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

IN THE MATTER OF

The Investigation as to the Propriety	)	
Of Proposed Gas Tariff Changes	)	**Docket No. 4770**
For National Grid	)	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

April 6, 2018

TESTIMONY OF BRUCE R. OLIVER
Docket No. 4770
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TABLE OF CONTENTS

TESTIMONY OF BRUCE R. OLIVER
Docket No. 4770
April 6, 2018

LIST OF ATTACHMENTS AND SCHEDULES

Attachment A	Resume for Bruce R. Oliver
Schedule BRO-1	Comparison of Class Cost of Service Allocation Results Schedule PMN-3 vs. Schedule PMN-9
Schedule BRO-2	Comparison of Class Cost of Service Allocation Results at 35% and 21% Federal Income Tax Rates
Schedule BRO-3	Division's Proposed Rate Class Distribution of National Grid's Requested $30.3 Million Gas Revenue Increase
Schedule BRO-4	Division's Illustrative Rate Class Distribution of a $15 Million Gas Revenue Increase
Schedule BRO-5	Comparison of National Grid's Gas Service Customer Costs with its Current and Proposed Customer Charges by Rate Class
Schedule BRO-6	Allocation of Distribution Costs to On-Peak versus Off-Peak by Rate Class
Schedule BRO-7	The Division's Gas Rate Design Proposals for Residential and Small Commercial Rate Classes

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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 gas cost of service, rate structure, and tariff change proposals presented by National Grid through the Direct Testimonies of Witness Norman and the Pricing Panel (i.e., Witnesses Leary and McCabe). This testimony also addresses considerations regarding National

Grid's consolidation of ISR charges for Residential Non-Heating and Residential Heating customers that have been carried forward from Docket No. 4781.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY ON BEHALF OF THE DIVISION IN PRIOR PROCEEDINGS BEFORE THIS COMMISSION?

A. Yes, I have participated in every gas base rate proceeding in Rhode Island over the last twenty years, as well as each annual Gas Cost Recovery (GCR) proceeding for National Grid and its predecessor organizations for more than twenty years and each annual Distribution Adjustment Charge (DAC) proceeding since the establishment of that mechanism. I have also testified on behalf of the Division in numerous other proceedings before this Commission. Other proceedings in which I have participated include merger proceedings involving National Grid, Southern Union, Providence Gas Company, and Valley Gas Company; as well as multiple gas long-term planning proceedings.

Q. HAVE YOU TESTIFIED IN UTILITY REGULATORY PROCEEDINGS IN OTHER JURISDICTIONS?

A. Yes. Over a period of more than forty years, I have testified in over 300 utility proceedings in twenty-four jurisdictions addressing a wide range of ratemaking and regulatory policy issues. Further detail regarding my experience, qualifications, and prior testimonies is provided in Attachment A to this testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR REVIEW OF NATIONAL GRID'S GAS COST OF SERVICE, RATE STRUCTURE, AND TARIFF CHANGE PROPOSALS IN THIS PROCEEDING?

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

<u>Gas Cost of Service Allocations</u>

1. With one exception, National Grid's cost-of-service allocations generally appear reasonable, but the cost of service model that Witness Normand employs lacks transparency and makes verification of the allocation details by account unnecessarily difficult as many of the formulas use to allocate costs to individual rate classes are hidden from view. In addition, the sources of key inputs are not documented or explained.

2. Although National Grid has filed a cost of service study that shows allocations of costs to all classes of customers as required by the terms of the settlement approved by the Commission in Docket No. 4323, Witness Normand essentially ignores the results of that study.

3. The Company's division of mains investment costs between mains of greater than 4 inches in diameter and mains of 4 inches or smaller diameter is an important element of the Company's plant cost allocations, but that division of mains costs within the Company's cost of service study is premised on what appears to be an unsupported assumption, rather than actual cost data.

4. In all class cost of service studies presented by National Grid in future base rate proceedings should include the Company's Non-Firm Service class with explicit allocations and assignments of costs to that class as can be found in Schedule PMN-9, pages 50 of 136 through 123 of 136.

<u>Rate Year Revenue</u>

5. National Grid's Weather Normalization of Test Year therm use fails to address the impacts of weather on billed demand charges which are also impacted by weather.

6. The Company's adjustments to Test Year Revenue to reflect Rate Year ISR and RDM charges do not and cannot fully depict the influences of charges that have been established since the Company's filing of its

Application and Support Testimony in this proceeding and charges that will be established subsequent to the litigation of this proceeding.

Gas Revenue Increase Distribution and Rate Design

7. The Company's proposed distribution of the revenue increase among rate classes does not properly reflect existing disparities in class rate of return and does not do enough to narrow those disparities.

8. National Grid's proposal to simplify its rates by flattening its Distribution Charges for Residential Heating customers is not appropriate and will place substantial rate burdens on larger gas users within that class.

9. The Company's existing On-Peak and Off-Peak Distribution Charges are reflective of identifiable differences in the Company's costs of serving On-Peak and Off-Peak loads, and thus, differences between the Company's Distribution Charges for On-Peak and Off-Peak gas use should be retained.

10. National Grid's movement toward consolidation of charges for its Residential Heating and Residential Non-Heating classes is not cost-based and should not be approved. Although customer costs for

Residential Heating and Residential Non-Heating customers may be similar, it is inappropriate to unify the distribution charges for those classes.

11. National Grid's proposed rate design changes do not display adequate and appropriate sensitivity to gradualism and ratemaking continuity in the proposed adjustments to charges within rate schedules.

12. National Grid's proposed increases in customer charges serve to dilute incentives for customers to deploy energy efficiency and energy conservation measures, and place increased rate burdens on low-use customers who typically have the most price inelastic gas service requirements.

13. National Grid's proposed Customer and Distribution charges for Non-Firm Gas service customers represent unjustifiable departures from cost-based ratemaking.

14. The Bill Impact Analyses National Grid has provided do not reflect known or reasonably anticipated costs increases that will add to the rate burdens customers will experience during the Rate Year end August 31, 2019.

15. Bill Impact Analyses for Delivery Services provided for Transportation Service customers should exclude gas costs.

Miscellaneous Service Fees

16. The Company's Returned Check Fee should be set at $7.95 per returned check.[1]

17. If the Commission is to approve fees for Credit Card Payments for inclusion in National Grid's tariff, such fees should be established as cost-based charges. No such support for National Grid's proposed provisions within its tariff for Residential and Non-Residential charges per transaction for credit card payments.

18. National Grid's proposed requirements for use of IP Wireless devices by FT-1 Firm Transportation Service customers, Non-Firm Sales Service customer, and Non-Firm Transportation Service customers are not appropriate for implementation as presented.

[1] Although this testimony focuses on National Grid's gas service rates, the analyses presented herein demonstrate that a $7.95 per returned check fee would be more appropriate for both gas and electric service.

19. The fees National Grid proposes for use of IP Wireless devices (a.k.a. Daily Metered Fees) are not well supported and not properly explained or justified.

Gas Tariff Changes

20. National Grid's proposed change to System Pressure Factor determinations under its Distribution Adjustment Charge is inappropriate, and should be re-written to be consistent with Company's position in its October 23, 2017 Reply Comments in Docket No. 4719.

21. National Grid's telemetering requirements and fees for daily metering are not consistent for the various classes of customers to whom such charges may apply.

22. The tariff should require that, where contributions in aid of construction ("CIAC") are assessed on the basis of engineering estimates, the Company's actual costs and dollar amounts for refunds of excess CIAC payments should be documented for the customer, and refunds should be required for all amounts in excess of $100.[2]

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[2] See National Grid's proposed Gas Tariff, Section 8, Service and Main Extension Policies, Schedule C, Sheet 4, Item 7.c.ii.

Other Issues

23. National Grid's consolidation of ISR charges for Residential Heating and Residential Non-Heating customers is inappropriate and should not be allowed to continue.

24. The Company's filed data and analyses in the proceeding demonstrate noticeable differences in the service characteristics and costs of service for Residential Non-Heating and Residential Heating customers that should not be ignored in the future ISR charge determinations.

25. National Grid's assignment of O&M expenses to the GCR as part of its presentation in this proceeding should not represent a guarantee of recovery of those costs through future GCR charges.

III. OVERVIEW

Q. WOULD YOU PLEASE PROVIDE AN OVERVIEW OF THE GAS RATE ISSUES ON WHICH YOU BELIEVE THE COMMISSION SHOULD FOCUS IN THIS PROCEEDING?

A. As initially filed National Grid sought an overall increase in its base gas revenues in this proceeding of $30.3 million or 14.32%.[3] Of that overall increase National Grid distributes responsibility for $30.1 million among its Firm Gas Service customer classes. The remainder is recovered primarily through adjustments to its rates for Non-Firm Service customers and to a much lesser extent through adjustments to charges for other non-standard services.

Despite the identification of large disparities in class rate of return, National Grid's proposed distribution of revenue increases among Firm Service rate classes is constrained such that no class receives greater than 1.15 times the average increase. Yet, in the development of proposed charges no similar constrain is exercised and increases in component charges within rate schedule range upward to more than 59%. This testimony recommends more flexibility in the distribution of revenue increases among classes to achieve greater movement toward parity in class rates of return, but greater consideration of the principals of gradualism and continuity in ratemaking in setting the magnitudes of component charges within rate schedules.

For Non-Firm customers, National Grid Witness Normand proposes a greater than average revenue increase despite the fact that his own analyses show the Non-Firm Class as having the highest rate or return among all the Company's classes of service. Correspondingly, Witness Normand's proposed

[3] On March 2, 2018 the Company filed updated revenue requirement schedules intended to show the impact of the Tax Cuts and Jobs Act (TCJA) on its revenue requirements for both its electric and gas businesses in Rhode Island. Those schedules suggest a significant reduction in National Grid's gas revenue requirement in this proceeding.

customer and distribution charges for Non-Firm service customers are well in excess of his own assessment of the underlying costs for those charges. Given that the Company's unbundled Non-Firm services are no longer subject to competition from alternative fuels, and have been billed at fixed rates since the conclusion of Docket No. 4323, no justification exists for such departures from cost-based ratemaking for National Grid's Non-Firm Service sales and transportation services.

National Grid also proposes a number of changes in its gas service tariff and in its charges for miscellaneous services. This testimony identifies a number of concerns regarding those changes and the analyses that have been presented to support the Company's tariff change and miscellaneous charge proposals. For this reason, the Commission is encouraged to carefully consider the propriety of those changes.

Finally, the Commission needs to be sensitive to the fact that the Company has deferred more than $20 million of projected end of period gas cost recovery deficiencies for recovery in the next GCR period. Those cost deferrals can be expected to add significantly to bills for all gas sales service customers during the rate effective period for new rates resulting from this proceeding. Yet, those added gas costs recovery requirements are not considered in National Grid's filed bill impact analyses in this proceeding. The bill impacts of the Company's rate proposals on larger use customers in National Grid's Residential and Small C&I classes are further amplified by the Company's effort to flatten its distribution charges for those classes. That one-time adjustment to the Company's existing rate designs which eliminates lower tail block charges lacks appropriate consideration of rate continuity and gradualism, particularly in light of large gas cost deferrals. If a flattening of distribution charges for Residential and Small C&I customers is to be pursued, it should reflect a more gradual approach to raising tail block charges.

IV. DISCUSSION OF ISSUES

<u>A. Allocated Costs of Service</u>

Q. HAS NATIONAL GRID PRESENTED ANALYSES IN THIS PROCEEDING THAT ALLOCATE THE COMPANY'S COSTS OF SERVICE AMONG RATE CLASSES?

A. Yes. It has provided two class cost of service studies. Schedule PMN-3 provides an allocation of the Company's projected costs among its **Firm Service rate classes** for the twelve month ended August 31, 2019. The results of the allocations detailed in Schedule PNM-3 are summarized in Schedule PNM-2. Buried within the workpapers provided as Schedule PNM-9, a second customer class cost allocation study is found.[4] That class cost of service study allocates the Company's Gas Delivery Service costs among all of its classes of service

[4] See Schedule PMN-9, pages 50 of 136 through 123 of 136, in Book 14 of the Company's Applications and Supporting Testimony and Schedules in this proceeding.

including both Firm Service and Non-Firm Service rate classes. However, Witness Normand indicates that study was provided only for "illustrative" purposes.[5]

Q. ON WHICH OF THE COMPANY'S CLASS COST OF SERVICE ANALYSES SHOULD THE COMMISSION RELY IN THIS PROCEEDING?

A. The Division's position in Docket No. 4323 and in this proceeding is that the National Grid's Non-Firm Service classes should be included explicitly in the Company's allocations of costs among rate classes. Although the National Grid has complied with the letter of its commitment Article III.B.3 of the Settlement approved by the Commission in Docket No. 4323 through its provision of the study presented at pages 50 through 123, its efforts to bury that study within Witness Norman's filed workpapers (as opposed to presenting it as a separately identifiable schedule) are not viewed by the Division as consistent with the spirit of the settlement in Docket No. 4323. As I explained in Docket No. 4323, the Company's approach to pricing service to non-firm transportation customers is like a *rudderless ship*. Although non-firm transportation service customers are presently billed on fixed rates that are computed at a discount from otherwise applicable firm service rates, National Grid offers no cost basis for its proposed charges for Non-Firm services.[6] In particular, the cost basis for the relationships

[5] National Grid's response to Division Data Request 7-11b.
[6] Docket No. 4323, the Direct Testimony of Division Witness Bruce R. Oliver, August 12, 2012, page 16, lines 1-6.

National Grid seeks to maintain between its Non-Firm Distribution Charges and its Distribution Charges for Extra Large C&I Firm Service customers need to be questioned.

In response to Division Data Request 7-11 and 7-12, Witness Normand offered his rationales for excluding the Company's Non-Firm Service rate classes from the cost allocation study on which he relies to guide his recommended revenue increase distribution and rate design proposals. However, his rationales are inconsistent with the Company's use of RSUM allocators for distribution costs are outdated and inappropriate. Witness Normand reasons that "*Narragansett Gas does not use a non-firm customer's peak load in the planning process for plant investments because the customer is subject to interruption by Narragansett Gas*."[7] The Company's RSUM allocators are specifically designed to apportion cost responsibilities to usage in **<u>all months</u>** of the year. Thus, the underlying rationale for use of the RSUM methodology directly contradicts Witness Norman's rationale for excluding Non-Firm customers and their usage from such allocations. The RSUM method, properly applied, should properly distribute a weighted portion of the allocated cost responsibilities to off-peak and non-firm service volumes as well as those that contribute to system peak requirements.

[7] National Grid's response to Division Data Request 7-11c.

Q. DO THE RSUM ALLOCATIONS THAT NATIONAL GRID HAS CONSTRUCTED FOR USE IN THE CLASS COST OF SERVICE ALLOCATIONS PRESENTED IN SCHEDULE PMN-9 INCLUDE ALLOCATIONS OF COSTS TO THE OFF-PEAK USAGE OF NON-FIRM CUSTOMERS, AS WELL AS THE OFF-PEAK USAGE OF ALL FIRM SERVICE RATE CLASSIFICATIONS?

A. Yes, they do. This can be seen in the workpapers labeled "Calculation of RSUM allocation Factor" that are presented in Schedule PMN-9, pages 124 of 136 through 127 of 136.

Q. HAVE YOU PREPARED A COMPARISON OF THE RESULTS OF THE COMPANY'S CUSTOMER CLASS COST ALLOCATION STUDIES IN SCHEDULES PMN-3 AND PMN-9 (I.E., WITH AND WITHOUT EXPLICIT ALLOCATIONS TO NON-FIRM SERVICE CUSTOMERS)

A. Yes. **Schedule BRO-1** presents that comparison. As shown in that exhibit, the results of the two studies in terms of computed class rates of return do not vary significantly for the Company's Firm Service classes. Again, the most important difference is that the study provided in Schedule PMN-3 (i.e., the study on which Witness Norman relies to guide his rate structure recommendations) denies the Commission any insight regarding the relationship between revenues and costs of service for the Company's Non-Firm Service customers. Thus, reliance only on the results presented in Schedule PMN-3 obscures the fact that Non-Firm Service customers currently provide the National Grid the highest rate of return of any class of gas customers served in Rhode Island. As shown on page 50 of 136 in Schedule PMN-9, National Grid's Non-Firm Service (Interruptible)[8] customers provide the Company a ROR of 8.35% and a unitized rate of return ("UROR") of 1.613.[9]

Q. WHY IS IT APPROPRIATE FOR THE COMMISSION TO REQUIRE NATIONAL GRID TO ALLOCATE ITS DELIVERY SERVICE COSTS TO ALL CLASSES OF CUSTOMERS, INCLUDING NON-FIRM CUSTOMERS?

