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

IN THE MATTER OF

National Grid Request For	**)**	
Change Of Gas Distribution	**)**	**Docket No. 4323**
Rates	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

August 30, 2012

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TESTIMONY OF BRUCE R. OLIVER
Docket No. 4323
August 30, 2012

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 its preparation and presentation of economic, utility planning, and 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 the sales and revenue forecasting, class costs of service, and the rate structure and tariff change proposals that National Grid (hereinafter “NG” or the “Company”) presents in this proceeding relative to its gas distribution business. This testimony reviews and offers comments regarding the testimony filed on behalf of the Company by witnesses Paul M. Normand, Ann E. Leary, and A. Leo Silvestrini, including the schedules and workpapers associated with those pre-filed testimonies. Further, given witness Leary's reliance on testimony by NG witness Evelyn M. Kaye, in the presentation of the Company's recommendation regarding a change in the GCR to annually reconcile bad debt, I will also address portions of the Direct Testimony of witness Kaye.

Q. WHAT SCHEDULES ARE YOU SPONSORING AS PART OF THIS TESTIMONY?

A. Attached to this testimony are eleven schedules. They include:

Schedule BRO-1	Summary Evaluation of National Grid's Forecasting Models
Schedule BRO-2	Comparison of RI Costs for Natural Gas and Fuel Oil Alternatives
Schedule BRO-3	Re-Allocation of Income Tax Responsibilities by Rate Class Using a Rate Base Allocation Factor
Schedule BRO-4	Comparison of Customer Charges for New England Gas Utilities
Schedule BRO-5	Proof of Revenue and Comparison of Computed Revenue Increases by Rate Class
Schedule BRO-6	Re-Design of National Grid's Base Rate Increases
Schedule BRO-7	Design of the Division's Proposed Base Rate Increase by Rate Class
Schedule BRO-8	Assessment of Rate Increases for Non-Firm Service
Schedule BRO-9	Comparison of Average Rate Year Use per Customer to Average Use per Customer

Schedule BRO-10 Comparison of Actual Dual Fuel Throughput and Revenue

Schedule BRO-11 Evidence of Revenue Shifts Among Rate Classes Under the Company's Current RDM

Schedule BRO-12 Alternative Non-Firm Distribution Charge Calculations

II. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES RELATING TO THE COMPANY'S FILING IN THIS PROCEEDING ORGANIZED?

A. This discussion is presented in three sections. Section A discusses National Grid's development of the billing determinants upon which the class cost of service and rate design elements of the Company's filing are premised. Section B reviews and evaluates the Company's efforts to assess its costs of providing service by customer class as reflected in the Class Cost of Service ("CCOS") study that National Grid witness Normand presents. Section C assesses the merits of the rate structure and tariff change proposals that National Grid offers in this proceeding through the testimony of witnesses Normand and Leary, including:

(1) The Company's proposed distribution of its requested revenue increase among rate classes;

(2) The Company's rate design proposals for firm service rate classifications;

(3) The Company's proposed changes in its treatment of Non-firm and Dual Fuel customers; and

(4) The Company's other tariff change proposals, including:

(a) Proposed revisions to the Company's Gas Cost Recovery (GCR) mechanism,

(b) Changes in its Distribution Adjustment Charge ("DAC") calculations,

(c) Proposed post-test year RDM Factor calculations, and

(d) Credits for use of paperless bills.

A. DEVELOPMENT OF RATE YEAR BILLING DETERMINANTS AND REVENUE

Q. WHAT ARE THE KEY ELEMENTS OF THE COMPANY'S DEVELOPMENT OF RATE YEAR BILLING DETERMINANTS FOR THIS PROCEEDING?

A. The key elements of the Company's development of Rate Year billing determinants are discussed in the Direct Testimony of NG witness Leary and supported in part by the forecasts prepared by witness Silvestrini. Witness Leary explains that the Company's development of Rate Year billing determinants for this proceeding has two key components. First, the Company computes estimates of the impacts of normal weather on the actual quantities of gas use for the test year. Second, estimates are made of expected growth in numbers of customers and weather-normalized gas use by rate class for the Rate Year.

Q. ARE THE COMPANY'S ESTIMATES OF RATE YEAR BILLING DETERMINANTS REASONABLE?

A. The Division finds problems in the forecasting methodologies that the Company has employed that undermine the reliability of its forecasts of numbers of customers and throughput volumes. Division witness Dave Effron presents testimony addressing specific recommendations for changes in the billing determinants the Company has developed. My testimony addresses certain analytical problems that influence the reliability of the Company's forecasts and discusses their implications for the Company's rate year cost allocation and proposed rate designs.

Q. HAVE YOU IDENTIFIED ELEMENTS IN THE COMPANY'S PRESENTAION OF ITS 2011 GAS DELIVERY FORECASTS THAT RAISE CONCERNS REGARDING THE RELIABILITY OF THOSE FORECASTS?

A. Yes. Three elements of the Company's presentation are of particular concern. First, several of the forecasting models presented do not explain large percentages of the variation observable in the Company's historic data. Second, for a number of classes, the use per customer models include variables for which the estimated co-efficient cannot be reliably differentiated from zero at the 95% confidence level. Third, the Company offers a very matter of fact presentation of the weather normalization process for actual data which may give the Commission a mistaken impression of the precision of the Company's weather normalization analyses.

Q. WHAT IS THE BASIS FOR YOUR ASSERTION THAT SEVERAL OF THE FORECASTING MODELS THE COMPANY HAS USED DO NOT EXPLAIN LARGE PERCENTAGES OF THE OBSERVABLE VARIATION IN THE COMPANY'S HISTORICAL DATA?

A. Appendix ALS to the Direct Testimony of witness Silvestrini presents specifications for the models used to forecast numbers of customers and use per customer for each rate class. By combining the estimated number of customers for a class with forecasted use per customer, the Company computes its estimate of delivery volumes. With one notable exception, the customer models all appear to offer high levels of explanatory power.[1] However, a review of the Use per Customer models presented for each rate class and the regression statistics reported for those

[1] The one referenced exception is the Customer Count model for the Small C&I class for which a comparatively low R-Square value of 0.6826 is reported. The Customer Count models for each of the other classes yield R-Square values in excess of 0.9.

models, finds comparatively low R-Square values for a number of the models. An R-Square value indicates the proportion of variability in a data set that is accounted for by the statistical model. An R-Square value of 1.0 would indicate that the model explains all of the variability in the input data. An R-Square value of 0.5 indicates that the model explains only 50% of the variation in the data set used.

The Summary Evaluation of National Grid's Forecasting Models presented in pages of Schedule BRO-1 indicates that for 12 of the models presented, R-Square values of less than 0.5 are reported. Six models have reported R-Square values of less than 0.3 indicating the over **70%** of the observable variation in the historical data inputs is **not explained** by the model the Company has used for the class. The Use per Customer forecasts for nearly every rate class are affected by these problems, and that raises concerns regarding the degree of confidence that the Commission can place in the Company's estimates of forecasted delivery volumes. Of particular concern is the comparatively low R-Square value (i.e., 0.2607) for the "Slope" model for the Residential Heating class. Given the size of the service volumes for the Residential Heating service class, the low R-Square value for this key component of the Company's Use per Customer forecast for the Residential Heating class has substantial influence on the level of confidence the Commission can place on the forecasting effort both overall and for National Grid's largest class of service.

Q. ARE THERE OTHER FACTORS THAT CAUSE YOU TO QUESTION THE RELIABILITY OF THE COMPANY'S FORECASTS OF DELIVERY VOLUMES?

A. Yes. For most of the Use per Customer models, National Grid reports the upper and lower bounds of the 95% confidence interval for coefficients it has estimated for each of the independent variables included in each model. These confidence intervals provide an indication of the degree of uncertainty (or potential error) associated with estimated coefficient for a variable. For example, a coefficient for a Heating Degree Day (HDD) variable indicates the amount of change in use that can be expected to result from a one unit change in an observed or assumed level of HDDs. However, where the 95% confidence interval straddles zero, the appropriate statistical conclusion is the estimated coefficient cannot be confidently differentiated from zero. Furthermore, this result suggests that there is sufficient uncertainty associated with the appropriate coefficient value for the variable that its actual value could be positive, negative or even zero. In other words, the model provides us no reliable indication of the influence of the variable, if any, on use per customer for the applicable rate class.

Q. IS IT YOUR INTENT TO SUGGEST THAT THE COMPANY DID A POOR JOB OF FORECASTING USE PER CUSTOMER?

A. No. Sometimes relationships within data do simply not lend themselves to modeling through the application of regression analysis. The observed problems may also be a function of the relationship specified in the model. Possibly a different variable or combination of variables would have greater explanatory value. Without substantial additional effort I cannot answer such questions. However, pages of data and equations that many may find difficult to follow do not necessarily produce reliable forecasts. My greatest concern is the Company's presentation has not placed greater emphasis on explanation of these limitations in its forecasting results and the potential impacts that those limitations may have on the Commission's ratemaking determinations in this case. My concern is that disclosure and explanation of these matters is necessary to enable the Commission to properly interpret and evaluate the information presented.

Q. DO YOU HAVE SIMILAR CONCERNS REGARDING THE PRECISION OF THE COMPANY'S WEATHER-NORMALIZATION ANALYSES?

A. Yes, I do. Weather-normalization adjustments are used to estimate the changes in use that would have been expected if the actual degree days for a given time period precisely matched an estimate of the degree days that would have occurred under normal weather conditions. Although the Company's testimony gives the impression that weather normalization is a comparatively straightforward process that renders relatively precise determinations, that is not actually the case. Although most utilities engage in weather-normalization analyses, the methods used to estimate weather-normalized usage vary considerably. When reviewing weather normalization adjustments, it should be recognized that: (1) there is no globally accepted method of measuring "normal" degree days; and (2) a multitude of factors exist which can influence actual normal usage patterns and complicate assessments of customer response to changes in reported degree day measures. Customers' responses to changes in degree day measures are not uniform even within rate classifications. The response for any individual customer account may be influenced by such factors as: (a) the types of gas consuming appliances used, (b) levels of thermal insulation within a home or building, (c) exposure of a home or building to wind and solar radiation, (c) the number of occupants in a building, (d) the ages of occupants, and (e) the activities in which occupants engage.

Moreover, there are substantial issues relating to differences in the sensitivity of gas use to degree day measures over the course of a year. To simplify the weather-normalization process, it is often assumed that the relationship between gas use and degree days for a class of customers (or for the entire system) is linear. In other words, the amount of gas use associated with a one degree day change is the same regardless of when the change is experienced or what the total number of degree days is for the period analyzed. However, analyses performed for individual months often find greater degree day sensitivity during high demand months. In addition, witnesses for the Company have noted in prior proceedings that the sensitivity of gas use to degree days appears to be greater on high demand days for the system than on days with lesser more moderate temperatures and lower levels of reported degree days.

The precision of weather normalization determinations is further impeded by difficulties in the identification of non-weather sensitive components of customers' gas use (i.e., Base Load volumes). Yet, in most cases, efforts to identify Base Load gas use are quite arbitrary and imprecise. Moreover, any errors in the estimation of

Base Load requirements tend to spill over into use per degree day analyses and diminish the precision and reliability of those efforts. Again, my primary concern is not the existence of these challenges in the estimation of measures of weather-normalized gas use. Rather, National Grid's presentation leaves open the potential that persons less well versed in forecasting methods and issues could simply accept the Company's forecasts without consideration of associated uncertainties. I believe that the Company could have presented the essence of these concerns to the Commission in non-technical terms and let the Commission evaluate the extent to which it should rely on such analyses.

B. CLASS COST OF SERVICE STUDY

Q. HAVE YOU REVIEWED THE DETAIL OF THE CLASS COST OF SERVICE STUDY THAT WITNESS NORMAND PRESENTS IN THIS PROCEEDING AS SCHEDULES PMN-2 THROUGH PMN-6 TO HIS DIRECT TESTIMONY?

A. Yes, I have. I have also reviewed the testimony which explains the development of that study, as well as witness Normand's responses to a substantial number of data requests that the Division propounded to the Company regarding the details of that study.

Q. FOR WHAT TIME PERIOD IS THE COMPANY'S CLASS COST OF SERVICE STUDY PREPARED?

A. As reflected in witness Normand's Schedules PMN-2 through PNM-6, the Company's class cost of service analyses have been prepared on the basis of the 12 months ended January 31, 2014. In other words, the Company has used a **fully projected** test period to assess class cost of service relationships.

Q. DOES THE COMPANY'S USE OF A FULLY PROJECTED TEST PERIOD FOR CLASS COST OF SERVICE DETERMINATIONS YIELD ANY CAUSE FOR CONCERN REGARDING THE RELIABILITY OF THE COMPANY'S CLASS COST OF SERVICE DETERMINATIONS?

A. Yes, it does. Where a fully projected or forecasted test year is used for class cost of service allocations, neither costs nor measures of use are know with certainty. The combined effects of errors associated with estimates of future costs and errors in the estimation of future measures of usage can amplify the magnitude of errors in computed cost allocations for a future test period, and that can erode the confidence that the Commission may place in calculated costs of service by rate class or function. Manipulation of thousands of numbers in a large computer-based model may provide the illusion of precision, but it does not necessarily yield reliable results.

By contrast, the use of a **fully historic** test period for class cost-of-service determinations has more direct ties to the Company's actual experience and reflects known costs and identifiable measures of use. Thus, use of fully projected test year for assessment of class cost responsibilities generally involves greater levels of uncertainty and greater potential estimation errors than similar analyses that are premised on historic cost and usage data.

Q. DO YOU OPPOSE THE USE OF A FULLY PROJECTED TEST YEAR FOR THE DETERMINATION OF CLASS COST RESPONSIBILITIES?

A. No, I do not. The foregoing observations do not necessarily negate fully the value of class cost of service analyses that are developed on the basis of fully projected data. However, the use of a fully projected test year places greater responsibility on anyone who presents such an analysis: (1) to demonstrate the reasonableness of the estimates of measures of service and costs upon which their presentation is based; and (2) assess the extent to which estimation errors in the data inputs used influence the reliability of cost allocation results for the projected period.

Q. DO YOU FIND EVIDENCE THAT UNCERTAINTIES ASSOCIATED WITH THE ESTIMATES OF MEASURES OF SERVICE EMPLOYED IN THE COMPANY'S CLASS COST OF SERVICE STUDY NEGATIVELY AFFECT THE CONFIDENCE THE COMMISSION CAN PLACE IN THE RESULTS OF THE COMPANY'S COST OF SERVICE ANALYSES?

A. Yes, I do. As explained in the preceding section of this Discussion of Issues, the methods National Grid has employed to produce estimates of numbers of customers and throughput by rate class for the projected test year do not warrant a high degree of confidence in the accuracy of the resulting estimates.

Q. IS IT YOUR POSITION THAT THE COMMISSION SHOULD NOT ALLOW THE COMPANY TO PRESENT A CLASS COST OF SERVICE STUDY THAT IS PREMISED ON A FULLY FORECASTED TEST PERIOD?

A. No. Presentation of such analyses can be instructive, if presented in the context of a similar analysis of based on actual historic data and if accompanied by detailed assessment and explanation of: (a) the projected changes in cost relationships between the historic and forecasted periods; and (b) the magnitudes of major uncertainties associated with the use of fully forecasted measures of service and costs.

Q. DO THE COST OF SERVICE ANALYSES THAT WITNESS NORMAND PRESENTS REASONABLY DEPICT NATIONAL GRID'S ACTUAL COSTS OF PROVIDING GAS SERVICE BY CUSTOMER CLASS IN RHODE ISLAND?

A. I find that the Class Cost of Service Study ("CCOS") witness Normand presents offers a general indication of the Company's costs of providing gas service by rate class, but I do not advise the Commission to place undue reliance on the precision of the results of that study by rate classification and function.

Q. ARE THERE FACTORS OTHER THAN ESTIMATION ERRORS IN PROJECTED FUTURE COST AND USAGE INPUTS THAT CONTRIBUTE TO YOUR CONCERNS REGARDING THE RELIABILITY OF THE COMPANY'S COST ALLOCATION RESULTS BY RATE CLASS?

A. Yes. Although the general methods that witness Normand describes for the development of the Company's filed class cost of service study appear reasonable and consistent with industry practice, there are several factors that distort those results of the Company's class cost of service allocation. Those factors include:

- A failure to show allocations of costs to non-firm service customers;
- A failure to identify any allocation or assignment of costs to gas marketers or provide any assessment of the cost basis for charges billed to gas marketers;
- Inappropriate allocation among classes of responsibility for Income Taxes;
- Allocation of production-related expenses in a manner that is inconsistent with the treatment of such costs within the DAC and GCR.

<u>1. Allocations of Costs to Non-Firm Service</u>

Q. WHY IS THE COMPANY'S FAILURE TO ALLOCATE COSTS TO NON-FIRM SERVICE CUSTOMERS A PROBLEM?

A. It is a concern for three reasons.

First, 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 as a discount from otherwise applicable firm service rates, National Grid offers no assessment of the continuing appropriateness of the cost basis for either (a) its non-firm transportation service charges or (b) the margin threshold that it proposes for its non-firm service revenue. Rather, the Company appears to believe that non-firm service customers should continue be billed on a value-of-service basis, but it offers no recommendation for a return to value-of-service pricing or analysis to support the appropriateness of such pricing given current market conditions.

