THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

APPLICATION FOR APPROVAL OF CHANGE IN
ELECTRIC AND GAS DISTRIBUTION RATES

RIPUC DOCKET NO. 4323

BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

TESTIMONY AND EXHIBITS
OF DAVID J. EFFRON

ON BEHALF OF THE

DIVISION OF
PUBLIC UTILITIES AND CARRIERS

AUGUST 30, 2012

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DIRECT TESTIMONY
OF DAVID J. EFFRON

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My business address is 12 Pond Path, North Hampton, New Hampshire, 03862.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("the Division").

Q. What is the purpose of your testimony?

A. I am addressing the revenue requirements of the Rhode Island electric and gas operations of The Narragansett Electric Company, d/b/a National Grid ("Narragansett" or "the Company") based on a test year consisting of the twelve months ended December 31 2011 and a rate year consisting of the twelve months ending January 31, 2014. I also address the Company's proposal to implement a fully reconciling mechanism for commodity related bad debt, the Company's proposal to extend the reconciling mechanism for pensions and other postretirement benefits to electric service, and the Company's proposal to implement a fully reconciling mechanism for property tax expense.

Q. How is your testimony organized?

A. I first address issues in the determination of the Company's revenue requirement for electric distribution service. I then address issues in the determination of the Company's revenue requirement for gas distribution service. Finally, I address the Company's proposals to implement certain reconciling mechanisms.

Q. Please summarize your testimony.

A. I have calculated a base rate revenue requirement of $246,766,000 for electric distribution service provided by National Grid in Rhode Island. The Company's electric base rate revenue deficiency is $13,158,000. This base rate revenue deficiency includes an allowance for increased storm fund recovery in base rates and eliminates the Company's temporary recovery mechanism to replenish the storm fund. My proposed modifications to Company's electric distribution cost of service and revenue deficiency are summarized on Schedule DJE-E-1. The base rate revenue requirement includes the effect of rolling certain items that are recovered through separate factors into base rates. The Company has calculated a total revenue deficiency for Narragansett Electric of $31,448,000. The comparable total revenue deficiency that I have calculated is $15,890,000.

I have calculated a base rate revenue requirement of $156,280,000 for gas distribution service provided by National Grid in Rhode Island (including the effect of Mr. Oliver's recommendation on the firm/non-firm margin threshold). The Company's gas base rate deficiency is $16,634,000. My proposed modifications to Company's gas distribution cost of service and revenue deficiency are summarized on Schedule DJE-G-1. The base rate revenue requirement includes the effect of rolling certain items that are recovered through separate factors into base rates. The Company has calculated a total revenue deficiency for Narragansett Gas of $19,952,000. The comparable total revenue deficiency that I have calculated is $6,197,000.

III. REVENUE REQUIREMENT - ELECTRIC

A. SUMMARY

Q. Have you prepared a summary of the Company's rate year electric revenue requirement?

A. Yes, my summary of the electric revenue requirement is shown on Schedule DJE-E-1. On this schedule, I compare the Company's presentation of its revenue deficiency to the Division's recommendation. I have begun with the Company's total cost of service. The base rate cost of service is comprised of operating expenses plus the return on rate base, as shown on my Schedule DJE-E-2. The total cost of service less the revenue produced by the proposed Storm Cost Recovery Factor ("SCRF") and miscellaneous revenues is the base rate cost of service.

I have calculated a reduction of $15,558,000 to the total cost of service presented by the Company. As shown on Schedule DJE-E-1, this adjustment translates into a reduction of $2,400,000 to the SCRF and a reduction of $13,158,000 to the base rate cost of service presented by the Company.

B. COST OF SERVICE

Q. What are the elements of the cost of service?

A. The elements of the rate year cost of service are operation and maintenance expenses (with uncollectible accounts expense, which is derived from the other elements of the revenue requirement, shown separately), depreciation, taxes other than income taxes, income taxes, and return on rate base. These elements of the total cost of service are summarized on Schedule DJE-E-2.

Q. Are you proposing adjustments to the rate year cost of service calculated by the Company?

A. Yes. The Company has calculated a pro forma rate year cost of service of $270,471,000. Based on the adjustments to the Company's position that I have identified, I am proposing a total cost of service of $254,724,000. I address the individual adjustments to the Company's calculated cost of service in the following testimony.

1. Operation and Maintenance Expenses

a. Variable Pay - DSM

Q. Is the Company proposing to adjust the actual variable pay expense accrued in the 2011 test year?

A. Yes. The Company's proposed adjustment to variable pay is summarized on Schedule MDL-3-ELEC, page 21. The purpose of this schedule is to adjust the actual variable recorded in the 2011 test year to the prospective targeted variable pay.

Q. Are you proposing any modifications to the pro forma adjustment quantified by the Company?

A. Yes. In calculating the pro forma adjustment, the Company compared the target variable pay including DSM to actual test year actual variable pay excluding DSM. This is not correct. In response to Division 1-7-ELEC, the Company provided a corrected calculation of the variable pay adjustment on Schedule MDL-3-ELEC, page 21 and the Union Goals adjustment on Schedule MDL-3-ELEC, page 22. The net effect of these corrections is to reduce pro forma test year operation and maintenance expenses by $400,000. I have reflected this adjustment on my Schedule DJE-E-4.

b. Uninsured Claims

Q. Have you analyzed the Company's proposed pro forma adjustment for uninsured claims?

A. Yes. The Company's pro forma adjustment for uninsured claims is shown on Schedule MDL-3-ELEC, page 30. It consists of normalizing the general auto & liability claims and workmen's compensation based on five year averages.

Q. Are you proposing to modify the Company's pro forma uninsured claims expense?

A. Yes. In response to Division 1-20-ELEC, the Company stated that certain expenses related to claims for Worker's Compensation were misclassified in 2011, and as a result the total amount of test year claims of $2,480,624 on Schedule MDL-3-ELEC, page 30 should have been $3,530,204. This increases the actual test year total Company electric expense to which the five year average is compared by $1,049,000 and reduces the pro forma jurisdictional uninsured claims expense by $1,021,000 (Schedule DJE-E-4).

c. O&M Related to Capital Spending

Q. Is the Company proposing to adjust test year operation and maintenance expense related to capital spending?

A. Yes. As explained by Mr. Laflamme: "For each dollar of capital spending, Narragansett Electric incurs a level of O&M spending. This O&M spending is for costs incurred as part of capital projects for activities that do not meet the definition of a capital asset under the Uniform System of Accounts and must therefore be charged to O&M expense as incurred." (Laflamme Direct testimony, page 51) The Company calculated that the average O&M related to capital spending for the fiscal years 2009 – 2011 was 10.71% of capital spending. The Company then applied this percentage to the difference between 2011 test year capital spending of $48,613,000 and forecasted rate year capital spending of $56,540,000, to calculate a pro forma adjustment to operation and maintenance expense of $849,000 (Schedule MDL-3-ELEC, page 39).

