ | 2-Year Change 2014-15 to 2016-17 % |
|---|---|---|---|---|---|---|---|
| Supply Fixed Costs | $ 35,338,864 | $ 28,975,016 | $ 28,022,697 | $ 6,363,848 | 22.0% | $ 7,316,167 | 25.2% |
| Storage Fixed Costs | $ 15,406,775 | $ 16,307,226 | $ 15,825,144 | $ (900,451) | -5.5% | $ (418,369) | -2.6% |
| Supply Variable Costs | $ 68,304,529 | $ 82,733,795 | $ 91,932,137 | $ (14,429,266) | -17.4% | $ (23,627,608) | -28.6% |
| Storage Variable Costs | $ 13,008,462 | $ 15,653,838 | $ 18,191,427 | $ (2,645,376) | -16.9% | $ (5,182,965) | -33.1% |
| TOTAL | $ 132,058,630 | $ 143,669,875 | $ 153,971,405 | $ (11,611,245) | -8.1% | $ (21,912,775) | -15.3% |
| Total Fixed Costs | $ 50,745,639 | $ 45,282,242 | $ 43,847,841 | $ 5,463,397 | 12.1% | $ 6,897,798 | 15.2% |
| Total Varible Costs | $ 81,312,991 | $ 98,387,633 | $ 110,123,564 | $ (17,074,642) | -17.4% | $ (28,810,573) | -29.3% |

1/ Source: Docket No. 4647, Attachment AEL-1, REVISED October 3, 2016, pages 2-5.
2/ Source: Docket No. 4576, Attachment AEL-1, September 1, 2015, pages 2-5.
3/ Source: Docket No. 4520, Attachment AEL-1S, September 16, 2014, pages 2-5.
4/ Source: Docket No. 4436, Attachment AEL-1, September 3, 2013, pages 2-5.

# National Grid- RI Gas

*Docket No. 4647 - 2016 Annual GRC Proceeding*

### *Computed Changes in Adjustments to GCR Fixed and Variable Costs*

| Ln No | Description | Dkt 4647 Forecasted Annual Cost 2016-17 | Dkt 4576 Forecasted Annual Cost 2015-16 | Change 2015-16 to 2016-17 $ | Change 2015-16 to 2016-17 % |
|---|---|---|---|---|---|
| | **Adjustments to Fixed Gas Costs** | | | | |
| 1 | NGPMP Customer Benefit | $ (13,700,000) | $ (9,400,000) | $ (4,300,000) | 45.7% |
| 2 | FT-2 Storage Demand Costs | $ (1,821,075) | $ (1,734,509) | $ (86,566) | 5.0% |
| 3 | LNG Demand to DAC | $ (1,488,790) | $ (1,488,790) | $ - | 0.0% |
| 4 | Supply Related LNG O&M Costs | $ 575,581 | $ 575,581 | $ - | 0.0% |
| 5 | Working Capital Requirement | $ 283,602 | $ 252,146 | $ 31,456 | 12.5% |
| 6 | Deferred Fixed Cost Over-Recovery | $ (5,220,624) | $ (2,888,677) | $ (2,331,947) | 80.7% |
| 7 | Reconciliation Amount from Fixed Costs - Marketer | $ (37,411) | $ (58,533) | $ 21,122 | -36.1% |
| 8 | Total Fixed Cost Adjustments | $ (21,408,717) | $ (14,742,782) | $ (6,665,935) | 45.2% |
| | **Adjustments to Variable Costs** | | | | |
| 9 | Working Capital | $ 459,741 | $ 566,477 | $ (106,736) | -18.8% |
| 10 | Def Variable Cost Under-Recoveries | $ 6,842,292 | $ 13,327,601 | $ (6,485,309) | -48.7% |
| 11 | Inventory Financing - LNG | $ 572,694 | $ 572,694 | $ - | 0.0% |
| 12 | Inventory Financing - Storage | $ 248,872 | $ 341,086 | $ (92,214) | -27.0% |
| 13 | Total Fixed Cost Credits | $ 632,657 | $ 599,371 | $ 33,286 | 5.6% |
| 14 | Total Variable Cost Adjustments | $ 8,756,256 | $ 15,407,229 | $ (6,650,973) | -43.2% |
| 15 | Total Adjustments to Gas Costs | $ (12,652,461) | $ 664,447 | $ (13,316,908) | |
| 16 | Annual Sales Volumes (Dth) | 25,929,986 | 27,009,019 | (1,079,033) | -4.0% |