Second, by not allocating or assigning costs directly to Non-Firm service customers, the Company implicitly allocates costs incurred to serve Non-Firm customers to its Firm Service rate classifications. This yields a distorted assessment of the Company's actual costs of service for its Firm Service rate classes. Even the purported unbundled rate calculations that witness Normand offers in his CCOS exhibits do not offer pure measures of the actual unbundled costs of serving each function and rate class when the resulting cost measures incorporate effective re-allocations of costs that the Company actually incurs to serve Non-Firm customers.

Third, witness Leary's testimony proposes to change the threshold for determining On-System Margin Credits/Surcharges under the DAC. That proposal should be directly related to the Company's pricing of Non-Firm service and should have at least some discernible tie to the Company's costs of serving Non-Firm customers. However, no such linkage to either cost of service or pricing for Non-firm service customers has been offered. Instead, the Company proposes to eliminate the current $2,816,000 margin revenue threshold for Dual-Fuel customers and replace it with a $1,512,209 margin revenue threshold that would be applicable only to Non-Firm Dual Fuel customers and for which no documentation has been provided. Without any cost basis for the threshold value used, that threshold is simply an arbitrary target with the Company's Firm Service customers responsible for any variation from that target. Thus, establishing a reasonable measure of the Company's costs of serving Non-Firm customers is an important and necessary step for ensuring the application of sound ratemaking practices and providing reasonably cost-based charges for all classes of service.

Q. DOES NATIONAL GRID AGREE THAT ITS CLASS COST OF SERVICE STUDY SHOULD INCLUDE EXPLICIT ALLOCATIONS OF COSTS TO NON-FIRM TRANSPORTATION SERVICE CUSTOMERS?

A. No, it does not. In its response to Division Data Request 4-2-GAS the Company suggests that (1) any such allocation requires considerable judgment and (2) non-firm customers can and do switch back and forth between alternative fuels to take advantage of price changes. As further support for its position National Grid also cites the Commission's determination in Docket No. 3943 that "…*price stability is* *generally desirable and that setting the price of non-firm service as a fixed percentage of the price of firm service is a fair and reasonable methodology*."[2]

Q. DO YOU ACCEPT THE COMPANY'S RATIONALES FOR NOT INCLUDING ALLOCATIONS OF COSTS TO NON-FIRM SERVICE IN ITS CCOS?

A. No, I do not. The Company's arguments are unfounded, inappropriate and not reflective of prevailing energy market conditions. They also deny the Commission important information that can be used as a benchmark or guide in assessing the reasonableness of rates charged to Non-Firm Service customers while improving the accuracy of cost measures computed for Firm Service customers.

Q. SHOULD THE COMMISSION ACCEPT THE COMPANY'S ARGUMENT THAT ALLOCATIONS OF COSTS TO NON-FIRM CUSTOMERS REQUIRES CON-SIDERABLE JUDGMENT AS A REASON FOR NOT INCLUDING NON-FIRM SERVICE IN ITS CCOS?

A. No. Many aspects of the Company's cost allocations require the exercise of considerable judgment, regardless of the class to which costs are being allocated. The judgments required to allocate costs to non-firm service customers are no greater than the judgments used in other elements of the Company's CCOS. In fact, the largest elements of the Company's cost for distribution service are costs

[2] National Grid's response to Division Data Request 4-2-Gas and this Commission's Decision and Order in Docket No. 3943 at page 86.

associated with its investments in mains, services, and meters. Those categories of plant costs represent more than 85% of National Grid's claimed Gas Rate Base for the rate year used in its CCOS. Yet, the Company's allocations of mains are based on RSUM allocations which, in turn, are driven by measures of monthly throughput. Moreover, the estimation of appropriate monthly throughput volumes for non-firm customers does not introduce significantly greater judgment than the estimation of service volumes for large firm service customers. Further the Company's allocations of costs for services are based on numbers of services and average costs per service for each rate class. As a result, the Company's allocations of service costs to non-firm customers would involve no substantial use of judgment. Similar findings can also be made with respect to costs for meters and meter installations which represent the next largest components of National Grid's rate base costs which involve costs for meters and meter installations.

Q. HAVE NATIONAL GRID'S NON-FIRM GAS CUSTOMERS SWITCHED BACK AND FORTH BETWEEN ALTERNATIVE FUELS FOR ECONOMIC REASONS IN RECENT YEARS?

A. No. The Company's arguments regarding non-firm customers switching back and forth between alternative fuels are inappropriate and not reflective of either prevailing market conditions or the Company's actual experience. As a follow-up to the Company's response to Division Data Request 4-2-GAS, the Company was asked in Division Data Request 13-3-GAS to document instances in which a non-firm customer has substituted an alternate fuel for natural gas to take advantage of price changes during periods when gas service was NOT subject to interruption or curtailment by the Company over the last three years. National Grid's response to that request states that it is **not aware of any such instance over the last three years**.[3]

In fact, the differences between natural gas and alternative fuel prices have been sufficiently large over the most of the last decade that use of alternate fuels has not been an economic option. The primary alternate fuels for the Company's non-firm customers are No. 2 fuel oil and No. 6 fuel oil. Schedule BRO-1 provides a comparison of current NYMEX prices for natural gas and for the identified fuel oil alternatives. That comparison indicates the cost of **No. 6 fuel oil** is at least **2.3 to 3.0** times the cost of natural gas for National Grid Non-Firm Sales Service customers, and the cost of **No. 2 fuel oil** is **1.6 to 2.0 times** the cost of natural gas service. Thus, substitution of alternate fuels for natural gas is not now and is not expected to be an economic alternative within the foreseeable future. Moreover, with such large differences in natural gas and alternate fuel prices, value-of-service pricing for natural gas based on the costs of fuel oil is simply usurious, and unnecessarily discourages the use of natural gas where the use of lower cost natural gas could encourage business development and stimulate economic activity.

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[3] National Grid's response to Division Data Request 13-3-GAS, filed 7/23/2012.

Q. DO YOU DISAGREE WITH THE COMMISSION'S FINDING IN DOCKET 3943 THAT "…*PRICE STABILITY IS GENERALLY DESIRABLE AND THAT SETTING THE PRICE OF NON-FIRM SERVICE AS A FIXED PERCENTAGE OF THE PRICE OF FIRM SERVICE IS A FAIR AND REASONABLE METHODOLOGY"*?

A. No. Clearly, price stability is generally desirable for non-firm, as well as, firm service customers. Moreover, in the context of Docket 3943, the Commission's determination that setting the price for non-firm service as a fixed percentage discount from the price of firm service was reasonable and appropriate. However, it must be remembered that the 20% discount adopted was a **compromise** offered by the Division in the face of considerable differences in the positions of the parties and of perceived inadequacies in the record in that case that inhibited the development of a more cost-based resolution of non-firm pricing issues in that proceeding.

<u>2. Allocations of Costs to Gas Marketers</u>

Q. WHY SHOULD THE COMMISSION EXPRESS CONCERN REGARDING NATIONAL GRID'S FAILURE TO ALLOCATE COSTS TO GAS MARKETERS?

A. Once again, I find two reasons for such concerns.

First, a failure to properly identify and account for costs incurred to support the Company's interaction with gas marketers results in a less than accurate portrayal of the Company's costs of providing service to other classes of service.

Second, National Grid expends considerable time and effort to interact with gas marketers on a day-to-day basis to process customer enrollments, schedule deliveries of gas, adjust assignments of capacity, account for imbalances in receipts and deliveries of gas, and modify gas marketer related tariff provisions. Yet, it has been many years since the Company performed a detailed assessment of the costs that the Company incurs on behalf of gas marketers. Cost-based ratemaking concepts suggest that charges billed to gas marketers should be reviewed and reset in each base rate filing in the same manner as the Company's charges to other customers are re-examined in each rate case. By doing so, the Commission can ensure that residential customers for whom competitive gas supply services are not an option are not asked to bear costs for services from which they derive no benefit.

3. Income Tax Allocations

Q. WHY SHOULD THE COMMISSION QUESTION NATIONAL GRID'S ALLOCATION OF RESPONSIBILITIES FOR INCOME TAXES AMONG RATE CLASSES?

A. The Company's determination of class responsibilities for income taxes yields perverse results. In this case the CCOS that witness Normand presents reflects a negative allocation of income taxes (i.e., -$709,671) for the Residential Non-Heating class. That allocation is the result of the application of a standard tax computation methodology to a class that has negative net income, negative taxable income, and a negative contribution to the Company's return requirements. In other words, the tax calculation methodology employed in its CCOS has the effect of rewarding a class that fails to contribute anything positive to the Company's required earnings by providing the class an income tax credit to offset portions of its other reasonably and appropriately allocated cost responsibilities. On the other hand, classes producing above system average rates of return are penalized for the positive contributions and saddled with increased income tax responsibilities.

Q. HOW SHOULD CLASS RESPONSIBILITIES FOR THE COMPANY'S INCOME TAX LIABILITIES BE DETERMINED?

A. Income taxes should be allocated to rate classes in proportion to each class's allocated Rate Base costs.

Q. WHY IS A DETERMINATION OF INCOME TAXES RESPONSIBILITIES ON THE BASIS OF ALLOCATED RATE BASE COSTS PREFERRABLE TO THE METHOD THE COMPANY HAS USED IN ITS CCOS?

A. Income taxes liabilities must generally be incurred to provide equity returns to shareholders. The magnitude of the Company's income tax liabilities is directly related to its equity return requirement, and its equity return requirement is a function of the amount of its rate base investment. If the Company is be provided a reasonable opportunity to achieve its authorized ROE, then its incurrence of income tax liabilities is essentially unavoidable.

Although the methodology that National Grid has used is often found in utility cost allocation studies, that methodology works best when differences in class rate of return are relatively narrow, and all classes have positive taxable income. In fact, in a scenario in which all classes provide identical rates of return, the results of the Company's Federal Income Tax allocation methodology would be identical to the results of the rate base allocation method that I recommend. However, as demonstrated above, the Company's methodology for allocating Federal Income taxes flounders and produces unintended distortions to class cost responsibilities where one or more classes of service have negative taxable income and make little or no positive contribution to the utility's equity return requirements.

The Commission should note that a class's failure to contribute to the Company's equity return requirement does not necessitate either: (1) exemption of the class from Federal Income Tax responsibilities; or (2) the class's receipt of additional cost subsidies through income tax credits which would serve to offset its other properly allocated expenses. Allocating Federal Income Taxes in proportion to allocated Rate Base by class still allows a class's rate of return to vary from the system average rate of return, but in a situation where a class has negative taxable income, it avoids effectively rewarding the class for its poor earnings performance.

A rate class is NOT a stand-alone entity, and if it were, a class that generated negative contributions to earnings would have trouble raising the capital necessary to support rate base investment requirements. When a class fails to provide positive taxable income, utility's need to provide positive returns to investors and incur income tax liabilities does not go away. Rather, the Company's income tax liabilities get shifted to other classes of service.

Q. HOW WOULD A RATE BASE ALLOCATION OF INCOME TAXES ALTER THE RESULTS OF THE COMPANY'S CCOS FOR RESIDENTIAL NON-HEATING CUSTOMERS?

A. The Company's CCOS suggests that the Residential Non-Heat class is providing a negative rate of return (i.e., -6.06%). However, if that class is required to continue to bear the full income tax liability associated with its allocated Rate Base costs, then return for that class would fall to -11.91%.[4] Furthermore, the net income for that class would fall from $(891,165) to $(1,751,410). Thus, even accepting a zero contribution to the Company's return requirements, the effective subsidy of that class's Operating Expense responsibilities would rise to more than $1.75 million.

As portrayed in National Grid's CCOS, the Residential Non-Heating class not only provides no contribution to the Company's required earnings, it also receives the benefit of a $709,671 income tax credit which serves to offset an equal amount of allocated Operating Expense responsibility. In other words, of the $7,366,601 of allocated Operating Expense responsibilities that the Company's CCOS attributes to the Residential Non-Heating class, $709,671 (or nearly 10%) of those expenses are funded, not through rates, but through a fictitious income tax credit.

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[4] Cost allocation results with income taxes reallocated on rate base for all classes are provided in Schedule BRO-3

Q. IS YOUR PRESENTATION RELATING TO THIS INCOME TAX ALLOCATION ISSUE INTENDED TO IMPLY THAT ALL CLASSES MUST PROVIDE EQUAL RATES OF RETURN?

A. No. It is intended to emphasize that the allowance of a less than system average rate of return for a rate class does not necessitate further subsidization of that class through the income tax allocation process. I recognize that Commission determinations regarding class revenue requirements must often consider non-cost-based factors that may justify deviations from strict cost-based ratemaking. However, in making its rate determinations the Commission should have as a guide a cost of service study that portrays actual cost relations and avoids to the maximum extent practicable, non-cost based considerations.

Q. ISN'T THE COMPANY'S INCOME TAX ALLOCATION METHODOLOGY WIDELY USED WITHIN THE INDUSTRY?

A. Yes, it is. However, that methodology only produces reasonable results when the returns of all classes are within reasonable proximity of the system average rate of return. As disparities in class rates of return increase, the size of effective cost subsidies through reduced or negative income tax allocations also grows.

4. Consistency with DAC and GCR Allocations

Q. WHAT ELEMENTS OF THE COMPANY'S CLASS COST OF SERVICE ALLOCATIONS DO YOU FIND TO BE INCONSISTENT WITH ALLOCATION METHODS USED IN ITS DETERMINATION OF DAC AND GCR CHARGES?

A. The Design Winter allocator that National Grid employs to determine class responsibilities for capacity-related LNG costs only uses degree day sensitive throughput volumes (Heat Load Dth) by class under Design Winter conditions. Base Load volumes are removed from consideration in the construction of that allocator. In the DAC and GCR related expenses are allocated among classes on the basis of total Design Winter throughput measures. This inconsistency should be resolved by amending Design Winter allocator in the Company's CCOS to include consideration of total Design Winter throughput. All winter service volumes effectively benefit from the Company's use of LNG facilities, and therefore, the appropriate approach to structuring the Design Winter allocator is to include both Heat Load and Base Load components of total throughput.

5. Other Considerations

Q. IN DOCKET 3943 YOU CRITICIZED THE COMPANY'S ALLOCATION OF PLANT COSTS ASSOCIATED WITH SERVICE LINES. HAS THE COMPANY

ADDRESSED THOSE CONCERNS IN ITS DEVELOPMENT OF ITS SERVICE COST ALLOCATIONS FOR THIS PROCEEDING?

A. Yes. The Company has provided workpapers for its development of Service Investment Allocator which demonstrate both its recognition of differences average costs for service lines among rate classes and differences between the numbers of customers served and the number of service lines installed for residential and small commercial customer classifications.

C. RATE STRUCTURE AND TARIFF CHANGES

Q. HOW IS YOUR DISCUSSION OF RATE STRUCTURE ISSUES ORGANIZED?

A. My assessment of rate structure issues associated with National Grid's proposals in this proceeding is presented in four major sections. Section 1 addresses the Company's proposals for distributing its proposed revenue increase among rate classes. Section 2 assesses the merits of the Company's proposed changes in rates for Firm service classes. Section 3 examines Non-Firm rate issues. Section 4 examines the data National Grid has used in its analysis of the impacts of its rate increase proposals on customers' bills, and Section 5 reviews other rate and tariff change proposals.

1. Distribution of the Revenue Increases

Q. HOW DOES NATIONAL GRID PROPOSE TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG RATE CLASSES?

A. The Company's proposed revenue increases by rate class are discussed in the Direct Testimony of NG witness Normand.[5] A summary of National Grid's recommended revenue increase distribution is presented in Table 1 on page 20 of witness Normand's Direct Testimony. The Company basically proposes to distribute its requested revenue increase among rate classes in a manner that places greater than average increases on classes with less than system average rates and less than average increases on classes that presently provide rates of return, as computed in the Company's CCOS, that above average rates of return. However, in the context of the Company's purported 13.27% overall rate increase request,[6] witness Normand recommends a cap on rate increases such that no class receives more than 115% of the overall average increase. Thus, the effective cap would be 15.26%. Yet, under the Company's proposal no class receives a 15.26% increase. However, the increases witness Normand presents for the Residential Non-Heating class and the Large C&I High Load Factor (HLF) class closely approximate that value with increases of 15.23% and 15.24% respectively.

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5 Direct Testimony of National Grid witness Normand at pages 20-22.

6 As I will explain later in this testimony, the actual increase in Base Rate Revenue that National Grid proposes is 22.23%. See Schedule BRO-5, page 4 of 4.

Witness Normand also indicates that he set a floor (or minimum) for the increase any rate class would receive. That floor is set at half the system average increase or 6.635%. However, his Table 1 indicates that under his proposals no class would receive less than an 8.76% increase.

Q. ARE THE RATE INCREASES BY CUSTOMER CLASS THAT WITNESS NORMAND PRESENTS REASONABLE AND APPROPRIATE?

A. Given the Company's representation of the overall base rate increase that it seeks, its proposed revenue increase distribution is generally reasonable. However, if the Commission chooses to accept the Company presentation of its proposed base rate increases, I would encourage the Commission to modify the Company's proposal in order to provide greater rate relief to the Extra Large C&I Low Load Factor (LLF) class.