Q. In your opinion, is this adjustment appropriate?

A. No. In response to Division 1-21-ELEC, the Company provided O&M associated with 243 capital projects over fiscal years 2009 – 2011. As can be seen in this response, large parts of the O&M expenses in each year are associated with relatively few capital projects. For example, in fiscal year 2009, 54% of the total O&M expenses related to only four projects; in fiscal year 2010, 53% of the total O&M expenses related to only five projects; and in fiscal year 2011, five projects accounted for 50% of the O&M expenses. This would imply that the relevant O&M expenses incurred in a given year would relate more to the particular projects in that year rather than the overall level of capital expenditures in that year.

The Company is forecasting that the capital spending will increase from $48,613,000 to $56,540,000 in the rate year. However the Company has not established that the capital spending activity in the projects or types of projects where the O&M expenses are concentrated will increase from the 2011 test year to the rate year. Thus even if the overall spending increases as forecasted by the Company, it is not clear that the related O&M expense will increase commensurately. In addition, the accuracy of the Company's proposed adjustment depends on the accuracy of the forecast of capital spending in the rate year. Even assuming that the ratio developed by the Company is accurate, if the increase in capital spending does not materialize, there will be no increase in the related O&M expense.

Q. What do you recommend?

A. The pro forma adjustment for O&M expenses related to capital spending should be eliminated. This elimination reduces pro form operation and maintenance expenses by $849,000 (Schedule DJE-E-4).

d. Customer Outreach and Education

Q. Please describe the Company's proposed customer outreach and education initiative.

A. As explained in the testimony of Mr. Laflamme, this initiative is "National Grid's effort to improve the delivery of the communications with customers on certain issues such as safety, storm preparedness, energy efficiency and the benefits of natural gas, billing information, and financial assistance." The Company would expand its communications in these areas by "leveraging new channels of communications, such as radio, outdoor advertising, newspapers and digital channels, including social media, to more effectively reach and educate customers on what they want to hear from their utilities." (Laflamme direct testimony, pages 52-53)

The Company has estimated that the proposed customer outreach and education initiative will cost an additional $521,000 in advertising expenses and has adjusted actual test year expenses to reflect this cost (Schedule MDL-3-ELEC, page 40.

Q. Has the Company established that this additional advertising expense should be included in its cost of service?

A. No. In response to Division 1-24-ELEC, the Company noted that it has primarily utilized bill inserts and website updates to support customer outreach and education activities. In Division 8-11-ELEC, the Company was asked to provide any research or studies that show that the contemplated campaigns are more effective than bill inserts and website updates for customer outreach and education activities. The Company's response provided some information that purports to show that web communications were one of the least used channels to receive communications and that bill inserts, although highly visible, were the least preferred channel of communications.

However, there does not appear to be any data or analysis showing how the new channels being contemplated by the Company would increase the effectiveness of communications or that the benefits of the expanded channels of communication would be commensurate with the additional $521,000 annual cost of the contemplated programs.

Q. What do you recommend?

A. Unless the Company can better establish that the benefits of the customer outreach and education justify the cost, the expense of this initiative should be eliminated from the cost of service. On Schedule DJE-E-4, I have reduced pro forma advertising expense by $521,000 to eliminate the cost of this program.

e. Customer Assistance Advocate Expense

Q. Please explain the Company's proposed pro forma adjustment for customer assistance advocate personnel.

A. As described in the testimony of Ms. Kaye, the Company is proposing to add personnel to serve in a Consumer Advocacy role that would improve implementation of the Company's low income discount and other public benefit programs. Pro forma test year operation and maintenance expense has been increased by $158,000 to recognize the costs of two additional employees associated with this program (Schedule MDL-3-ELEC, page 44).

Q. Should this pro forma adjustment be included in the determination of the Company's revenue requirement?

A. No. The Company has not established that these additional employees are necessary or that National Grid is the appropriate party to fill the role of Consumer Advocate with regard to low income and other public benefit programs. Accordingly, I have reduced pro forma test year operation and maintenance expense by $158,000 to eliminate the cost of customer assistance advocate personnel from the Company's revenue requirement (Schedule DJE-E-4).

f. Foundation Support Staff

Q. Has the Company adjusted 2011 test year expenses to reflect the cost of additional personnel to provide support for the SAP operating platform being implemented in association with the US Foundation Project?

A. Yes. As explained by Mr. Laflamme, the new SAP platform will require support from personnel in addition to the test year complement of employees. Accordingly Schedule MDL-3-ELEC, page 45 reflects an adjustment to increase test year operation and maintenance expenses by $240,000 to reflect the salaries of those additional employees.

Q. Have any of these additional employees actually been hired?

A. As of the time of the response to Division 15-4-ELEC, none of the employees had been hired, although in the response the Company noted that it expected that the additional employees would be hired by October 2012.

Q. Should the test year expenses be adjusted to reflect the cost of these additional employees?

A. Not until at least some of the employees hiring has commenced. Therefore, on Schedule DJE-E-4, I have reduced pro forma operation and maintenance expenses by $240,000 to reflect the elimination of the costs related to the additional Foundation support staff.

g. Uncollectible Accounts Expense

Q. Have you adjusted the uncollectible accounts expense to reflect your proposed base rate revenue requirement?

A. Yes. The allowance for uncollectible accounts is calculated as a percentage of the other components of the cost of service. Therefore, the pro forma uncollectible accounts expense is affected by the other adjustments to the Company's revenue requirement. My calculation of the uncollectible accounts expense on my proposed cost of service and using the adjusted write-off percentage recommended by Mr. Gay is shown on Schedule DJE-E-3. For the purpose of simplicity of presentation, I have included the energy efficiency revenues in the base for the calculation of the uncollectible accounts expense on this schedule. However, the Division does not oppose the Company's proposal to recover uncollectible accounts on the energy efficiency revenues outside of base rates, so long as that recovery is limited to the approved bad debt rate times the actual energy efficiency revenues.

Q. Is the Company also proposing a new mechanism related to commodity related uncollectible accounts expense?

A. Yes. As explained in the testimony of Company Witness Kaye, National Grid is requesting a fully reconciling mechanism for commodity-related bad debt to recover its commodity-related uncollectible accounts expense. The proposed reconciliation mechanism would "defer and reconcile any differences between the Company's actual net write-offs associated with commodity revenues and the revenue generated by applying the uncollectible rate to commodity and commodity-related administrative expense revenue." (Kaye Direct Testimony, page 19)

Q. Is the Company's proposed reconciliation mechanism for write-offs of uncollectible accounts related to commodity revenues appropriate?

A. No. As a general matter, reconciliation mechanisms are contrary to sound ratemaking practice, as such mechanisms tend to either reduce or eliminate incentives to control costs authorized under standard ratemaking. The Company presents its proposal as a mechanism to protect its interests (as well as those of customers). However, the Company has not provided any measurement of potential financial impairment from increases in uncollectible accounts; nor has the Company compared the magnitude or volatility of uncollectible accounts expenses relative to other costs for which there is no reconciliation mechanism.