A. As explained in prior proceedings before this Commission, National Grid's provision of service to Non-Firm customers is no longer subject to competitive pressure from alternative fuels.[10] As a result, National Grid's service to Non-Firm customers is no longer subject to monthly pricing fluctuations to respond to changes in market costs for competitive fuels, and cost recovery for delivery services provided to Non-Firm customers is no longer threatened by the pricing of alternative fuels. Rather, recent history suggests that Rhode Island has a viable competitive market for gas supply services that insulates the Company from competitive fuel price issues. Moreover, since Docket No. 4323, Non-Firm

[8] Schedule PMN-9 uses the term "Interruptible" as a substitute or synonym for "Non-Firm Service." Although Non-Firm service is an interruptible service, the Company's tariff consistently uses the term "Non-Firm" to describe customers who utilize gas sales or transportation services that are subject to interruption.

[9] An UROR of 1.631 indicates that the rate of return for the Non-Firm class is **61.3% above** the overall rate of return for the Company's gas service in Rhode Island.

[10] In the context of now well-established competitive markets for gas supply services, the role of responding to changes in the prices of alternative fuels falls primarily on Competitive Service Providers ("CSPs") in their pricing of gas supply services. All evidence suggests that the competitive market has operated effectively in this role, providing National Grid considerable stability in its Non-Firm margin revenue over the past several years.

customers have been billed at fixed, Commission-approved, tariff rates, and their revenues have been as predictable as those for National Grid's Firm Service classes.[11] Further, the Commission has accepted that there is no longer a need for sharing margin revenue that the Company derives from Non-Firm Service. Thus, there is no longer any need for National Grid's Firm Service customers to be allocated costs more appropriately attributable to its Non-Firm customers.

Q. IN YOUR SUMMARY FOR THIS TESTIMONY YOU INDICATE THAT WITH ONE EXCEPTION YOU GENERALLY FIND THE METHODS USED TO ALLOCATE COSTS AMONG RATE CLASSES IN THE COMPANY'S ALLOCATED COST OF SERVICE STUDIES REASONABLE. WHAT IS THAT ONE EXCEPTION?

A. The one exception is National Grid's approach to the allocation of income tax responsibilities. National Grid has allocated income taxes among classes on the basis of its assessment of taxable income by class. This is inappropriate and distorts the Company's assessment of class responsibilities for income taxes. The Company's approach allocates disproportionately small amounts (or negative amounts) of income tax responsibilities to classes having below system average rates of return and unduly burdens classes with greater than system average rates of return.

[11] See National Grid's Response to Division Data Request DIV 7-33, Attachment 7-33-1.

Q. HOW SHOULD INCOME TAX RESPONSIBILITIES BY RATE CLASS BE COMPUTED?

A. Income taxes are a function of the Company's rate base and its required equity return on its investment in facilities that are required to serve each rate class. The fact that a class has a below system average or negative rate of return (as in the case of the Company's Residential Non-Heating service) does not reduce the level of equity return and income tax that the Company must incur to support its investment in facilities for a rate class. Likewise, classes that support the system by providing above system average rates of return should bear no responsibility for income taxes on the portions of the return they provide that exceed the system average. Rather, the income taxes assigned to each rate class should be directly proportional to the amount of rate base allocated to the class, and the failure of a class to provide a system average rate of return should not exempt a class from income taxes that the Company does cannot avoid if it is to earn its authorized overall rate of return.

Q. HOW DOES THE PERVERSE NATURE OF THE COMPANY'S ALLOCATION OF INCOME TAXES REVEAL ITSELF IN THIS PROCEEDING?

A. The Company's class cost of service allocations were developed on the basis of a 35% Federal income tax rate. With the passage of the Tax Cut and Jobs Act ("TCJA") after the submission of the Company's Application in this proceeding, the applicable Federal income tax rate fell to 21%. National Grid has not re-filed its Allocated Cost of Service Studies to reflect the lower tax rate. However, I have applied the new 21% Federal income tax rate in the Company's cost of service model for the ACOSS provided in Schedule PMN-9 which includes allocations of costs to Non-Firm service as a separate identifiable class. **Schedule BRO-2** shows the class rates of return (RORs) and unitized rates of return (URORs) that result from using a 21% Federal income tax rate and compares those results with the Company's results based on a 35% Federal income tax rate. **Schedule BRO-2** demonstrates that, due to the method used in the Company's model to allocate income taxes, the change in the applicable Federal income tax rate does not impact class rates of return in a uniform manner. Rather, when the applicable tax rate is reduced, all class rates of return move further from the system average rate of return. Classes with below system average rates of return at a 35% Federal income tax rates have even lower rates of return when the new 21% Federal income tax rate is applied. Conversely, rate of return for classes with above average rates at a 35% Federal income tax rate have even higher rates of return relative to the system average when the Federal income tax rate is lowered.

Q. HOW WOULD CLASS RATES OF RETURN BE IMPACTED BY THE CHANGE IN THE FEDERAL INCOME TAX RATE IF INCOME TAX RESPONSIBILITIES WERE ALLOCATED AMONG CLASSES ON A BASIS THAT REFLECTS THE ALLOCATION OF RATE BASE BY CLASS?

A. If income tax responsibilities were allocated in proportion to the Company's rate base investment for each class, and therefore in proportion to the Company's equity return requirement by class, the change in the Federal income tax rate would impact all classes in a proportional manner (i.e., Federal Income Taxes for all classes would decline by 40% (i.e., the difference between the former 35% Federal income tax rate and the new 21% income tax rate).

B. Adjustments to Reflect Rate Year Revenue

Q. HAVE YOU REVIEWED THE ADJUSTMENTS THE COMPANY PRESENTS TO SUPPORT ITS ESTIMATES OF RATE YEAR REVENUE?

A. Yes, I have. The Company's development of Rate Year revenue is presented in the testimony of the Pricing Panel (Witnesses Leary and McCabe) and in Schedule PP-1(a)-GAS. I have also reviewed the testimony of Witness Poe with respect to the Company's weather normalization analyses for gas service, the results of which are reflected in Schedule PP-1(a)-GAS.

Q. DO YOU HAVE ANY CONCERNS WITH RESPECT TO NATIONAL GRID'S EFFORTS TO WEATHER NORMALIZE ITS TEST YEAR SALES AND REVENUE?

A. I do. Most importantly, I find that the Company has failed to weather normalize its measures of billing demands for C&I classes that are subject to separately billed demand charges. As set forth in the Company's Gas Tariff, Section 5, customers served under each of National Grid's gas rate schedules for Firm Gas Sales services are subject to a monthly billed demand charge per therm based on the customer's maximum average daily quantity ("MADQ") for the most recent November through April period. Such measures of gas use are clearly weather sensitive. However, adjustment of the demand measures billed during the test year requires consideration of differences between actual and normal heating degree days for the historical November through April period on which the applicable Test Year billing demand measures were established. That is a different time period with different weather conditions than National Grid has addressed in its weather normalization of the therm use measures bills under its Distribution Charges. In this context, I recommend that the Commission require in all future base rate proceedings that National Grid compute and fully document its assessment of weather normalization adjustments to Test Year billed MADQ therms for all classes subject to Demand Charges.

Q. ARE THE COMPANY'S OTHER ADJUSTMENTS TO TEST YEAR REVENUE REASONABLE AND APPROPRIATE?

A. Not entirely. To the extent ISR costs are being rolled into base rates, the Company's adjustments to distribution revenue to reflect the roll-in of ISR costs are appropriate. However, since the filing of the Company's Application in this proceeding, adjustments have been made to National Grid's Gas ISR costs that have not been reflected in the Company's estimates of test year revenues for cost allocation and rate design purposes. Furthermore, the Company's estimates of Rate Year ISR revenue address a period that extends five months beyond the effective period for the ISR charges recently accepted by the Commission in Docket No. 4781. Those charges will only be in effect through March 31, 2019. Charges for the period April 1, 2019 through the August 31, 2019 end of the Rate Year are yet to be determined. I recognize that the Company has submitted estimates of its ISR costs for future periods, but there is no assurance that its subsequent ISR filings will conform to those estimates, and subsequent ISR reconciliations address variations of ISR charge revenues from projected ISR recoveries but do not adjust ISR amounts included in base rates.

Similar concerns are expressed with respect to RDM revenue adjustments. Including uncertain future levels of RDM revenue in Distribution rates in this proceeding increases the likelihood of mismatches between actual RDM revenue during the Rate Year and RDM revenue amounts included in base distribution rates.

C. Gas Revenue Increase Distribution

Q. HOW DOES NATIONAL GRID PROPOSED TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE FOR GAS SERVICE CUSTOMERS AMONG RATE CLASSES?

A. National Grid Witness Normand explains that his revenue targets by class were set by first establishing a cap on the increases applied to any individual rate class at 1.15 times the overall average increase of 14.37%. This approach limits increases to not more than 16.52%. He also proposes that all classes, regardless of each class's rates of return ("ROR") at present rates, receive a rate increase. Witness Norman applies his maximum rate increase to three classes: Residential Non-Heating, Small Commercial and Industrial ("Small C&I"), and Large Commercial and Industrial High Load Factor ("Large C&I HLF"). However, as shown in Schedule BRO-1, those thee classes have substantially different rates of return at present rates. The Residential Non-Heating class ROR at present rates is **negative** (i.e., -1.28%).[12] The Small C&I class has a ROR of 3.47% or roughly **67% of the system average** rate of return, and the Large C&I HLF class has a ROR 4.93% or **95.3% of the system average** rate of return at present rates.

The vastly different class rates of return for these three classes do not warrant equal treatment in the distribution of the Company's revenue increase. Moreover, the ROR for the Large C&I HLF class at 95% of the system average rate of return is much closer to that for the Residential Heating class (which is at 98% of the system average rate of return) than the ROR for the Residential Non-Heating class. However, Witness Norman applies his computed **maximum** rate increase to the Large C&I HLF class while applying a slightly less than system

[12] A negative rate of return for a rate class indicates that the class fails to provide any contribution to the Company's required return on investment of plant that is used to serve the class.

average increase to the Residential Heating class. The disparity in Witness Norman's treatment of the Large C&I HLF class and the Residential Heating class is difficult to rationalize.

Although gradualism is an important consideration, equity and fairness require balancing gradualism considerations with achieving more balanced class rates of return when distributing revenue requirements among classes.

Q. DOES WITNESS NORMAND PROPOSE AN INCREASE IN RATES FOR NATIONAL GRID'S NON-FIRM SERVICE CUSTOMERS?

A. Yes. Schedule PMN-7 indicates that National Grid seeks to increase its Non-Firm Service revenue by $210,053.[13] The Company also represents that its Rate Year Non-Firm Margins at present rates total $1,388,117. Thus, the proposed $210,053 Non-Firm Service revenue increase equates to a **15.13%** increase for the Non-Firm class. Yet, the Company requested overall gas revenue increase request is only **14.37%**. Thus, despite the fact that Schedule PMN-9 shows the Company's Non-Firm class as having the highest rate of return of all of its classes at 1.613 times the system average rate of return, Witness Normand proposes a greater than average rate increase for National Grid's Non-Firm service customers.

Although National Grid and Witness Normand have gone through the motions of preparing a cost of service study that shows Non-Firm Service as a

[13] Schedule PMN-7, page 4 of 6, column (U), line 108.

separate rate class, the results of the study provided in Schedule PMN-9 have not utilized the results of that study in the development of their proposed gas revenue increase among rate classes.

Q. SHOULD THE COMMISSION BE SENSITIVE TO NATIONAL GRID'S PROPOSAL TO PRICE ITS NON-FIRM GAS SERVICE AT LEVELS WELL IN EXCESS OF THE ALLOCATED COSTS OF SERVICE FOR THAT CLASS?

A. I believe it should. Given the extreme cold weather and the extremely high costs for incremental gas purchases that National Grid has experienced in three of the last five winters, the value gained from the ability to interrupt customers' service requirements during period of extreme cold weather can be substantial.

During the recently late December 2017 the first half of January 2018, National Grid experienced a period of particularly severe cold weather. As a result of increased gas use during that period, daily spot market prices soared far above the levels budgeted by the Company in the development of its GCR rates, reaching a high of over $80 per dekatherm (i.e., $8.00 per therm). Moreover, National Grid purchased more than 765,000 dekatherms of gas during that period at an average cost of over $31.00 per dekatherm. By comparison the average variable cost of gas recovered through National Grid's GCR charges was only $3.5711 per dekatherm (or $0.3571 per therm).[14] Thus, for each additional therm of Non-Firm gas service that National Grid could have inter-

[14] See National Grid's January 29, 2018 Interim Gas Cost Recovery Filing, Attachment AEL-1, page 1 of 1, line (2).

rupted during that period, the Company would have avoided more than $27 per dekatherm of increased gas costs.

However, for a number of reasons, the Company's Non-Firm service class has been declining in size, and it can only be surmised that the Company's pricing of its Non-Firm service at rates well in excess of its costs of service has contributed to that decline. Although Witness Normand focuses on the value of Non-Firm load in terms of the avoidance of peak capacity costs, the Company's ability to service customers on a non-firm (i.e., interruptible) basis also enables it to avoid additional purchases of firm gas supply during period of high incremental gas purchase costs. As previously noted, in three of the last five winters, the ability to interrupt service to greater portions of the Company's total load would have generated significant gas cost savings. Thus, before accepting the elimination of existing Non-Firm Service options, the Commission should more carefully consider the potential value of encouraging expanded use of non-firm gas services.

Q. HAS NATIONAL GRID TAKEN STEPS IN OTHER JURISDICTIONS TO EXPAND THE AMOUNT OF LOAD IT CAN CURTAIL DURING PERIODS OF HIGH DEMAND AND HIGH INCREMENTAL COSTS?

A. Yes, as noted in the memorandum I submitted to the Commission regarding National Grid's Interim GCR Filing dated February 22, 2018, National Grid has recently received approval of a pilot gas demand-side management program in

New York. This effort to investigate other forms of service curtailment is further indication of the value of being able to reduce greater amounts of load during peak periods. It also suggests that policies and practices, which discourage use of non-firm (i.e., interruptible) gas services by pricing those services in excess of fully allocated costs, may not be well-advised at this time.

Q. HOW SHOULD THE COMPANY'S REQUESTED GAS REVENUE INCREASE BE DISTRIBUTED AMONG RATE CLASSES?

A. The Commission should distribute the Company's requested increase in a manner that is more reflective of the identified differences in class rates of return and thereby act to narrow the current disparities in rates of return among rate classes. **Schedule BRO-3** depicts a revenue increase distribution at the Company's requested gas revenue requirement that apportions the revenue increase among classes in a manner that moves all rate classes, including the Company's Non-Firm Service class, closer to parity. All Firm Service Class would receive at least 80% of the overall average increase, and no class would receive an increase of greater than 1.4 times the average increase. Class with below system average rates of return at present rates are given greater than average increases, but the relative magnitudes of those increase are differentiated with classes further below the system average receiving somewhat larger percentage increase. The Non-Firm class with a current ROR at 1.6 times that overall average rate of return (the highest ROR of any class) is given half the system average increase.

Q. HOW DOES YOUR PROPOSED REVENUE INCREASE DISTRIBUTION AT THE COMPANY'S FULL REQUESTED GAS REVENUE INCREASE IMPACT DISPARITIES IN CLASS RATES OF RETURN?

A. The class cost of service study presented in Schedule PMN-9, which includes allocations to Non-Firm Service, shows current ROR's by rate class ranging from -1.28% to +8.35% and unitized rates of return ("URORs") ranging from -.25 to +1.61. After applying my proposed revenue increase distribution, range for class URORs would be 0.24 to 1.25. This represents a substantial improvement in rate equity among classes.

Q. HOW SHOULD THE COMMISSION ADJUST THE DISTRIBUTION OF ANY APPROVED REVENUE INCREASE IF THE APPROVED INCREASE IN GAS BASE RATE REVENUE IS LESS THAN THE COMPANY'S FULL REVENUE INCREASE REQUEST IN THIS PROCEEDING?

A. **Schedule BRO-4** presents a proposed gas revenue increase distribution for a $15 million overall gas revenue increase (i.e., about half the Company file request).[15] Schedule BRO-4 depicts a scenario under which rates of return for all

[15] The $15 million revenue increase assumed for illustrative purposes is roughly reflective of the impact of the TCJA, maintenance of the Company's current 9.50% return on equity, and an allowance for other minor adjustments to revenue and expenses.

classes move closer to the system average and the disparity in class rates of return in noticeably reduced.