# National Grid- RI Gas

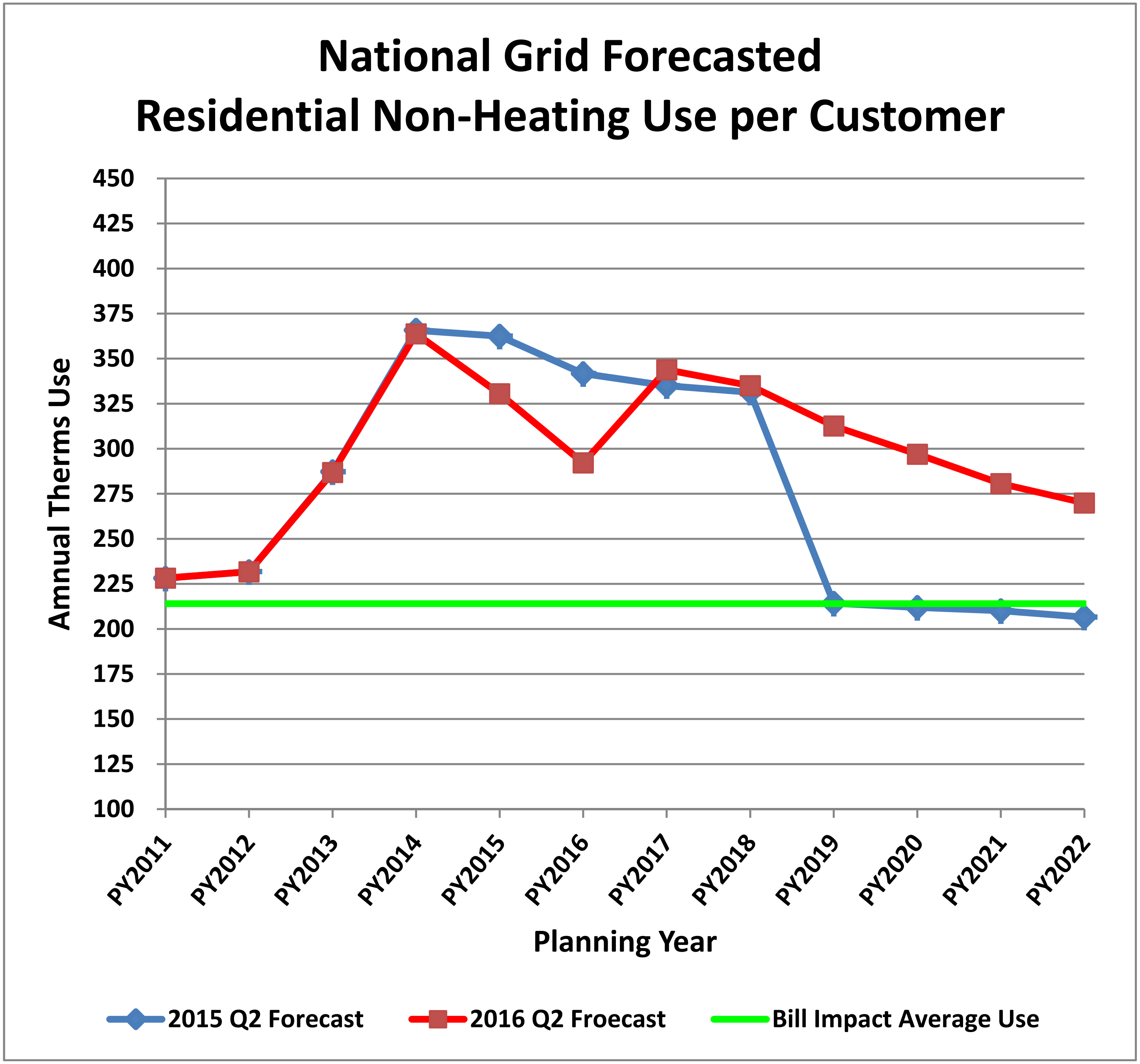
*Docket No. 4647 - 2016 Annual GRC Proceeding*