Q. In addition to these general concerns, are there any problems that are more specific to the Company?

A. Yes. The Company claims that its proposal will not mitigate incentives to minimize net write-offs because "the Company will still be exposed to fluctuations in uncollectible accounts expense associated with the delivery portion of customer bills." (Kaye, Direct Testimony, page 21) However, Mr. Gay addresses certain issues with regard to the Company's revenue recovery practices in his testimony. If these issues exist in the absence of a fully reconciling mechanism for commodity related bad debt, the implementation of such a mechanism could only have the effect of reducing incentives to resolve those issues. The present method of recovering bad debt on commodity revenues holds the Company harmless from changes in bad debt due to fluctuations in commodity revenues, which are arguably beyond the Company's control. The Company has not established that these protections should be expanded to recover changes in the net write-offs as a percentage of commodity revenues, over which the Company does have some control.

Q. Should the Company's proposed mechanism to reconcile changes in commodity related uncollectible accounts be approved?

A. No. Such reconciling mechanisms are appropriate only for expenses that are large, volatile, and beyond the utility company's control. The Company has not established that its proposed mechanism to reconcile increases in commodity related uncollectible accounts is necessary to protect its financial integrity. The reconciling mechanism would shift risk from the Company to its ratepayers for an expense over which the Company has some control, but over which ratepayers have no control. The Company's proposal should not be approved.

h. Storm Fund Accrual

Q. What is the status of the Company's storm fund?

A. As of March 31, 2012 there was a deficit (debit balance) of approximately $11.5 Million in the storm fund (Laflamme Direct Testimony, page 112). This debit balance represents the cumulative excess of charges to the fund over accruals recovered through rates since the establishment of the fund. As of August 2011, there was a credit balance of approximately $22 million in the storm fund (Division 1-29-ELEC), but costs associated with Tropical Storm Irene eliminated that credit balance and resulted in a storm fund deficiency.

Q. Is the Company proposing a mechanism to address the deficiency in the storm fund?

A. Yes. The Company's proposed mechanism consists of three parts. First, the annual storm fund accrual of $1,041,000 that existed before the 2009 Electric Rate Case would be reinstated. Second, a temporary Storm Cost Recovery Factor ("SCRF") would be implemented. The SCRF would be in effect for three years and would be designed to produce annual revenues of $2.4 million, with the revenues dedicated to the storm fund. Third, the Company is presently recording amortization expense of $2.5 million per year related to the 2003 voluntary early retirement offer. That amortization will be complete on December 31, 2013, which falls within the rate year in this case. Rather than normalize the remaining balance (approximately $2.3 million) to be amortized when the rates in this case go into effect over the expected term of the new rates, the Company is proposing to shift the amortization of the $2.5 million per year to a credit of $2.5 million to the storm fund annually, commencing January 1, 2014.

Q. Do you agree that the deficit in the storm fund needs to be addressed?

A. Yes. However, I am proposing to modify the mechanisms presented by the Company.

Q. Please explain your modifications to the Company's proposed storm fund mechanisms.

A. Mr. Laflamme states that the Company's proposal will virtually eliminate the deficit in the storm fund by January 31, 2016, three years after the rates in this case go into effect. However, this projection does not include the effect of the $1,041,000 storm damage accrual in the base rate cost of service. In the response to Division 1-30-ELEC, the Company stated that the intent of the proposed SCRF is to specifically address the Company's current storm fund deficit and is not intended to restore a much needed Storm Fund Reserve for the benefit of customers. In my opinion, this is a false distinction. Any mechanism that addresses the storm fund deficit restores the storm fund reserve and vice-versa. That is, any credits to the storm fund both reduce the deficit and ultimately restore the reserve.

Any accrual for storm damage included in the base rate cost of service will first decrease the deficit and when the deficit is eliminated will restore the reserve. The Company has not established that the SCRF is necessary or appropriate, if the accrual for storm damage is otherwise adequate.

I recommend that the storm fund accrual be reinstated in the base rate cost of service at a rate of $1,800,000 annually, or $150,000 per month. I agree with the Company's proposal to shift the amortization of the $2.5 million per year to a credit of $2.5 million to the storm fund annually, commencing January 1, 2014. Thus, as of January 1, 2014, the annual credit to the storm fund reserve will be $4.3 million. The adequacy of this accrual and the storm fund reserve can be reviewed in the Company's next base rate case. The proposed SCRF should not be implemented.

Q. How does your proposal affect the Company's revenue requirement?

A. The Company includes a $3,441,000 storm damage accrual in its total cost of service. Of this amount, $1,041,000 would be recovered in base rates, and $2,400,000 would be recovered through the SCRF. I am proposing to include an accrual of $1,800,000 in the base rate cost of service. This is $759,000 more than the amount reflected by the Company in its base rate cost of service. Therefore, the Company's base rate cost of service should be increased by $759,000 (Schedule DJE-E-4). However, I am also proposing to eliminate the SCRF. This adjustment is reflected as a reduction to the SCRF of $2,400,000 on Schedule DJE-E-1. Therefore, while my proposal results in an increase of $759,000 to the base rate cost of service, it results in a reduction of $1,641,000 ($759,000 - $2,400,000) to the Company's *total* rate year cost of service.

i. Storm Damage Expense

Q. In addition to the accruals to storm fund, did the Company charge actual storm repair and restoration costs to operation and maintenance expenses in the 2011 test year?

A. Yes. If the costs of repairs and restoration associated with any particular storm fall below the threshold amount, those costs are charged to operation and maintenance expenses rather then being charged against the storm damage reserve. The Company charged $7,464,000 (Division 8-5-ELEC) of such storm damage costs to operation and maintenance expense in 2011. After normalizing adjustments of $2,385,000 on Schedule MDL-3-ELEC, the net storm damage expense reflected in test year expenses is $5,079,000. (In response to Division 1-2-ELEC, the Company stated that the normalizing adjustment should be corrected to $1,159,000, which would increase net storm damage expense to $6,395,000. However, that correction has not yet been reflected in the cost of service as filed by the Company.)

Q. How does the Company's adjusted net expense of $5,079,000 compare to storm damage costs charged to operation and maintenance expense in other recent years?

A. It is significantly higher. In response to Division 8-6-ELEC, the Company provided the storm damage costs charged to operation and maintenance expense in the years

2006 – 2010. The inflation adjusted storm costs in those years ranged from $1,812,000 to $4,516,000. The storm damage costs charged to expenses in 2011 was well in excess of the normal level of such expenses in other recent years.

Q. Are you proposing to adjust the level of storm damage expenses included in the Company's revenue requirement?

A. Yes. The storm damage costs charged to expense vary widely from year to year. The expense included in the revenue requirement should reflect a normal level of expense that the Company can reasonably expect to incur on a prospective basis. The expense incurred in 2011 was clearly higher then the normal level of expense and should be normalized for the purpose of determining the Company's revenue requirement.