D. Gas Rate Design

1. Firm Service Rate Design

Q. HOW HAS NATIONAL GRID APPROACHED THE DESIGN OF CHARGES BY RATE CLASS TO RECOVER THE COMPANY'S REQUESTED REVENUE INCREASE?

A. The two guiding principles set forth by Witness Normand's development of proposed charges by rate class appear to be: (1) increased recovery of cost through fixed monthly charges;[16] and (2) elimination of all existing block structures.[17]

Q. ARE WITNESS NORMAN'S RATE DESIGN OBJECTIVES REASONABLE AND APPROPRIATE IN THE CONTEXT OF THIS PROCEEDING?

A. No. Many of the Company's proposed customer charge and distribution charge increases lack reasonable consideration of the principles of gradualism and ratemaking continuity. In particular, National Grid's proposed increases in customer charges for Residential and Small C&I customers and its proposed

[16] The Direct Testimony of National Grid Witness Normand at page 18 of 31, lines 19-22.
[17] Id., at page 22 of 31, lines 5-7.

increases in tail block distribution charges display a substantial lack of sensitivity to gradualism and ratemaking continuity considerations. Further, the Company proposes to raise its charges for residential non-heating service to be essentially identical to its proposed charges for Residential Heating service. The clear implication is that National Grid is moving toward elimination of its separate Residential Non-Heating service class by consolidating its charges for Residential Heating and Residential Non-Heating services. Yet, the Company's underlying costs for providing service to those classes are not same, and thus, consolidation of charges for Residential Heating and Residential Non-Heating service represent a movement away from cost-based ratemaking.

The Company's efforts to eliminate "*all existing block structures*" in this case are not reasonable or appropriate. That proposal exhibits a substantial lack of sensitivity to the principles of gradualism and rate continuity and should be rejected. As shown in Table 1 below, the tail block rate increases National Grid Witness Normand proposes for Residential Heat and Small commercial customers are dramatic.

Table 1
Comparison of National Grid's Current and Proposed Distribution Charges for Tail Block Usage

	Tail Block Charge		Proposed Increase	
Rate Case	Current	Proposed	$	%
Residential Heat	$0.3010	$0.6034	$0.3024	100.5%
Small C&I	$0.2242	$0.4773	$0.3024	112.9%

These proposed Tail Block rate increases are not gradual and can be expected to place significant cost increases on larger uses within those classes. Moreover, as noted in the Overview section of this testimony, the Commission should be sensitive to the bill impacts that the rates approved in this proceeding can be expected to have on larger users within the Company's Residential and Small C&I classes. During the rate effective period, rate increases experienced by Residential and Small C&I customers will be compounded by significant GCR costs that have been deferred for recovery in the next GCR year.

Q. WHAT ARE THE MAGNITUDES OF THE CUSTOMER CHARGE INCREASES THAT NATIONAL GRID PROPOSES FOR GAS SERVICE CUSTOMERS?

A. The Company's proposed customer charge increases for gas service rate classes are presented in **Schedule BRO-5**. All of the proposed customer charge increases for the Company's Residential Non-Heating, Residential Heating, Small C&I, and Medium C&I classes are in excess of 20%. However, Witness Normand proposes a customer charge increase for Small C&I customers that exceeds **59%.** Table 2 summarizes National Grid's proposed customer charge increases for Residential and Small C&I rate classes.

Table 2

National Grid's Proposed Customer Charge Increases
For Residential and Small C&I Customers

Rate Case	Customer Charge Current	Customer Charge Proposed	Proposed Increase $	Proposed Increase %
Residential Non-Heat	$13.00	$16.00	$3.00	23.08%
Residential Heat	$13.00	$16.00	$3.00	23.08%
Small C&I	$22.00	$35.00	$13.00	59.09%

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S RATE DESIGN ANALYSES?

A. I do. In the development of National Grid's proposed rate designs, the Company has adjusted revenue at present rates to include revenue amounts for ISR charges, RDM charges, and ERC Normalization. I do not find the RDM element of those adjustments to be inappropriate. The Revenue Decoupling Adjustment Component of the Distribution Adjustment Charge that will be applicable during most of the Rate Year ended August 31, 2019 was not known at the time National Grid filed its Direct Testimony and supporting exhibits in this docket and is not scheduled to be submitted for review until the end of the second quarter of this year (i.e., not later than July 1, 2018).[18]

[18] National Grid's Gas Tariff, Section 3, Distribution Adjustment Charge, Schedule A, Item 1.2, Sheets 1 and 2.

Q. HOW SHOULD THE COMPANY'S PROPOSED RATE DESIGNS BE ADJUSTED FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Two major adjustments to National Grid's proposed rate designs for Residential and Small Commercial customers are recommended. First, the Commission should hold the Company's customer charges at their current levels. Second, the increase for each of those classes should be apportioned between the Head Block and Tail Block charges in a manner that provides for more gradual movement toward equalization of Head Block and Tail Block charges. The Commission should find that equalization of those charges through a one-step adjustment in this proceeding is inappropriate, does not properly reflect gradualism and rate continuity, and would be unduly burdensome to large users within the Residential Heating and Small C&I classes.

Q. HAVE YOU PREPARED PROPOSED RATE DESIGNS FOR THE COMPANY'S RESIDENTIAL AND SMALL C&I RATE CLASSES?

A. Yes, I have. Those proposed rate designs are presented in **Schedule BRO-7**. In the development of these rate design proposals I have assumed for illustrative purposes that the Company's approved overall revenue requirement for Rhode Island gas service will be $15 million, or roughly half of its filed gas revenue increase request.[19] For each rate class the Customer Charge is held at its

[19] As previously noted, $15 million revenue increase assumed for illustrative purposes is roughly reflective of the impact of the TCJA, maintenance of the Company's current 9.50% return on equity, and an allowance for other minor adjustments to revenue and expenses.

present level, and the applicable revenue increase is recovered through the proposed Distribution Charges.

2. <u>Rate Design for Non-Firm Service</u>

Q. HOW HAS WITNESS NORMAND APPROACHED THE DESIGN OF CHARGES FOR NATIONAL GRID'S NON-FIRM SERVICE CUSTOMERS?

A. Witness Normand increases Non-Firm customer charges by applying the average increase for Extra Large C&I customers to the current average Non-Firm customer charge. As shown in Table 2 in Witness Normand's Direct Testimony, he raises current Non-Firm average customer charge of $625 per month by $110 or 17.6% to arrive at a proposed Non-Firm customer charge of $735 per customer. Witness Normand's proposed Non-Firm Distribution Charges are computed to reflect a 20% discount from Distribution Charges for the otherwise applicable Extra Large C&I Firm Service rate schedules.

Q. DO YOU SUPPORT NATIONAL GRID'S APPROACH FOR ESTABLISHING CHARGES FOR ITS NON-FIRM DELIVERY SERVICE CUSTOMERS?

A. No, I do not. Witness Norman's own analyses suggest that both the Company's proposed Non-Firm Customer Charges and Non-Firm Distribution Charges exceed National Grid's costs of providing those services. **Schedule BRO-4** shows that the Company's proposed customer charges are well in excess of its identified customer-related costs for all sizes and types of Non-Firm gas users. Further, Witness Normand's presentation in this case suggests that, despite the fact that current Non-Firm Distribution Charges are 39% to 53% below those for Extra Large Firm Service customers, the Non-Firm class is providing a noticeably higher rate of return than the Company's Extra Large Firm Service customers, and the highest rate of return of any Rhode Island gas service class. In this context, it is difficult to argue that a 20% discount from Extra Large Firm Service distribution charges reflects a cost-based approach to setting Distribution Charges for customers served under National Grid's Non-Firm rate schedules.

Q. DOES WITNESS NORMAND ACCURATELY REPRESENT THE CURRENT MONTHLY CUSTOMERS CHARGES BILLED TO NATIONAL GRID'S NON-FIRM GAS SERVICE CUSTOMERS?

A. No. The Company's current Gas Tariff has not one, but three, separate customer charges for Non-Firm Service customers that are differentiated based on a Non-Firm customer's therm usage. Below 35,000 therms, the monthly customer charge is currently **$275.00 per month**. For Non-Firm customers with usage between 35,000 therms and 150,000 therms, the current customer charge is **$485.00 per month**. Non-Firm customers that use in excess of 150,000 therms pay a currently pay a customer charge **$715 per month**. Although Witness Normand's Table 2 on page 23 of his Direct Testimony represents the current Non-Firm customer charge as $625.00 per month, no such charge is found in the National Grid's Rhode Island gas tariff. The $625 amount referenced by Witness Normand appears to reflect a weighted average of the charges billed to Non-Firm customers during the historic test year.

I recognize that the Non-Firm class has continued to decline in terms of numbers of customers and that in the most recent periods there were no customers billed in the below 35,000 therm category, but that history does not, necessarily justify elimination of separate Non-Firm Service customer charges for potential Non-Firm Service customers having usage either below 35,000 therms or between 35,000 and 150,000 therms. The costs to National Grid of maintain its current three-tiered customer charge structure for Non-Firm Service are minimal, and a decision to replace that long-standing three-tiered customer charge structure with a single charge that is designed to be applicable only to customers of a size equivalent to those served under Extra Large C&I Firm Service rates should await an investigation of the merits of encouraging expansion of the Company's Non-Firm Service offerings.[20]

Q. HAS A COST OF SERVICE STUDY DEPICTING THE COMPANY'S COSTS OF PROVIDING SERVICE TO NON-FIRM CUSTOMERS BEEN PRESENTED IN THIS CASE?

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[20] As previously discussed, the ability to interrupt service during period of high gas use has been particularly valuable to National Grid's gas operations in at least three of the past five years, and in that context efforts to maintain or improve opportunities for a greater number of customers to economically participate in the Non-Firm Service offerings warrant further consideration at this time.

A. Yes, as previously noted, that study is found in Schedule PMN-9 at pages 50 of 136 through 123 of 136. The results of that study suggest the Company's Non-Firm customers are providing the highest rate of return of any class of gas service customers in Rhode Island. The Company does not compute unbundled costs for customer and distribution charges as part of that study, and thus little or no guidance for the setting charges for National Grid's Non-Firm Service customers is provided.

Q. WHAT IS THE BASIS FOR THE 20% DISCOUNT THAT WITNESS NORMAND APPLIES TO THE COMPARABLE FIRM RATES TO DERIVE HIS PROPOSED NON-FIRM DISTRIBUTION CHARGES?

A. The determination of Non-Firm Distribution Charges using a 20% discount from firm rates was a tool employed, in the absence of cost data, in prior cases reaching back to Docket No. 3943. Since the Company did not include the Non-Firm class in its ACOSS in those prior proceedings, the 20% discount methodology was adopted as a proxy for a cost-based rate determination Non-Firm distribution charges. However, in the settlement of Docket 4323 the Settling Parties agreed that the Company "*would submit an allocated cost of service study in its next base-rate proceeding, which details the allocations of its full costs of service to all classes with Non-Firm service shown as a separate class* …" The Division supported that element of the settlement as a means of establishing at least some cost basis for the Company's Non-Firm rate determinations in Docket No. 4323, while providing for Non-Firm rate determinations in subsequent cases that would be less arbitrary and have more clearly discernible cost foundations.

Q. HOW SHOULD THE COMPANY'S CHARGES FOR NON-FIRM SERVICE CUSTOMERS BE DESIGNED?

A. If there is an increase in the approved revenue requirement for Non-Firm Service customers, any such increase should be recovered through proportional adjustments to the existing Distribution Charges for Non-Firm Sales Service (Rate 60) and Non-Firm Transportation Service (Rate 61). Given that the Company's customer charges already appear to be well in excess of its customer costs, no increase in the monthly Customer Charges for Non-Firm Service customers is warranted. I also encourage the Commission to retain the existing Tiered Customer Charge structures for Non-Firm Sales and Non-Firm Transportation Services at least until the merits of encouraging greater participation in Non-Firm Service rate offerings are more fully explored.

3. Bill Impact Analysis

Q. DO YOU FIND THE ASSESSMENT OF BILL IMPACTS PRESENTED IN SCHEDULE PMN-8 REASONABLY INDICATIVE OF THE COST INCREASES THAT NATIONAL GRID'S RHODE ISLAND RATEPAYERS WILL EXPER-

IENCE IF THE COMPANY'S REQUESTED REVENUE INCREASE IN THIS PROCEEDING IS APPROVED?

A. No. I do not. Witness Normand's assessment of bill impacts includes consider-ation of GCR and DAC charges. Yet, the GCR and DAC charges that will be applicable during most of the Rate Year ended August 31, 2019, have not been established and will not become effective until November 1, 2018. As previously noted herein, substantial deferred gas costs balances (not identifiable at the time of the Company's filing in this proceeding) are now expected to be added to the Company's gas cost recovery requirements for its next GCR year, and those deferred GCR balances will amplify the bill increases that the Company's Gas Sales Service customers will experience. Likewise, at this point no basis has been established for assessing the level of RDM charges that will be applicable during the Rate Year.

The Commission should also recognize that the assessments of rate impacts presented in Schedule PMN-8 for C&I classes are only applicable to C&I customers who utilize the Company's Sale Service. C&I Transportation Service customers obtain their gas supplies through competitive markets, and there is no reason to believe that the gas supply costs incurred by those customers are reasonably or appropriately reflected by bill impact analyses that are premised on the Company's GCR charges. In future base rate, DAC, and ISR proceedings, rate impacts for C&I Transportation Service customers should be shown separ-ately without consideration of gas costs.

E. Administrative Fees

Q. DOES THE COMPANY PROPOSE CHANGES IN ITS ADMINISTRATIVE FEES IN THIS PROCEEDING?

A. Yes. The Company's proposed changes in Administrative Fees[21] are set forth in a new, separate item within Section 1, General Rules and Regulations, Schedule A, Sheet 12, Item 12, as "Administrative Fees and Charges." Support for the proposed Administrative Fees and Charges is presented in Schedule PP-3, as well as in National Grid's response to Division Data Request 7-34 and associated attachments 7-34-1 through 7-34-5. Included among the proposed fees and charges are:

- Account Restoration Fees (Gas and Electric),
- IP Wireless Fees (Gas and Electric),
- Returned Check Fees (Gas and Electric),
- Lighting Service Fee (Gas only),
- Off-Cycle Metering Fees,
- Enhanced Metering Fees (Electric)
- Line Extension Fees (Electric)

[21] The Company's proposed tariff references uses the phrase "Administrative Fees and Charges." However, the same fees are referenced in Schedule PP-3 as "Miscellaneous Fees." For clarity and consistency with the Company's tariff, this testimony uses the phrase "Administrative Fees."

Although my focus is on National Grid's gas service offerings, I will address the Company's development of comparable electric service fees where I believe such comparisons are instructive.

Q. ARE THERE ANY OF THE PROPOSED MISCELLANEOUS FEES WITH WHICH YOU TAKE ISSUE?

A. Yes. I have concerns regarding the Company's support for its proposed Return Check Fees, its proposed IP Wireless Fees[22] for gas service customers, and its proposed Paperless Billing Credit. I also have some concern regarding the magnitude of the Company's proposed increase in its proposed Account Restoration Charge for gas service.

1. *Returned Check Fees*

Q. WHAT ARE YOUR CONCERNS WITH RESPECT TO RETURNED CHECKS FEES THAT ARE PROPOSED IN SCHEDULE PP-3(C)?

A. My concerns are twofold. First, although the data used to compute the proposed returned check fees for gas and electric service are virtually identical. They produce different total costs. Second, the Company has inexplicably truncated its computed cost per return check rendering a proposed fee that is more than 13% below its computed costs.

[22] The IP Wireless Fees developed in Schedule PP-3(b) of the Company's filing are presented in National Grid's proposed Gas Service Tariff as "Daily Metered Equipment Fees" and "Daily Metered Data Plan Fees" in Section 1, General Rules and Regulations, Schedule A, Sheet 12, Item 12.

Q. WHAT IS THE DIFFERENCE BETWEEN NATIONAL GRID'S COSTS FOR RETURNED CHECKS FOR ELECTRIC SERVICE AND FOR GAS SERVICE?

A. In its development of costs for Gas Returned Checks, Schedule PP-3(c), page 1 of 2, reflects $11,844 of costs for Internal Labor which includes $6,948 for Base Labor and $4,896 for Labor Overheads. However, in Schedule PP-3(c), page 2 of 2, the same Base Labor cost is found, but the charge for Labor Overheads is listed as zero dollars. No explanation is offered for the observed difference, and since the Base Costs are identical, the omission of Labor Overheads in the development of the costs for Electric Returned Checks appears to reflect an inadvertent error.

Q. IF LABOR OVERHEAD COSTS ARE INCLUDED IN RETURNED CHECK COSTS FOR BOTH GAS AND ELECTRIC SERVICE, WHAT ARE THE RESULTING COSTS PER RETURNED CHECK?