## Changes in Forecasted Gas Fixed and Variable GCR Costs

*After Adjustments and Reconciliations*

| GCR Cost Component | Dkt 4647 Forecasted Annual Cost 2016-17 1/ | Dkt 4576 Forecasted Annual Cost 2015-16 2/ | Dkt 4520 Forecasted Annual Cost 2014-15 3/ | Change 2015-16 to 2016-17 $ | % | 2-Year Change 2014-15 to 2016-17 $ | % |
|---|---|---|---|---|---|---|---|
| Fixed Costs | $ 29,336,921 | $ 30,539,461 | $ 27,606,777 | $ (1,202,540) | -3.9% | $ 1,730,144 | 6.3% |
| Variable Costs | $ 90,077,675 | $ 113,794,863 | $ 148,700,716 | $ (23,717,188) | -20.8% | $ (58,623,041) | -39.4% |
| TOTAL | $ 119,414,596 | $ 144,334,324 | $ 176,307,493 | $ (24,919,728) | -17.3% | $ (56,892,897) | -12.5% |

1/ Source: Docket No. 4647, Attachment AEL-1, REVISED October 3, 2016, pages 2-3.
2/ Source: Docket No. 4576, Attachment AEL-1, Revised October 23, 2015, pages 2-3.
3/ Source: Docket No. 4520, Attachment AEL-1S, September 16, 2014, pages 2-3.
4/ Source: Docket No. 4436, Attachment AEL-1, September 3, 2013, pages 2-3.


National Grid Forecasted
Residential Non-Heating Use per Customer
Amnual Therms Use
450
425
400
375
350
325
300
275
250
225
200
175
150
125
100
PY2011
PY2012
PY2013
PY2014
PY2015
PY2016
PY2017
PY2018
PY2019
PY2020
PY2021
PY2022
Planning Year
2015 Q2 Forecast
2016 Q2 Froecast
Bill Impact Average Use

## National Grid - RI Gas

*Docket 4647 - 2016 GCR Filing*

### *Comparison of Heat Factors by Rate Class by Month - Docket 4576 vs Docket 4647*

| | **Docket 4576** | **Nov-15** | **Dec-15** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov - Oct** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential Non-Heating | 43 | 51 | 63 | 91 | 112 | 142 | 101 | 183 | 547 | - | 21 | 14 | 76 |
| 2 | Residential Heating | 1,861 | 2,097 | 2,477 | 2,923 | 3,054 | 3,841 | 3,716 | 8,332 | 27,643 | - | 344 | 482 | 2,579 |
| 3 | Small C&I Sales | 176 | 389 | 412 | 426 | 435 | 502 | 564 | 1,064 | 7,330 | - | - | 53 | 383 |
| 4 | Small C&I Transport | 6 | 7 | 9 | 10 | 10 | 14 | 14 | 34 | 329 | - | - | 4 | 9 |
| 5 | Medium C&I Sales | 219 | 344 | 421 | 594 | 579 | 635 | 557 | 794 | 6,778 | - | - | 77 | 441 |
| 6 | Med C&I Transport | 191 | 234 | 272 | 351 | 333 | 388 | 353 | 578 | 6,781 | - | - | 92 | 282 |
| 7 | Large Low Load - Sales | 72 | 106 | 110 | 115 | 116 | 134 | 147 | 264 | 1,027 | - | 28 | 31 | 106 |
| 8 | Large Low Load - Transport | 259 | 316 | 323 | 334 | 332 | 359 | 385 | 547 | - | - | 128 | 195 | 316 |
| 9 | Large High Load - Sales | - | 4 | 7 | 8 | - | - | - | - | - | 3,692 | - | - | 4 |
| 10 | Large High Load - Transport | 34 | 48 | 53 | 64 | 63 | 71 | 55 | 175 | 1,252 | - | 42 | 22 | 54 |
| 11 | XL Low Load - Sales | 5 | 15 | 18 | 15 | 16 | 19 | 27 | 58 | 841 | - | - | 10 | 15 |
| 12 | XL Low Load - Transport | 161 | 167 | 168 | 159 | 160 | 170 | 202 | 318 | 2,572 | - | 31 | 177 | 167 |
| 13 | XL High Load - Sales | 9 | 13 | 1 | - | - | - | - | - | - | - | 187 | 14 | 6 |
| 14 | XL High Load - Transport | 207 | 173 | 179 | 171 | 119 | 73 | - | - | - | 10,544 | 515 | 144 | 156 |
| 15 | Total | 3,243 | 3,963 | 4,512 | 5,260 | 5,329 | 6,346 | 6,121 | 12,348 | 55,100 | 14,236 | 1,296 | 1,317 | 4,594 |