Under the Company's proposals, the post-increase rate of return for the Extra Large C&I LLF class is still more than **twice** the system average rate of return and **nearly 600 basis points above** the post-increase rate of return for any other class of service. I find that result to be unnecessary and in appropriate. Instead, I recommend that the Commission modify the Company's proposed revenue increase distribution to lower the increase for the Extra Large C&I LLF class to the **6.635%** floor increase recommended by witness Normand (i.e., half the system average increase).

I also recommend that the Commission should compensate for the reduced revenue from the Extra Large C&I LLF class (which I compute to be $28,729) by increasing slightly the revenue requirements of Company's other non-residential rate classes. Given that Extra Large C&I LLF class is the smallest of the Company's C&I rate classes in terms of revenue at present rates, this modification of the Company's proposal would, on average, add less than 0.1% to the increase proposed for other C&I rate classes.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE COMPANY'S PROPOSED REVENUE INCREASE DISTRIBUTION?

A. Yes. In the context of the Company's 13.27% overall increase request, I appreciate the cap that National Grid proposes to place on increases for individual rate classes. However, I am concerned by the negative rates return that the Company has computed for the Residential Non-Heating class at both present and proposed rates and the even more negative rate of return value that is found when the fictitious income tax credit for that class is removed.[7] No class should be permitted to remain in a negative rate of return position for an extended period of time. Therefore, I encourage the Commission to consider a mechanism under which the revenue requirement of the Residential Non-Heating class would be gradually ratcheted upward on an annual basis between rate cases with offsetting revenue reductions flowed to other classes through the DAC. Alternatively, an increase of

[7] See Schedule BRO-3.

approximately 1.5 times the system average would appear to be sufficient as a one-time adjustment to raise the computed rate of return for the Residential Non-Heating class under the Company's CCOS into positive territory.

Q. IF THE COMMISSION GRANTS NATIONAL GRID LESS THAN ITS FULL REVENUE INCREASE REQUEST, HOW SHOULD THE COMPANY'S DISTRIBUTION OF THE REVENUE INCREASE AMONG RATE CLASSES BE ADJUSTED?

A. If the Company is granted less than its full revenue increase request, I would recommend that increase for the Residential Non-Heating be set at the lower of the Company's proposed increase for that class or 1.67 times the overall average increase (including any accepted adjustments between rate cases). The proposed increases for all other classes should be reduced in a roughly proportional manner.

2. Firm Service Rate Design

Q. HOW DOES THE COMPANY APPROACH THE DESIGN OF RATES FOR FIRM SERVICE RATE CLASSES?

A. The Company's approach first determines customer charge increases. Then, where applicable, it develops proposed demand charge increases, and finally determines distribution charges to recover the remaining revenue requirement for each class. Witness Normand testifies that Residential and Small C&I customer charges were increased by 25% while customer charges for Medium, Large and Extra Large C&I

customers were adjusted to more closely approximate his determination of full cost of service levels for those charges. For each class the proposed percentage increase in the monthly Customer Charge exceeded the overall percentage increase assigned to the class. For classes subject to demand billing, witness Normand indicates that demand charges were increased by the Company's overall requested revenue increase percentage (i.e., 13.27%). This approach thus implicitly yields less than class average increases in the distribution charges for each of the Company's firm rate schedules.

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL AND COMMERCIAL CUSTOMER CHARGES COMPARE WITH THOSE FOR OTHER GAS UTILITIES IN NEW ENGLAND?

A. Schedule BRO-2 provides a comparison of NG's current and proposed customer charges with those for other New England utilities. That comparison suggests that the Company's proposed customer charges are generally above median levels for New England gas utilities, and are near or above the averages computed by rate classification for the listed utilities. It also indicates that the majority of the companies listed have equal customer charges for their Residential Heating and Residential Non-Heating service classifications.[8] That contrasts with the Company's present and proposed rates which reflect a $2.00 higher customer charge for Residential Heating customers at present rates (i.e., $12.00 of Heating customers

[8] The two listed companies from Connecticut have higher customer charges for Residential Non-Heating customers than for Residential Heating customers.

and $10.00 for Non-Heating customers) and a customer charge for Residential Heating under proposed rates that is $2.50 higher than the proposed charge for Residential Non-Heating customers (i.e., $15.00 vs. $12.50).

Given that the Company's cost of service analyses suggest that its Residential Heating and Residential Non-Heating customer costs are relatively close in magnitude, the proposed increase in the differential between the National Grid's Residential customer charges seems to be a step in the wrong direction. I also observe that the Company's proposed Residential Heating customer charge is noticeably above both the average and the median Residential Heating customer charge levels for New England. Thus, the rationales for moving that charge to the $15.00 per month level appear less compelling.

Q. AT WHAT LEVEL SHOULD THE RESIDENTIAL HEATING CUSTOMER CHARGE BE SET?

A. If the Company is granted an overall revenue increase that is at or near its full request in this proceeding, I would recommend setting the Residential Heating customer charge at not more than $14.00 per month. If the Company is granted substantially less than its full revenue request then I would scale the increase in the charge further downward, but not below the proposed level of the Residential Non-Heating customer charge, i.e., $12.50 per month.

Q. DOES IT CONCERN YOU THAT A LESSER INCREASE IN THE RESIDENTIAL HEATING CUSTOMER CHARGE IN THIS PROCEEDING WOULD IMPEDE PROGRESS TOWARD MORE COST-BASED CUSTOMER CHARGE LEVELS?

A. No. In the context of the Company's implementation of a revenue decoupling mechanism the importance of pursuing customer charges that more fully reflect its fully allocated customer-related costs is greatly diminished. On the other hand, I support the Company's efforts to move to more cost-based customer charge levels for classes not subject to the Company's revenue decoupling mechanism.

Q. WITNESS NORMAND'S DIRECT TESTIMONY STATES, "*THE DELIVERY COSTS TO SERVICE THE COMPANY'S GAS CUSTOMERS ARE ESSENTIALLY FIXED IN NATURE…*" AND THEREFORE "*…COST RECOVERY AND PRICING SHOULD EMPHASIZE FIXED MONTHLY CHARGES THROUGH THE USE OF SEPARATE CUSTOMER AND FACILITIES CHARGES*."[9] DO YOU AGREE?

A. Only in part. Although I agree that the Company's costs of delivery service are primarily customer and demand-related, Witness Normand's statement reflects the perspective of a utility that is focused on its own cost recovery concerns and lacks sensitivity to interclass and intra-class rate equity considerations. There are many differences in the costs of providing service to individual customers that tend to get lost in simplifying assumptions used to facilitate the completion of cost allocation studies. For this reason, the Commission's retention of some flexibility to use the

[9] Direct Testimony of National Grid witness Normand at page 16.

available measures of service to provide greater recognition of such cost differences within a rate class is reasonable and appropriate.

Q. BEYOND THE CUSTOMER CHARGE CONSIDERATIONS DISCUSSED ABOVE, DO YOU FIND THE OTHER ASPECTS OF THE COMPANY'S PROPOSE RATE AND CHARGES FOR ITS FIRM SERVICE RATE CLASSIFICATIONS TO BE REASONABLE AND APPROPRIATE?

A. No. Although I generally accept the rationales for establishing new charges for each rate schedule that witness Normand has outlined in his Direct Testimony, I do not find that his rate design analysis properly computes new charges of any of the Company's firm service rate classes. I discovered this problem while trying to verify the effective percentage increases in charges for the Company's Medium, Large and Extra Large C&I rate classifications. In that process, I found that when both the revenues generated by the Company's current and proposed rates are computed using the same set of billing determinants the resulting increases in revenue by charge are not consistent with the percentage increases by rate class that witness Normand presents in Table 1 on page 20 of his Direct Testimony and in Column (Z) on page 4 of Schedule PNM-7.

Schedule BRO-3 provides a proof of revenue analysis for the Company's present and proposed rates for Medium, Large and Extra Large C&I customer classifications. Although witness Normand represents that the Medium C&I class would receive a 9.32% overall increase, my analysis of the Company's present and proposed rates finds a **20.83% increase** for the Medium C&I class. Moreover, for all of the Company's Medium, Large and Extra Large C&I rate classifications, I compute effective percentage increases that are significantly above those indicated by witness Normand. The following table summarizes those differences:

Rate Class	N Grid Proposed Increase	Division Computed Increase	Difference
Medium C&I	9.32%	20.83%	11.51%
Large LLF C&I	9.39%	15.65%	6.26%
Large HLF C&I	15.24%	21.94%	6.70%
XL LLF C&I	8.76%	13.70%	4.94%
XL HLF C&I	9.16%	13.90%	4.74%

Q. WHAT EXPLAINS THESE SUBSTANTIAL DIFFERENCES IN THE MAGNITUDES OF THE BASE RATE INCREASES THAT THE COMPANY AND THE DIVISION HAVE COMPUTED FOR THE MEDIUM, LARGE AND EXTRA LARGE C&I CLASSES?

A. These differences are explained by the Company's inappropriate inclusion of revenue for estimated forward-looking RDA and ISR adjustments in its base rate revenue for the purpose of computing new base rate charges. As shown on page 1 of Schedule BRO-3, I have fully reconciled my proof of revenue analysis with the Company's presentation, and that analysis clearly demonstrates that the Company designed its proposed base rate charges to recover $30.4 million of additional base rate revenue even those it's requested base revenue increase is only about $19.6 million. The difference is $10.8 million of which $6.9 million is represented as ISR adjustment revenue and $3.9 is RDA adjustment revenue. However, those revenue amounts represent estimates of projected revenue variances that have no appropriate role in the determination of base rate charges for gas service.

Q. HAVE YOU DEVELOPED RATES THAT CORRECT THE PROBLEMS FOUND IN THE COMPANY'S DEVELOPMENT OF ITS RATE DESIGN PROPOSALS IN THIS PROCEEDING?

A. Yes. Corrected rate designs at the Company's full revenue increase level are presented in Schedule BRO-6. I also present a set of rates that have been designed to recover the Division's recommended revenue increase for the Company of $7.6 million. That set of rate designs is presented in Schedule BRO-7.

3. Non-Firm Rate Design

Q. WILL THE COMPANY'S CHARGES FOR NON-FIRM GAS TRANSPORTATION SERVICE CHANGE AS A RESULT OF ITS PROPOSALS IN THIS PROCEEDING?

A. Yes, they will. Although the Company's filing does not explicitly discuss increases in charges for Non-Firm Service customers, the analysis presented on page 5 of Schedule PMN-7 and the changes presented in the marked-up version of the Company's tariff (see Schedule AEL-4, pages 85 and 93 of 145) clearly reflect increases in National Grid's charges for Non-Firm Service. Moreover, the charges proposed reflect dramatic and **unacceptably large increases** in the charges that would be applicable to Non-Firm service customers. As shown in Schedule BRO-6 the percentage increases that result from National Grid's proposed charges for Non-Firm Service range from low of **26.2%** to a high of **84.7%**.[10]

Q. ARE THE COMPANY'S PROPOSED NON-FIRM SERVICE CHARGES PROPERLY COMPUTED?

A. No, they are not. Based on the Non-Firm pricing determinations made in Docket 3943, the Company's Distribution Charges for Non-Firm Service customers are intended to be computed as a 20% discount from the Company's otherwise applicable Firm Service rate schedules. However, further review of the data and calculations underlying the Company's proposed Non-Firm Service charges finds two major problems in the development of the proposed charges for Non-Firm service.

First, National Grid has inappropriately included revenue from Firm Service customer charges in the data used to compute distribution charges for Non-Firm Service.

Second, the Firm Service rates, from which the proposed charges of Non-Firm Service are computed, are themselves incorrectly developed due to the Company's incorrect treatment of ISR and RDA revenues

[10] It was through efforts to understand the source of these unexpectedly large increases in the Company's charges for Non-Firm Service that significant problems in the Company's overall presentation of its rate design and revenue increase distribution recommendations were discovered.

Q. WHY IS IT INAPPROPRIATE TO INCLUDE CUSTOMER CHARGE REVENUE FOR THE MEDIUM, LARGE AND EXTRA LARGE C&I CLASSES IN THE DETERMINATION OF DISTRIBUTION CHARGES FOR NON-FIRM SERVICE CUSTOMERS?

A. Non-Firm Service customers are separately billed monthly customer charges under the Company's Non-Firm Service rates. Therefore, it is neither necessary nor appropriate to include revenue from Firm Service customer charges in the determination of discounted distribution rates for Non-Firm customers. Inclusion of Firm Service customer charge revenue in the determination of Non-Firm distribution charges would effectively double recover customer costs from Non-Firm customers.

Q. HOW SHOULD NATIONAL GRID'S CHARGES FOR NON-FIRM TRANSPORTATION SERVICE CUSTOMERS BE STRUCTURED?

A. Although the development of an appropriate cost basis for pricing Non-Firm Transportation Services is necessary and appropriate to ensure that Non-Firm customers are served at just and reasonable rates, it is not possible at this time to set cost-based fixed rates for National Grid's Non-Firm Transportation service customers in the absence of a fully developed set of cost allocations for that class. Thus, I recommend that the Commission continue the use of the 20% discount from otherwise applicable Firm rates as an interim measure until the completion the Company's next base rate proceeding. In addition, the Commission should direct the Company to file a CCOS in its next base rate case that includes explicit allocations of costs to Non-Firm service customers.

When such a study is produced it will serve as an important guide for the Commission in its determination of appropriate revenue requirements and charges for Non-Firm Service rate classifications. However, the Commission will retain discretion to use the results of that study as it deems appropriate.

Q. HAVE YOU PREPARED ALTERNATIVE CALCULATIONS OF DISTRIBUTION CHARGES FOR NON-FIRM SERVICE CUSTOMERS?

A. Yes. Schedule BRO-12 provides four alternative sets of Non-Firm Distribution Charge calculations. Page 1 of 3 shows the results of Company's Non-Firm Distribution Charge Non-Firm Distribution Charge analysis with Firm Service customer charges removed.[11] Schedule BRO-12, page 2 of 3, provide a second analysis which removes ISR and RDA Revenue Adjustments, as Customer Charge Revenue from the Company's Non-Firm Distribution Charge calculations. Finally, Schedule BRO-12, page 3 of 3, provides Non-Firm Distribution Charge calculations based on the Division's recommended overall revenue increase for National Grid's Gas service and the Division's calculated Firm Service rates by class that are presented in Schedule BRO-7, page 2 of 4.

[11] Although the analysis in witness Normand's Schedule PMN-7, page 5 of 5, only appears to include Demand charge revenue (Column (B)) and Distribution charge revenue (Column (C)), I was able to verify from the data on the prior pages of Schedule PMN-7 that the data in Column (C) include both distribution charge revenue and customer charge revenue. For example, the $14,216,619 for Distribution revenue shown on Schedule PMN-7, page 5 of 5, Line 1, Column (C), precisely equals the sum of $3,605,980

Each of the pages of Schedule BRO-12 shows progressively lower Distribution Charges for Non-Firm service. However, even the lowest of these alternatives appears to produce comparatively large increases for Non-Firm customers who would otherwise qualify for Extra Large C&I service. Upon further investigation of these results, I have concluded that the large percentage increases computed for Extra Large C&I customer classifications is primarily a product of the Company's efforts to alter its Firm Service rate designs to recover a greater portion of its total delivery service revenue for Firm C&I customers through Demand Charges and a lesser percentage through per therm charges based on throughput. This rate design change places greater emphasis on demand charges and greater weight on differences between the load characteristics of Firm Service and Non-Firm Service customers.

Implicit in the Company's methodology for applying the 20% rate discount a presumption that the load factors (i.e., ratios of average throughput to demand) for Firm and Non-Firm customers are relatively homogeneous. That assumption was not problematic when demand related revenue accounted for a lower percentage of total Firm Service revenue for these classes. However, with the shift to greater recovery of Firm Service revenue through demand charges, differences in load factors receive greater emphasis. Thus, in the absence of a more cost-based methodology for pricing Non-Firm Service, the Company's current methodology for determining discount needs to be revised.

Medium C&I Customer Charge revenue shown in Schedule PMN-7, page 4 of 5, Column (P), Line 77, and $10,610,639 of First Block Therm revenue shown on Line 77, Column (R) on that same page.

4. Bill Impact Analysis

Q. DO YOU HAVE ANY CONCERNS REGARDING THE BILL IMPACT ANALYSES THE COMPANY HAS PRESENTED IN THIS PROCEEDING?

A. Yes, I do. My concerns are twofold.

First, although the Company's weather-normalized historic throughput data and projections of throughput for the rate year reflect noticeable changes in use per customer those changes are not reflected in the Company's bill comparisons. Rather, National Grid continues to present bill comparisons in this proceeding based on the same average use per customer measures that it presented in Docket 3943 even though those data appear substantially out-of-date.

Second, National Grid's bill comparisons are computed using an inappropriate RDA factor.

Q. WHAT IS THE BASIS OF YOUR ASSESSMENT THAT THE DATA USED TO REPRESENT AVERAGE USE BY RATE CLASS IN THE COMPANY'S BILL IMPACT ANALYSES IS OUT OF DATE?