A. For both Gas and Electric Returned Checks, the computed cost per returned check is **$7.95**. This is confirmed in National Grid's response to Division Data Request DIV 7-38e. In that response National Grid verifies that its returned check costs equate to $7.95 per returned check, but then it explains "*the Company truncated the calculation of the proposed fee [to $7.00] in order to result in an easily reference amount in whole dollars*."

Q. DO YOU BELIEVE IT IS APPROPRIATE TO TRUNCATE THAT COMPUTED CHARGE TO $7.00 PER RETURNED CHECK AS NATIONAL GRID PROPOSES?

A. No. I do not. The appropriate charge is $7.95 per returned check. If the Company wanted "*an easily referenced amount in whole dollars*," the more appropriate step would be to round that charge to $8.00 per returned check. I would not have a significant problem if the Company rounded the charge upward in that manner. However, I believe that a cost-based charge of $7.95 per returned check would equally understandable for customers. Truncating the computed $7.95 cost per return check to $7.00 would yield a noticeable (13.6%) under collection of the Company's identified costs and is not justified.

Q. HAS NATIONAL GRID PROPERLY ASSESSED THE REVENUE THAT WOULD BE GENERATED BY ITS PROPOSED RETURNED CHECK CHARGE FOR GAS SERVICE?

A. No. As shown in Attachment DIV 7-34-3 at line (27), National Grid has computed its test year Returned Check Charge revenue for gas service based on 4,248 annual returned items. This number appears low and understates a reasonable assessment of Returned Check Charge revenue going forward. The data provided in National Grid's response to Division Data Request DIV 7-23c. show the numbers of gas returned checks for the last three calendar years. Those are as follows:

Table 3

Retuned Check Items by Year

Calendar Year	Returned Check Items
2015	4,530
2016	4,835
2017	5,254

The reported actual numbers of gas returned checks are all in excess of the 4,248 gas returned checks reflected in the Company's calculated gas Returned Check Charge revenue. The average for the three most recent calendar years is 4,873 gas returned items. However, the last three years of data also shows noticeable annual growth in the numbers of gas returned checks. The average annual growth rate in the numbers of gas returned checks over the three years shown above is 7.69% per year. Applying that growth rate, it appears that a more accurate representation of expected returned checks for the twelve months ended August 31, 2019 is **5,982** returned items. That is 40.8% above the level assumed by National Grid. Use of this higher level of returned checks for the future test year will increase projected revenue levels proportionally upward for any established level for the gas returned check charge.

Q. WHAT LEVEL OF GAS RETURN CHECK CHARGE REVENUE WILL THE DIVISION'S RECOMMENDED RETURNED CHECK CHARGE OF $7.95 PER RETURNED CHECK GENERATE?

A. Using the Company's representation of Test Year gas returned items a returned check charge of $7.95 would yield $33,884 annually. If the Division's estimate of **5,982** gas returned items for the twelve months ended August 31, 2019 is used, the annual revenue would be **$47,557**.

2. *IP Wireless Fees*

Q. SHOULD THE COMMISSION ACCEPT NATIONAL GRID'S PROPOSED IP WIRELESS FEES AS PRESENTED?

A. No. I find the proposed IP Wireless Fees (a.k.a. Daily Metered Fees) that National Grid proposes inappropriate and not well supported. I, therefore, urge the Commission to carefully and critically review the proposed fees, in terms of: (1) reasonableness and equity of charging customers the proposed up-front lump sum fee for an IP Wireless Device; (2) the accuracy and reliability of the underlying cost data from which the proposed fees are computed; and (3) consistency of the proposed charge with other elements of the Company's tariff and pricing practices.

Q. IS THE COMPANY'S PROPOSAL TO CHARGE CUSTOMERS REQUIRING TELEMETERING A ONE-TIME LUMP SUM FEE FOR THE COST OF AN IP WIRELESS DEVICE REASONABLE?

A. No. Except for new customers added to the affected rate schedules, all FT-1 Firm Transportation Service customers and Non-Firm Service customers should already have telemetering equipment in place, and those existing customers should have already paid a one-time fee for the installation of telemetering equipment. Charging those customers a second "one-time" fee as part of the Company's decision to convert to a new technology is not appropriate.

Furthermore, the IP Wireless Devices National Grid seeks to install are essentially a form of Advanced Metering Infrastructure (i.e., "AMI" or "Smart Metering") for gas service. As such I find no reason why the costs of that equipment cannot be treated like other forms of Smart Metering and included in the Company's rate base, as opposed to being recovered through a one-time charge. If the costs of the referenced IP Wireless Device are included in National Grid's gas rate base, the costs of that equipment can be recovered over the useful life of the equipment. Moreover, those costs can be directly assigned to classes using that technology and recovered through monthly customer charges assessed to those classes. Accepting arguendo the Company's estimate of the installed cost for an IP Wireless Device and assuming a ten year useful life for that equipment, the estimated incremental monthly cost for the use of such devices would be in the range of $12. That would represent a comparatively small adder to the current monthly customer charges for the affected classes.

Q. IS THE COST SUPPORT FOR NATIONAL GRID'S PROPOSED IP WIRELESS FEES REASONABLE AND APPROPRIATE?

A. No. I find key elements of the supporting data for both the proposed IP Wireless Device and the fee for the monthly Data Plan questionable.

Schedule PP-3(b) suggests that the incremental cost of "Meter Equipped with a Wireless Module" is $1,035. Supporting workpapers provided in response to Division Data Request 7-34, as Attachment 7-34-4, page 2 of 2, indicates that the "Device, a "Honeywell Wireless Module (CNI4)" has a cost of $1,000. Incremental costs for installation parts account for the other $35 of the amount cited in Schedule PP-3(b). The cited $1,000 per unit cost of the Honeywell Wireless Module (CNI4) appears to be at best a very rough estimate of the purchase cost for such a unit. The Division has an outstanding follow-up data request which seeks greater support for the cited $1,000 cost, but it appears that cost may not be appropriately cost-based. Further, the labor overhead rate applied to the installation labor costs for this IP Wireless Device is 95.88%. As developed by the Company in Attachment DIV 7-34-5 the referenced 95.88% labor overhead rate is for Capital. However, the Company has indicated its plan to assess customers a one-time lump-sum fee for this equipment. Thus, the module will not be capitalized, and the Company's use of a 95.88% labor overhead rate should be questioned. In addition, the Company's response to Division Data Request DIV 7-37.d.3. indicates the estimated time for an IP Wireless Device installation is 2.667 hours based on its assessment that on average a technician can complete three telemetering installations in one eight-hour day. Yet, the Company arbitrarily rounds that estimate upward to three hours per installation. That adds unnecessary incremental labor costs and overheads to the overall costs the Company seeks to bill customers for an IP Wireless Device installation.

Schedule PP-3(b) also indicates that the proposed $17 annual cost for an "IP Wireless Data Plan" represents a weighted average cost for a "Low End" data plan and a "High End" data plan. However, the derivation of the costs cited by the Company for the Low End and High End data plans is unclear. Attachment DIV 7-37 purportedly represents the source of the Data Plan costs cited by National Grid in Schedule PP-3(b). Attachment DIV 7-37 provides information regarding three Verizon Wireless Data Plans, but the monthly fees for the plans presented in that attachment do not correspond to the fees National Grid has used to compute its proposed Data Plan charges. Moreover, each of the plans cited is a "Shared" data plan, but according to National Grid, each electric and/or gas service meter "*will require a separate data plan*."[23] Thus, apparently no sharing of data services will be permitted by National Grid, despite allowances for data sharing under the cited Verizon Wireless Data Plans.

[23] National Grid's response to Division Data Request 3-37.d.4.

As noted in the Company's response to Division Data Request 7-31.c. and 7-31.e., the contract for wireless data services is between National Grid U.S.A. and Verizon Wireless. FT-1 Transportation Service customers (and presumably Non-Firm Service customers) in Rhode Island who use the referenced IP Wireless Devices and data plans, would not have the option of installing their own equipment and/or contracting for their own wireless data plans. Still, National Grid will have multiple customers and multiple devices served under the National Grid – Verizon contract. This suggests the actual costs National Grid or its parent (National Grid U.S.A) will incur could be considerably less than those the Company proposes to bill its customers. Attachment DIV 7-37 suggests that for a cost of just $14.00 per month, or $168.00 per year, the Company could obtain a plan for 1 gigabyte (1 GB) of shared data, and that would probably represent more data than all of the Company's FT-1 and Non-Firm customers combined would require. Yet, that cost is less than the charges National Grid would assess for just 10 customers with IP Wireless data plans. Thus, many elements of National Grid's proposed IP Wireless fees warrant further investigation before such charges would warrant inclusion in the Company's tariff.

Q. DO YOU HAVE ANY FURTHER OBSERVATIONS REGARDING THE COMPANY'S PROPOSED COSTS FOR IP WIRELESS DATA PLANS?

A. Yes, I do.

First, the Company's response to Division Data Request 7-37.d.6. suggests that its weighting of Low End and High End data usage requirements is based on "*actual cost information on a number of existing meters in other National Grid service territories having IP wireless devices*," but none of that actual data from other National Grid service territories has been provided.

Second, given the Company's estimate that the data requirements for 85% of affected customers are less than one megabyte (1 MB) per month, the application of a weighted average cost of $1.46 per month as opposed to the low-end data plan rate appears inappropriate. Data requirements for the Company's billing requirements should be fairly uniform. Thus, it would appear that higher levels of data usage would only be applicable where the customer uses the device for its own data gathering or transmission purposes. If that is accurate, then only those customers who require higher levels of data usage should pay the added costs for larger data plans. Importantly, where customers do not have opportunities to use competitive services, the Company's charges should be more tightly tied to its costs, and the provision of IP wireless equipment and services should not be source of incremental profit for the Company.

Q. WHY DO YOU QUESTION THE CONSISTENCY OF NATIONAL GRID'S APPLICATION OF THE PROPOSED IP WIRELESS DEVICE FEES?

A. First, the Company includes telemetering requirements in its proposed tariff in for three classes of customers: (1) three **Non-Firm Sales** Service, Rate 60;[24] Non-Firm Transportation Service, Rate 61,[25] and Firm FT-1 Transportation Service.[26] In the Company's proposed tariff, Section 5, Commercial and Industrial Services, Schedule G, Sheet 4, Item 8.0 offers customers who wish to use Non-Firm Sales Service the option of us using Wireless communications or telemetering equipment. However, for Non-Firm Transportation Service, Rate 61, simply states that "*Telemetering equipment is required*," and makes no explicit reference to use of Wireless communications. Section 6, Non-Firm Transportation Service, Schedule A, Sheet 3, Item 6.0, Rate 61, indicates "*the customer may have access to the telemetering equipment for data gathering and transmission*,"[27] but similar references to customer access to telemetering equipment for data gathering and transmission are not found in the Company's proposed tariff provisions for Firm FT-1 Transportation Service or Non-Firm Sales Service.

[24] National Grid's proposed Gas Tariff, Book 15 of the Company's November 27, 2017 Application and Supporting Testimony and Schedules, Section 5, Commercial and Industrial Services, Schedule G, Sheet 4, Item 8.0.

[25] National Grid's proposed Gas Tariff, Section 6, Non-Firm Transportation Service, Schedule A, Sheet 3, Item 6.0.

[26] National Grid's proposed Gas Tariff, Section 6, Transportation Services, Schedule C, Sheet 1, Firm Transportation Service, Item 2.02.

[27] National Grid's proposed Gas Tariff, Book 15 of the Company's November 27, 2017 Application and Supporting Testimony and Schedules, Section 6, Non-Firm Transportation Service, Schedule A, Sheet 3, Item 6.0.

3. <u>Paperless Billing Credit</u>

Q. DO YOU SUPPORT COMMISSION APPROVAL OF THE PROPOSED INCREASE IN NATIONAL GRID'S PAPERLESS BILLING CREDIT?

A. The proposed increase in National Grid's Paperless Billing Credit is only $0.03 per paperless bill per month (i.e., and increase from $0.34 to $0.37). In concept, I find the idea of recognizing cost savings associated with the provision of paperless bills reasonable. However, from a practical perspective the credit computed by National Grid is sufficiently small that it has no meaningful impact on customers' bills.

The entire credit, much less the small proposed increase in the credit, is not consequential for even the smallest of customers. Thus, the offering of this credit is more symbolic than substantive. On an annual basis, the proposed paperless billing credit equates to only $4.44 per year where the average Residential Non-Heating customer is shown in the Company's bill comparisons as having an annual bill at current rates of $454.87. In other words, the proposed paperless billing credit represents less than one-percent of a Residential Non-Heating customer's annual charges. The proposed Paperless Billing Credit is also dwarfed by other rate adjustments that have recently been approved (e.g., Interim GCR rate adjustments and ISR charges) and other adjustments that may be anticipated between now and the end of the Rate Year. In this context, I find that little is accomplished through the offering of this credit, and at least some of the perceived benefit may be offset by increased costs associated with tracking and reporting the revenue impacts of such credits. Thus, the Commission should view continuation of this credit as discretionary.

4. <u>Gas Account Restoration Fees</u>

Q. DOES NATIONAL GRID PROPOSE TO INCREASE ITS GAS ACCOUNT RESTORATION FEE?

A. Yes. The Company's current account restoration fee for gas service customers is $25.00. National Grid asks for authorization to increase that charge to $96.00. That represents an increase of $71.00 per restoration, and it equates to a 284% increase.

Q. HOW DOES THE COMPANY'S PROPOSED GAS ACCOUNT RESTORATION FEE COMPARE TO IT ACCOUNT RESTORATION FEE FOR ELECTRIC SERVICE?

A. For electric service the Company's current account restoration fee is $39.00, and National Grid proposal in this case is to reduce its current fee to $32.00. As a result, the proposed Gas Account Restoration Fee will be **three times** the level of its proposed Electric Account Restoration Fee.

Q. HAVE YOU REVIEWED THE COST SUPPORT OFFERED FOR THE COMPANY'S PROPOSED GAS AND ELECTRIC ACCOUNT RESTORATION FEES?

A. I have. Support for National Grid's proposed increase in its Gas Account Restoration charges is found in Schedule PP-3(a), page 1 of 2, and further detailed in the Company's response to Division Data Request DIV 7-34, and Attachment 7-34-4.

Q. SHOULD THE PROPOSED INCREASE IN GAS ACCOUNT RESTORATION CHARGES BE APPROVED AS PRESENTED?

A. No. Although the Company's analysis, with which I have no substantial issues, supports the proposed increase, I would encourage the Commission to approve a lesser increase in this proceeding. The rationales for my position are threefold. First, there is nothing that indicates that the Company's costs for Gas Account Restoration have suddenly increased. Rather, it appears the Company's costs for account restorations have long exceeded the revenue generated by its Gas Account Restoration Fee. Although I generally support the establishment of cost-base charges for such activities, I do not find a compelling argument for attempting to eliminate the substantial gap between costs and revenues associated with gas account restorations through a large one-time adjustment to the current fee. Rather, an argument can be made for more gradual adjustment of this fee. Second, customers who are assessed account restoration fees are generally customers who already have bill payment problems. The imposition of the proposed $96.00 fee for Gas Account Restoration on such customer may serve to further burden individuals who already are likely to have limited financial resources. From this perspective, a fee that is beyond a customer's ability to pay may simply add to future uncollectible accounts expenses and is not necessarily productive.

For these reasons, I suggest that the Commission should consider setting the proposed Gas Account Restoration Charge at $40.00. This would signal that gas account restoration costs are greater than those for electric account restorations, but would not be as dunning for payment troubled individuals as the proposed $96.00 charge. Of course, the suggested $40.00 charge reflects an arbitrary determination, and I would be open to consideration of other alternatives.

F. Other Tariff Change Proposals

Q. DOES NATIONAL GRID PROPOSE OTHER TARIFF CHANGES THAT YOU WISH TO ADDRESS?

A. Yes. In addition to rate design changes, changes in Administrative Fees, and minor editorial changes, National Grid seek Commission approval of a number of more substantive changes to its gas tariff. Among the changes presented are:

- The establishment of a separate Schedule of Administrative Fees and Charges;

- The addition of new language for low-income customer assistance and recovery of costs for such assistance;

- Changes to several elements of its Distribution Adjustment Clause (Tariff Section 3);

- Introduction of a new section of the tariff for Service and Main Extension Policies (Section 8).

The Company's proposed Administrative Fees were addressed in the previous section of this testimony. In addition, I have reviewed National Grid's proposed tariff changes relating to its restructured low-income assistance programs, and I have no problems with the language proposed for implementation of those restructured programs. Thus, the remainder of this section will focus on elements of the last two items listed above, i.e., changes in the DAC and the Company new tariff section for Service and Main Extension Policies.