| | **Docket 4647** | Nov-16 | Dec-16 | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Jul-17 | Aug-17 | Sep-17 | Oct-17 | Nov - Oct |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16 | Residential Non-Heating | 63 | 69 | 77 | 94 | 92 | 118 | 123 | 241 | 144 | - | 19 | 30 | 82 |
| 17 | Residential Heating | 1,997 | 2,255 | 2,585 | 3,152 | 3,111 | 3,940 | 4,066 | 7,056 | 10,762 | - | 437 | 1,066 | 2,737 |
| 18 | Small C&I Sales | 286 | 339 | 394 | 478 | 472 | 582 | 566 | 677 | 1 | - | - | 116 | 403 |
| 19 | Small C&I Transport | 12 | 13 | 15 | 18 | 17 | 22 | 23 | 40 | 49 | - | 3 | 6 | 15 |
| 20 | Medium C&I Sales | 305 | 343 | 391 | 478 | 469 | 597 | 614 | 1,084 | 1,176 | - | 82 | 163 | 415 |
| 21 | Med C&I Transport | 219 | 243 | 276 | 339 | 331 | 425 | 439 | 807 | 371 | - | 69 | 114 | 295 |
| 22 | Large Low Load - Sales | 78 | 87 | 99 | 120 | 118 | 149 | 155 | 265 | 427 | - | 15 | 41 | 105 |
| 23 | Large Low Load - Transport | 230 | 257 | 292 | 353 | 348 | 441 | 457 | 797 | 1,172 | - | 49 | 123 | 309 |
| 24 | Large High Load - Sales | 7 | 7 | 8 | 11 | 10 | 13 | 13 | 35 | - | - | 6 | 3 | 9 |
| 25 | Large High Load - Transport | 31 | 32 | 37 | 49 | 45 | 60 | 57 | 138 | - | - | 28 | 15 | 41 |
| 26 | XL Low Load - Sales | 7 | 8 | 9 | 11 | 11 | 14 | 15 | 31 | 42 | - | 1 | 4 | 10 |
| 27 | XL Low Load - Transport | 124 | 138 | 156 | 190 | 186 | 237 | 244 | 426 | 521 | - | 30 | 65 | 165 |
| 28 | XL High Load - Sales | - | - | - | - | - | - | - | 4 | - | - | 5 | - | - |
| 29 | XL High Load - Transport | 75 | 70 | 85 | 139 | 98 | 148 | 69 | 170 | - | - | 229 | 28 | 96 |
| 30 | Total | 3,434 | 3,861 | 4,426 | 5,432 | 5,307 | 6,746 | 6,842 | 11,771 | 14,663 | - | 975 | 1,773 | 4,681 |