Q. What do you recommend?

A. The average of inflation adjusted storm damage costs charged to operation and maintenance expense in the years 2007 – 2011 was $3,967,000. I believe this five year average is reasonably representative of the normal annual level of storm damage expense that the Company can expect to incur overt time. The five year average is $1,112,000 less than the net storm damage expense of $5,079,000 reflected by the Company. Therefore, I propose to reduce pro forma test year operation and maintenance expenses by $1,112,000, in order to normalize the storm damage expenses included in the Company' revenue requirement (Schedule DJE-E-4).

2. Depreciation Expense

Q. Have you reflected an adjustment to test year depreciation expense in your calculation of the rate year cost of service?

A. Yes. As depreciation expense is calculated by applying the relevant depreciation accrual rates to the depreciable plant in service, my proposed adjustment to plant in service (addressed in my testimony on rate base) affects the rate year depreciation expense. The adjustment to depreciation expense resulting from my proposed adjustment to plant in service is shown on Schedule DJE-E-5.

3. Taxes Other Than Income Taxes

Q. Are you proposing any adjustments to the taxes other than income taxes included by the Company in its revenue requirement?

A. Yes. Certain of my adjustments to operation and maintenance expenses entail the elimination of wages and salaries. Consistent with those adjustments, I am proposing to eliminate the related payroll taxes. My adjustments to payroll taxes are shown on Schedule DJE-E-6.

4. Income Tax Expense

Q. Have you calculated the pro forma income tax expense to be included in the Company's revenue requirement?

A. Yes. I have calculated the pro forma income tax expense on my Schedule DJE-E-7. I have used what is commonly referred to as the "return method" of calculating pro forma income tax expense. This method begins by calculating the taxable income base (that is, the net income after income tax expense) by applying the weighted return on equity to the rate base and adjusting the product of that calculation by permanent tax reconciling items. To determine the taxable income, the adjusted net income must then be grossed up, as the income tax expense itself is not deductible for federal income taxes. Finally, the income tax rate of 35% is applied to the taxable income to calculate the pro forma income tax expense to be included in the Company's revenue requirement. This method has traditionally been employed by the Commission in calculating pro forma income tax expense. Although the mechanics of this calculation are different from the method shown on Schedule MDL-3-ELEC, page 60, there is no substantive difference.

5. Return on Rate Base

Q. How is the return on rate base to be included in the total revenue requirement calculated?

A. The return on rate base is calculated by multiplying the rate of return by the rate base. The rate base is the net investment in facilities necessary to provide utility service. I am proposing adjustments to rate base, and I have incorporated the recommendation of Mr. Kahal on rate of return into my calculation of the required return on rate base.

a. Plant in Service

Q. How did the Company determine the balance of gross utility plant that it is proposing to include in its pro forma rate base?

A. The gross utility plant included in rate base is the forecasted average balance for the twelve months ending January 31, 2014, the Company's rate year. The Company began with the actual balance of plant as of December 31, 2011, the end of the test year, and then adjusted that balance for forecasted additions to and retirements from plant through January 31, 2014. The average balance of gross utility plant forecasted by the Company for its rate year is $1,338,779,000 (Schedule MDL-3-ELEC, page 63).

Q. Have you analyzed the Company's forecast of gross utility plant for the twelve months ending January 31, 2014?

A. Yes. I have reviewed the budgeted additions to plant. I have also compared the Company's forecasts of additions and retirements to actual additions and retirements in recent years, and I have reviewed the actual and budgeted additions to plant in service from January 2012 through June 2012.

Q. Based on your analysis, are you proposing to adjust the forecasted plant balance included in rate base by the Company?

A. Yes. As explained by Mr. Laflamme, the forecast of Infrastructure, Reliability, and Safety ("ISR") plant will be, in effect, be trued up through the ISR mechanism. The ISR plant represents the great majority of plant additions, and there is little purpose to adjusting the Company's forecast, because any discrepancy between the forecasted additions and actual additions will be reconciled through the ISR mechanism. However, the Company's forecast also includes certain non-ISR plant additions, and the forecasted rate of those additions is significantly higher than the actual rate of non-ISR plant additions in 2012 through June. Therefore, I am proposing to adjust the non-ISR plant included in the Company's rate year rate base.

Q. Please explain your proposed adjustment to the Company's forecast of non-ISR plant additions.

A. The actual non-ISR plant additions in 2012 through June were $317,000. This translates into an annual rate of $634,000. Projecting this annual rate of non-ISR plant additions through January 2014, the pro-forma adjustment for non-ISR plant additions through the rate year is $1,004,000 (Schedule DJE-E-8.1). This is $3,986,000 less than the non-ISR plant included in the Company's pro-forma adjustment for plant additions through the rate year. Therefore, I am proposing to reduce the non-ISR plant included in the Company's projected rate year rate base by $3,986,000.

b. Depreciation Reserve

Q. Are you also proposing to adjust the rate year balance of accumulated depreciation reserve?

A. Yes. I have calculated an adjustment of $94,000 to the average balance of rate year accumulated depreciation in association with my adjustment to non-ISR plant in service.

Q. Are you proposing any other adjustment to the rate year balance of accumulated depreciation reserve?

A. Yes. The Company's balance sheet shows a net liability for Asset Retirement Obligation ("ARO"). The ARO represents accumulated depreciation reserve balances that have been reclassified for financial statement presentation. For the purpose of determining the Company's rate base, the ARO should be treated as accumulated depreciation and included in the balance that is deducted from plant in service. On Schedule DJE-E-8, I have adjusted the depreciation reserve by $570,000 to include the ARO on the Company's balance sheet in the depreciation reserve deducted from plant in service in the determination of the Company's rate base.

c. Accumulated Deferred Income Taxes

Q. Are you proposing any adjustments to the balance of accumulated deferred income taxes deducted ("ADIT") from plant in service in the determination of the Company's rate base?

A. Yes. First, my proposed adjustment to rate year plant results in adjustment to ADIT. Second, in response to Division 8-3-ELEC, the Company stated that the ADIT balance was understated by $11,935,000. The balance of ADIT should be adjusted accordingly. Third, I am proposing to eliminate the deferred tax debit balance related to net operating losses ("NOL") from the determination of the rate base deduction for ADIT. My adjustments to the rate year balance of ADIT are summarized on Schedule DJE-E-8.2

Q. What does the deferred debit balance related to the NOL represent?

A. The NOL represents the effect of tax deductions that the Company could not use in given years, because the tax deductions drive the taxable income below zero. The Company shows the NOL as a reduction to the net balance of ADIT that are deducted from rate base. As of December 31, 2011, the total NOL balance was $15,195,000.