1. Distribution Adjustment Clause (DAC)

Q. ARE NATIONAL GRID'S CHANGES TO ITS DISTRIBUTION ADJUSTMENT CLAUSE EXTENSIVE?

A. Yes. The provisions of the Company's DAC, tariff Section 3, are the most heavily edited provision of the Company's existing tariff sections. However, most of the proposed changes simply update the tariff to reflect changes in practices and/or calculations that have been adopted since the Company's last general rate proceeding.

Q. OF THE CHANGES PROPOSED TO THE COMPANY'S DISTRIBUTION ADJUSTMENT CLAUSE, DO ANY WARRANT PARTICULAR ATTENTION?

A. Only two items. The first relates to the Company's proposed language for the annual determination of its System Pressure Factor. The second involves the manner in which transfers of customers between rate classes are considered in allocations of ISR costs and the determination of Revenue Decoupling Adjustments.

a. System Pressure Factor

Q. HOW DOES THE COMPANY'S PROPOSED SYSTEM PRESSURE FACTOR DETERMINATION READ?

A. The language National Grid proposes for System Pressure Factor determinations reads as follows:

> *The System Pressure factor shall be computed annually and shall be based on a forecast of gas supply costs that are required to maintain pressure on the Company's distribution system*.[28]

The Company's proposed language for System Pressure Factor determinations is intended to replace an outdated formula for those determinations that currently is included in DAC. However, I am concerned that the language the Company proposes is inconsistent with the position the Division presented and the Company accepted in National Grid's most recent DAC proceeding, Docket No. 4708. As reflected in National Grid's "Reply Comments" in Docket No. 4708:

> National Grid agrees to **allocate 100% of the demand costs associated with Crary Street deliveries to the DAC**. As the Division's Comments point out, the transfer decreases National Grid's projected 2017-18 GCR factors and increases the 2017-18 DAC factors, but the total costs recovered by National Grid through its combined GCR and DAC factors are unaffected. See Division's Comments at 2. **In addition,** as requested by the Division, prior to next year's DAC filing **National Grid will provide the Division with further clarification of costs incurred to maintain system pressure to other parts of the Rhode Island distribution system, to determine the extent to which such costs warrant incorporation in the System Pressure Factor**.[29]

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[28] National Grid's proposed Gas Tariff, Section 3. Distribution Adjustment Charge, Schedule A, Sheet 3, Item 3.1 System Pressure Factor.

[29] National Grid, Reply Comments, filed October 23, 2017, at page 1.

My concern is that the System Pressure Factor language proposed by National Grid does not explicitly embrace either of the two key elements of the Company's position in its Reply Comments in Docket No. 4708. Those are: (1) allocation to the DAC of 100% of the demand costs associated with Crary Street deliveries; and (2) further investigation and delineation of costs incurred by the Company to maintain system pressure in other parts of the Company's distribution system (i.e., areas not directly served by the Crary Street gate station).

Q. DO YOU OFFER ALTERNATIVE LANGUAGE FOR SYSTEM PRESSURE FACTOR DETERMINATIONS UNDER THE DAC?

A. Yes, I recommend Commission adoption of the following language for System Pressure Factor determinations:

> *The System Pressure factor shall be computed in a manner that identifies and includes all fixed and variable gas supply costs required on an annual basis to maintain pressure within the Company's distribution system and shall identify and consider all gas supply costs that are required to maintain pressure for all portions of the Company's distribution system*.

b. Adjustments for Customer Transfers

Q. HOW DO TRANSFERS OF CUSTOMERS BETWEEN RATE SCHEDULES IMPACT DAC DETERMINATIONS?

A. Between general rate proceedings, transfers of customers transfer from one rate schedule to another can cause cost allocation relationships established in the Company's last base rate case to produce distorted and inappropriate results. Customer transfers between the Residential Non-Heating and Residential Heating classes have been a particular concern over the last few years in terms of the impacts of those transfers on allocations of ISR costs and the determination of revenue decoupling adjustments.

Q. DOES THE COMPANY'S CURRENT TARIFF PROVIDE ANY GUIDANCE WITH RESPECT TO THE MANNER IN WHICH THE IMPACTS OF CUSTOMER TRANSFERS SHOULD BE RECOGNIZED IN DAC DETERMINATIONS?

A. No. At present the Company's Gas Tariff is mute on the issue. For example, Section 3, Schedule A, Sheet 6, Item 3.2, Infrastructure, Safety and Reliability Factor, provides, "*The Company shall allocate the Cumulative [ISR] Revenue Requirements to its rate classes based on the rate base allocation approved by the PUC in the Company's most recent general rate proceeding*.." The impacts of potential customer transfers are not addressed. Yet, as noted above, recent customer transfers between the Company's Residential Non-Heating and Residential Heating customer classes have had noticeable impact on the reasonableness and equity of cost allocations within the DAC mechanism.

2. Service & Main Extension Policies

Q. WHAT IS YOUR ASSESSMENT OF THE NEW SECTION THAT NATIONAL GRID SEEKS TO ADD TO ITS GAS TARIFF FOR SERVICE AND MAIN EXTENSION POLICIES?

A. Several elements of the proposed tariff Section 8, or Service and Main Extension Policies are not new. Rather, they primarily reflect provisions relocated from Section 1, General Terms and Conditions, of the Company's gas tariff. In that context, many of the provisions contained in the proposed tariff Section 8 represent policies previously accepted by this Commission. In general, it is not the intent of this testimony to challenge such previous determinations. Still, there is one element of the proposed Section 8 that warrants further consideration. That provision relates the Company's refund of excess CIAC payments.

Q. PLEASE EXPLAIN YOUR CONCERNS REGARDING THE PROPOSED TARIFF LANGUAGE RELATING TO REFUNDS OF EXCESS CIAC PAYMENTS?

A. As proposed, Section 8, Schedule A, Item 6.5.2., provides that where engineering estimates are relied upon as the basis for determining CIAC payment amounts, customers will only be refunded a difference between the engineering estimate and the actual cost if that difference exceeds "the greater of (a) $1,000 or (b) 10% of the engineering estimate. I find that threshold for refunding excess CIAC assessments in appropriately high. I submit that a more appropriate threshold for refunds would be $100. The Company's retention of an extra $1,000 or 10% of a project's costs may not represent a large amount to the Company, but it may be significant for individual customers. Again, CIAC payments should be cost-based assessments, and the Company should not be incented through the retention of excess payments to over-estimate project costs.

G. Other Issues

1. Consolidation of Residential ISR Charges

Q. WHY IS YOUR TESTIMONY IN THIS PROCEEDING ADDRESSING THE COMPANY'S CONSOLIDATION OF RESIDENTIAL ISR CHARGES?

A. The data and allocations procedures the Company presently uses to re-compute its ISR charges on an annual basis were first established in the Company's last base rate case, Docket No. 4323. Moreover, the concerns expressed by the Company in Docket No. 4781 in support of its proposal to consolidate its ISR charges for Residential Heating and Residential Non-Heating customers related directly to the outdated nature of relationships established in Docket No. 4323. In that context, and considering the more current information being presented in this docket, the Division felt that issues regarding the Company's consolidation of

ISR charges for its Residential classes would be more appropriately addressed in this proceeding.

Q. DO YOU SUPPORT NATIONAL GRID'S CONTINUED USE OF A SINGLE ISR RATE FOR ALL OF ITS RESIDENTIAL CUSTOMERS?

A. No. I agree with National Grid that the relationships established for ISR rate determinations in Docket No. 4323 are no longer appropriate, but I do not agree that consolidation of ISR charges for Residential Heating and Residential Non-Heating customers is a reasonable or appropriate approach to resolving the problems the Company observed when it recommended consolidation of Residential ISR charges.

Q. WHAT IS NATURE OF THE PROBLEM THAT LED NATIONAL GRID TO PROPOSED CONSOLIDATION OF ITS RESIDENTIAL ISR CHARGES?

A. In Section 4: Rate Design and Bill Impacts in the Company's FY 2019 Gas Infrastructure, Safety, and Reliability Plan, in Docket No. 4781, National Grid indicates that it proposed the consolidation of Residential Non-Heating and Residential Heating ISR revenue requirements, "*due to recent transfers of Residential Non-Heating customers to the Residential Heating classes*." The Company further explains that as a result of such transfers the number of Residential Non-Heating customers has declined by over 20% causing the rate base allocator for the Residential Non-Heating class that was established in

Docket No. 4323 to no longer be representative of the number of customers currently receiving service under Residential Non-Heating rates.

Q. DO YOU AGREE THAT TRANSFERS OF SIGNIFICANT NUMBERS OF CUSTOMERS FROM RESIDENTIAL NON-HEATING SERVICE TO RESIDENTIAL HEATING SERVICE HAVE CAUSED THE RATE BASE ALLOCATORS ESTABLISHED FOR THE RESIDENTIAL NON-HEATING CLASS IN DOCKET NO. 4323 TO NO LONGER BE REPRESENTATIVE OF THAT CLASS?

A. I do. In fact, I have addressed related issues in several prior DAC and GCR proceedings.

Q. DID THE RESOLUTION OF SUCH ISSUES IN THOSE PRIOR PROCEEDINGS INVOLVED COMBINING CHARGES FOR THE COMPANY'S RESIDENTIAL NON-HEATING AND RESIDENTIAL NON-HEATING CLASSES?

A. No. In those proceedings, the problem was generally addressed through making adjustments to allocations or forecasts to better reflect the changed composition of the Residential Non-Heating and Residential Heating classes. This form of explicit recognition and adjustment for customer transfers is found in the Company's past Annual RDM and DAC filings[30]

[30] See, for example, Schedule PP-1(2c)-GAS, page 5 of 5, in this proceeding, as well as Schedule AEL-4 in National Grid's June 30, 2017 Gas Revenue Decoupling Mechanism Reconciliation filing and Schedule SLN-4 in National Grid's June 30, 2016 Gas Revenue Decoupling Mechanism Reconciliation filing.

Q. WHAT WAS THE REASON FOR THE CUSTOMER TRANSFERS THAT CAUSED TO OBSERVED REDUCTION IN THE NUMBER OF RESIDENTIAL NON-HEATING CUSTOMERS?

A. The referenced transfers were the result of the Company's identification of significant numbers of Residential customers that were misclassified as Non-Heating customers. Customers that use gas for domestic space heating purposes typically have a noticeably higher percentage of their total annual gas use during peak winter months. Thus, misclassified customers were identified on the basis of their load characteristics. Where a customer was found to have gas use patterns that were reflective of Residential Heating service requirements, the Company flagged the customer for transfer to Residential Heating Service.

Q. WHY IS THE RE-CLASSIFICATION OF RESIDENTIAL NON-HEATING CUSTOMERS TO THE RESIDENTIAL HEATING SERVICE CLASS IMPORTANT?

A. It underscores the fact that the basic service characteristics of Residential Non-Heating customers and Residential Heating customers are distinct and separately identifiable. National Grid's costs of serving its Residential Non-Heating and Residential Heating rate classes are **not uniform** or even reasonably similar. Thus, consolidation of ISR charges for National Grid's residential classes may be administratively convenient, but it is not consistent with, or reflective of, cost-based ratemaking principles.

Q. HAS NATIONAL GRID DOCUMENTED THE REFERENCED CUSTOMER TRANSFERS FROM RESIDENTIAL NON-HEATING TO RESIDENTIAL HEATING IN THIS PROCEEDING?

A. Yes. The numbers of customers transferred from Residential Non-Heating Service to Residential Heating Service are shown by month and by year of transfer in Schedule PP-1(c)-Gas, page 5 of 5, lines (3) through (5) and lines (11) through (13). Overall the number of customers for the Residential Non-Heating class has been reduced by 16.3% as a result of the identified numbers of customer transfers.[31]

2. <u>O&M Costs to Assigned GCR</u>

Q. WHAT IS THE CURRENT AMOUNT OF O&M COSTS DESIGNATED FOR RECOVERY THROUGH THE COMPANY'S GAS COST RECOVERY ("GCR") MECHANISM?

A. National Grid's current GCR charges are premised on recovery of **$575,581** of "Supply Related LNG O&M Costs."[32]

Q. WHAT IS THE AMOUNT OF O&M COSTS THE COMPANY DESIGNATES FOR RECOVERY THROUGH THE GCR IN THIS PROCEEDING?

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[31] This is less than the 20% reduction in Residential Non-Heating customers the Company referenced in its FY 2019 ISR filing, Section 4: Rate Design and Bill Impacts, page 1 of 2.

[32] Attachment AEL-1S filed in Docket No. 4719 on September 29, 2017, page 2 of 15, line (8).

A. Schedule MAL-32, page 6 of 6, in this proceeding details "GCR-Related Operations & Maintenance" expenses totaling $1,088,655 for the Test Year, and $1,308,279 for the Rate Year. The Rate Year GCR-Related O&M expense shown in Schedule MAL-32 represents an increase of **$725,698** or **127.3%** over the level currently included in National Grid's GCR charges.[33] .

Q. HAS THE COMPANY EXPLAINED OR JUSTIFIED THE INCREASE IN COSTS ASSIGNED TO THE GCR IN THIS CASE?

A. No, it has not. Schedule MAL-32 details the components of the Company's Test Year and Rate Year GCR-Related O&M expenses, but it does not explain the causes of those increases included therein. The Test Year costs alone represent an **89%** increase over the levels presented in Docket No. 4323 and currently included in National Grid's GCR charges, and that 89% increase is not explained. Likewise, the Company's Rate Year cost claim includes an unexplained **25% increase in Labor Costs**.

Q. WHY ARE THESE COSTS THAT ARE EXCLUDED FROM THE COMPANY'S REVENUE REQUIREMENT IN THIS PROCEEDING OF CONCERN?

A. As reflected in the Company's Annual GCR filings, National Grid has relied upon its assignments of costs in prior base rate proceedings as the basis for the

[33] The Commission should note that National Grid's Interim GCR filing on January 29, 2018, included no increase in its Fixed Cost Factor and no increase in Supply Related LNG O&M Costs. See Attachment AEL-2, January 29, 2018, page 4 of 9, line (63), Col. (m) which shows the same $575,581 amount for Supply Related LNG O&M Costs that was presented in Attachment AEL-1S filed in Docket No. 4719 on September 29, 2017, page 2 of 15, line (8).

Supply Related LNG O&M Costs that it is permitted to recover in GCR proceedings. However, the determination of an appropriate level of Supply Related LNG O&M Costs for recovery through future Annual GCR filings is complicated by considerations relating Cumberland Tank replacement costs. The Division is concerned that the large increases observed in National Grid's Test Year and Rate Year GCR Related O&M costs are heavily influenced by costs incurred by the Company as part of its efforts to compensate for the unanticipated closure of its Cumberland LNG Tank. The inclusion of such replacement costs in future GCR costs based on the limited evidence presented by the Company in this proceeding is problematic are problematic for two reasons. First, the Commission needs to clearly establish that nothing in this proceeding should dictate the level of Supply Related LNG O&M Costs recovered the GCR charges as part of future GCR. Second, the Company has not established that the level of GCR-Related O&M expenses that it has assigned to the GCR in this proceeding is indicative of an on-going level of expense. As the Company develops and implements a long-term solution for replacement of its Cumberland LNG Tank and its peaking supply capabilities, the Commission may anticipate that at least some of these expenses will no longer be incurred.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. However, I reserve the right to file supplemental testimony to address updates to National Grid's Gas schedules filed on April 3, 2017.

BRUCE R. OLIVER

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EXPERIENCE

Over 40 years of experience specializing in the areas of utility rates, energy, and regulatory policy. Offers unusual depth and breadth in his understanding of energy and utility industries which leads to creative and effective resolution of rate issues. Has presented expert testimony in regulatory proceedings in more than 300 proceedings before regulatory commissions in 24 jurisdictions, and has served a diverse group of clients on issues encompassing a wide range of energy and utility-related activities. Assists clients in the assessment of competitive energy markets for retail services and in the negotiation of contracts for the purchase of such services. Clients have included commercial and industrial energy users, hospitals and universities, state regulatory commissions, utilities, consumer advocates, municipal governments, federal agencies, and suppliers of equipment and services to utility markets.

1985-Present — Revilo Hill Associates, Inc.
President and CEO

Directs the firm's consulting practice, with specialization in the areas of industrial economics, energy, utilities and regulatory policy. Provides expert testimony in regulatory proceedings. Assists individual commercial and institutional customers in the competitive procurement of energy services and resolution of utility service and billing issues. Regulatory work includes participation in electric, gas, water and sewer utility rate and policy matters, with particular specialization in the areas of utility costs of service, rate structure, rate of return, utility planning, and forecasting. Examples of recent projects include:

- Investigation of utility merger issues including ring-fencing, costs to achieve, estimated merger benefits, and allocation of merger benefits among customers for electric and gas utility mergers.