**National Grid- RI Gas**

*Docket No. 4647 - 2016 Annual GRC Proceeding*



***Changes in Forecasted Normal Weather Annual Throughput by Rate Classification***

*Docket 4647 vs Docket 4576*

| **TOTAL THROUGHPUT** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov - Oct** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential Non-Heating | | | | | | | | | | | | | |
| Forecasted 2016-17 | 61,398 | 89,290 | 110,313 | 112,206 | 98,591 | 78,155 | 53,411 | 35,271 | 25,629 | 24,348 | 25,656 | 35,674 | **749,942** |
| Forecasted 2015-16 | 48,049 | 71,423 | 92,942 | 107,427 | 113,117 | 87,291 | 46,799 | 31,200 | 24,471 | 22,307 | 24,221 | 28,799 | **698,046** |
| Difference | 13,349 | 17,867 | 17,371 | 4,779 | (14,526) | (9,136) | 6,612 | 4,071 | 1,158 | 2,041 | 1,435 | 6,875 | 51,896 |
| % Difference | 27.8% | 25.0% | 18.7% | 4.4% | -12.8% | -10.5% | 14.1% | 13.0% | 4.7% | 9.1% | 5.9% | 23.9% | 7.4% |
| Residential Heating | | | | | | | | | | | | | |
| Forecasted 2016-17 | 1,468,822 | 2,422,361 | 3,163,979 | 3,252,058 | 2,798,847 | 2,097,234 | 1,245,874 | 622,889 | 333,615 | 289,355 | 335,174 | 684,134 | 18,714,342 |
| Forecasted 2015-16 | 1,462,287 | 2,349,767 | 3,119,896 | 3,107,497 | 2,828,266 | 2,124,881 | 1,241,085 | 751,389 | 425,245 | 352,061 | 402,675 | 561,110 | 18,726,159 |
| Difference | 6,535 | 72,594 | 44,083 | 144,561 | (29,419) | (27,647) | 4,789 | (128,500) | (91,630) | (62,706) | (67,501) | 123,024 | (11,817) |
| % Difference | **0.4%** | 3.1% | 1.4% | 4.7% | -1.0% | -1.3% | 0.4% | -17.1% | -21.5% | -17.8% | -16.8% | 21.9% | -0.1% |
| Small C&I | | | | | | | | | | | | | |
| Forecasted 2016-17 | 174,414 | 330,132 | 451,453 | 466,152 | 391,675 | 276,157 | 136,161 | 33,921 | 2,491 | 2,243 | 2,511 | 43,678 | 2,310,988 |
| Forecasted 2015-16 | 155,461 | 421,163 | 514,559 | 456,333 | 406,403 | 284,086 | 183,207 | 98,723 | 59,708 | 45,821 | 48,940 | 71,448 | 2,745,852 |
| Difference | 18,953 | (91,031) | (63,106) | 9,819 | (14,728) | (7,929) | (47,046) | (64,802) | (57,217) | (43,578) | (46,429) | (27,770) | (434,864) |
| % Difference | 12.2% | -21.6% | -12.3% | 2.2% | -3.6% | -2.8% | -25.7% | -65.6% | -95.8% | -95.1% | -94.9% | -38.9% | -15.8% |
| Medium C&I | | | | | | | | | | | | | |
| Forecasted 2016-17 | 455,215 | 701,951 | 890,573 | 910,903 | 793,576 | 614,469 | 395,543 | 234,724 | 158,138 | 147,199 | 159,385 | 250,580 | 5,712,256 |
| Forecasted 2015-16 | 420,216 | 727,334 | 950,360 | 1,061,970 | 914,720 | 646,050 | 395,507 | 243,192 | 202,482 | 178,069 | 180,123 | 246,393 | 6,166,416 |
| Difference | 34,999 | (25,383) | (59,787) | (151,067) | (121,144) | (31,581) | 36 | (8,468) | (44,344) | (30,870) | (20,738) | 4,187 | (454,160) |
| % Difference | 8.3% | -3.5% | -6.3% | -14.2% | -13.2% | -4.9% | 0.0% | -3.5% | -21.9% | -17.3% | -11.5% | 1.7% | -7.4% |
| Large C&I LLF | | | | | | | | | | | | | |
| Forecasted 2016-17 | 213,509 | 356,808 | 466,290 | 476,816 | 407,446 | 302,671 | 175,337 | 81,992 | 38,056 | 31,484 | 38,657 | 92,056 | 2,681,122 |