Q. Why are you proposing to eliminate the NOL from the balance of ADIT deducted from rate base?

A. In response to Division 15-10-ELEC, the Company stated that "The Net Operating Loss as of December 2011 is related to the tax years ended March 31, 2009 and March 31, 2010. These net operating losses must be carried back to prior years, and the Company will have sufficient taxable income in the carry back period to fully utilize these net operating losses."

If the Company will have sufficient taxable income in the carry back period to fully utilize these net operating losses, then the deferred NOL balance should cease to exist. Therefore, I believe that it is appropriate to eliminate the NOL balance in the determination of the rate base deduction for ADIT.

Q. What is the effect of your proposed adjustment to eliminate the NOL from the balance of ADIT deducted from rate base?

A. The Company uses the balance of ADIT as of December 31, 2011 as the starting point for its calculation of the projected rate year balance of ADIT. I have calculated that the jurisdictional balance of the NOL as of December 31, 2011 is $12,132,000 (Schedule DJE-E-8.2). Therefore, elimination of the NOL increases the rate year balance of ADIT by $12,132,000 and reduces the rate year rate base accordingly.

d. Injuries and Damages

Q. Did the Company deduct the accrued reserve for injuries and damages from plant in service in the determination of its rate base?

A. No. The Company's calculation of rate base is shown on Schedule MDL-3-ELEC, Page 63. As can be seen on this schedule there is no rate base deduction for injuries and damages reserve.

Q. Does this represent a departure from the Company's practice in prior rate cases?

A. Yes. For example, in Docket No. 4065, the Company reflected a deduction of $4,762,000 for injuries and damages in its determination of the rate year rate base.

Q. Has the Company explained this change in the treatment of the injuries and damages reserve?

A. As far as I can determine, it has not.

Q. Should the accrued reserve for injuries and damages be deducted from plant in service in the determination of the Company's rate base?

A. Yes. The accrued reserve for injuries and damages represents expenses accrued in excess of actual cash disbursements. Accordingly, the reserve should be deducted from the Company's rate base.

Q. What balance of injuries and damages are you proposing to deduct from the Company's rate base?

A. The average balance of injuries and damages reserve in 2011 was $6,147,000. Of this balance, $4,908,000 is allocable to distribution service. Accordingly, I have reflected a rate base deduction of $4,908,000 for injuries and damages reserve on my Schedule DJE-E-8.

e. Rate of Return

Q. What rate of return have you used to calculate the return requirement to be included in the total cost of service?

A. I have used the rate of return of 7.11% proposed by Mr. Kahal to calculate the required return on rate base.

Q. What return on rate base have you calculated?

A. I have calculated a required return on rate base of $38,528,000 (Schedule DJE-E-8) and included this return requirement in the Company's total revenue requirement.

IV. REVENUE REQUIREMENT - GAS

A. SUMMARY

Q. Have you prepared a summary of the Company's rate year gas revenue requirement?

A. Yes, my summary of the gas revenue requirement is shown on Schedule DJE-G-1. I compare the Company's presentation of its revenue deficiency to the Division's recommendation on this schedule. I have begun with the Company's total cost of service. The base rate cost of service is comprised of operating expenses plus the return on rate base, as shown on my Schedule DJE-G-2. The total cost of service less the revenue produced by the other rate factors shown on Schedule DJE-G-1 and miscellaneous revenues is the base rate cost of service.

I have calculated a reduction of $13,755,000 to the total revenue deficiency presented by the Company.

B. COST OF SERVICE AND REVENUE DEFICIENCY

Q. Are you proposing adjustments to the rate year cost of service calculated by the Company?

A. Yes. The Company has calculated a pro forma rate year cost of service of $173,128,000. Based on the adjustments to the Company's position that I have identified, I am proposing a total cost of service of $164,621,000. I address the individual adjustments to the Company's calculated cost of service in the following testimony. I also address an adjustment to forecasted rate year revenues, which does not affect the cost of service but does affect the calculation of the revenue deficiency under present rates.

1. Operation and Maintenance Expenses

a. Variable Pay - DSM

Q. Please describe your proposed adjustment to variable pay.

A. As in the case of Narragansett Electric, in calculating the pro forma adjustment to variable pay, the Company compared the target variable pay including DSM to actual test year actual variable pay excluding DSM. In response to Division 2-7-GAS, the Company provided a corrected calculation of the variable pay adjustment on Schedule MDL-3-GAS, page 21. The effect of the correction is to reduce pro forma test year operation and maintenance expenses by $176,000. I have reflected this adjustment on my Schedule DJE-G-4.

b. Uninsured Claims

Q. Please describe your proposed adjustment to uninsured claims.

A. As in the case of Narragansett Electric, certain expenses for claims for Worker's Compensation were misclassified in 2011. As a result, the total amount of test year claims of $395,202 on Schedule MDL-3-GAS, page 31 should have been $618,449. This increases the actual test year expense to which the five year average is compared by $223,000 and reduces the pro forma uninsured claims expense by the same amount (Schedule DJE-G-4).

c. LNG Processing Terminal Labor

Q. Are you proposing to adjust the LNG processing terminal labor included in the base gas distribution cost of service?

A. Yes. In response to Division 9-2-GAS, the Company stated that $453,344 of gas supply costs were incorrectly charged to Account 844.2 and should have been included in the Gas Cost Recovery Mechanism. This amount should be removed from the gas base rate cost of service. Therefore, I have reduced pro forma test year operation and expense by $453,000 on Schedule DJE-G-4.

d. Customer Outreach and Education

Q. Please describe your adjustment to the Company's proposed customer outreach and education initiative.

A. As in the case of Narragansett Electric, the Company is prosing to expand its communications with customers, with an incremental increase of $354,000 in gas advertising expenses (Schedule MDL-3-GAS, page 42.) Again, there does not appear to be any data or analysis showing how the new channels being contemplated by the Company would increase the effectiveness of communications or that the benefits of the expanded channels of communication would be commensurate with the additional $156,000 annual cost. Therefore, on Schedule

DJE-G-4, I have reduced pro forma advertising expense by $156,000 to eliminate the cost of this program.

e. Customer Assistance Advocate Expense

Q. Please explain your adjustment to the Company's proposed expense for customer assistance advocate personnel.

A. As in the case of Narragansett Electric, the Company is proposing to increase pro forma gas operation and maintenance expenses for personnel to serve in a Consumer Advocacy role. As noted previously, the Company has not established that these additional employees are necessary or that National Grid is the appropriate party to fill the role of Consumer Advocate with regard to low income and other public benefit programs. Accordingly, I have reduced pro forma test year gas operation and maintenance expense by $156,000 to eliminate the cost of customer assistance advocate personnel from the Company's revenue requirement (Schedule DJE-G-4).

f. Foundation Support Staff

Q. Please describe your adjustment to the cost of additional personnel to provide support for the SAP operating platform being implemented in association with the US Foundation Project.