- Investigation of gas utility expansion proposals, tariff changes, and ratemaking mechanism.

- Examination of utility proposals undergrounding overhead electric distribution facilities and the recovery of costs for undergrounding activities.

- Assessment of plans for accelerated replacement of distribution mains by an LDC.

- Evaluation of utility proposals for the deployment of Advanced Metering Infrastructure (AMI) and the development of dynamic pricing rates to be implemented using AMI equipment.

- Assistance to large commercial and institutional utility customers in the procurement of competitive electricity and natural gas services.

- Analysis of utility revenue decoupling proposals including assessment of the cost of service and rate impacts of such proposals and the development of appropriate tariff language for such proposals.

- Investigation of matters relating to a utility outsourcing of significant components of its Administrative and General and Customer Service activities.

- Assessments of a utility's long-range gas supply planning and the prudence of its gas procurement activities.

- Evaluation of the merits of the proposed utility mergers including assessments of impacts on customers and on competition.

- Strategic analysis and policy guidance for a major commercial consumer group in the development and presentation of positions before legislative and regulatory bodies regarding electric and gas regulatory issues.

- Development of Asset Management incentive programs for natural gas distribution utilities.

- Investigation and preparation of a report on the causes of large heating oil price increases for the Attorney General of a New England state.

- Participation as a member of a three-person panel hearing a gas marketer complaint of anti-competitive behavior by a local gas distribution utility in its provision of unbundled gas transportation services.

- Preparation of cost allocation studies and rate structure proposals for electric, gas, water and wastewater utility regulatory proceedings;

- Analysis of proposals for restructuring and the unbundling of rates for local gas distribution companies, and negotiated terms, conditions, and pricing for restructured utility services.

2000-Present AOBA Alliance, Inc.
Director and Chief Economist

Key technical advisor to one of the nation's largest and most successful customer-based energy aggregation programs. Assists non-residential customers in the Washington, D.C. area in the procurement of competitive retail energy services, including the evaluation and negotiation of contract terms for competitive electricity, natural gas, energy information services. Monitors energy markets and keeps participants informed regarding energy market developments and pricing trends. Focused primarily on the commercial building industry, the AOBA Alliance, Inc. serves more than 9,000 electric and natural gas accounts in twelve states and the District of Columbia. Those participants use over 3.0 billion kWh per year and over 660 MW of electrical peak load.

1981-85 Resource Dynamics Corporation
Principal and Vice President

Responsible for the firm's activities in the areas of energy pricing, utility rates and regulatory policy. Provided expert testimony before utility regulatory commissions on issues relating to costs of service, rate design, load management, load research, fuel price forecasting, utility costing analyses, and cost allocation methods. Evaluated utility fuel procurement practices, fuel price forecasts, and price forecasting methodologies. Contributed to modeling efforts relating to the estimation of national and regional electric utility load curves and coal market prices. Participated in the development handbooks for cogeneration feasibility assessment.

1980-81 Potomac Electric Power Company
Manager of Rate Research Department

Directed the development of all rate related programs. Supervised the costing, design and analysis of traditional and innovative rates (including time-of-use, load management and cogeneration tariffs). Also was responsible for corporate revenue forecasting activities, as well as the development of marginal and avoided cost studies.

1979-80 Pacific Gas and Electric Company
Rate Experimentation Supervisor

Responsible for design, implementation and analysis of innovative rate programs for both gas and electric service. Developed programs for curtail-able service; cogeneration; conservation; residential load cycling; and commercial, industrial, and agricultural time-of- use rates. Directed analyses of time-of-use and lifeline price elasticities and development of marginal and avoided costing methods.

1973-79 ICF Incorporated
Project Manager

Specialized in energy policy and utility regulatory analyses. Performed detailed analysis of U.S. petroleum, natural gas, coal and electric utility industries. Provided expert testimony on utility rate issues. Designed experimental rates for federally funded time-of-use rate and load management programs in North Carolina. Provided technical support to the DOE Regulatory Intervention Program. Contributed to the design and development of the National Coal Model, and prepared forecasts of low sulfur fuel availability for utility markets.

1972-73 U.S. Cost-of-Living Council - Pay Board
Labor Economist

Served in the Office of the Chief Economist. Responsible for macroeconomic analyses of Board decisions, and for the development data systems to support assessments of the impacts of Board decisions and the reporting of aggregate statistics on wage increases granted by the Board.

EDUCATION

1972 M.A., Economics, Virginia Polytechnic Institute and State University

1970 B.A., Economics, Virginia Polytechnic Institute and State University

RATE CASE PARTICIPATION

Alberta, Canada

Canadian Western Natural Gas	1998 General Rate Application
NOVA Gas Transmission Ltd.	1995 GRA, Phase II
Canadian Western Natural Gas	Core Market Direct Purchase
Northwestern Utilities	Core Market Direct Purchase
TransAlta Utilities Corp.	Load Retention Rate Offering
Alberta Power Ltd.	1993 General Rate Application

Arizona

Southwest Gas Corporation	Docket No. U-1551-93-272
Sun City Water Company	Docket No. U-1656-91-134

Havasu Water Company	Docket No. U-2013-91-133
Arizona Water Company	Docket No. U-1445-91-227
California	
Pacific Gas & Electric Company	Application No. 58089
Connecticut	
Southern Connecticut Gas Company	Docket No. 89-09-06
Connecticut Light & Power Company	Docket No. 87-07-01
Delaware	
Chesapeake Utilities Corporation	Docket No. 95 - 73
Delmarva Power & Light Company	Docket No. 94 - 141
Delmarva Power & Light Company	Docket No. 94 - 129
Delaware Electric Cooperative	Docket No. 94 - 100
Delmarva Power & Light Company	Docket No. 92 - 85
Delmarva Power & Light Company	Docket No. 92 - 71F
Delaware Electric Cooperative	Docket No. 91 - 37
Delmarva Power & Light Company	Docket No. 91 - 24
Delmarva Power & Light Company	Docket No. 91 - 20
Delmarva Power & Light Company	Docket No. 90 - 31
Delmarva Power & Light Company	Docket No. 90 - 21
Delmarva Power & Light Company	Docket No. 89 - 26
Chesapeake Utilities Corporation	Docket No. 88 - 39F
Delmarva Power & Light Company	Docket No. 88 - 34
Delmarva Power & Light Company	Docket No. 88 - 32, Phase 2
Delmarva Power & Light Company	Docket No. 88 - 32
Delaware Electric Cooperative	Docket No. 87 - 34, Phase 2
Delaware Electric Cooperative	Docket No. 87 - 34
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 5
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 4
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 3
Delmarva Power & Light Company	Docket No. 87 - 9, Phase 2
Delmarva Power & Light Company	Docket No. 87 - 9
Delmarva Power & Light Company	Docket No. 86 - 43
Delmarva Power & Light Company	Docket No. 86 - 24
District of Columbia	
Potomac Electric Power Company	Case No. 1149
Potomac Electric Power Company	Case No. 1145
WGL – AltaGas Merger	Case No. 1142
Potomac Electric Power Company	Case No. 1139
Washington Gas Light Company	Case No. 1137
Potomac Electric Power Company	Case No. 1133
Potomac Electric Power Company	Case No. 1130
Potomac Electric Power Company	Case No. 1121

Exelon – Pepco Merger	Case No. 1119
Potomac Electric Power Company	Case No. 1116
Washington Gas Light Company	Case No. 1115
Potomac Electric Power Company	Case No. 1103
Washington Gas Light Company	Case No. 1093
Potomac Electric Power Company	Case No. 1087
Washington Gas Light Company	Case No. 1079
Potomac Electric Power Company	Case No. 1076
Potomac Electric Power Company	Case No. 1056
Washington Gas Light Company	Case No. 1054
Potomac Electric Power Company	Case No. 1053, Phase II
Potomac Electric Power Company	Case No. 1053
Washington Gas Light Company	Case No. 1016
Potomac Electric Power/Conectiv Merger	Case No. 1002
Washington Gas Light Company	Case No. 989
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Case No. 951
Potomac Electric Power Company	Case No. 945
Potomac Electric Power Company	Case No. 939
Washington Gas Light Company	Case No. 934
Washington Gas Light Company	Case No. 922
District of Columbia Natural Gas	Case No. 890
Potomac Electric Power Company	Case No. 889
Potomac Electric Power Company	Case No. 869
District of Columbia Natural Gas	Case No. 845
District of Columbia Natural Gas	Case No. 840
Potomac Electric Power Company	Case No. 834
Potomac Electric Power Company	Case No. 813, Phase II
Potomac Electric Power Company	Case No. 813
Washington Gas Light Company	Case No. 787
Potomac Electric Power Company	Case No. 785
Potomac Electric Power Company	Case No. 759, Phases III
Potomac Electric Power Company	Case No. 759, Phases II
Potomac Electric Power Company	Case No. 759, Phases I
Potomac Electric Power Company	Case No. 758

Guam

Guam Power Authority	Docket No. 11-090, Ph II
Guam Power Authority	Docket No. 11-090
Guam Power Authority	Docket No. 07-010
Guam Power Authority	Docket No. 98-002
Guam Power Authority	Docket No. 96-004
Guam Power Authority	Docket No. 95-001
Guam Power Authority	Docket No. 94-001

Guam Power Authority	Docket No. 92-002
Guam Power Authority	Docket No. 89-002 A,B,C
Illinois	
Commonwealth Edison Company	Docket No. 86-0128
Maryland	
WGL – AltaGas Merger	Case No. 9449
Washington Gas Light Company	Case No. 9443
Washington Gas Light Company	Case No. 9433
Potomac Electric Power Company	Case No. 9418
Exelon – Pepco Merger	Case No. 9361
Potomac Electric Power Company	Case No. 9336
Washington Gas Light Company	Case No. 9335
Washington Gas Light Company	Case No. 9322
Potomac Electric Power Company	Case No. 9311
Potomac Electric Power Company	Case No. 9286
Washington Gas Light Company	Case No. 9267
Potomac Electric Power Company	Case No. 9217
Potomac Electric Power Company	Case No. 9207
Washington Gas Light Company	Case No. 9158
Washington Gas Light Company	Case No. 9104, Phase II
Washington Gas Light Company	Case No. 9104
Potomac Electric Power Company	Case No. 9092, Phase II
Potomac Electric Power Company	Case No. 9092
Standard Offer Service Docket	Case No. 9063
Standard Offer Service Docket	Case No. 9056
Standard Offer Service Docket	Case No. 9037
Potomac Electric Power Company	Case No. 8895
Washington Gas Light Company	Case No. 8991
Washington Gas Light Company	Case No. 8959
Washington Gas Light Company	Case No. 8920, Phase II
. Washington Gas Light Company	Case No. 8920
Potomac Electric Power Company	Case No. 8895
Potomac Electric Power Company	Case No. 8890
Potomac Electric Power Company	Case No. 8791
Potomac Electric Power Company	Case No. 8773
Generic Electric Industry Restructuring	Case No. 8738
Potomac Electric Power Company/Baltimore Gas & Electric Company Merger	Case No. 8725
Washington Gas Light Company	Case No. 8545
Potomac Electric Power Company	Case No. 8315
Potomac Electric Power Company	Case No. 8251
Maryland Natural Gas	Case No. 8191
Potomac Electric Power Company	Case No. 8162
Maryland Natural Gas	Case No. 8119

Potomac Electric Power Company	Case No. 8079
Baltimore Gas & Electric Company	Case No. 8070
Maryland Natural Gas	Case No. 8060
Potomac Electric Power Company	Case No. 7972
Potomac Electric Power Company	Case No. 7874
Washington Gas Light Company	Case No. 7649

Massachusetts

Investigation of Rate Structures to Promote Efficient Deployment of Demand Management	Docket No. 07-50

North Carolina

Generic Electric Load Management	Docket No. M100, Sub 78

New Jersey

Public Service Electric and Gas	Docket No. GT93060242
Public Service Electric and Gas	Docket No. ER91111698J
Elizabethtown Gas Company	Docket No. 8812-1231
Elizabethtown Gas Company	Docket No. 8612-1374
Public Service Electric and Gas	Docket No. 8512-1163
Jersey Central Power & Light	Docket No. 8511-1116
New Jersey Natural Gas Company	Docket No. 8510-974
South Jersey Gas Company	Docket No. 850-8858
Public Service Electric and Gas	Docket No. 850-2231
New Jersey Natural Gas Company	Docket No. 850-7732
South Jersey Gas Company	Docket No. 843-184, Phase II
Atlantic Electric Company	Docket No. 8310-883, Phase II
New Jersey Natural Gas Company	Docket No. 831-46
Public Service Electric and Gas	Docket No. 837-620
Public Service Electric and Gas	Docket No. 8210-869

New Mexico

Gas Company of New Mexico	Case No. 2353
Gas Company of New Mexico	Case No. 2340
Gas Company of New Mexico	Case No. 2307
Gas Company of New Mexico	Case No. 2183
Gas Company of New Mexico	Case No. 2147 (Remand)
Gas Company of New Mexico	Case No. 2147
Gas Company of New Mexico	Case No. 2093

New York

Consolidated Edison Company	Docket No. 94-E-0334
Consolidated Edison Company	Docket No. 91-E-0462
Brooklyn Union Gas Company	Docket No. 90-G-0981

Ohio

Toledo Edison Company	Case No. 78-628-EL-FAC

Pennsylvania

PECO Energy Company	Docket No. R-20028394
PG Energy, Inc.	Docket No. R-00061365
Philadelphia Electric Company	Docket No. R-00970258
Mechanicsburg Water Company	Docket No. R-00922502
West Penn Power Company	Docket No. R-00922378
Pennsylvania Electric Company	Docket No. M-920312
North Penn Gas Company	Docket No. R-922276
Metropolitan Edison Company	Docket No. R-922314
York Water Company	Docket No. R-922168
Dauphin Consolidated Water Company	Docket No. R-921000
Pennsylvania Electric Company	Docket No. M-920312
Duquesne Light Company	Docket No. C-913424
Pennsylvania American Water Company	Docket No. R-911909
West Penn Power Company	Docket No. R-901609
Pennsylvania Gas & Water Co. Water Div.	Docket No. R-891209
Pennsylvania Power Company	Docket No. R-881112
Duquesne Light Company	Docket No. R-870651
Pennsylvania Electric Company	Docket No. R-870172
Metropolitan Edison Company	Docket No. R-870171
Western Pennsylvania Water Company	Docket No. R-860397
Duquesne Light Company	Docket No. R-860378
Philadelphia Electric Company	Docket No. R-850290
Pennsylvania Power Company	Docket No. R-850267
Pennsylvania Power & Light Company	Docket No. R-850251
Philadelphia Electric Company	Docket No. R-850152
Western Pennsylvania Water Company	Docket No. R-850096
Pennsylvania Power Company	Docket No. R-842740
Pennsylvania Power & Light Company	Docket No. R-842651
Pennsylvania Electric Company	Docket No. R-832550
Metropolitan Edison Company	Docket No. R-832549
Duquesne Light Company	Docket No. R-842383
UGI Corporation-Gas Utility Division	Docket No. R-832331
Pennsylvania Power & Light Company	Docket No. I-830374
Pennsylvania Electric Company	Docket No. R-822250
Metropolitan Edison Company	Docket No. R-822249
Pennsylvania Power & Light Company	Docket No. R-822169
Pennsylvania Gas & Water Co. - Water Div.	Docket No. R-822102
Columbia Gas Co. of Pennsylvania	Docket No. R-822042
Pennsylvania Gas & Water Co. - Gas Div.	Docket No. R-821961
Philadelphia Electric Company	Docket No. R-811626

Philadelphia, City of

Philadelphia Gas Works	1992 Rate Design Proceeding
Philadelphia Water Dept	1992 Rate Increase Request
Philadelphia Gas Works	1990 Rate Increase Request
Philadelphia Water Dept	1990 Rate Increase Request
Philadelphia Gas Works	1989 Proceeding
Philadelphia Gas Works	1988 Rate Increase Request
Philadelphia Gas Works	1987-88 Operating Budget
Philadelphia Gas Works	1986 Rate Increase Request
Philadelphia Water Dept	1985 Rate Increase Request