| Forecasted 2015-16 | 246,341 | 448,979 | 532,256 | 473,022 | 413,083 | 277,780 | 177,315 | 90,375 | 57,303 | 47,629 | 62,819 | 133,210 | 2,960,112 |
| Difference | (32,832) | (92,171) | (65,966) | 3,794 | (5,637) | 24,891 | (1,978) | (8,383) | (19,247) | (16,145) | (24,162) | (41,154) | (278,990) |
| % Difference | -13.3% | -20.5% | -12.4% | 0.8% | -1.4% | 9.0% | -1.1% | -9.3% | -33.6% | -33.9% | -38.5% | -30.9% | -9.4% |
| Large C&I HLF | | | | | | | | | | | | | |
| Forecasted 2016-17 | 90,041 | 106,911 | 119,621 | 121,603 | 113,399 | 101,004 | 85,940 | 75,294 | 69,410 | 68,640 | 69,473 | 76,143 | 1,097,479 |
| Forecasted 2015-16 | 93,247 | 124,616 | 142,560 | 139,652 | 125,841 | 106,329 | 87,435 | 81,426 | 76,676 | 77,129 | 74,284 | 82,377 | 1,211,572 |
| Difference | (3,206) | (17,705) | (22,939) | (18,049) | (12,442) | (5,325) | (1,495) | (6,132) | (7,266) | (8,489) | (4,811) | (6,234) | (114,093) |
| % Difference | -3.4% | -14.2% | -16.1% | -12.9% | -9.9% | -5.0% | -1.7% | -7.5% | -9.5% | -11.0% | -6.5% | -7.6% | -9.4% |
| Extra Large C&I LLF | | | | | | | | | | | | | |
| Forecasted 2016-17 | 101,540 | 162,218 | 208,146 | 212,593 | 183,292 | 139,027 | 85,231 | 45,726 | 26,996 | 24,231 | 27,220 | 49,633 | 1,265,853 |
| Forecasted 2015-16 | 120,455 | 194,112 | 229,125 | 185,748 | 164,866 | 109,942 | 77,209 | 40,969 | 28,653 | 20,455 | 25,797 | 88,741 | 1,286,072 |
| Difference | (18,915) | (31,894) | (20,979) | 26,845 | 18,426 | 29,085 | 8,022 | 4,757 | (1,657) | 3,776 | 1,423 | (39,108) | (20,219) |
| % Difference | -15.7% | -16.4% | -9.2% | 14.5% | 11.2% | 26.5% | 10.4% | 11.6% | -5.8% | 18.5% | 5.5% | -44.1% | -1.6% |
| Extra Large C&I HLF | | | | | | | | | | | | | |
| Forecasted 2016-17 | 560,270 | 598,755 | 627,612 | 630,434 | 611,840 | 583,749 | 549,611 | 524,542 | 528,931 | 527,168 | 529,074 | 543,369 | 6,815,355 |
| Forecasted 2015-16 | 562,576 | 624,790 | 649,518 | 576,616 | 537,808 | 465,428 | 426,966 | 412,940 | 410,885 | 456,166 | 473,724 | 505,396 | 6,102,813 |
| Difference | (2,306) | (26,035) | (21,906) | 53,818 | 74,032 | 118,321 | 122,645 | 111,602 | 118,046 | 71,002 | 55,350 | 37,973 | 712,542 |
| % Difference | -0.4% | -4.2% | -3.4% | 9.3% | 13.8% | 25.4% | **28.7%** | **27.0%** | 28.7% | 15.6% | 11.7% | 7.5% | 11.7% |
| Total Throughput | | | | | | | | | | | | | |
| Forecasted 2016-17 | 3,125,209 | 4,768,426 | 6,037,987 | 6,182,765 | 5,300,075 | 4,114,311 | 2,727,108 | 1,654,359 | 1,183,266 | 1,114,668 | 1,187,150 | 1,775,267 | 39,170,591 |
| Forecasted 2015-16 | 3,108,632 | 4,962,184 | 6,231,216 | 6,108,265 | 5,504,104 | 4,101,787 | 2,635,523 | 1,750,214 | 1,285,423 | 1,199,637 | 1,292,583 | 1,717,474 | 39,897,042 |
| Difference | 16,577 | (193,758) | (193,229) | 74,500 | (204,029) | 12,524 | 91,585 | (95,855) | (102,157) | (84,969) | (105,433) | 57,793 | (726,451) |
| % Difference | **0.5%** | -3.9% | -3.1% | 1.2% | -3.7% | 0.3% | 3.5% | -5.5% | -7.9% | -7.1% | -8.2% | 3.4% | -1.8% |