A. Schedule MDL-3-GAS, page 43 reflects an adjustment in to increase test year operation and maintenance expenses by $92,000 to reflect the salaries of additional employees to support the new SAP platform, in addition to the test year complement of employees. None of the employees had been hired. Therefore, on Schedule DJE-G-4, I have reduced pro forma operation and maintenance expenses by $92,000 to reflect the elimination of the costs related to the additional Foundation support staff.

g. Uncollectible Accounts Expense

Q. Have you adjusted the uncollectible accounts expense to reflect your proposed base rate revenue requirement?

A. Yes. The allowance for uncollectible accounts is calculated as a percentage of the other components of the cost of service. Therefore, the pro forma uncollectible accounts expense is affected by the other adjustments to the Company's revenue requirement. My calculation of the uncollectible accounts expense on my proposed gas base rate revenue requirement using the adjusted write-off percentage recommended by Mr. Gay is shown on Schedule DJE-G-3.

Q. Is the Company also proposing a new mechanism related to commodity related uncollectible accounts expense?

A. Yes. As in the case of Narragansett Electric, the Company is requesting a fully reconciling mechanism for gas commodity-related bad debt to recover its commodity-related uncollectible accounts expense. As noted above, the present method of recovering bad debt on gas commodity revenues holds the Company harmless from changes in bad debt due to fluctuations in commodity revenues, which are arguably beyond the Company's control. The Company has not established that these protections should be expanded to recover changes in the net write-offs as a percentage of commodity revenues, over which the Company does have some control. For the reasons described in my testimony on the electric cost of service, the Commission should not approve the Company's requested fully reconciling mechanism for gas commodity-related bad debt.

2. Taxes Other Than Income Taxes

Q. Are you proposing any adjustments to the taxes other than income taxes included by the Company in its revenue requirement?

A. Yes. Certain of my adjustments to operation and maintenance expenses entail the elimination of wages and salaries. Consistent with those adjustments, I am proposing to eliminate the related payroll taxes. My adjustments to payroll taxes are shown on Schedule DJE-G-5.

3. Income Tax Expense

Q. Have you calculated the pro forma income tax expense to be included in the Company's revenue requirement?

A. Yes. I have calculated the pro forma income tax expense on my Schedule DJE-G-6. Again, I have used what is commonly referred to as the "return method" of calculating pro forma income tax expense.

Q. Have you reflected any substantive changes to the Company's calculation of pro forma income tax expense?

A. Yes. In response to Division 2-25-GAS, the Company acknowledged that $708,000 of AFUDC income should be eliminated from the determination of taxable income. This decrease to taxable income is partially offset by an increase to taxable income of $11,000 related to depreciation of previously capitalized AFUDC income. Accordingly, the income included in the calculation of the taxable income base should be reduced by $697,000. I have reflected this adjustment on Schedule DJE-G-6.

4. Return on Rate Base

Q. Are you proposing adjustments to the rate base used in calculating the return requirement included in the Company's cost of service?

A. Yes. As can be seen on Schedule DJE-G-7, I am proposing to adjust the balances of depreciation reserve and injuries and damages.

a. Depreciation Reserve

Q. Please describe your proposed adjustment to the rate year balance of accumulated depreciation reserve.

A. Yes. As in the case of Narragansett Electric, the Company's balance sheet shows a net liability for ARO. The ARO represents accumulated depreciation reserve balances that have been reclassified for financial statement presentation. For the purpose of determining the Company's rate base, the ARO should be treated as accumulated depreciation and included in the balance that is deducted from plant in service. On Schedule DJE-G-7, I have adjusted the depreciation reserve by

$2,623,000 to include the ARO on the Company's balance sheet in the depreciation reserve reflected in the calculation of rate base.

b. Injuries and Damages

Q. Please describe your proposal to deduct the accrued reserve for injuries and damages from plant in service in the determination of the Company's gas rate base.

A. The Company's calculation of rate base is shown on Schedule MDL-3-GAS, Page 58. As with Narragansett Electric, there is no rate base deduction for injuries and damages reserve on this schedule. Again, this represents a departure from the Company's practice in prior rate cases**.** For example, in Docket No. 3943, the Company reflected a deduction of $840,000 for injuries and damages in its determination of the rate year rate base.

The accrued reserve for injuries and damages represents expenses accrued in excess of actual cash disbursements. Accordingly, the reserve should be deducted from the Company's rate base. The average balance of injuries and damages reserve in 2011 was $190,000. Accordingly, I have reflected a rate base deduction of $190,000 for injuries and damages reserve on my Schedule DJE-G-7.

e. Rate of Return

Q. What rate of return have you used to calculate the return requirement to be included in the total gas cost of service?

A. I have used the rate of return of 7.39% proposed by Mr. Kahal to calculate the required return on rate base.

Q. What return on rate base have you calculated?

A. I have calculated a required return on rate base of $27,159,000 (Schedule DJE-G-7) and included this return requirement in the Company's total revenue requirement.

5. Revenues and Billing Determinants

Q. Have you analyzed the Company's forecast of rate year base rate gas revenues and billing determinants?

A. Yes. Mr. Silvestrini addresses the Company's forecasts of customer counts and gas deliveries, and Ms. Leary provides schedules and workpapers supporting the forecasts of rate year gas revenues under present and proposed rates.

Q Are you proposing any adjustments to the Company's forecast of rate year revenues under present rates?

A. Yes. I am proposing adjustments to the revenues for the residential heat, medium commercial and industrial sales customers, medium commercial and industrial FT-2, and HLF XL FT-1 rate classes. These adjustments do not directly affect the Company's cost of service. However, they affect the calculated revenue deficiency and the determination of the rates necessary to produce the required revenues.

Q Please explain your proposed adjustment to residential heat revenues and billing determinants.

A. The Company is forecasting an average level of residential heat customers of 202,140 (including low income customers) for the twelve months ending January 2014, the rate year in this case. For the twelve months ended June 2012, the actual average number of residential heat customers was 200,133 (response to Division 16-4-GAS). Thus the Company is forecasting an increase of 2,007 customers for the nineteen month period from June 2012 to January 2014, which translates into annual growth rate of 1,268 customers. This is lower than the actual growth rate of residential customers in recent years. For example for the five years from 2006 – 2011, the average annual growth rate of residential heat customers was 1,541 (Narragansett Schedule ALS-5). If anything, the prospective forecasted growth rate should be higher than in recent years, because the Company is forecasting an increase in conversions from oil to gas as compared to recent years and includes the additional plant associated with those increased conversions in its rate base (responses to Division 2-20-GAS and Division 9-5-GAS). Therefore, I recommend that the forecasted number of residential heat customers in the rate year be increased.

Q How do you propose to adjust the number of rate year residential heat customers forecasted by the Company?