A. Schedule BRO-8 provides calculations of average annual use per customer, based on the rate year billing determinants presented in witness Normand's Schedule PMN-7, and compares the results of those calculations to the average usage levels shown for each rate class on the pages of Schedule PMN-8. For every rate class a noticeable difference is found between the average use data employed in Schedule PMN-8 and computed average use for the same rate class for the rate year.

Q. WHY ARE THE IDENTIFIED DIFFERENCES IN AVERAGE USE IMPORTANT?

A. The observed differences suggest that the Commission and possibly the general public are not being provided accurate and reliable information regarding the anticipated impacts of the Company's proposals. For this reason, the Company should be required to update its filed bill impact analyses, and to provide bill impact assessments based on the Commission's final order using average use levels by rate class that are more indicative of the average usage levels customer are expected to have on a weather-normalized basis during the rate effective period.

Q. WHY IS THE RDA USED IN THE COMPANY'S BILL IMPACT ANALYSES INAPPROPRIATE?

A. First, the RDA is a retrospective adjustment mechanism. It provides for adjustment to be made during a future period for actual revenue variances during a past period. Nothing in the RDA tariff provisions allows for the billing of an RDA factor for anticipated future revenue variances. Second, Section 3, Schedule A, Sheet 18 of the Company's tariff provides that the "*Target Revenue per Customer*" be established "*at the time of the most recent rate case*." Thus, when assessing bill impacts for the Rate Year, the appropriate Revenue-per-Customer targets are those based on new revenue-per-customer benchmarks computed for this proceeding, not data from a prior proceeding. Yet, witness Leary testifies that the Company has "*incorporated an RDA pro forma adjustment equal to the variance between the forecasted revenue per customer for residential, small and medium commercial and industrial customers for the rate year and the revenue per customer benchmarks approved in Docket No. 4206*."[12]

If Target Revenue per Customer ("RPC") benchmarks are reset properly in this proceeding, then there should be no *a priori* expectation of an RDA adjustment based on an expectation of future revenue variances. Rather, the only revenue variances that might be appropriate to include in bill comparisons are those that will result from the RDA factor currently being considered by this Commission in the Company's 2012 DAC proceeding (Docket 4339). Moreover, that RDA factor will only be in effect for the first 9 months of the rate year. For the last three months of the rate year no information exists on which to base the determination of an appropriate RDA factor, and any effort to produce such a factor would at best reflect a high degree of speculation.

Q. IS THERE ANYTHING IN THE COMMISSION'S ORDER IN DOCKET 4206 THAT AUTHORIZES THE APPLICATION OF A FORWARD LOOKING RDA FACTOR IN BASE RATE PROCEEDING?

A. No. I have reviewed the Commission order in Docket 4206, and nothing in that order either explicitly or implicitly recognizes the appropriateness of such an RDA

[12] Direct Testimony of witness Leary at page 6, lines 4-7.

factor. Likewise, there is no mention of such a forward-looking RDA anywhere in the Company's tariff. Thus, this distortion of the appropriate application of the Company's gas revenue decoupling mechanism must be rejected.

5. Other Rate and Tariff Change Issues

Q. WHAT ARE THE OTHER RATE AND TARIFF CHANGE ISSUES THAT YOU WILL ADDRESS?

A. The following discussion addresses changes that the Company seeks in its GCR and DAC mechanisms. It also addresses the proposal witness Leary offers regarding "paperless bill credits," and discusses evidence in this docket regarding: (a) RDM related interclass revenue shifts (i.e., cross-subsidization between classes) that results from the present formulation of the Company's revenue decoupling mechanism, and (b) further elaborates on the unjustified and inappropriate nature of the forward-looking RDA revenue adjustment that witness Leary discusses.

a. Gas Cost Recovery (GCR) Changes

Q. HOW DOES NATIONAL GRID PROPOSE TO MODIFY ITS TARIFF PROVISIONS RELATING TO THE COMPANY'S GAS COST RECOVERY ("GCR") CLAUSE?

A. The testimony of witness Leary indicates that National Grid proposes two changes in tariff provisions relating to its GCR. Those changes include:

- A proposal to include a true-up mechanism for commodity-related bad debt; and
- A simplified treatment of gas supply refunds.

Q. SHOULD THE COMMISSION ACCEPT NATIONAL GRID'S PROPOSAL FOR TRUING-UP COMMODITY-RELATED BAD DEBT COSTS WITHIN ITS GCR MECHANISM?

A. No. Although this proposal is discussed in greater detail in the testimony of Division witness David Effron, I urge the Commission to recognize that the mechanism the Company proposes for reconciling commodity-related bad debt costs within the GCR is inconsistent with the Commission's long-established policy to seek stability in the gas costs that the Company bills to its Rhode Island sales service customers. In contrast to that objective, National Grid's proposal would add to, rather than mitigate, year-to-year volatility the Company's GCR charges.

Q. ARE THE PROCEDURES THAT NATIONAL GRID PROPOSES FOR SIMPLIFYING THE TREATMENT OF GAS SUPPLY REFUNDS REASONABLE?

A. Yes, they are.

b. Distribution Adjustment Clause (DAC) Changes

Q. DO NATIONAL GRID'S PROPOSALS IN THIS PROCEEDING INCLUDE CHANGES TO THE COMPANY'S DISTRIBUTION ADJUSTMENT CLAUSE?

A. Yes. Witness Leary explains that National Grid proposes (1) a simplification of the Dual Fuel customer tracking mechanism; (2) a new Property Tax Adjustment factor; and (3) other minor administrative changes.

Q. SHOULD THE COMMISSION ACCEPT THE COMPANY'S PROPOSAL FOR SIMPLIFYING DUAL FUEL CUSTOMER TRACKING?

A. No. This proposal is closely related to the change in the Dual Fuel margin threshold that the Company proposes, and for basically the same reasons I believe the proposed change in the Dual Fuel customer tracking mechanism that National Grid requests in this proceeding is not appropriate. Most importantly, the new mechanism the Commission has just approved should be given an opportunity show its merits before it is summarily dismissed. It is not clear that the Company's proposal would necessarily simplify Dual Fuel customer tracking. Moreover, the return of focus to only Non-Firm Dual Fuel customers may be more appropriate once a reasonable cost basis for Non-Firm Service has been established and there is greater indication that migration between Firm and Non-Firm service options has stabilized.

In my experience, other gas utilities do not necessarily encounter the same degree of migration between firm and non-firm service that National Grid has experienced in Rhode Island. Perhaps a better alternative is for the Company to investigate means for limiting short-term (less than one-year) shifts between service options. This can often be accomplished through contract terms and/or the use of demand ratchets.

Q. WHAT ARE THE CHANGES THAT NATIONAL GRID SEEKS IN ITS THRESHOLD DETERMINATIONS RELATING TO THE DETERMINATION OF DAC ADJUSTMENTS FOR DUAL-FUEL REVENUE?

A. The Company's proposals for modifying the current DAC credit/surcharge determinations have two components. First, the threshold would be modified to apply only to Dual-Fuel customers who take Non-Firm service. Second, it would set the threshold for determining DAC credits or surcharges based on its **projection** of Non-Firm revenue for those customers for the test year (i.e., **$1,512,209**). Witness Leary's testimony notes that the proposed threshold that would be applicable only to Non-Firm revenue margins is "…*close to the $1.6 million revenue requirement attributed to non-firm customers at the time of the 2008 Gas Rate Case* [Docket No. 3943]."[13]

Q. IS THERE ANY PARTICULAR RELEVANCE TO WITNESS LEARY'S OBSERVATION THAT THE PROPOSED THRESHOLD FOR NON-FIRM REVENUE IS "CLOSE TO THE $1.6 MILLION REVENUE REQUIREMENT ATTRIBUTED TO NON-FIRM CUSTOMERS PRIOR TO THE COMMISSION'S FINAL DETERMINATIONS IN DOCKET 3943?

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[13] Ibid., page 8.

A. No. Any correspondence between the former $1.6 million amount and the $1,512,209 amount that the Company proposes in this proceeding should be considered coincidental given changes in both throughput volumes and applicable rates for Non-Firm service.

Q. WHY WAS A SINGLE REVENUE THRESHOLD ESTABLISHED IN DOCKET 3943 FOR FIRM AND NON-FIRM DUAL-FUEL REVENUE?

A. A single threshold applicable to both Firm and Non-Firm revenue from Dual-Fuel customers was established to address concerns regarding the potential for migration of customers between Firm and Non-Firm rate classifications after the final rates in Docket No. 3943 were established.

Q. IS THE $1,512,209 THRESHOLD FOR MARGIN CREDIT DETERMINATIONS THAT THE COMPANY PROPOSES REASONABLE?

A. No. It is not. The $1,512,209 understates the margin revenue that should be expected from Non-Firm Service customers. As shown in Schedule BRO-8, the Company's actual Non-Firm Margin Revenue for each of last three years reflected in the Company's annual DAC filings has exceeded the level projected by National Grid for the test year. Even the Company's most recent DAC filing, which was submitted to the Commission on August 1, 2012, shows total Non-Firm margin revenue for the twelve months ended June 30, 2012 of **$1,540,756**[14] despite that

[14] See Attachment MCS-7, pages 10-15, attached to the testimony of Mariella Smith in Docket 4339.

period including significantly warmer than normal weather. In addition, the Company's projected Non-Firm Margin Revenue for the Test Year does not appear to consider the impacts of the Company's requested rate increase in this proceeding on its Non-Firm margin revenue.

Given that the Company's distribution charges for Non-Firm customers are computed as discounts from the Company's Firm Service rates, the base rate increase that National Grid requests should be expected to have a noticeable impact on its Non-Firm rates and revenue margins. I find that if after removing the errors in the Company's Firm Service rates, the average increase in the Company's distribution charges for Non-Firm Service at its full requested revenue increase would be about 11.70%. Applying that increase to the Company's actual Non-Firm revenue margins for the twelve months ended June 30, 2012 (without making any adjustment for warmer than normal weather during that 12-month period), yields expected post-rate increase revenue margins from Non-Firm customers of $1,721,024. If we adjust the Non-Firm throughput for that period to reflect normal weather, the expected revenue margins would likely be in excess of $1.8 million. Therefore, if the threshold for calculation of On-System Margin Credits is based on just Non-Firm margins, I would recommend that the threshold be set at **$1.8 million**.

However, I encourage the Commission to maintain the current formula for determining On-System Margin Credits which is based on revenue margins for both Firm and Non-Firm Dual Fuel customers. I believe that maintenance of the current formulation of the On-System Margin Credit threshold is particularly important in the context of the extremely large increases in Non-Firm Distribution Charges that the Company has proposed.

Much of the frustration of the parties that attempted to address Non-Firm pricing issues in Docket 3943 was related to the difficulties in the determination of costs of service for Dual Fuel customers due to the potential for migration of such customers between Firm and Non-Firm gas service alternatives. That is the primary reason that the current $2.8 million On-System Margin threshold addresses both Firm and Non-Firm margin revenue for Dual Fuel customers. As long as significant throughput volumes for firm customers maintain Dual Fuel capability and migration between Firm and Non-Firm rate classifications remains an option, the maintenance of a margin revenue threshold that addresses both Firm and Non-Firm customers having Dual Fuel capability is appropriate. I understand that the administration of an On-System Margin Credit mechanism that addresses both Firm and Non-Firm revenue margins requires some effort on the part of the Company, but simply shifting revenues between Firm and Non-Firm service classifications when customers with Dual Fuel capabilities move between Firm and Non-Firm rates is not the answer, particularly when the 20% discount for Non-Firm Service is considered. With those discounts, the amount of margin revenue expected from a Dual Fuel customer served under a Firm Service rate classification should not be expected to equal the amount of margin revenue derived from the same customer served under a Non-Firm Rate offering.

Finally, I reiterate that the Company and the Division have negotiated, and the Commission has recently accepted, amendments to the On-System Margin Credit mechanism in the DAC which address certain aspects of Dual Fuel customer migration between Non-firm and Firm service rate classifications. I believe some time should be provided to observe the success of those amendments before they are discarded in favor of the Company's proposals in this proceeding. Moreover, in the face of large percentage increases in distribution charges for Extra Large Non-Firm customers, the Company may experience additional migration of Dual Fuel customers and service volumes from the Company's Non-Firm service offerings to its Firm Service rates. As shown in Schedule BRO-8, page 1 of 2, the proposed Non-Firm distribution charges that witness Normand presents in Schedule PMN-7, page 5 of 5, yield increases of **84.7%** and **45.6%** respectively on Dual Fuel Extra Large C&I LLF and Extra Large C&I HLF who presently use Non-Firm delivery service.[15] Considering that those increases may provide impetus for further migration of Dual Fuel customers between Firm and Non-Firm rate schedules, maintenance of the current On-System Margin Credit structure appears even more imperative.

Q. IF THE THRESHOLD FOR DUAL FUEL MARGIN REVENUE IS ESTABLISHED TO ADDRESS BOTH FIRM AND NON-FIRM SERVICE MARGINS, SHOULD THE CURRENT $2.8 MILLION THRESHOLD BE ADJUSTED?

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[15] Based on the supporting data for the Company's On-System Margin Credit calculations in its recent 2012 DAC filing (Docket 4339), I find that the vast majority of throughput for the Non-Firm service customers is comprised of throughput for customers who would otherwise qualify for the XL C&I LLF and XL C&I HLF service classifications.

A. Yes. As shown in Schedule BRO-8, the combined margin revenue from Firm and Non-Firm Dual Fuel customers over the last three years has consistently been in the range of **$3.5 million** per year or roughly 25% above the current $2.8 million threshold. Furthermore, in the absence of a CCOS that enables the Commission to separately identify Non-Firm costs of service, I recommend that the threshold be revised upward to reflect the actual average Dual Fuel revenue margin over the last three years (i.e., $3.5 million adjusted upward to reflect the average increase in Non-Firm Distribution charges that results from the Commission's final rate determinations in this proceeding.[16] Given that most of the Company's Non-Firm throughput is for Extra Large customers, this methodology should yield an increase well in excess of the Company's overall average percentage increase. Thus, I assess that a reasonable estimate of the combined Firm and Non-Firm rate year revenue margins from Dual Fuel customers would be in the range of **$3.8 million**.

c. Revenue Decoupling Related Issues

Q. ARE YOU COMFORTABLE WITH THE COMPANY'S TREATMENT OF RDA REVENUES IN THE DEVELOPMENT OF ITS RATE PROPOSALS FOR THIS PROCEEDING?

[16] Thus, the Commission should order the Company to compute the final threshold level using the formula outlined above as part of its compliance filing in this case when the final "average increase in Non-Firm Distribution Charges" is known.

A. As this is the first base rate proceeding since those mechanisms were approved, the Commission should take care in considering the impacts, if any, in which the RDA impacts base rate determinations.

Q. SHOULD ISR AND RDA REVENUES BE INCLUDED IN THE REVENUE FOR EACH RATE CLASS SUBJECT TO THE RDM WHEN REVENUE PER CUSTOMER AMOUNTS ARE RESET AT THE CONCLUSION OF THIS CASE?

A. No, they should not. The calculation of revised revenue per customer amounts should be computed using only base rate revenue.

Q. SHOULD ISR AND RDA REVENUES BE INCLUDED IN BASE RATE REVENUE WHEN COMPUTING BASE REVENUE INCREASES FOR EACH RATE CLASS?

A. No. ISR and RDA revenues are not part of the Company's base rates.

Q. IS IT APPROPRIATE TO INCLUDE ISR AND RDA CHARGES IN THE COMPUTATION OF BILL IMPACTS FOR THE NEW RATES ADOPTED IN THIS PROCEEDING?

A. It is appropriate to include those adjustments in existing rates for comparisons based on an historic test year. It is only appropriate to include those adjustments for a projected rate year to the extent that the amounts of those adjustments are known at this time. The gas ISR revenue adjustment and the RDA revenue adjustment are yet to be approved, but each has been filed with the Commission for implementation as of November 1, 2012. Those charges would therefore be applicable for the first nine months of the test year to the extent the filed charges for those adjustments are reasonably known and appropriately computed.[17]

Q. IN ITS MAY 25, 2012 ORDER IN DOCKET 4206 THE COMMISSION INDICATED THAT IT WOULD "*DEFER FINDING ON* [THE ISSUE OF CROSS-SUBSIDIZATION AMONG RATE CLASSES] *UNTIL THE NEXT RATE CASE*."[18] DO YOU FIND EVIDENCE OF SUCH CROSS-SUBSIDIZATION IN THIS PROCEEDING?

A. Yes, I do. Witness Leary's Schedule AEL-3, page 1 of 4, provides the calculation of an estimated Rate Year RDA factor.[19] Using projected revenue variances and projected throughput measures for Residential, Small C&I and Medium C&I classes, witness Leary computes an "Estimated Rate Year RDA Factor" of $0.0153 per therm. To test the effects of that RDA factor on revenue collections by rate class, I applied the computed $0.0153 per therm to the Rate Year throughput estimates by class that witness Leary uses, and I compare those projected revenue collections by class with the computed revenue variances by class. The results of that exercise

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[17] The factor that would be effective for the first nine months of the Rate Year (i.e. February 2013 through November 2013 will be determined in the Company's 2012 DAC proceeding. My preliminary review of the Company's 8/1/2012 DAC filing finds that the RDA charge computed on page 11 of Attachment MSC-10 is incorrectly computed. The factor presented $0.302 per therm is calculated using Total Annual Firm Throughput rather than the annual firm throughput for just those classes for which the RDA is applicable. It appears that, with use of the projected throughput for just the Residential and Small C&I classes, the appropriate RDA factor for the November 2012 through October 2013 period would be $0.0421 per therm (See Schedule BRO-10, page 2 of 2).