# National Grid- RI Gas

*Docket No. 4647 - 2016 Annual GRC Proceeding*



## Comparison of National Grid's Forecasted Design Winter Sales

*Docket No. 44647 vs Docket No. 4576 by Rate Class by Month*

| | Forecasted Design Winter Sales | | | | | Design |
|---|---|---|---|---|---|---|
| | Nov | Dec | Jan | Feb | Mar | Nov - Mar |
| **Residential Non-Heating** | | | | | | |
| Forecasted 2016-17 | 70,090 | 97,034 | 117,723 | 121,080 | 109,244 | 515,171 |
| Forecasted 2015-16 | 53,941 | 77,188 | 98,971 | 115,968 | 126,115 | 472,183 |
| Difference | 16,149 | 19,846 | 18,752 | 5,112 | (16,871) | 42,988 |
| % Difference | 29.9% | 25.7% | 18.9% | 4.4% | -13.4% | 9.1% |
| **Residential Heating** | | | | | | |
| Forecasted 2016-17 | 1,742,439 | 2,677,188 | 3,412,157 | 3,548,322 | 3,159,670 | 14,539,776 |
| Forecasted 2015-16 | 1,717,242 | 2,586,711 | 3,357,695 | 3,382,220 | 3,182,483 | 14,226,351 |
| Difference | 25,197 | 90,477 | 54,462 | 166,102 | (22,813) | 313,425 |
| % Difference | 1.5% | 3.5% | 1.6% | 4.9% | -0.7% | 2.2% |
| **Small C&I** | | | | | | |
| Forecasted 2016-17 | 204,548 | 354,125 | 470,892 | 492,298 | 430,187 | 1,952,050 |
| Forecasted 2015-16 | 174,169 | 456,463 | 542,538 | 485,434 | 446,417 | 2,105,021 |
| Difference | 30,379 | (102,338) | (71,646) | 6,864 | (16,230) | (152,971) |
| % Difference | 17.4% | -22.4% | -13.2% | 1.4% | -3.6% | -7.3% |
| **Medium C&I** | | | | | | |
| Forecasted 2016-17 | 296,466 | 438,183 | 548,327 | 567,770 | 508,198 | 2,358,944 |
| Forecasted 2015-16 | 257,001 | 462,575 | 606,594 | 708,784 | 631,256 | 2,666,210 |
| Difference | 39,465 | (24,392) | (58,267) | (141,014) | (123,058) | (307,266) |
| % Difference | 15.4% | -5.3% | -9.6% | -19.9% | -19.5% | -11.5% |
| **Large C&I LLF** | | | | | | |
| Forecasted 2016-17 | 63,090 | 98,666 | 125,858 | 130,264 | 115,134 | 533,012 |
| Forecasted 2015-16 | 62,348 | 121,502 | 142,955 | 128,647 | 117,169 | 572,621 |
| Difference | 742 | (22,836) | (17,097) | 1,617 | (2,035) | (39,609) |
| % Difference | 1.2% | -18.8% | -12.0% | 1.3% | -1.7% | -6.9% |
| **Large C&I HLF** | | | | | | |
| Forecasted 2016-17 | 18,157 | 20,943 | 23,143 | 23,587 | 22,278 | 108,108 |
| Forecasted 2015-16 | 14,538 | 19,734 | 24,407 | 23,071 | 14,405 | 96,155 |
| Difference | 3,619 | 1,209 | (1,264) | 516 | 7,873 | 11,953 |
| % Difference | 24.9% | 6.1% | -5.2% | 2.2% | 54.7% | 12.4% |
| **Extra Large C&I LLF** | | | | | | |
| Forecasted 2016-17 | 5,623 | 8,689 | 11,051 | 11,439 | 10,137 | 46,939 |
| Forecasted 2015-16 | 4,929 | 16,378 | 22,481 | 16,056 | 15,379 | 75,223 |
| Difference | 694 | (7,689) | (11,430) | (4,617) | (5,242) | (28,284) |
| % Difference | 14.1% | -46.9% | -50.8% | -28.8% | -34.1% | -37.6% |
| **Extra Large C&I HLF** | | | | | | |
| Forecasted 2016-17 | 11,272 | 11,153 | 11,069 | 11,090 | 11,109 | 55,693 |
| Forecasted 2015-16 | 30,194 | 37,373 | 25,233 | 16,451 | 15,315 | 124,566 |
| Difference | (18,922) | (26,220) | (14,164) | (5,361) | (4,206) | (68,873) |
| % Difference | -62.7% | -70.2% | -56.1% | -32.6% | -27.5% | -55.3% |
| **Total Throughput** | | | | | | |
| Forecasted 2016-17 | 2,411,685 | 3,705,981 | 4,720,220 | 4,905,850 | 4,365,957 | 20,109,693 |
| Forecasted 2015-16 | 2,314,362 | 3,777,924 | 4,820,874 | 4,876,631 | 4,548,539 | 20,338,330 |
| Difference | 97,323 | (71,943) | (100,654) | 29,219 | (182,582) | (228,637) |
| % Difference | 4.2% | -1.9% | -2.1% | 0.6% | -4.0% | -1.1% |

# National Grid- RI Gas

*Docket No. 4647 - 2016 Annual GRC Proceeding*

***Docket No. 4647 - 2016 Annual GRC Proceeding***

| Forecast | **Docket 4576** *2015-16* | **Docket 4647** *2016-17* | Change from Prior Year | % Change from Prior Year |
|---|---|---|---|---|
| Annual Sales | 27,009,852 | 25,929,986 | (1,079,866) | **-4.0%** |
| Annual Throughput | 39,897,042 | 39,347,340 | (549,702) | -1.4% |
| Design Winter Sales | 20,338,327 | 20,109,626 | (228,701) | -1.1% |
| Design Day Requirements | 341,091 | 357,153 | 16,062 | **4.7%** |