A. For the six months ended June 30, 2012, the average number of residential heat customers was 202,212. This represents an increase of 2,270 over the six months ended June 30, 2011. As noted above, the actual average number of residential heat customers was 200,133 for the twelve months ended June 30, 2012. If that number is projected to grow by 2,270 annually, then the projected residential heat customers for the twelve months ending January 31, 2014 is 203,728 (Schedule DJE-G-8). This is 1,588 customers greater than the rate year level of 202,140 forecasted by the Company. An annual growth rate of 2,270 is greater than the actual growth rate in other recent years, but an increase to the growth rate is consistent with the increase in gas conversions described by the Company.

The average annual base rate gas revenue per residential heat customer is $439. Thus, an increase of 1,588 to the forecasted level of rate year residential heat customers results in additional base rate revenues of $697,000 and decreases the base rate revenue deficiency accordingly. The increased customer bills and therm sales associated with additional residential heat customers should also be incorporated into the billing determinants in calculation of the rates necessary to produce the Company's base rate gas revenue requirement.

Q Please explain your proposed adjustment to medium commercial and industrial ("C&I") sales customers and billing determinants.

A. The Company is forecasting an average level of medium C&I sales customers of 2,832 for the twelve months ending January 2014. The actual average number of medium C&I sales customers for the twelve months ended June 2012 was 2,938. Thus, the Company is forecasting a decrease of 106 medium C&I sales customers for the nineteen months from June 2012 to January 2014. The actual number of medium C&I sales customers has declined somewhat in recent years, but given the experience in the more recent periods I believe that the Company has understated the likely average number of C&I sales customers in the rate year. In fact, the average number of medium C&I sales customers in the first six months of 2012 actually increased by 35 over the corresponding period in 2011. Given the most recent experience, I believe that it would be reasonable to assume that the number of medium C&I sales customers will at least hold steady from the twelve months ended June 2012 to the rate year.

The actual average number of medium C&I sales customers for the twelve months ended June 30, 2012 is 106 greater than the number of medium C&I sales customers forecasted by the Company for the rate year. The average annual base rate gas revenue per medium C&I sales customer is $3,442. Thus, an increase of 106 to the forecasted level of rate year medium C&I sales customers results in additional base rate revenues of $365,000 and decreases the base rate revenue deficiency accordingly (Schedule DJE-G-8). Again, the increased customer bills and therm sales associated with additional medium C&I sales customers should be incorporated into the billing determinants in calculation of the rates necessary to produce the Company's base rate gas revenue requirement.

Q Please explain your proposed adjustment to the medium C&I FT-2 customers and billing determinants.

A. The Company is forecasting an average level of medium C&I FT-2 customers of 1,030 for the twelve months ending January 2014. The actual average number of medium C&I FT-2 customers for the twelve months ended June 2012 was 1,055.

Thus, the Company is forecasting a decrease of 25 medium C&I FT-2 customers for the nineteen months from June 2012 to January 2014. As can be seen on Schedule ALS-5, this forecasted decrease is completely inconsistent with the Company's actual experience in recent years. Further, the average number of medium C&I FT-2 customers in the first six months of 2012 increased by 123 over the corresponding period in 2011. This rate of increase is consistent with the experience in other recent years. Therefore, I recommend that the forecasted number of medium C&I FT-2 customers in the rate year be increased.

Q How do you propose to adjust the number of rate year medium C&I FT-2 customers forecasted by the Company?

A. For the six months ended June 30, 2012, the average number of medium C&I FT-2 customers was 1,093. This represents an increase of 123 over the six months ended June 30, 2011. As noted above, the actual average number of medium C&I FT-2 customers was 1,055 for the twelve months ended June 30, 2012. If that number is projected to grow by 123 annually, then the projected medium C&I FT-2 customers for the twelve months ending January 31, 2014 is 1,250 (Schedule DJE-G-8). This is 220 customers greater than the rate year level of 1,036 forecasted by the Company. An annual growth rate of 123 is not out of line than the actual growth rate in other recent years, although it is slightly lower then actual average growth rate of 132 for the years 2006-2011.

The average annual base rate gas revenue per medium C&I FT-2 customer is $3,826. Thus, an increase of 220 to the forecasted level of rate year medium C&I

FT-2 customers results in additional base rate revenues of $842,000 and decreases the base rate revenue deficiency accordingly. The increased customer bills and therm sales associated with additional medium C&I FT-2 customers should also be incorporated into the billing determinants in calculation of the rates necessary to produce the Company's base rate gas revenue requirement.

Q Please explain your proposed adjustment to the forecasted rate year HLF XL FT-1 revenues.

A. The Company is forecasting rate year HLF XL FT-1 revenues of $3,890,000. This compares to actual HLF XL FT-1 revenues of $4,947,000 is the 2011 test year. The reason for the decrease in revenues is a forecasted decrease in deliveries. In Division 9-7, the Company was asked to explain the forecasted decrease in deliveries from Fiscal Year 2012 to Fiscal Year 2014 for the HLF XL FT-1 rate class. The Company responded that "The forecasted decreases in deliveries from Fiscal Year 2012 to Fiscal Year 2014 for the HLF XL FT-1 rate class are caused by the decrease in customer counts for this class, which are projected to decline from an average of 61 in Fiscal Year 2012 to an average of 50 in Fiscal Years 2013 and 2014."

The average number of HLF XL FT-1 customers in the first six months of 2012 was 64 (response to Division 16-4-GAS, Page 2). Further, referring to the response to Division 16-5, it can be seen that the deliveries to the HLF XL FT-1 customers in the first six months on 2012 were approximately the same as (98.6% of) the deliveries in the corresponding months of 2011. Therefore, the forecasted decrease in deliveries to this rate class does not appear to be taking place, and the Company's rate year forecast of deliveries to the HLF XL FT-1 customers should be adjusted accordingly.

Q How do you propose to adjust the forecast of deliveries to HLF XL FT-1 customers?

A. The deliveries to HLF XL FT-1 customers for the twelve months ended June 30, 2012 were approximately the same as the calendar 2011 deliveries and exceed the forecasted fiscal year 2012 deliveries shown on Schedule ALS-4. There is no discernible downward trend in deliveries to HLF XL FT-1 customers. Therefore, I recommend that forecast of rate year revenues for HLF XL FT-1 customers be adjusted to the level of revenues for the 2011 test year. This results in an increase of $1,057,000 to rate year revenues (Schedule DJE-G-8). The billing determinants used in the calculation of new rates should also be adjusted to reflect 2011 test year deliveries to HLF XL FT-1 customers.

Q Please summarize your proposed adjustment to rate year gas revenues under present rates.

A. I am proposing to increase rate year gas revenues by $2,960,000 (Schedule DJE-G-8). Again, this adjustment does not affect the cost of service, but it does affect the revenue deficiency and the rates necessary to produce the calculated revenue requirement.

V. PENSION ADJUSTMENT MECHANISM

Q. Is the Company proposing to implement a Pension Adjustment Mechanism ("PAM") for Narragansett Electric to reconcile actual pension and other post-employment benefits ("PBOP") expense to the expenses reflected in base rates?