[18] The Commission May 25, 2012 Order in Docket 4206 at page 38.

[19] As I have previously noted, such a forward-looking RDA factor is not authorized by the Commission and is inappropriate for inclusion in ratemaking determinations in this proceeding.

are shown in Schedule BRO-10, page 1 of 2. Most notably, Schedule BRO-10, page 1 of 2, shows a shifting of more than $2.4 million of revenue requirements from the Residential Heating class to the other three rate classes shown. As a result of this use of a uniform dollars per therm factor for all affected classes, the Medium C&I which had a positive revenue variance (i.e., over-collection) of $689,302 is assessed $804,269 of additional charges. That is a shift of nearly $1.5 million to the Medium C&I class. Likewise, the Small C&I class is hit with an effective shift of over $500,000 and the Residential Non-Heating class is required to provide a $332,500 subsidy to Residential Heating customers.

Q. IS THE EXAMPLE CITED ABOVE UNIQUE IN TERMS OF THE DIRECTION AND MAGNITUDE OF THE RESULTING REVENUE SHIFTS?

A. No. Schedule BRO-11, page 2 of 2, provides a second example of a substantial shift of revenues among the same classes. This second example reflects an RDA adjustment based on the actual RDA data that National Grid has included in its recent 2012 DAC filing (Docket 4339). Based on the information presented in Attachment MCS-10 to the Testimony of witness Mariella Smith in that proceeding, I again find a large shift of revenue requirements from the Residential Heating class to the Residential Non-Heat, Small C&I, and Medium C&I classes.[20] In this

[20] As noted previously, the Company's filed RDA adjustment in Docket 4339 is incorrectly computed due to what appears to have been the inadvertent use of an incorrect measure of throughput in the Company's calculation of the proposed RDA factor. However, the revenue shifts identified in the analysis on page 2 of Schedule BRO-11, correct for that error.

instance, there is a shift of $1.95 million with $1.4 million of the burden of that revenue shift falling on Medium C&I customers.

Q. HOW SHOULD THE COMMISSION ADDRESS THESE SIGNIFICANT SHIFTS OF REVENUE RESPONSIBILITIES AMONG RATE CLASSES?

A. The Commission should alter the RDM to require the Company to reconcile revenue recovery separately for each applicable rate class and to compute all future RDA factors on a class-by-class basis.

<u>4. Paperless Bill Credits</u>

Q. HAVE YOU CONSIDERED THE COMPANY'S PROPOSAL FOR OFFERING RATE CREDITS TO CUSTOMERS WHO ELECT TO RECEIVE PAPERLESS BILLS FROM THE COMPANY?

A. I have. Paperless bills are now widely used by a wide variety of organizations, and the Company's offering of a paperless bill credit can provide customers an easy cost-based method for lowering their monthly charges. However, in offering such a program, the Company assumes a responsibility for providing reasonable access at all times to both current bills and a reasonable number of prior bills in a secure electronic format. In addition, for at least the first couple years that this program is offered, the Company should be required to provide periodic reports (e.g., annually or semi-annually) which document actual customer participation and actual cost savings achieved.

Finally, it should be understood that revenue credits granted to customers electing to use paperless bills should not be included in the determination of revenue variances for which the Company is compensated as part of future RDA factors. Assuming the proposed credits are cost-based, any revenue foregone as a result of the offering of bill credits should be off set by reductions in the Company's costs of providing service.

III. DIVISION RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE KEY RECOMMENDATIONS THAT YOU PRESENT IN THIS TESTIMONY?

A. The following represents a summary of a number of the key elements of my guidance to the Commission in this proceeding. I note, however, that the omission of any specific finding or recommendation from this summary should not be interpreted as a suggestion that an omitted recommendation or finding is of lesser importance. Given the foregoing, the key findings of this testimony include:

1. The Commission should find that the Company's forecasts of Use per Customer and Throughput volumes do not warrant a high degree of confidence in their accuracy and reliability.

2. The Commission should find that the Company's omission of any analysis of its costs of providing service to both Non-Firm customers and gas marketers unduly impedes the Commission ability to assess the reasonableness of the rates and charges for both Non-Firm Service and Firm Service customers.

3. The Commission should conclude that with the modification proposed herein the Company's proposed revenue increase distribution is reasonable, but the methods the Company has used to apply those increases are not reasonable and are not consistent with the revenue increase distribution that witness Normand outlines in his Direct Testimony.

4. The Commission should find that rates for Non-Firm service presented on page 5 of Schedule PMN-7 are incorrectly computed and significantly overstate that charges that should be applied to the Company's Non-Firm Service customers.

5. The Commission should find that the $1,512,209 revenue margin threshold for Non-Firm Dual Fuel customers National Grid has proposed under-states

the expected margin revenue from Non-Firm Dual Fuel customers. The appropriate threshold level should be computed in the Company's compliance filing as the average applicable margin revenue adjusted by the average increase in Non-Firm Distribution Charges resulting from the Commission's rate order in this proceeding.[21]

6. The Commission should find that RDA factor National Grid proposes to implement based on a prospective assessment of revenue variances is inappropriate and unnecessary. Moreover the Commission should direct the Company to update and reset its Target Revenue per Customer based on the final determinations in this proceeding as required by its tariff. .

7. The Commission should direct National Grid to update the usage data upon which it relies to represent impacts on "average" customers for each of its rate classes when preparing bill comparisons for the Commission or the general public given that the average gas use statistics it currently relies upon in those analyses are not reflective of its usage patterns.

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[21] If, as recommended herein, the margin revenue threshold is applied to revenue margins for both Firm and Non-Firm Dual Fuel customers, I estimate that, using this formula, the appropriate threshold level will be in the range of **$3.8 million**. However, if the Commission should choose to apply the threshold only to revenue margins derived from Non-Firm Dual Fuel customers, the appropriate level of the threshold should be in the range of **$1.8 million**.

8. On the basis of the evidence presented in this proceeding, the Commission should conclude that the current RDM produces unacceptable large re-distributions of revenue requirements among rate classes, and it should initiate a new proceeding to investigate methods for mitigating such interclass revenue transfers.

9. The Commission also should find that neither actual historic nor estimated future RDA and ISR revenues are appropriate for inclusion in base rate revenue requirements when designing new rates and charges in a base rate proceeding. The Commission should also conclude that the RDA and ISR revenue requirements are not appropriate for inclusion in the determination of discounted rates for the Company's Non-Firm Service customers.

10. The Commission should reject the Company's prospective estimate of a $3,888,810 RDA revenue requirement for the Rate Year, finding no basis for such an adjustment in either the Company's tariff or the Commission order in Docket 4206. Further, the Commission should find that if Revenue per Customer targets are reset in this case, as called for in the Company's tariff, the expected RDA on a forward-looking basis should be zero. Only after-the-fact identification of RDA adjustment amounts is appropriate.

11. Based on the evidence of significant shifts of revenue requirements between rate classes that are documented in this testimony, the Commission should require future RDA determinations to employ individual rate class reconciliations and separate RDA factors for each applicable rate class.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

National Grid - Gas
RIPUC Docket No. 4323

Summary Evaluation of National Grid's Forecasting Models

Rate Class					Model		Reported R-Square Value	No. of Variables for which 95% Confidence Interval Straddles Zero
1012		Res	Non-Heating		Customer Counts		0.9198	
1012		Res	Non-Heating		Use Per Customer		0.7778	
1247		Res	Heating		Customer Counts		0.9843	
1247		Res	Heating		Use Per Customer	Base	0.7535	
1247		Res	Heating		Use Per Customer	Slope	**0.2607**	One
2107		C&I	Small		Customer Counts		**0.6828**	
2107		C&I	Small		Use Per Customer	Base	**0.2132**	
2107		C&I	Small		Use Per Customer	Slope	**0.2470**	One
2237	1/	C&I	Medium	Sales	Customer Counts		0.9804	
2237	1/	C&I	Medium	Sales	Use Per Customer	Base	**0.2632**	
2237	1/	C&I	Medium	Sales	Use Per Customer	Slope	**0.4299**	Two
22EN		C&I	Medium	FT-1	Customer Counts		0.9352	
22EN		C&I	Medium	FT-1	Use Per Customer	Base	0.5858	
22EN		C&I	Medium	FT-1	Use Per Customer	Slope	**0.3538**	Two
2221		C&I	Medium	FT-2	Customer Counts		0.9891	
2221		C&I	Medium	FT-2	Use Per Customer	Base	0.9282	
2221		C&I	Medium	FT-2	Use Per Customer	Slope	0.7603	One

National Grid - Gas
RIPUC Docket No. 4323

Summary Evaluation of National Grid Forecasting Models

Rate Class				Model		Reported R-Square Value	No. of Variables for which 95% Confidence Interval Straddles Zero
3367	C&I	LLF Large	Sales	Customer Counts		0.9832	
3367	C&I	LLF Large	Sales	Use Per Customer	Base	0.7597	
3367	C&I	LLF Large	Sales	Use Per Customer	Slope	**0.4457**	Two
33EN	C&I	LLF Large	FT-1	Customer Counts		0.6052	
33EN	C&I	LLF Large	FT-1	Use Per Customer	Base	**0.4483**	
33EN	C&I	LLF Large	FT-1	Use Per Customer	Slope	**0.4570**	
3321	C&I	LLF Large	FT-2	Customer Counts		0.9650	
3321	C&I	LLF Large	FT-2	Use Per Customer	Base	0.0000	
3321	C&I	LLF Large	FT-2	Use Per Customer	Slope	n/a	
2367	C&I	HLF Large	Sales	Customer Counts		0.9333	
2367	C&I	HLF Large	Sales	NH Model		0.0000	
23EN	C&I	HLF Large	FT-1	Customer Counts		**0.4626**	
23EN	C&I	HLF Large	FT-1	NH Model		**0.2673**	One
2321	C&I	HLF Large	FT-2	Customer Counts		0.9839	
2321	C&I	HLF Large	FT-2	NH Model		0.0000	
3496	C&I	LLF XL	Sales	Customer Counts	Constant	n/a	
3496	C&I	LLF XL	Sales	Use Per Customer	Base	0.7233	
3496	C&I	LLF XL	Sales	Use Per Customer	Slope	0.6948	
34EN	C&I	LLF XL	FT-1	Customer Counts	Constant	n/a	
34EN	C&I	LLF XL	FT-1	Use Per Customer	Base	**0.1685**	One
34EN	C&I	LLF XL	FT-1	Use Per Customer	Slope	0.5832	
3421	C&I	LLF XL	FT-2	Customer Counts	Constant	n/a	
3421	C&I	LLF XL	FT-2	Use Per Customer	Base	n/a	
3421	C&I	LLF XL	FT-2	Use Per Customer	Slope	0.6431	
2496	C&I	HlF XL	Sales	Customer Counts	Constant	n/a	
2496	C&I	HlF XL	Sales	NH Model		0.9481	
24EN	C&I	HlF XL	FT-1	Customer Counts	Constant	n/a	
24EN	C&I	HlF XL	FT-1	NH Model		n/a	
2421	C&I	HlF XL	FT-2	Customer Counts	Constant	n/a	
2421	C&I	HlF XL	FT-2	NH Model		0.0000	

National Grid - Gas

RIPUC Docket No. 4323

Comparison of RI Costs for Natural Gas and Fuel Oil Alternatives

Natural Gas Cost Data for RI	Natural Gas - C&I XL HLF	Natural Gas - C&I XL HLF	Natural Gas - C&I Large LLF	Natural Gas - C&I Large LLF	Natural Gas - C&I Medium	Natural Gas - C&I Medium
Average Annual Bill @ Proposed Rates	$ 271,837	$ 271,837	$ 67,513	$ 67,513	$ 13,332	$ 13,332
Average Annual Therm Use	284,094	284,094	57,742	57,742	10,950	10,950
Average Cost per Therm (Incls. GCR, DAC & ISR)	$ 0.96	$ 0.96	$ 1.17	$ 1.17	$ 1.22	$ 1.22
Price with 20% Discount From Firm Rate	$ 0.77	$ 0.77	$ 0.94	$ 0.94	$ 0.97	$ 0.97
Therms per MMBtu	10	10	10	10	10	10
Natural Gas Cost per MMBtu	**$ 7.65**	**$ 7.65**	**$ 9.35**	**$ 9.35**	**$ 9.74**	**$ 9.74**

Fuel Oil Cost Data	No.2 Fuel Oil	No. 6 Fuel Oil	No.2 Fuel Oil	No. 6 Fuel Oil	No.2 Fuel Oil	No. 6 Fuel Oil
Winter 2012-13 Price per Gallon	$ 3.15	$ 2.15	$ 3.15	$ 2.15	$ 3.15	$ 2.15
Delivery Charges	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Total Cost (Excluding on-site storage costs)	$ 3.35	$ 2.35	$ 3.35	$ 2.35	$ 3.35	$ 2.35
Gallons per MMBtu	7.25	7.25	7.25	7.25	7.25	7.25
Fuel Oil Cost per MMBtu	**$ 22.84**	**$ 15.59**	**$ 22.84**	**$ 15.59**	**$ 22.84**	**$ 15.59**
Ratio: Fuel Oil Cost to Delivered Natural Gas Cost	**2.98**	**2.04**	**2.44**	**1.67**	**2.34**	**1.60**

Notes:

Low Load Factor Natural Gas customers may not have sufficient volume requirements to purchase No. 6 Fuel Oil economically.

These comparisons are gas priced at National Grid's GCR rate in Rhode Island. However, many non-firm customers are able to obtain natural gas at lower prices from third party suppliers.

National Grid - Gas
RIPUC Docket No. 4323

Re-Allocation of Income Taxes Responsibilities by Rate Class Using a Rate Base Allocation Factor

	Total Company	Residential Non-Heating	Residential Heating	Small C&I	Medium C&I	Large C&I- HLF	Large C&I- LLF	Extra Large C&I- HLF	Extra Large C&I- LLF
Rate Base	369,945,458	14,706,535	229,906,980	30,724,264	47,732,910	22,827,675	8,907,894	2,935,729	12,203,471
Total Gas Operating Revenues	152,127,765	5,765,766	97,902,615	13,500,366	18,346,560	7,885,295	2,478,650	1,423,775	4,824,739
Purchased Gas Costs	-	-	-	-	-	-	-	-	-
Other O&M Expense	84,434,192	5,051,467	56,744,418	7,398,182	7,983,665	3,381,242	1,306,430	507,617	2,061,171
Depreciation & Amortization Exp	29,811,204	1,495,278	19,232,669	2,645,907	3,364,557	1,500,820	575,157	194,940	801,876
Other Taxes	16,196,620	819,854	10,466,880	1,437,427	1,815,215	807,729	309,713	105,617	434,187
Income Taxes 1/	**3,787,749**	**150,575**	**2,353,941**	**314,576**	**488,721**	**233,725**	**91,205**	**30,058**	**124,947**
Interest on Customer Deposits	127,506	3	601	65,276	50,159	7,886	1,911	-	1,671
Total Operating Expense	134,357,271	7,517,177	88,798,509	11,861,368	13,702,317	5,931,402	2,284,416	838,232	3,423,852
Operating Income	17,770,494	(1,751,411)	9,104,106	1,638,998	4,644,243	1,953,893	194,234	585,543	1,400,887
Rate of Return	**4.80%**	**-11.91%**	**3.96%**	**5.33%**	**9.73%**	**8.56%**	**2.18%**	**19.95%**	**11.48%**
Relative Rate of Return	1.000	(2.479)	0.824	1.111	2.026	1.782	0.454	4.152	2.390
National Grid Rate of Return	4.80%	-6.06%	4.26%	5.15%	8.01%	7.24%	3.10%	14.65%	9.14%
Relative Rate of Return	1.000	(1.261)	0.886	1.072	1.667	1.508	0.645	3.049	1.903

1/ Allocated on Rate Base

	Total Company	Residential Non-Heating	Residential Heating	Small C&I	Medium C&I	Large C&I- HLF	Large C&I- LLF	Extra Large C&I- HLF	Extra Large C&I- LLF
Rate Base Allocator	1.0000	0.0398	0.6215	0.0831	0.1290	0.0617	0.0241	0.0079	0.0330
Reallocated Income Tax	3,787,749	150,575	2,353,941	314,576	488,721	233,725	91,205	30,058	124,947
Orginal Income Tax Allocation	3,787,749	(709,671)	1,675,089	371,676	1,311,701	533,799	9,424	185,642	410,088
Difference	-	860,246	678,852	(57,100)	(822,980)	(300,074)	81,781	(155,584)	(285,141)