Rhode Island – Public Utilities Commission

National Grid – Gas Annual ISR Filing	Docket No. 4781
National Grid – Gas Base Rates	Docket No. 4770
National Grid – Gas GCR	Docket No. 4719
National Grid – Gas DAC	Docket No. 4708
National Grid – Gas GCR	Docket No. 4647
National Grid – Gas DAC	Docket No. 4634
National Grid – Gas Long-Range Plan	Docket No. 4608
National Grid – Gas GCR	Docket No. 4576
National Grid – Gas DAC	Docket No. 4573
National Grid – Gas Customer Choice	Docket No. 4523
National Grid – Gas GCR	Docket No. 4520
National Grid – Gas DAC	Docket No. 4514
National Grid – Gas GCR	Docket No. 4436
National Grid – Gas DAC	Docket No. 4431
National Grid – Gas GCR	Docket No. 4346
National Grid – Gas DAC	Docket No. 4339
National Grid – Gas On-System Margins	Docket No. 4333
National Grid – Gas Base Rates	Docket No. 4323
National Grid – Gas GCR	Docket No. 4283
National Grid – Gas DAC	Docket No. 4269
National Grid – Electric Backup Service	Docket No. 4232
National Grid – Elec & Gas Revenue Decoupling	Docket No. 4206
National Grid – Gas GCR	Docket No. 4199
National Grid – Gas DAC	Docket No. 4196
National Grid – Gas GCR	Docket No. 4097
National Grid – Gas DAC	Docket No. 4077
National Grid – Electric	Docket No. 4065
National Grid – Gas Portfolio Mgmt	Docket No. 4038
National Grid – Gas GCR	Docket No. 3982
National Grid – Gas DAC	Docket No. 3977
National Grid – Gas GCR	Docket No. 3961
National Grid – Gas Base Rates	Docket No. 3943
National Grid – Gas GCR	Docket No. 3868
National Grid – Gas DAC	Docket No. 3859

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National Grid – Gas GCR	Docket No. 3766
National Grid – Gas DAC	Docket No. 3760
New England Gas Company	Docket No. 3696
New England Gas Company	Docket No. 3690
Block Island Power Company	Docket No. 3655
New England Gas Company	Docket No. 3548
New England Gas Company	Docket No. 3459
New England Gas Company	Docket No. 3436
New England Gas Company	Docket No. 3401
Providence Gas Company	Docket No. 3295
Narragansett Electric Company	Docket No. 2930
Providence Gas Company	Docket No. 2902
Providence Gas Company	Docket No. 2581
Providence Gas Company	Docket No. 2552
Providence Gas Company	Docket No. 2374
Providence Gas Company	Docket No. 2286
Valley Gas Company	Docket No. 2276
Valley Gas Company	Docket No. 2138, Phase II
Valley Gas Company	Docket No. 2138, Phase I
Providence Gas Company	Docket No. 2082
Providence Gas Company	Docket No. 2076
Providence Gas Company	Docket No. 2001, Phase II
Valley Gas Company	Docket No. 2038
Providence Gas Company	Docket No. 2001
Block Island Power Company	Docket No. 1998
Providence Gas Company	Docket No. 1971
Generic Gas Transportation	Docket No. 1951
Valley Gas Company	Docket No. 1736
Providence Gas Company	Docket No. 1723
Providence Gas Company	Docket No. 1673

Rhode Island – Division of Public Utilities

National Grid Acquisition of New England Gas Company's Rhode Island Assets	Docket No. D-06-13
Merger of Southern Union, Valley Gas Company And Bristol & Warren Gas Company	Docket No. D-00-02

South Dakota

Northern States Power Company	Docket No. F-3188

Vermont

Department of Public Service	Docket No. 5378
Department of Public Service	Docket No. 5307

Virginia

AltaGas – WGL Merger	Docket No. PUR 2017-00049
Virginia Electric Power Company	Docket No. PUE 2016-00021
Virginia Electric Power Company	Docket No. PUE 2016-00001
Virginia Electric Power Company	Docket No. PUE 2015-00027
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Washington Gas Light Company	Docket No. PUE 2010-00139
Virginia Electric Power Company	Docket No. PUE 2009-00019
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Virginia Electric Power Company	Docket No. PUE 2009-00017
Virginia Electric Power Company	Docket No. PUE 2009-00016
Virginia Electric Power Company	Docket No. PUE 2009-00011
Washington Gas Light Company	Docket No. PUE 2006-00059
Washington Gas Light Company	Docket No. PUE 2005-00010
Washington Gas Light Company	Docket No. PUE 2003-00603
Washington Gas Light Company	Docket No. PUE 2002-00364
Virginia Electric Power Company	Docket No. PUE 000584
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Virginia Electric Power Company	Docket No. PUE 980212
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Washington Gas Light Company	Docket No. PUE 940031
Virginia Electric Power Company	Docket No. PUE 920041
Virginia Electric Power Company	Docket No. PUE 910047
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Northern Virginia Natural Gas	Docket No. PUE 880024
Virginia Electric Power Company	Docket No. PUE 830029
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Virgin Islands

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Water and Power Authority – Electric Rates	Docket No. 612
Water and Power Authority – Water Rates	Docket No. 576
Water and Power Authority – Electric Rates	Docket No. 575
Water and Power Authority – Electric Rates	Docket No. 533

Wisconsin

Gas Transportation - Generic	Docket No. 05-GI-102

Federal Energy Regulatory Commission

Weaver's Cove Energy, LLC.	Docket No. CP04-36-000
Mill River Pipeline, LLC.	Docket No. CP04-41-000
Columbia Gulf Transmission Co.	Docket No. RP86-167-000
Columbia Gas Transmission Corp.	Docket No. RP86-168-000
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National Grid - RI Gas
RIPUC Docket No. 4770

Comparison of Class Cost of Service Allocation Results
Including and Excluding Non-Firm Service (from PMN-3 and PMN-9, Respectively)

Ln No	Rate Class	Schedule PMN-3 ACOSS **Excl. Non-Firm** ROR	Schedule PMN-3 ACOSS **Excl. Non-Firm** UROR	Schedule PMN-9 ACOSS **Incl. Non-Firm** ROR	Schedule PMN-9 ACOSS **Incl. Non-Firm** UROR
1	Residential Non-Heat	-1.27%	-0.245	-1.28%	-0.248
2	Residential Heat	5.07%	0.980	5.06%	0.977
3	Small Commercial	3.49%	0.675	3.47%	0.670
4	Medium Commercial	6.30%	1.217	6.28%	1.213
5	Large LLF C&I	7.25%	1.400	7.24%	1.399
6	Large HLF C&I	4.98%	0.963	4.93%	0.953
7	Extra Large LLF C&I	7.70%	1.489	7.70%	1.487
8	Extra Large LLF C&I	7.34%	1.418	7.24%	1.400
	Total Firm Service				
9	Non-Firm Service	NA	NA	8.35%	1.613
10	Total RI Delivery Service	5.14%	1.000	5.14%	1.000

National Grid - RI Gas
RIPUC Docket No. 4770

Comparison of Class Cost of Service Allocation Results
At 35% and 21% Federal Income Tax Rates

		Schedule PMN-9 At **35%** Fed Inc Tax Rate		Schedule PMN-9 At **21%** Fed Inc Tax Rate	
Ln No	**Rate Class**	ROR	UROR	ROR	UROR
1	Residential Non-Heat	-1.28%	(0.248)	-2.10%	(0.365)
2	Residential Heat	5.06%	0.977	5.60%	0.975
3	Small Commercial	3.47%	0.670	3.67%	0.639
4	Medium Commercial	6.28%	1.213	7.09%	1.234
5	Large LLF C&I	7.24%	1.399	8.26%	1.438
6	Large HLF C&I	4.93%	0.954	5.46%	0.950
7	Extra Large LLF C&I	7.70%	1.487	8.82%	1.534
8	Extra Large LLF C&I	7.24%	1.400	8.27%	1.438
9	Total Firm Service	5.15%	0.996	5.72%	0.996
10	Non-Firm Service	8.35%	1.613	9.61%	1.672
11	Total RI Delivery Service	5.17%	1.000	5.75%	1.000

National Grid - RI Gas
RI PUC Docket No. 4770

Class Cost of Service Results at Old and New Federal Income Tax Rates
Based on Class Costs of Service Including Non-Firm Service from Schedule PMN-9

Ln No	Decription	Federal Income Tax Rate	Total Company	Res Non-Heat	Res Heat	C&I Small	C&I Medium	C&I Large LLF	C&I Large HLF	C&I Extra Large LLF	C&I Extra Large HLF	Non-Firm
1	Income Tax Expense	35%	$ 11,091,251	$ (401,390)	$ 6,746,505	$ 318,940	$ 1,904,807	$ 1,088,213	$ 225,170	$ 205,845	$ 842,059	$ 161,102
2	Income Tax Expense	21%	$ 6,663,979	$ (240,704)	$ 4,052,634	$ 191,848	$ 1,144,429	$ 653,888	$ 135,570	$ 123,642	$ 505,910	$ 96,761
4	Operating Income	35%	$ 40,022,498	$ (252,151)	$ 24,896,660	$ 2,144,652	$ 5,896,409	$ 3,094,977	$ 851,929	$ 567,553	$ 2,394,424	$ 428,044
5	Operating Income	21%	$ 44,449,770	$ (413,048)	$ 27,584,793	$ 2,270,850	$ 6,658,760	$ 3,531,298	$ 942,836	$ 649,945	$ 2,731,801	$ 492,537
6	Rate Base	35%	$ 773,427,484	$ 19,650,188	$ 492,477,417	$ 61,814,727	$ 93,903,332	$ 42,750,478	$ 17,265,372	$ 7,374,785	$ 33,062,135	$ 5,129,049
7	Rate Base	21%	$ 773,427,484	$ 19,667,598	$ 492,493,018	$ 61,830,639	$ 93,886,839	$ 42,735,601	$ 17,263,977	$ 7,372,040	$ 33,051,148	$ 5,126,624
8	ROR	35%	5.1747%	-1.2832%	5.0554%	3.4695%	6.2792%	7.2396%	4.9343%	7.6959%	7.2422%	8.3455%
9	ROR	21%	5.7471%	-2.1001%	5.6011%	3.6727%	7.0923%	8.2631%	5.4613%	8.8164%	8.2654%	9.6074%
10	UROR	35%	1.000	(0.248)	0.977	0.670	1.213	1.399	0.954	1.487	1.400	1.613
11	UROR	21%	1.000	(0.365)	0.975	0.639	1.234	1.438	0.950	1.534	1.438	1.672

National Grid - RI Gas

RIPUC Docket No. 4770

Division's Proposed Rate Class Distribution of National Grid's Requested $30.3 Million Gas Revenue Increase

			Division Proposal							National Grid
Ln No	**Rate Class**	Present Revenue 1/	Proposed Incr %	% of Avg Increase	Proposed Increase	Proposed Revenue	Post-Incr ROR	Post-Incr UROR	**Current** UROR 3/	Post-Incr UROR
1	Residential Non-Heat	$ 4,776,680	19.96%	140.0%	$ 953,616	$ 5,730,296	1.82%	0.237	(0.245)	0.167
2	Residential Heat	$ 139,501,953	14.28%	100.0%	$ 19,919,908	$ 159,421,861	7.63%	0.995	0.980	0.992
3	Small Commercial	$ 17,038,095	18.54%	130.0%	$ 3,158,522	$ 20,196,617	6.72%	0.877	0.675	0.831
4	Medium Commercial	$ 24,856,177	14.26%	100.0%	$ 3,544,491	$ 28,400,668	8.68%	1.132	1.217	1.110
5	Large LLF C&I	$ 10,692,336	9.18%	64.4%	$ 981,198	$ 11,673,534	8.69%	1.133	1.400	1.216
6	Large HLF C&I	$ 3,668,219	18.56%	130.0%	$ 680,935	$ 4,349,154	7.47%	0.974	0.963	0.936
7	Extra Large LLF C&I	$ 1,990,734	9.18%	64.4%	$ 182,683	$ 2,173,417	9.24%	1.205	1.489	1.292
8	Extra Large HLF C&I	$ 8,522,092	9.18%	64.4%	$ 782,043	$ 9,304,135	8.82%	1.149	1.418	1.233
9	Total Firm Service	$ 211,046,286	14.26%	100.0%	$ 30,203,396	$ 241,249,682	7.66%	0.999	1.000	0.997
10	Non-Firm Service	$ 1,388,117	7.13%	50%	$ 98,973	$ 1,487,090	9.57%	1.248	1.613	1.428
11	Total RI Delivery Service	$ 212,434,403	14.28%		$ 30,302,369	$ 242,736,772				

1/ From Schedule PMN-7, page 2 of 6, Column (R)
2/ From Schedule PMN-7, page 4 of 6, Column (AA)
3/ From Schedule PMN-9, ACOSS incl. Non-Firm

National Grid - RI Gas

RIPUC Docket No. 4770

Division's Illustrative Rate Class Distribution of a $15.0 Million Gas Revenue Increase

			Division Proposal							
Ln No	**Rate Class**	Present Revenue 1/	Proposed Incr %	% of Avg Increase	Proposed Increase	Proposed Revenue	Post-Incr ROR	Post-Incr UROR	Current UROR 3/
1	Residential Non-Heat	$ 4,776,680	14.12%	200.0%	$ 674,563	$ 5,451,243	0.55%	0.076	(0.365)
2	Residential Heat	$ 139,501,953	7.30%	103.4%	$ 10,182,289	$ 149,684,242	7.20%	0.994	0.975
3	Small Commercial	$ 17,038,095	12.36%	175.0%	$ 2,105,356	$ 19,143,451	6.31%	0.871	0.639
4	Medium Commercial	$ 24,856,177	3.53%	50.0%	$ 877,532	$ 25,733,709	7.82%	1.079	1.234
5	Large LLF C&I	$ 10,692,336	3.53%	50.0%	$ 377,486	$ 11,069,822	8.95%	1.235	1.438
6	Large HLF C&I	$ 3,668,219	9.89%	140.0%	$ 362,618	$ 4,030,837	7.09%	0.978	0.950
7	Extra Large LLF C&I	$ 1,990,734	3.53%	50.0%	$ 70,282	$ 2,061,016	9.55%	1.319	1.534
8	Extra Large LLF C&I	$ 8,522,092	3.53%	50.0%	$ 300,867	$ 8,822,959	8.97%	1.239	1.438
9	Total Firm Service	$ 211,046,286	14.26%		$ 14,950,993	$ 225,997,279	7.23%	0.998	0.996
10	Non-Firm Service	$ 1,388,117	3.53%	50.0%	$ 49,007	$ 1,437,124	9.57%	1.322	1.672
11	Total RI Delivery Service	$ 212,434,403	7.06%		$ 15,000,000	$ 227,434,403	7.24%	1.000	1.000

1/ From Schedule PMN-7, page 2 of 6, Column (R)
2/ From Schedule PMN-7, page 4 of 6, Column (AA)
3/ From Schedule PMN-9, ACOSS Incl. Non-Firm at 21% Fed Income Tax Rate

National Grid - RI Gas

RIPUC Docket No. 4770

Assessment of National Grid's Proposed Customer Charge Increases

Ln No	Rate Class	Cost of Service @ Sys Avg ROR ($/Cust/mo	Cost of Service @ Present Rates ($/Cust/mo	Current Customer Charge ($/Cust/mo	Current Charge % of COS @ Sys Avg ROR	Current Charge % of COS @ Present Rates	NGrid Proposed Customer Charge ($/Cust/mo	Proposed Increase $	Proposed Increase %	Proposed Customer Charge % of Cost of Service @ Sys Avg ROR	Proposed Customer Charge % of Cost of Service @ Present Rates
	Firm Service										
1	Residential Non-Heating	$30.55	$20.66	$13.00	42.6%	62.9%	$16.00	$3.00	23.1%	52.4%	77.4%
2	Residential Heating	$30.73	$27.90	$13.00	42.3%	46.6%	$16.00	$3.00	23.1%	52.1%	57.3%
3	Small C&I	$48.76	$42.42	$22.00	45.1%	51.9%	$35.00	$13.00	59.1%	71.8%	82.5%
4	Medium C&I	$114.61	$110.26	$70.00	61.1%	63.5%	$85.00	$15.00	21.4%	74.2%	77.1%
5	Large C&I LLF	$233.99	$231.28	$175.00	74.8%	75.7%	$200.00	$25.00	14.3%	85.5%	86.5%
6	Large C&I HLF	$207.65	$192.03	$175.00	84.3%	91.1%	$200.00	$25.00	14.3%	96.3%	104.2%
7	Extra Large C&I LLF	$529.12	$529.56	$425.00	80.3%	80.3%	$500.00	$75.00	17.6%	94.5%	94.4%
8	Extra Large C&I HLF	$551.10	$547.41	$425.00	77.1%	77.6%	$500.00	$75.00	17.6%	90.7%	91.3%
9	**Non-Firm Sales**										
10	a. < 35,000 therms	$114.61 1/	$110.26 1/	$275.00	239.9%	249.4%	$735.00	$460.00	167.3%	641.3%	666.6%
11	b. > 35,0000 and < 150,000 therms	$233.99 1/	$231.28 1/	$485.00	207.3%	209.7%	$735.00	$250.00	51.5%	314.1%	317.8%
12	c. > 150,000 therms	$551.10 1/	$547.41 1/	$715.00	129.7%	130.6%	$735.00	$20.00	2.8%	133.4%	134.3%
13	**Non-Firm Transportation**										
14	a. < 35,000 therms	$114.61 1/	$110.26 1/	$275.00	239.9%	249.4%	$735.00	$460.00	167.3%	641.3%	666.6%
15	b. > 35,0000 and < 150,000 therms	$110.26 1/	$110.26 1/	$485.00	439.9%	439.9%	$735.00	$250.00	51.5%	666.6%	666.6%
16	c. > 150,000 therms	$551.10 1/	$547.41 1/	$715.00	129.7%	130.6%	$735.00	$20.00	2.8%	133.4%	134.3%
17	Weighted Average of XL C&I Firm	$546.70 1/	$543.84 1/	$625.00	114.3%	114.9%	$735.00	$110.00	17.6%	134.4%	135.2%

1/ Based on customer costs for comparable firm service customer categories.