National Grid - Gas

RIPUC 4323 Electric and Gas Base Rate Case

Comparison of Customer Charges for New England Gas Utilities

Utility	Jurisdiction	Residential Non Heat	Residential Heating	Small C&I	Medium C&I	Large C&I
National Grid Rhode Island						
Present Rates	RI	$ 10.00	$ 12.00	$ 18.60	$ 60.00	$ 120.00
Proposed Rates	RI	$ 12.50	$ 15.00	$ 23.25	$ 70.00	$ 175.00
Boston Gas Company	MA	$ 8.00	$ 10.00	$ 21.00	$ 39.00	$ 100.00
Colonial Gas Company	MA	$ 6.00	$ 8.00	$ 11.00	$ 25.00	$ 100.00
Energy North Natural Gas	NH	$ 11.98	$ 17.33	$ 40.77	$ 122.32	$ 524.96
Berkshire Gas	MA	$ 11.42	$ 11.42	$ 12.51	$ 32.65	$ 163.19
New England Gas	MA	$ 9.90	$ 9.90	$ 22.00	$ 33.00	$ 770.00
Connecticut Natural Gas	CT	$ 17.00	$ 14.00	$ 40.00	$ 95.00	$ 217.00
NStar	MA	$ 7.05	$ 7.05	$ 15.55	$ 30.55	$ 100.55
Vermont Gas	VT	$ 18.56	$ 18.56	$ 30.77		$ 98.17
Maine Natural Gas	ME	$ 24.34	$ 24.34	$ 34.77		$ 260.79
Columbia Gas	MA	$ 10.94	$ 10.94	$ 17.51	$ 71.11	$ 233.02
Southern Connecticut Gas	CT	$ 17.00	$ 14.00	$ 35.00	$ 75.00	$ 244.00
Average		$ 12.93	$ 13.23	$ 25.53	$ 58.18	$ 255.61
High		$ 24.34	$ 24.34	$ 40.77	$ 122.32	$ 770.00
Low		$ 6.00	$ 7.05	$ 11.00	$ 25.00	$ 98.17
Median		$ 11.18	$ 11.18	$ 21.50	$ 36.00	$ 190.10

National Grid - Gas
RIPUC Docket No. 4323

Proof of Revenue Summary and Comparison of Computed Increases by Rate Class to National Grid's Representation of Proposed Base Rate Increases by Classes

Rate Class	Revenue at Present Rates	Revenue at Proposed Rates	Computed Base Rate Incr Dollars	Computed Base Rate Incr Percent	N Grid Final Base Increase Dollars 1/	N Grid Final Base Increase Percent 2/	Difference In Base Increase Col (H) - Col (J)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Gas Lights	$ 19,302	$ 24,121	$ 4,819	**24.97%**	$ 4,826	**13.25%**	$ (7)
Residential Non-Heat 3/	$ 5,214,784	$ 6,503,764	$ 1,288,980	**24.72%**	$ 855,207	**14.75%**	$ 433,773
Residential Heat 3/	$ 88,698,216	$ 109,708,322	$ 21,010,106	**23.69%**	$ 14,025,018	**13.84%**	$ 6,985,088
Small C&I	$ 11,980,488	$ 14,388,557	$ 2,408,070	**20.10%**	$ 1,461,959	**11.31%**	$ 946,111
Medium C&I	$ 15,815,013	$ 19,108,578	$ 3,293,565	**20.83%**	$ 1,628,730	**9.32%**	$ 1,664,835
Large C&I LLF	$ 7,118,867	$ 8,232,838	$ 1,113,972	**15.65%**	$ 706,950	**9.39%**	$ 407,022
Large C&I LHF	$ 2,226,443	$ 2,715,028	$ 488,586	**21.94%**	$ 359,121	**15.24%**	$ 129,465
XL C&I LLF	$ 1,293,213	$ 1,470,319	$ 177,106	**13.70%**	$ 118,434	**8.76%**	$ 58,672
XL C&I LHF	$ 4,339,232	$ 4,942,251	$ 603,019	**13.90%**	$ 414,749	**9.16%**	$ 188,270
Total Firm Service	$136,705,557	$ 167,093,779	$ 30,388,223	**22.23%**	$ 19,574,994	**13.27%**	**$ 10,813,229**
Adjustments to Revenue							
ISR Revenue 4/	$ 6,924,425						
RDA Revenue 4/	$ 3,888,810						
Total Adjustments	**$ 10,813,235**						
Total Revenue	$147,518,792	$ 167,093,779	$ 19,574,988	**13.27%**			

1/ From Schedule PMN-7, page 4, Column (X)
2/ From Schedule PMN-7, page 4, Column (Z)
3/ Includes Low Income
4/ From Schedule PMN-2, page 5 of 5.

National Grid - Gas
RIPUC Docket No. 4323

Assessment of National Grid's Proposed Rate Increases for Medium, Large & Extra Large C&I Classes

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Medium C&I									
Customer Charge	51,514	$ 60.00	$ 3,090,840	51,514	$ 70.00	$ 3,605,980	$ 10.00	$ 515,140	16.67%
Demand Charge	3,597,029	$ 1.20	$ 4,316,435	3,597,029	$ 1.36	$ 4,891,959	$ 0.16	$ 575,525	13.33%
Distribution Charge	52,450,019	$ 0.1603	$ 8,407,738	52,450,019	$ 0.2023	$ 10,610,639	$ 0.0420	$ 2,202,901	26.20%
			$ 15,815,013			$ 19,108,578		**$ 3,293,565**	**20.83%**
Large C&I LLF									
Customer Charge	4,916	$ 120.00	$ 589,920	4,916	$ 175.00	$ 860,300	$ 55.00	$ 270,380	45.83%
Demand Charge	1,905,602	$ 1.20	$ 2,286,722	1,905,602	$ 1.36	$ 2,591,619	$ 0.16	$ 304,896	13.33%
Distribution Charge	25,898,807	$ 0.1638	$ 4,242,225	25,898,807	$ 0.1846	$ 4,780,920	$ 0.0208	$ 538,695	12.70%
			$ 7,118,867			$ 8,232,838		**$ 1,113,972**	**15.65%**
Large C&I LHF									
Customer Charge	1,906	$ 120.00	$ 228,720	1,906	$ 175.00	$ 333,550	$ 55.00	$ 104,830	45.83%
Demand Charge	539,464	$ 1.66	$ 895,510	539,464	$ 1.88	$ 1,014,192	$ 0.22	$ 118,682	13.25%
Distribution Charge	12,329,000	$ 0.0894	$ 1,102,213	12,329,000	$ 0.1109	$ 1,367,286	$ 0.0215	$ 265,074	24.05%
			$ 2,226,443			$ 2,715,028		**$ 488,586**	**21.94%**
XL C&I LLF									
Customer Charge	372	$ 300.00	$ 111,600	372	$ 425.00	$ 158,100	$ 125.00	$ 46,500	41.67%
Demand Charge	743,527	$ 1.20	$ 892,232	743,527	$ 1.36	$ 1,011,197	$ 0.16	$ 118,964	13.33%
Distribution Charge	8,315,525	$ 0.0348	$ 289,380	8,315,525	$ 0.0362	$ 301,022	$ 0.0014	$ 11,642	4.02%
			$ 1,293,213			$ 1,470,319		**$ 177,106**	**13.70%**
XL C&I LHF									
Customer Charge	768	$ 300.00	$ 230,400	768	$ 425.00	$ 326,400	$ 125.00	$ 96,000	41.67%
Demand Charge	1,763,971	$ 1.66	$ 2,928,192	1,763,971	$ 1.88	$ 3,316,265	$ 0.22	$ 388,074	13.25%
Distribution Charge	44,053,752	$ 0.0268	$ 1,180,641	44,053,752	$ 0.0295	$ 1,299,586	$ 0.0027	$ 118,945	10.07%
			$ 4,339,232			$ 4,942,251		**$ 603,019**	**13.90%**
Total Medium, Large & Extra Large C&I			$ 30,792,768			$ 36,469,015		$ 5,676,247	**18.43%**

National Grid - Gas
RIPUC Docket No. 4323

Assessment of National Grid's Proposed Rate Increases for Residential Classes

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Residential Non-Heat									
Customer Charge	300,402	$ 10.00	$ 3,004,020	300,402	$ 12.50	$ 3,755,025	$ 2.50	$ 751,005	25.00%
Distribution Charge	5,242,613	$ 0.4029	$ 2,112,249	5,242,613	$ 0.5009	$ 2,626,025	$ 0.0980	$ 513,776	24.32%
			$ 5,116,269			$ 6,381,050		$ 1,264,781	**24.72%**
Residential Non-Heat Low Income									
Customer Charge	3,878	$ 9.00	$ 34,902	3,878	$ 11.25	$ 43,628	$ 2.25	$ 8,726	25.00%
Distribution Charge	175,436	$ 0.3626	$ 63,613	175,436	$ 0.4508	$ 79,087	$ 0.0882	$ 15,473	24.32%
			$ 98,515			$ 122,714		$ 24,199	**24.56%**
Total Residential Non-Heat			**$ 5,214,784**			**$ 6,503,764**		**$ 1,288,980**	
Residential Heat, Peak									
Customer Charge	1,094,896	$ 12.00	$ 13,138,752	1,094,896	$ 15.00	$ 16,423,440	$ 3.00	$ 3,284,688	25.00%
Distribution Charge									
First Block	91,321,210	$ 0.3881	$ 35,441,762	91,321,210	$ 0.4776	$ 43,615,010	$ 0.0895	$ 8,173,248	23.06%
Tail Block	32,554,371	$ 0.2500	$ 8,138,593	32,554,371	$ 0.3076	$ 10,013,725	$ 0.0576	$ 1,875,132	23.04%
			$ 56,719,106			$ 70,052,174		$ 13,333,068	**23.51%**
Residential Heat, Off-Peak									
Customer Charge	1,075,571	$ 12.00	$ 12,906,852	1,075,571	$ 15.00	$ 16,133,565	$ 3.00	$ 3,226,713	25.00%
Distribution Charge									
First Block	23,332,481	$ 0.3881	$ 9,055,336	23,332,481	$ 0.4776	$ 11,143,593	$ 0.0895	$ 2,088,257	23.06%
Tail Block	5,504,725	$ 0.2500	$ 1,376,181	5,504,725	$ 0.3076	$ 1,693,253	$ 0.0576	$ 317,072	23.04%
			$ 23,338,369			$ 28,970,411		$ 5,632,042	**24.13%**
Residential Heat, Low Income, Peak									
Customer Charge	128,742	$ 10.80	$ 1,390,414	128,742	$ 13.50	$ 1,738,017	$ 2.70	$ 347,603	25.00%
Distribution Charge									
First Block	11,159,688	$ 0.3493	$ 3,898,079	11,159,688	$ 0.4298	$ 4,796,434	$ 0.0805	$ 898,355	23.05%
Tail Block	2,971,198	$ 0.2250	$ 668,520	2,971,198	$ 0.2768	$ 822,428	$ 0.0518	$ 153,908	23.02%
			$ 5,957,012			$ 7,356,879		$ 1,399,866	**23.50%**
Residential Heat, Low Income, Off-Peak									
Customer Charge	126,469	$ 10.80	$ 1,365,865	126,469	$ 13.50	$ 1,707,332	$ 2.70	$ 341,466	25.00%
Distribution Charge									
First Block	3,142,132	$ 0.3493	$ 1,097,547	3,142,132	$ 0.4298	$ 1,350,488	$ 0.0805	$ 252,942	23.05%
Tail Block	979,184	$ 0.2250	$ 220,316	979,184	$ 0.2768	$ 271,038	$ 0.0518	$ 50,722	23.02%
			$ 2,683,728			$ 3,328,858		$ 645,130	**24.04%**
Total Residential Heat			**$ 88,698,216**			**$ 109,708,322**		**$ 21,010,106**	**23.69%**
Total Residential			**$ 93,913,000**			**$ 116,212,086**		**$ 22,299,086**	**23.74%**

National Grid - Gas

RIPUC Docket No. 4323

Assessment of National Grid's Proposed Rate Increases for Gas Lights and Small C&I

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Gas Lights									
Customer Charge	2,434	$ 7.93	$ 19,302	2,434	9.91	$ 24,121	$ 1.98	$ 4,819	24.97%
Distribution Charge	-	$ -	$ -	-	$ -	$ -	$ -	$ -	
Total Gas Lights			**$ 19,302**			**$ 24,121**		**$ 4,819**	**24.97%**
Small C&I, Peak									
Customer Charge	111,565	$ 18.60	$ 2,075,109	111,565	$ 23.25	$ 2,593,886	$ 4.65	$ 518,777	25.00%
Distribution Charge									
First Block	8,898,615	$ 0.4845	$ 4,311,379	8,898,615	$ 0.5696	$ 5,068,651	$ 0.0851	$ 757,272	17.56%
Tail Block	11,604,499	$ 0.2000	$ 2,320,900	11,604,499	$ 0.2351	$ 2,728,218	$ 0.0351	$ 407,318	17.55%
			$ 8,707,388			$ 10,390,755		$ 1,683,367	**19.33%**
Small C&I, Off-Peak									
Customer Charge	108,374	$ 18.60	$ 2,015,756	108,374	$ 23.25	$ 2,519,696	$ 4.65	$ 503,939	25.00%
Distribution Charge									
First Block	1,415,022	$ 0.4845	$ 685,578	1,415,022	$ 0.5696	$ 805,997	$ 0.0851	$ 120,418	17.56%
Tail Block	2,858,826	$ 0.2000	$ 571,765	2,858,826	$ 0.2351	$ 672,110	$ 0.0351	$ 100,345	17.55%
			$ 3,273,100			$ 3,997,802		$ 724,702	**22.14%**
Total Small C&I			**$ 11,980,488**			**$ 14,388,557**		**$ 2,408,070**	**20.10%**
Total Gas Lights & Small C&I			**$ 11,999,789**			**$ 14,412,678**		**$ 2,412,889**	**20.11%**

Footnotes for pages 1 of 4, 2 of 4, and 3 of 4

1/ From Schedule PMN-7, page 1 of 5, Columns (B), (G) and (L).
2/ From Schedule PMN-7, page 3 of 5, Columns (C), (F) and (G).
3/ From Schedule PMN-7, page 3 of 5, Columns (E), (H) and (J).
4/ From Schedule PMN-7, page 4 of 5, Column (X).

National Grid - Gas
RIPUC Docket No. 4323

Proof of Revenue Summary for Redesign of National Grid Base Rate Increase Proposal
At National Grid's Proposed Revenue Requirement

Rate Class	Revenue at Present Rates 1/	Revised Base Rates - Initial Target Revenue Increase: Percent	Revised Base Rates - Initial Target Revenue Increase: Dollars	Revenue at Proposed Rates	Revised Base Rate - Adj Target Revenue Increase: Percent	Revised Base Rate - Adj Target Revenue Increase: Dollars	Revenue at Proposed Rates	Final Rates	Variance From Target
	(A)	(D)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Gas Lights	$ 19,302	**14.32%**	$ 2,764	$ 22,065	**14.32%**	$ 2,764	$ 22,065	$ 2,604	$ (159)
Residential Non-Heat 2/	$ 5,214,784	**16.47%**	$ 858,716	$ 6,073,500	**16.47%**	$ 858,837	$ 6,073,621	$ 859,102	$ 264
Residential Heat 2/	$ 88,698,216	**16.47%**	$ 14,605,896	$ 103,304,112	**15.58%**	$ 13,820,399	$ 102,518,615	$ 13,812,353	$ (8,046)
Small C&I	$ 11,980,488	**10.74%**	$ 1,286,623	$ 13,267,110	**10.74%**	$ 1,286,623	$ 13,267,110	$ 1,286,702	$ 79
Medium C&I	$ 15,815,013	**10.74%**	$ 1,698,425	$ 17,513,437	**10.70%**	$ 1,692,763	$ 17,507,776	$ 1,690,319	$ (2,444)
Large C&I LLF	$ 7,118,867	**10.74%**	$ 764,518	$ 7,883,385	**14.32%**	$ 1,019,501	$ 8,138,368	$ 1,020,104	$ 603
Large C&I HLF	$ 2,226,443	**16.47%**	$ 366,627	$ 2,593,070	**16.46%**	$ 366,571	$ 2,593,014	$ 366,925	$ 354
XL C&I LLF	$ 1,293,213	**7.16%**	$ 92,588	$ 1,385,801	**7.16%**	$ 92,601	$ 1,385,814	$ 92,906	$ 305
XL C&I HLF	$ 4,339,232	**10.02%**	$ 434,937	$ 4,774,169	**10.02%**	$ 434,937	$ 4,774,169	$ 433,579	$ (1,359)
Total Firm Service	$ 136,705,557	**14.71%**	$ 20,111,093	$ 156,816,650	**14.32%**	$ 19,574,996	$ 156,280,553	$ 19,564,593	$ (10,403)
Adjustments to Revenue									
ISR Revenue 3/	$ 6,924,425						$ 6,924,425		
RDA Revenue 3/	$ 3,888,810						$ 3,888,810		
Total Adjustments	**$ 10,813,235**						**$ 10,813,235**		
Total Revenue	$ 147,518,792						$ 167,093,788		

1/ From Column (C), pages 1 of 4 through 3 of 4.
2/ Includes Low Income
3/ From Schedule PMN-2, page 5 of 5.

National Grid - Gas
RIPUC Docket No. 4323

Redesign of National Grid's Proposed Base Rate Increases for Medium, Large & Extra Large C&I Classes
At National Grid's Proposed Revenue Requirement

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Medium C&I									
Customer Charge	51,514	$ 60.00	$ 3,090,840	51,514	$ 70.00	$ 3,605,980	$ 10.00	$ 515,140	16.67%
Demand Charge	3,597,029	$ 1.20	$ 4,316,435	3,597,029	$ 1.33	$ 4,778,293	$ 0.13	$ 461,859	10.70%
Distribution Charge	52,450,019	$ 0.1603	$ 8,407,738	52,450,019	$ 0.1739	$ 9,121,058	$ 0.0136	$ 713,320	8.48%
			$ 15,815,013			$ 17,505,332		**$ 1,690,319**	**10.69%**
Large C&I LLF									
Customer Charge	4,916	$ 120.00	$ 589,920	4,916	$ 175.00	$ 860,300	$ 55.00	$ 270,380	45.83%
Demand Charge	1,905,602	$ 1.20	$ 2,286,722	1,905,602	$ 1.37	$ 2,614,295	$ 0.17	$ 327,573	14.33%
Distribution Charge	25,898,807	$ 0.1638	$ 4,242,225	25,898,807	$ 0.1801	$ 4,664,375	$ 0.0163	$ 422,151	9.95%
			$ 7,118,867			$ 8,138,971		**$ 1,020,104**	**14.33%**
Large C&I LHF									
Customer Charge	1,906	$ 120.00	$ 228,720	1,906	$ 175.00	$ 333,550	$ 55.00	$ 104,830	45.83%
Demand Charge	539,464	$ 1.66	$ 895,510	539,464	$ 1.93	$ 1,042,946	$ 0.27	$ 147,436	16.46%
Distribution Charge	12,329,000	$ 0.0894	$ 1,102,213	12,329,000	$ 0.0987	$ 1,216,872	$ 0.0093	$ 114,660	10.40%
			$ 2,226,443			$ 2,593,368		**$ 366,925**	**16.48%**
XL C&I LLF									
Customer Charge	372	$ 300.00	$ 111,600	372	$ 425.00	$ 158,100	$ 125.00	$ 46,500	41.67%
Demand Charge	743,527	$ 1.20	$ 892,232	743,527	$ 1.29	$ 956,101	$ 0.09	$ 63,869	7.16%
Distribution Charge	8,315,525	$ 0.0348	$ 289,380	8,315,525	$ 0.0327	$ 271,918	$ (0.0021)	$ (17,463)	-6.03%
			$ 1,293,213			$ 1,386,119		**$ 92,906**	**7.18%**
XL C&I LHF									
Customer Charge	768	$ 300.00	$ 230,400	768	$ 425.00	$ 326,400	$ 125.00	$ 96,000	41.67%
Demand Charge	1,763,971	$ 1.66	$ 2,928,192	1,763,971	$ 1.83	$ 3,221,717	$ 0.17	$ 293,525	10.02%
Distribution Charge	44,053,752	$ 0.0268	$ 1,180,641	44,053,752	$ 0.0278	$ 1,224,694	$ 0.0010	$ 44,054	3.73%
			$ 4,339,232			$ 4,772,811		**$ 433,579**	**9.99%**
Total Medium, Large & Extra Large C&I			$ 30,792,768			$ 34,396,600		$ 3,603,832	**11.70%**

National Grid - Gas
RIPUC Docket No. 4323

Redesign of National Grid's Proposed Base Rate Increases for Residential Classes
At National Grid's Proposed Revenue Requirement

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Residential Non-Heat									
Customer Charge	300,402	$ 10.00	$ 3,004,020	300,402	$ 12.50	$ 3,755,025	$ 2.50	$ 751,005	25.00%
Distribution Charge	5,242,613	$ 0.4029	$ 2,112,249	5,242,613	$ 0.4213	$ 2,208,713	$ 0.0184	$ 96,464	4.57%
			$ 5,116,269			$ 5,963,738		$ 847,469	**16.56%**
Residential Non-Heat Low Income									
Customer Charge	3,878	$ 9.00	$ 34,902	3,878	$ -	$ -	$ (9.00)	$ (34,902)	-100.00%
Distribution Charge	175,436	$ 0.3626	$ 63,613	175,436	$ -	$ -	$ (0.3626)	$ (63,613)	-100.00%
			$ 98,515			$ -		$ (98,515)	**-100.00%**
Total Residential Non-Heat			**$ 5,214,784**			**$ 5,963,738**		**$ 748,954**	**14.36%**
Residential Heat, Peak									
Customer Charge	1,094,896	$ 12.00	$ 13,138,752	1,094,896	$ 14.00	$ 15,328,544	$ 2.00	$ 2,189,792	16.67%
Distribution Charge									
First Block	91,321,210	$ 0.3881	$ 35,441,762	91,321,210	$ 0.4465	$ 40,774,920	$ 0.0584	$ 5,333,159	15.05%
Tail Block	32,554,371	$ 0.2500	$ 8,138,593	32,554,371	$ 0.2876	$ 9,362,637	$ 0.0376	$ 1,224,044	15.04%
			$ 56,719,106			$ 65,466,101		$ 8,746,995	**15.42%**
Residential Heat, Off-Peak									
Customer Charge	1,075,571	$ 12.00	$ 12,906,852	1,075,571	$ 14.00	$ 15,057,994	$ 2.00	$ 2,151,142	16.67%
Distribution Charge									
First Block	23,332,481	$ 0.3881	$ 9,055,336	23,332,481	$ 0.4465	$ 10,417,953	$ 0.0584	$ 1,362,617	15.05%
Tail Block	5,504,725	$ 0.2500	$ 1,376,181	5,504,725	$ 0.2876	$ 1,583,159	$ 0.0376	$ 206,978	15.04%
			$ 23,338,369			$ 27,059,106		$ 3,720,737	**15.94%**
Residential Heat, Low Income, Peak									
Customer Charge	128,742	$ 10.80	$ 1,390,414	128,742	$ -	$ -	$ (10.80)	$ (1,390,414)	-100.00%
Distribution Charge									
First Block	11,159,688	$ 0.3493	$ 3,898,079	11,159,688	$ -	$ -	$ (0.3493)	$ (3,898,079)	-100.00%
Tail Block	2,971,198	$ 0.2250	$ 668,520	2,971,198	$ -	$ -	$ (0.2250)	$ (668,520)	-100.00%
			$ 5,957,012			$ -		$ (5,957,012)	**-100.00%**
Residential Heat, Low Income, Off-Peak									
Customer Charge	126,469	$ 10.80	$ 1,365,865	126,469	$ -	$ -	$ (10.80)	$ (1,365,865)	-100.00%
Distribution Charge									
First Block	3,142,132	$ 0.3493	$ 1,097,547	3,142,132	$ -	$ -	$ (0.3493)	$ (1,097,547)	-100.00%
Tail Block	979,184	$ 0.2250	$ 220,316	979,184	$ -	$ -	$ (0.2250)	$ (220,316)	-100.00%
			$ 2,683,728			$ -		$ (2,683,728)	**-100.00%**
Total Residential Heat			**$ 88,698,216**			**$ 92,525,207**		**$ 3,826,991**	**4.31%**
Total Residential			**$ 93,913,000**			**$ 98,488,945**		**$ 4,575,945**	**4.87%**

Schedule BRO - 6

National Grid - Gas

RIPUC Docket No. 4323

Redesign of National Grid's Proposed Base Rate Increases for Gas Lights and Small C&I

At National Grid's Proposed Revenue Requirement

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase		
							$/Unit	Dollars	Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Gas Lights									
Customer Charge	2,434	$ 7.93	$ 19,302	2,434	$ 9.00	$ 21,906	$ 1.07	$ 2,604	13.49%
Distribution Charge	-	$ -	$ -	-	$ -	$ -	$ -	$ -	
Total Gas Lights			**$ 19,302**			**$ 21,906**		**$ 2,604**	**13.49%**
Small C&I, Peak									
Customer Charge	111,565	$ 18.60	$ 2,075,109	111,565	$ 23.25	$ 2,593,886	$ 4.65	$ 518,777	25.00%
Distribution Charge									
First Block	8,898,615	$ 0.4845	$ 4,311,379	8,898,615	$ 0.5007	$ 4,455,537	$ 0.0162	$ 144,158	3.34%
Tail Block	11,604,499	$ 0.2000	$ 2,320,900	11,604,499	$ 0.2067	$ 2,398,650	$ 0.0067	$ 77,750	3.35%
Total Small C&I, Peak			$ 8,707,388			$ 9,448,073		$ 740,685	**8.51%**
Small C&I, Off-Peak									
Customer Charge	108,374	$ 18.60	$ 2,015,756	108,374	$ 23.25	$ 2,519,696	$ 4.65	$ 503,939	25.00%
Distribution Charge									
First Block	1,415,022	$ 0.4845	$ 685,578	1,415,022	$ 0.5007	$ 708,502	$ 0.0162	$ 22,923	3.34%
Tail Block	2,858,826	$ 0.2000	$ 571,765	2,858,826	$ 0.2067	$ 590,919	$ 0.0067	$ 19,154	3.35%
Total Small C&I, Off- Peak			$ 3,273,100			$ 3,819,116		$ 546,017	**16.68%**
Total Small C&I			**$ 11,980,488**			**$ 13,267,189**		**$ 1,286,702**	**10.74%**
Total Gas Lights & Small C&I			**$ 11,999,789**			**$ 13,289,095**		**$ 1,289,306**	**10.74%**

National Grid - Gas
RIPUC Docket No. 4323

Proof of Revenue Summary for the Design of the Division's Base Rate Increase Proposal
At the Division's Recommended Proposed Revenue Requirement

Rate Class		Revenue at Present Rates 1/	Revised Base Rates - Initial Target Revenue Increase Percent	Revised Base Rates - Initial Target Revenue Increase Dollars	Revenue at Proposed Rates	Revised Base Rate - Adj Target Revenue Increase Percent	Revised Base Rate - Adj Target Revenue Increase Dollars	Revenue at Proposed Rates	Final Rates	Variance From Target
		(A)	(D)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Gas Lights		$ 19,302	**5.54%**	$ 1,070	$ 20,371	**5.54%**	$ 1,070	$ 20,371	$ 1,071	$ 1
Residential Non-Heat	2/	$ 5,214,784	**11.08%**	$ 577,988	$ 5,792,772	**9.25%**	$ 482,620	$ 5,697,404	$ 482,679	$ 59
Residential Heat	2/	$ 88,698,216	**5.54%**	$ 4,915,500	$ 93,613,716	**5.76%**	$ 5,112,120	$ 93,810,336	$ 5,115,723	$ 3,603
Small C&I		$ 11,980,488	**5.54%**	$ 663,938	$ 12,644,425	**5.26%**	$ 630,741	$ 12,611,228	$ 631,095	$ 354
Medium C&I		$ 15,815,013	**4.16%**	$ 657,330	$ 16,472,343	**4.21%**	$ 666,007	$ 16,481,020	$ 667,266	$ 1,258
Large C&I LLF		$ 7,118,867	**4.16%**	$ 295,886	$ 7,414,753	**4.43%**	$ 315,612	$ 7,434,479	$ 315,277	$ (335)
Large C&I HLF		$ 2,226,443	**6.93%**	$ 154,232	$ 2,380,675	**7.37%**	$ 164,103	$ 2,390,546	$ 163,834	$ (269)
XL C&I LLF		$ 1,293,213	**2.77%**	$ 35,834	$ 1,329,046	**2.77%**	$ 35,834	$ 1,329,046	$ 36,069	$ 236
XL C&I HLF		$ 4,339,232	**3.88%**	$ 168,331	$ 4,507,563	**3.87%**	$ 167,874	$ 4,507,106	$ 167,844	$ (30)
Total Firm Service		$136,705,557	**5.46%**	$ 7,470,109	$ 144,175,666	**5.54%**	$ 7,575,981	$ 144,281,537	$ 7,580,858	$ 4,877
Adjustments to Revenue										
ISR Revenue	3/	$ 6,924,425						$ 6,924,425		
RDA Revenue	4/	$ -						$ -		
Total Adjustments		**$ 6,924,425**						**$ 6,924,425**		
Total Revenue		$143,629,982						$ 151,205,962		

1/ From Column (C), pages 1 of 4 through 3 of 4.
2/ Includes Low Income
3/ From Schedule PMN-2, page 5 of 5.
4/ RDA Revenue Adjustment Recommended for Disallowance

National Grid - Gas
RIPUC Docket No. 4323

Design of the Division's Proposed Base Rate Increases for Medium, Large & Extra Large C&I Classes
At the Division's Recommended Proposed Revenue Requirement

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Medium C&I									
Customer Charge	51,514	$ 60.00	$ 3,090,840	51,514	$ 66.00	$ 3,399,924	$ 6.00	$ 309,084	10.00%
Demand Charge	3,597,029	$ 1.20	$ 4,316,435	3,597,029	$ 1.25	$ 4,496,286	$ 0.05	$ 179,851	4.17%
Distribution Charge	52,450,019	$ 0.1603	$ 8,407,738	52,450,019	$ 0.1637	$ 8,586,068	$ 0.0034	$ 178,330	2.12%
			$ 15,815,013			$ 16,482,278		**$ 667,266**	**4.22%**
Large C&I LLF									
Customer Charge	4,916	$ 120.00	$ 589,920	4,916	$ 150.00	$ 737,400	$ 30.00	$ 147,480	25.00%
Demand Charge	1,905,602	$ 1.20	$ 2,286,722	1,905,602	$ 1.25	$ 2,382,003	$ 0.05	$ 95,280	4.17%
Distribution Charge	25,898,807	$ 0.1638	$ 4,242,225	25,898,807	$ 0.1666	$ 4,314,741	$ 0.0028	$ 72,517	1.71%
			$ 7,118,867			$ 7,434,144		**$ 315,277**	**4.43%**
Large C&I LHF									
Customer Charge	1,906	$ 120.00	$ 228,720	1,906	$ 150.00	$ 285,900	$ 30.00	$ 57,180	25.00%
Demand Charge	539,464	$ 1.66	$ 895,510	539,464	$ 1.78	$ 960,246	$ 0.12	$ 64,736	7.23%
Distribution Charge	12,329,000	$ 0.0894	$ 1,102,213	12,329,000	$ 0.0928	$ 1,144,131	$ 0.0034	$ 41,919	3.80%
			$ 2,226,443			$ 2,390,277		**$ 163,834**	**7.36%**
XL C&I LLF									
Customer Charge	372	$ 300.00	$ 111,600	372	$ 375.00	$ 139,500	$ 75.00	$ 27,900	25.00%
Demand Charge	743,527	$ 1.20	$ 892,232	743,527	$ 1.23	$ 914,538	$ 0.03	$ 22,306	2.50%
Distribution Charge	8,315,525	$ 0.0348	$ 289,380	8,315,525	$ 0.0331	$ 275,244	$ (0.0017)	$ (14,136)	-4.89%
			$ 1,293,213			$ 1,329,282		**$ 36,069**	**2.79%**
XL C&I LHF									
Customer Charge	768	$ 300.00	$ 230,400	768	$ 375.00	$ 288,000	$ 75.00	$ 57,600	25.00%
Demand Charge	1,763,971	$ 1.66	$ 2,928,192	1,763,971	$ 1.72	$ 3,034,030	$ 0.06	$ 105,838	3.61%
Distribution Charge	44,053,752	$ 0.0268	$ 1,180,641	44,053,752	$ 0.0269	$ 1,185,046	$ 0.0001	$ 4,405	0.37%
			$ 4,339,232			$ 4,507,076		**$ 167,844**	**3.87%**
Total Medium, Large & Extra Large C&I			$ 30,792,768			$ 32,143,057		$ 1,350,290	**4.39%**