National Grid - RI Gas

Docket No. 4770

Allocation of Distribution Costs to On-Peak versus Off-Peak Usage by Rate Class

RSUM Allocation Percentages by Rate Class with Interruptibles Accounts Included

		Allocation Fractions by Rate Class by Month								
Ln No	Month	Res N-H	Res Heat	C&I Small	C&I Medium	C&I Large LLF	C&I Large HLF	C&I XL LLF	C&I XL HLF	Non-Firm
1	Feb	0.0018	0.1467	0.0190	0.0344	0.0193	0.0055	0.0083	0.0247	0.0000
2	Jan	0.0013	0.0938	0.0127	0.0252	0.0134	0.0042	0.0062	0.0192	0.0000
3	Mar	0.0018	0.0905	0.0122	0.0235	0.0119	0.0038	0.0048	0.0171	0.0035
4	Dec	0.0008	0.0507	0.0069	0.0150	0.0084	0.0028	0.0042	0.0147	0.0000
5	Apr	0.0010	0.0434	0.0057	0.0122	0.0054	0.0024	0.0022	0.0128	0.0028
6	Nov	0.0004	0.0218	0.0024	0.0068	0.0037	0.0017	0.0021	0.0102	0.0028
7	May	0.0005	0.0187	0.0021	0.0063	0.0024	0.0018	0.0010	0.0089	0.0024
8	Jun	0.0003	0.0083	0.0011	0.0030	0.0009	0.0014	0.0004	0.0074	0.0018
9	Oct	0.0002	0.0074	0.0009	0.0030	0.0013	0.0012	0.0010	0.0072	0.0021
10	Aug	0.0002	0.0054	0.0006	0.0023	0.0005	0.0012	0.0002	0.0069	0.0027
11	Sep	0.0002	0.0057	0.0007	0.0021	0.0007	0.0010	0.0003	0.0068	0.0023
12	Jul	0.0002	0.0055	0.0006	0.0022	0.0005	0.0012	0.0002	0.0070	0.0020
13	Total	0.0087	0.4979	0.0649	0.1360	0.0684	0.0282	0.0309	0.1429	0.0224
14	Total On-Peak	0.0071	0.4469	0.0589	0.1171	0.0621	0.0204	0.0278	0.0987	0.0091
15	Total Off-Peak	0.0016	0.0510	0.0060	0.0189	0.0063	0.0078	0.0031	0.0442	0.0133
16	% On-Peak (Nov-Apr)	81.61%	89.76%	90.76%	86.10%	90.79%	72.34%	89.97%	69.07%	40.63%
17	% Off-Peak (May-Oct)	18.39%	10.24%	9.24%	13.90%	9.21%	27.66%	10.03%	30.93%	59.38%
18	Ratio On-Peak to Off-Peak	4.4	8.8	9.8	6.2	9.9	2.6	9.0	2.2	0.7

Source: Schedule PMN-9, page 127 of 136

National Grid - RI Gas

RIPUC Docket No. 4770

Division's Proposed Rate Design for Residential Non-Heating Customers *(Based on a $15.0 Million Overall Revenue Increase)*

Ln No	Rate Class/Type of Charge	Billing Determinants	Current Charge	Revenue At Current Charge	RDM, ISR & Norm ERC Revenue Adjustment	RDM, ISR & Norm ERC Charge Adjustment	Adjusted Present Revenue	Adjusted Current Charge	Proposed Charge	Revenue At Proposed Charge	Increase in Charge $	Increase in Charge %	Increase in Revenue $	Increase in Revenue %
	Monthly Customer Charge													
1	Residential Non-Heat	201,541	$ 13.00	$ 2,620,033	$ -	$ -	$ 2,620,033	$ 13.00	$ 13.00	$ 2,620,033	$ -	0.00%	$ -	0.00%
2	Residential Heat - Low Income	2,492	$ 11.70	$ 29,156	$ -	$ -	$ 29,156	$ 11.70	$ 13.00	$ 32,396	$ 1.30	11.11%	$ 3,240	11.11%
3	Total Customer Charges	204,033		$ 2,649,189	$ -	$ -	$ 2,649,189	$ -		$ 2,652,429			$ 3,240	0.12%
	Distribution Charges													
4	Residential Non-Heat	3,673,573	$ 0.4386	$ 1,611,229	$ 441,706	$ 0.1202	$ 2,052,935	$ 0.5588	$ 0.7345	$ 2,698,265	$ 0.1757	31.43%	$ 1,087,036	67.47%
5	Residential Heat - Low Income	101,774	$ 0.3947	$ 40,170	$ 12,237	$ 0.1202	$ 52,407	$ 0.5149	$ 0.7345	$ 74,754	$ 0.2196	42.64%	$ 34,584	86.09%
6	Total Distribution Charges	3,775,347		$ 1,651,399	$ 453,943	$ 0.1202	$ 2,105,342			$ 2,773,019			$ 1,121,619	67.92%
11	Gas Lights	2,326	$ 9.52	$ 22,144	$ -	$ -	$ 22,144	$ 9.5200	$ 11.09	$ 25,795	$ 1.57	16.49%	$ 3,652	16.49%
12	**Total Residential Non-Heat**			$ 4,322,732			$ 4,776,675			**$ 5,451,243**			$ 1,128,511	26.11%

National Grid - RI Gas

RIPUC Docket No. 4770

Division Proposed Rate Design for Residential Heating Customers *(Based on $15.0 Million Overall Revenue Increase)*

Ln No	Rate Class/Type of Charge	Billing Determinants	Current Charge	Revenue At Current Charge	RDM, ISR & Norm ERC		Adjusted Present Revenue	Adjusted Current Charge	Proposed Charge	Revenue At Proposed Charge	Increase in Charge		Increase in Revenue	
					Revenue Adj	Charge Adj					$	%	$	%
	Residential Heating													
1	Monthly Customer Charge	2,520,283	$ 13.00	$ 32,763,679	$ -	$ -	$ 32,763,679	$ 13.00	$ 13.00	$ 32,763,679	$ -	0.00%	$ -	0.00%
	Distribution Charges													
	Peak													
2	Head Block	107,825,814	$ 0.4672	$ 50,376,220	$ 12,964,831	$ 0.1202	$ 63,341,051	$ 0.5874	$ 0.6400	$ 69,013,398	$ 0.0526	11.26%	$ 5,672,347	8.96%
3	Tail Block	36,228,505	$ 0.3010	$ 10,904,780	$ 4,356,067	$ 0.1202	$ 15,260,847	$ 0.4212	$ 0.5000	$ 18,115,242	$ 0.0788	26.18%	$ 2,854,395	18.70%
4	Total	144,054,319		$ 61,281,000	$ 17,320,898		$ 78,601,898			$ 87,128,640			$ 8,526,741	
	Off-Peak													
5	Head Block	26,285,200	$ 0.4672	$ 12,280,445	$ 3,160,497	$ 0.1202	$ 15,440,942	$ 0.5874	$ 0.6350	$ 16,689,900	$ 0.0475	10.17%	$ 4,409,454	28.56%
6	Tail Block	7,157,291	$ 0.3010	$ 2,154,345	$ 860,583	$ 0.1202	$ 3,014,928	$ 0.4212	$ 0.4800	$ 3,435,520	$ 0.0588	19.52%	$ 1,281,176	42.49%
7	Total	33,442,491		$ 14,434,790	$ 4,021,080		$ 18,455,870			$ 20,125,420			$ 5,690,630	
8	Total Distribution Charges	177,496,810		$ 75,715,790	$ 21,341,978	$ 0.1202	$ 97,057,768			$ 107,254,060			$ 14,217,371	18.78%
9	**Total Res Heat Base Revenue**			$ 108,479,469	$ 21,341,978		$ 129,821,447			$ 140,017,739			$ 14,217,371	
	Residential Heating - Low Income													
10	Monthly Customer Charge	204,901	$ 11.70	$ 2,397,342	$ -	$ -	$ 2,397,342	$ 11.70	$ 13.00	$ 2,663,713	$ 1.30	11.11%	$ 266,371	11.11%
	Distribution Charges													
	Peak													
11	Head Block	9,125,974	$ 0.4205	$ 3,837,472	$ 1,097,295	$ 0.1202	$ 4,934,767	$ 0.5407	$ 0.6400	$ 5,841,036	$ 0.0993	18.36%	$ 2,003,564	40.60%
12	Tail Block	2,410,048	$ 0.2709	$ 652,882	$ 289,781	$ 0.1202	$ 942,663	$ 0.3911	$ 0.5000	$ 1,205,090	$ 0.1089	27.84%	$ 552,208	58.58%
13	Total	11,536,022		$ 4,490,354	$ 1,387,076		$ 5,877,430			$ 7,046,126			$ 2,555,772	
	Off-Peak													
14	Head Block	2,270,725	$ 0.4205	$ 954,840	$ 273,029	$ 0.1202	$ 1,227,869	$ 0.5407	$ 0.6350	$ 1,441,807	$ 0.0942	17.42%	$ 486,967	39.66%
15	Tail Block	454,736	$ 0.2709	$ 123,188	$ 54,677	$ 0.1202	$ 177,865	$ 0.3911	$ 0.4800	$ 218,275	$ 0.0889	22.72%	$ 95,087	53.46%
16	Total	2,725,461		$ 1,078,028	$ 327,706		$ 1,405,734			$ 1,660,081			$ 582,053	
17	Total Distribution Charges	14,261,483		$ 5,568,382	$ 1,714,782	$ 0.1202	$ 7,283,164			$ 8,706,207			$ 3,137,825	56.35%
19	**Total Res Heat Low-Income Base Revenue**			$ 7,965,724	$ 1,714,782		$ 9,680,506			$ 11,369,920			$ 3,404,196	42.74%
	Total Residential Heating Base Rate Revenue			$ 116,445,193	$ 23,056,760		$ 139,501,953			$ 151,387,659			$ 17,621,568	15.13%
19	RDM & ISR Adjust & Norm			$ 23,056,760										
20	**Adj Total Res Heat Present Revenue**			$ 139,501,953						$ 151,387,659			$ 11,885,706	8.52%

National Grid - RI Gas

RIPUC Docket No. 4770

National Grid Proposed Rate Design for Small C&I Customers *(Based on a $15.0 Million Overall Revenue Increase)*

Ln No	Rate Class/Type of Charge	Billing Determinants	Current Charge	Revenue At Current Charge	RDM, ISR & Norm ERC Revenue Adj	RDM, ISR & Norm ERC Charge Adj	Adjusted Present Revenue	Adjusted Current Charge	Proposed Charge	Revenue At Proposed Charge	Increase in Charge $	Increase in Charge %	Increase in Revenue $	Increase in Revenue %
	Small C&I Sales													
	Monthly Customer Charge													
1	Peak	111,874	$ 22.00	$ 2,461,228	$ -	$ -	$ 2,461,228	$ 22.00	$ 22.00	$ 2,461,228	$ -	0.00%	$ -	0.00%
2	Off-Peak	111,049	$ 22.00	$ 2,443,078	$ -	$ -	$ 2,443,078	$ 22.00	$ 22.00	$ 2,443,078	$ -	0.00%	$ -	0.00%
3	Total	222,923		$ 4,904,306	$ -	$ -	$ 4,904,306			$ 4,904,306			$ -	
	Distribution Charges													
	Peak													
4	Head Block	8,877,404	$ 0.5431	$ 4,821,318	$ 1,062,078	$ 0.1196	$ 5,883,396	$ 0.6627	$ 0.7800	$ 6,924,781	$ 0.1173	17.70%	$ 1,041,384	17.70%
5	Tail Block	10,170,948	$ 0.2242	$ 2,280,327	$ 1,216,836	$ 0.1196	$ 3,497,162	$ 0.3438	$ 0.4100	$ 4,170,089	$ 0.0662	19.24%	$ 672,926	19.24%
6	Total	19,048,352		$ 7,101,645	$ 2,278,914	$ 0.1196	$ 9,380,559			$ 11,094,869			$ 1,714,311	
	Off-Peak													
7	Head Block	1,263,285	$ 0.5431	$ 686,090	$ 151,137	$ 0.1196	$ 837,227	$ 0.6627	$ 0.7200	$ 909,565	$ 0.0573	8.64%	$ 72,338	8.64%
8	Tail Block	2,575,531	$ 0.2242	$ 577,434	$ 308,132	$ 0.1196	$ 885,566	$ 0.3438	$ 0.4100	$ 1,055,968	$ 0.0662	19.24%	$ 170,401	19.24%
9	Total	3,838,816		$ 1,263,524	$ 459,270	$ 0.1196	$ 1,722,794			$ 1,965,533			$ 242,739	
10	Total Distribution Charges	22,887,168		$ 8,365,169	$ 2,738,184		$ 11,103,352			$ 13,060,402			$ 1,957,050	17.63%
11	**Total Small C&I Sales Revenue**			$ 13,269,475	$ 2,738,184		$ 16,007,658			$ 17,964,708			$ 1,957,050	12.23%
	Small C&I FT-2													
	Monthly Customer Charge													
12	Peak	4,163	$ 22.00	$ 91,586	$ -	$ -	$ 91,586	$ 22.0000	$ 22.00	$ 91,586	$ -	0.00%	$ -	0.00%
13	Off-Peak	4,231	$ 22.00	$ 93,082	$ -	$ -	$ 93,082	$ 22.0000	$ 22.00	$ 93,082	$ -	0.00%	$ -	0.00%
14	Total	8,394		$ 184,668	$ -	$ -	$ 184,668			$ 184,668			$ -	0.00%
	Distribution Charges													
	Peak													
15	Head Block	652,721	$ 0.5431	$ 354,493	$ 78,090	$ 0.1196	$ 432,583	$ 0.6627	$ 0.7800	$ 509,152	$ 0.1173	17.70%	$ 76,569	17.70%
16	Tail Block	740,093	$ 0.2242	$ 165,929	$ 88,544	$ 0.1196	$ 254,472	$ 0.3438	$ 0.4100	$ 303,438	$ 0.0662	19.24%	$ 48,966	19.24%
17	Total	1,392,814		$ 520,422	$ 166,634	$ 0.1196	$ 687,056			$ 812,590			$ 125,535	
	Off-Peak													
18	Head Block	118,400	$ 0.5431	$ 64,303	$ 14,165	$ 0.1196	$ 78,468	$ 0.6627	$ 0.7200	$ 85,248	$ 0.0573	8.64%	$ 6,780	8.64%
19	Tail Block	233,376	$ 0.2242	$ 52,323	$ 27,921	$ 0.1196	$ 80,244	$ 0.3438	$ 0.4100	$ 95,684	$ 0.0662	19.24%	$ 15,441	19.24%
20	Total	351,776		$ 116,626	$ 42,086	$ 0.1196	$ 158,712			$ 180,932			$ 22,220	
21	Total Distribution Charges	1,744,590		$ 637,048	$ 208,720		$ 845,767			$ 993,522			$ 147,755	17.47%
22	**Total Small C&I FT-2 Revenue**			$ 821,716	$ 208,720		$ 1,030,435			$ 1,178,190			$ 147,755	14.34%
23	**Total Base Revenue - All Small C&I**			$ 14,091,190	$ 2,946,904		$ 17,038,094			$ 19,142,899			$ 2,104,805	12.35%