National Grid - Gas

RIPUC Docket No. 4323

Design of the Division's Proposed Base Rate Increases for Residential Classes

At the Division's Recommended Proposed Revenue Requirement

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges 3/	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Residential Non-Heat									
Customer Charge	300,402	$ 10.00	$ 3,004,020	300,402	$ 12.50	$ 3,755,025	$ 2.50	$ 751,005	25.00%
Distribution Charge	5,242,613	$ 0.4029	$ 2,112,249	5,242,613	$ 0.3516	$ 1,843,303	$ (0.0513)	$ (268,946)	-12.73%
			$ 5,116,269			$ 5,598,328		$ 482,059	**9.42%**
Residential Non-Heat Low Income									
Customer Charge	3,878	$ 9.00	$ 34,902	3,878	$ 11.25	$ 43,628	$ 2.25	$ 8,726	25.00%
Distribution Charge	175,436	$ 0.3626	$ 63,613	175,436	$ 0.3164	$ 55,508	$ (0.0462)	$ (8,105)	-12.74%
			$ 98,515			$ 99,135		$ 620	**0.63%**
Total Residential Non-Heat			**$ 5,214,784**			**$ 5,697,463**		**$ 482,679**	**9.26%**
Residential Heat, Peak									
Customer Charge	1,094,896	$ 12.00	$ 13,138,752	1,094,896	$ 13.20	$ 14,452,627	$ 1.20	$ 1,313,875	10.00%
Distribution Charge									
First Block	91,321,210	$ 0.3881	$ 35,441,762	91,321,210	$ 0.4026	$ 36,765,919	$ 0.0145	$ 1,324,158	3.74%
Tail Block	32,554,371	$ 0.2500	$ 8,138,593	32,554,371	$ 0.2593	$ 8,441,348	$ 0.0093	$ 302,756	3.72%
			$ 56,719,106			$ 59,659,895		$ 2,940,788	**5.18%**
Residential Heat, Off-Peak									
Customer Charge	1,075,571	$ 12.00	$ 12,906,852	1,075,571	$ 13.20	$ 14,197,537	$ 1.20	$ 1,290,685	10.00%
Distribution Charge									
First Block	23,332,481	$ 0.3881	$ 9,055,336	23,332,481	$ 0.4026	$ 9,393,657	$ 0.0145	$ 338,321	3.74%
Tail Block	5,504,725	$ 0.2500	$ 1,376,181	5,504,725	$ 0.2593	$ 1,427,375	$ 0.0093	$ 51,194	3.72%
			$ 23,338,369			$ 25,018,569		$ 1,680,200	**7.20%**
Residential Heat, Low Income, Peak									
Customer Charge	128,742	$ 10.80	$ 1,390,414	128,742	$ 11.88	$ 1,529,455	$ 1.08	$ 139,041	10.00%
Distribution Charge									
First Block	11,159,688	$ 0.3493	$ 3,898,079	11,159,688	$ 0.3623	$ 4,043,155	$ 0.0130	$ 145,076	3.72%
Tail Block	2,971,198	$ 0.2250	$ 668,520	2,971,198	$ 0.2334	$ 693,478	$ 0.0084	$ 24,958	3.73%
			$ 5,957,012			$ 6,266,088		$ 309,075	**5.19%**
Residential Heat, Low Income, Off-Peak									
Customer Charge	126,469	$ 10.80	$ 1,365,865	126,469	$ 11.88	$ 1,502,452	$ 1.08	$ 136,587	10.00%
Distribution Charge									
First Block	3,142,132	$ 0.3493	$ 1,097,547	3,142,132	$ 0.3623	$ 1,138,394	$ 0.0130	$ 40,848	3.72%
Tail Block	979,184	$ 0.2250	$ 220,316	979,184	$ 0.2334	$ 228,542	$ 0.0084	$ 8,225	3.73%
			$ 2,683,728			$ 2,869,388		$ 185,659	**6.92%**
Total Residential Heat			**$ 88,698,216**			**$ 93,813,939**		**$ 5,115,723**	**5.77%**
Total Residential			**$ 93,913,000**			**$ 99,511,402**		**$ 5,598,403**	**5.96%**

National Grid - Gas
RIPUC Docket No. 4323

Design of the Division's Proposed Base Rate Increases for Gas Lights and Small C&I
At the Division's Recommended Proposed Revenue Requirement

Rate Class/Charge	Billing Units 1/	Present Charges 2/	Revenue at Present Rates	Billing Units 1/	Proposed Charges	Revenue at Proposed Rates	Proposed Increase $/Unit	Proposed Increase Dollars	Proposed Increase Percent
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Gas Lights									
Customer Charge	2,434	$ 7.93	$ 19,302	2,434	$ 8.37	$ 20,373	$ 0.44	$ 1,071	5.55%
Distribution Charge	-	$ -	$ -	-	$ -	$ -	$ -	$ -	
Total Gas Lights			**$ 19,302**			**$ 20,373**		**$ 1,071**	**5.55%**
Small C&I, Peak									
Customer Charge	111,565	$ 18.60	$ 2,075,109	111,565	$ 20.50	$ 2,287,083	$ 1.90	$ 211,974	10.22%
Distribution Charge									
First Block	8,898,615	$ 0.4845	$ 4,311,379	8,898,615	$ 0.4976	$ 4,427,951	$ 0.0131	$ 116,572	2.70%
Tail Block	11,604,499	$ 0.2000	$ 2,320,900	11,604,499	$ 0.2054	$ 2,383,564	$ 0.0054	$ 62,664	2.70%
Total Small C&I, Peak			$ 8,707,388			$ 9,098,597		$ 391,210	**4.49%**
Small C&I, Off-Peak									
Customer Charge	108,374	$ 18.60	$ 2,015,756	108,374	$ 20.50	$ 2,221,667	$ 1.90	$ 205,911	10.22%
Distribution Charge									
First Block	1,415,022	$ 0.4845	$ 685,578	1,415,022	$ 0.4976	$ 704,115	$ 0.0131	$ 18,537	2.70%
Tail Block	2,858,826	$ 0.2000	$ 571,765	2,858,826	$ 0.2054	$ 587,203	$ 0.0054	$ 15,438	2.70%
Total Small C&I, Off- Peak			$ 3,273,100			$ 3,512,985		$ 239,885	**7.33%**
Total Small C&I			**$ 11,980,488**			**$ 12,611,582**		**$ 631,095**	**5.27%**
Total Gas Lights & Small C&I			**$ 11,999,789**			**$ 12,631,955**		**$ 632,166**	**5.27%**

Footnotes for pages 1 of 4, 2 of 4, and 3 of 4

1/ From Schedule PMN-7, page 1 of 5, Columns (B), (G) and (L).

2/ From Schedule PMN-7, page 3 of 5, Columns (C), (F) and (G).

National Grid - Gas

RIPUC Docket No. 4323

National Grid's Present and Proposed Charges For Non-Firm Gas Service

Otherwise Applicable Firm Rate	Distribution Charges		
	Present Rates	Proposed Rates	% Increase
Medium C&I	$ 0.1923	$ 0.2915	**51.6%**
Large C&I LLF	$ 0.2015	$ 0.2543	**26.2%**
Large C&I LHF	$ 0.1372	$ 0.1762	**28.4%**
XL C&I LLF	$ 0.0766	$ 0.1415	**84.7%**
XL C&I LHF	$ 0.0616	$ 0.0897	**45.6%**

National Grid - Gas

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Comparison of the Company's Proposed Charges for Firm and Non-Firm Service

Otherwise Applicable Firm Rate	Proposed Charges (Excluding Customer Charges) — Firm Service Rates: Distribution Charges (A)	Demand Cost Per Therm (B) = (K)	Composite Dem & Dist (C) = (A)+(B)	**Non-Firm Rates** (D)	Difference Non-Firm Less Firm (E) = (D)-(C)	Percent Non-Firm > Firm Charges (F) = (E)/(C)
Medium C&I	$ 0.2023	$ 0.0933	**$ 0.2956**	**$ 0.2915**	$ (0.0041)	-1.38%
Large C&I LLF	$ 0.1109	$ 0.1001	**$ 0.2110**	**$ 0.2543**	$ 0.0433	20.54%
Large C&I LHF	$ 0.1109	$ 0.0823	**$ 0.1932**	**$ 0.1762**	$ (0.0170)	-8.78%
XL C&I LLF	$ 0.0766	$ 0.1216	**$ 0.1982**	**$ 0.1415**	$ (0.0567)	-28.61%
XL C&I LHF	$ 0.0616	$ 0.0753	**$ 0.1369**	**$ 0.0897**	$ (0.0472)	-34.47%

	Demand Charges (G)	Distribution Throughput (H)	MADQ (I)	Throughput per MADQ (J) = (H)/(I)	Demand Cost Per Therm (K) =(G)/(J)
Medium C&I	$ 1.3600	52,450,019	3,597,029	14.58	$ 0.0933
Large C&I LLF	$ 1.3600	25,898,807	1,905,602	13.59	$ 0.1001
Large C&I LHF	$ 1.8800	12,329,000	539,464	22.85	$ 0.0823
XL C&I LLF	$ 1.3600	8,315,525	743,527	11.18	$ 0.1216
XL C&I LHF	$ 1.8800	44,053,753	1,763,971	24.97	$ 0.0753

National Grid - Gas

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Comparison of Average Rate Year Use per Customer to Average Use Per Customer Shown in the Company's Bill Comparisons

Rate Class	Annual Therm Sales & Trans Througphput	Average Customers	Calculated Annual Therms per Customer	Avg Annual Therms per Customer From PMN-8	Change in Use/Customer Therms	Change in Use/Customer Percent
Res Non Heat	5,418,049	25,357	**214**	189	25	13.1%
Res Heat	170,964,989	202,140	**846**	922	(76)	-8.3%
C&I Small	24,776,962	18,328	**1,352**	1,269	83	6.5%
C&I Medium	52,450,019	4,293	**12,218**	10,950	1,268	11.6%
C&I Large LLF	25,898,807	410	**63,219**	57,742	5,477	9.5%
C&I Large HLF	12,329,000	159	**77,622**	58,418	19,204	32.9%
C&I Extra Large LLF	8,315,525	31	**268,243**	291,462	(23,219)	-8.0%
C&I Extra Large HLF	44,053,752	64	**688,340**	284,094	404,246	142.3%

National Grid - Gas

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Comparison of Actual Dual Fuel Throughput and Revenue

	Jul 09 - Jun 10 1/	Jul 10 - Jun 11 2/	Jul 11 - Jun 12 3/	Average
Throughput (Dth)				
Firm	1,412,942	1,754,128	1,575,287	1,580,786
Non-Firm	2,658,128	2,484,610	2,218,086	2,453,608
Total Dual-Fuel	4,071,070	4,238,738	3,793,373	4,034,394
Non-Firm % of Dual-Fuel	65.3%	58.6%	58.5%	60.8%
Margin Revenue				
Firm	$ 1,583,725	$ 2,000,007	$ 2,013,652	$ 1,865,795
Non-Firm	$ 1,824,841	$ 1,594,036	$ 1,540,756	$ 1,653,211
Total Dual-Fuel	$ 3,408,566	$ 3,594,043	$ 3,554,408	$ 3,519,006
Non-Firm % of Dual-Fuel	53.5%	44.4%	43.3%	47.0%

1/ Jul 09 - Jun 10 data from Docket 4196, Attachment JFN-7.
2/ Jul 10 - Jun 11 data from Docket 4269, Attachment JFN-7.
3/ Jul 11 - Jun 12 data from Docket 4339, Attachment MCS-7.

National Grid - Gas
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Revenue Shifts Under the Company's Proposed RDA Calculation
RDA calculation from Schedule AEL-3, page 1 of 4.

	RDA Variance for RYE 01/31/2014	RYE 01/31/2014 Throughput (therms)	RDA Variance Per Unit of Throughput	Estimated Rate Year RDA Factor	Estimate Rate Year RDA Collections	RDA Variance Less Est RYE RDA Revenue	Percent Difference
Residential							
Non-Heat 1/	$ (249,420)	5,418,049	$ (0.04604)	**$ 0.01533**	$ 83,080	$ (332,500)	133.3%
Heat 1/	**$ 4,963,332**	170,961,989	$ 0.02903	**$ 0.01533**	$ 2,621,532	**$ 2,341,800**	47.2%
Small C&I	$ (135,799)	24,776,962	$ (0.00548)	**$ 0.01533**	$ 379,930	$ (515,729)	379.8%
Medium C&I	$ (689,302)	52,450,019	$ (0.01314)	**$ 0.01533**	$ 804,269	$ (1,493,571)	216.7%
Total	**$ 3,888,811**	**253,607,019**	**$ 0.01533**		**$ 3,888,811**	$ -	0.0%

1/ Include Low Income

National Grid - Gas
RIPUC Docket No. 4323

Revised RDA Factor Calculation and Comparison of Variance & Projected Revenue Collections by Class
RDA Variance from Docket 4339 - 8/1/12 DAC Filing

	RDA Variance for DAC Year TME 6/30/12 *($)*	**DAC Year Ending 10/31/2013 Throughput** *(therms)*	**RDA Variance Per Unit of Throughput** *($/therm)*	**Calculated DAC Year RDA Factor** *($/therm)*	**Estimated DAC Year RDA Collections** *($)*	**RDA Variance Less Estimated DAC Year RDA Collections** *($)*	**Difference as % of RDA Variance** *(%)*
Residential							
Non-Heat 1/	$ (371,459)	5,495,618	$ (0.06759)	**$ 0.04205**	$ 231,097	$ (602,556)	162.2%
Heat 1/	$ 9,175,126	171,715,333	$ 0.05343	**$ 0.04205**	$ 7,220,829	**$ 1,954,297**	21.3%
Small C&I	$ 1,124,798	24,651,554	$ 0.04563	**$ 0.04205**	$ 1,036,626	$ 88,172	7.8%
Medium C&I	$ 775,907	52,693,410	$ 0.01472	**$ 0.04205**	$ 2,215,819	$ (1,439,912)	-185.6%
Total	$ 10,704,372	254,555,916	**$ 0.04205**		**$ 10,704,372**	$ -	0.0%

1/ Include Low Income

National Grid - Gas
RIPUC Docket No. 4323

Revised Calculation of National Grid's Proposed Charges for Non-Firm Service with Customer Charge Revenue Removed
Based on 20% Discount from Otherwise Applicable Firm Service Rate

Firm Rate	Demand Charge Revenue	Distribution Charge Revenue	Total	20% Discount	Discounted Revenue	Distribution Throughput	Revised Calculation of N Grid's Proposed Non-Firm Charges	N Grid's Existing Non-Firm Charges	Percent Increase
Medium C&I	$ 4,891,960	$ 10,610,639	$ 15,502,599	$ 3,100,520	$ 12,402,079	52,450,019	$ 0.2365	$ 0.1923	**23.0%**
Large C&I LLF	$ 2,591,618	$ 4,780,920	$ 7,372,538	$ 1,474,508	$ 5,898,030	25,898,807	$ 0.2277	$ 0.2015	**13.0%**
Large C&I LHF	$ 1,014,193	$ 1,367,286	$ 2,381,479	$ 476,296	$ 1,905,183	12,329,000	$ 0.1545	$ 0.1372	**12.6%**
XL C&I LLF	$ 1,011,197	$ 301,022	$ 1,312,219	$ 262,444	$ 1,049,775	8,315,525	$ 0.1262	$ 0.0766	**64.8%**
XL C&I LHF	$ 3,316,268	$ 1,299,586	$ 4,615,854	$ 923,171	$ 3,692,683	44,053,753	$ 0.0838	$ 0.0616	**36.1%**
	$ 12,825,236	$ 18,359,453	$ 31,184,689	$ 6,236,938	$ 24,947,751	143,047,104			

National Grid - Gas
RIPUC Docket No. 4323

Revised Calculation of National Grid's Proposed Charges for Non-Firm Service
With RDA Revenue Adjustment, ISR Revenue Adjustment and Firm Customer Charge Revenue Removed
Based on 20% Discount from Otherwise Applicable Firm Service Rate

Firm Rate	Demand Charge Revenue	Distribution Charge Revenue	Total	20% Discount	Discounted Revenue	Distribution Throughput	Revised Calculation of N Grid's Proposed Non-Firm Charges	N Grid's Existing Non-Firm Charges	Percent Increase
Medium C&I	$ 4,778,293	$ 9,121,058	$ 13,899,352	$ 2,779,870	$ 11,119,481	52,450,019	$ 0.2120	$ 0.1923	**10.2%**
Large C&I LLF	$ 2,614,295	$ 4,664,375	$ 7,278,671	$ 1,455,734	$ 5,822,936	25,898,807	$ 0.2248	$ 0.2015	**11.6%**
Large C&I LHF	$ 1,042,946	$ 1,216,872	$ 2,259,818	$ 451,964	$ 1,807,854	12,329,000	$ 0.1466	$ 0.1372	**6.9%**
XL C&I LLF	$ 956,101	$ 271,918	$ 1,228,019	$ 245,604	$ 982,415	8,315,525	$ 0.1181	$ 0.0766	**54.2%**
XL C&I LHF	$ 3,221,717	$ 1,224,694	$ 4,446,411	$ 889,282	$ 3,557,129	44,053,753	$ 0.0807	$ 0.0616	**31.1%**
	$ 12,613,352	$ 16,498,918	$ 29,112,270	$ 5,822,454	$ 23,289,816	143,047,104			

National Grid - Gas
RIPUC Docket No. 4323

Calculation of Charges for Non-Firm Service Based on the Division's Recommended Overall Revenue Requirement and Firm Rate Designs
Based on 20% Discount from Otherwise Applicable Firm Service Rates

Firm Rate	Demand Charge Revenue	Distribution Charge Revenue	Total	20% Discount	Discounted Revenue	Distribution Throughput	Revised Calculation of N Grid's Proposed Non-Firm Charges	N Grid's Existing Non-Firm Charges	Percent Increase
Medium C&I	$ 4,496,286	$ 8,586,068	$ 13,082,354	$ 2,616,471	$ 10,465,883	52,450,019	$ 0.1995	$ 0.1923	**3.8%**
Large C&I LLF	$ 2,382,003	$ 4,314,741	$ 6,696,744	$ 1,339,349	$ 5,357,395	25,898,807	$ 0.2069	$ 0.2015	**2.7%**
Large C&I LHF	$ 960,246	$ 1,144,131	$ 2,104,377	$ 420,875	$ 1,683,502	12,329,000	$ 0.1365	$ 0.1372	**-0.5%**
XL C&I LLF	$ 914,538	$ 271,918	$ 1,186,456	$ 237,291	$ 949,165	8,315,525	$ 0.1141	$ 0.0766	**49.0%**
XL C&I LHF	$ 3,034,030	$ 1,224,694	$ 4,258,724	$ 851,745	$ 3,406,980	44,053,753	$ 0.0773	$ 0.0616	**25.5%**
	$ 11,787,103	$ 15,541,553	$ 27,328,656	$ 5,465,731	$ 21,862,924	143,047,104			