A. Yes. The Company presently has a PAM in effect for Narragansett Gas. The Company is proposing to implement a similar PAM for Narragansett Electric.

Q. What is the position of the Division on the implementation of a PAM for Narragansett Electric?

A. In Docket No. 3943 I presented testimony in opposition to the implementation of PAM for Narragansett Gas. However, the Commission approved the Company's proposal, and the PAM proposed by the Company is now in effect for Narragansett Gas. In Docket No. 4065, the Company proposed to implement a similar PAM for Narragansett Gas, but the Commission rejected it.

I still believe the points that I presented in opposition to the PAM in Docket No. 3943 are still valid. On the other hand, there is little reason why Narragansett Electric should be treated differently from Narragansett Electric in regard to this matter. Therefore, the Division is not taking a position in opposition to the implementation of a PAM for Narragansett Electric in this case.

In the review of the Company's DAC in 2011, it was discovered that Narragansett Gas was not fully funding its pension and PBOP obligation, although the Commission's original approval of the PAM was in part based on the premise that it would ensure full funding of the pension and PBOP obligation. The Company has represented that if the Commission approves the PAM for Narragansett Electric, it will fund the Narragansett Electric pension and PBOP obligation in an amount at least equal to the amount collected from customers. If the Commission does approve the PAM for Narragansett Electric, this minimum funding level should be a required provision of the approved mechanism.

VI. PROPERTY TAX RECOVERY MECHANISM

Q. Is the Company proposing to implement a reconciliation mechanism for property tax expense?

A. Yes. As explained in the testimony of Mr. Laflamme, the Company is proposing to reconcile the property tax expense recovery in base rates for its gas and electric operations to actual property tax expense by means of a separate adjustment mechanism. The ISR formula would be modified to eliminate property tax from the revenue requirement calculation.

Q. Should the Commission approve the Company's proposal to implement a reconciliation mechanism for property tax expense?

A. No. As I noted above, reconciliation mechanisms are generally contrary to sound ratemaking practice, as such mechanisms tend to either reduce or eliminate incentives to control costs authorized under standard ratemaking.

In addition, the proposed reconciliation mechanism is unnecessary. Two factors cause changes in property tax expense: changes in taxable property (plant) and changes in property tax rates. In response to Division 8-13-ELEC, the

Company provided the increase in electric property tax expense from 2010 to 2011 related to increases in rates and the increase in property tax expense related to the increase in taxable property. Approximately two-thirds of the increase was due to the increase taxable property and only one-third due to the increase in tax rates. Similarly, based on the response to Division 2-22-GAS, four-fifths of the increase in gas property tax expense from 2010 to 2011 was due to the increase taxable property and only one-fifth due to the increase in tax rates.

The Company already recovers the increases in property tax expense related to increases in plant through the ISR mechanism. Thus, as matters stand now, Narragansett already recovers the major cause of changes in property tax expense outside of base rates. The Company's proposal would extend the automatic recovery to changes in property tax rates, which accounts for only a minority of changes in property tax expense. The Company has not established that a new reconciling mechanism that captures the effect of changes in property tax rates as well the effect of increases in plant is appropriate or necessary.

Q. Does this conclude your direct testimony?

A. Yes.

NATIONAL GRID - RI ELECTRIC
RATE YEAR REVENUE REQUIREMENT
($000)

	(A) Company Position	Adjustments		Division Position
Total Cost of Service	$ 270,471	$ (15,558)	(B)	$ 254,913
Storm Cost Recovery Factor	2,400	(2,400)	(C)	-
Other Miscellaneous Revenues	8,147	-		8,147
Base Rate Revenue Requirement	$ 259,924	$ (13,158)		$ 246,766
Base Rate Revenues, Present Rates	233,433	-		233,433
Base Rate Revenue Deficiency	$ 26,491	$ (13,158)		$ 13,333
Rate Increase by Element:				
Base Rate Revenue	$ 26,491	(13,158)		$ 13,333
Storm Cost Recovery Factor	2,400	(2,400)		-
Revenue Decoupling	6,019	-		6,019
ISR Factor	(3,462)	-		(3,462)
Total	$ 31,448	$ (15,558)		$ 15,890

Notes:
- (A) Schedule MDL-3-ELEC, Page 3
- (B) Schedule DJE-E-2
- (C) See Testimony

NATIONAL GRID - RI ELECTRIC
COST OF SERVICE
($000)

	(A) Company Position	Adjustments		Division Position
Uncollectible Accounts Expense	$ 4,349	$ (1,629)	(B)	$ 2,720
Other Operation & Maintenance Expense	122,343	(3,542)	(C)	118,801
Depreciation and Amortization	45,768	(136)	(D)	45,632
Taxes Other Than Income Taxes	35,618	(61)	(E)	35,557
Interest on Customer Deposits	161			161
Income Taxes	17,072	(3,558)	(F)	13,514
Return on Rate Base	45,160	(6,632)	(G)	38,528
Total Cost of Service	$ 270,471	$ (15,558)		$ 254,913

Sources:

(A) Schedule MDL-3-ELEC, Pages 1,3,7
(B) Schedule DJE-E-3
(C) Schedule DJE-E-4
(D) Schedule DJE-E-5
(E) Schedule DJE-E-6
(F) Schedule DJE-E-7
(G) Schedule DJE-E-8

NATIONAL GRID - RI ELECTRIC
ADJUSTMENTS TO UNCOLLECTIBLE ACCOUNTS EXPENSE
($000)

Total Cost of Service Excl. Uncollectible Accounts	(A)	$ 252,194
Conservation Revenues	(B)	48,849
Other Miscellaneous Revenues	(C)	(8,147)
Total Revenues Subject to Write-offs		292,896
Grossed-up Write-off Rate	(D)	0.929%
Pro Forma Uncollectible Accounts Expense		$ 2,720

Sources:

(A)	Schedule DJE-E-2	
(B)	Schedule MDL-3-ELEC, Page 46	
(C)	Schedule DJE-E-1	
(D)	Testimony of Mr. Gay	0.0092/(1-0.0092)

NATIONAL GRID - RI ELECTRIC
OPERATION AND MAINTENANCE EXPENSE
($000)

Variable Pay - DSM	(A)	$ (400)
Uninsured Claims	(B)	(1,021)
Opex Related to Capital Additions	(C)	(849)
Advertising	(D)	(521)
Consumer Advocate	(E)	(158)
Foundation Support Staff	(F)	(240)
Storm Damage Normalization	(G)	(1,112)
Storm Fund Accrual	(H)	759
Total Adjustment to Operation and Maintenance Expense		$ (3,542)

Sources

(A)	Division 1-8-ELEC 151-551	
(B)	Division 1-20-ELEC, Sch. MDL-3-ELEC, p. 30	(2481-3530)*(1-0.0264)
(C)	Schedule MDL-3-ELEC, Page 39	
(D)	Schedule MDL-3-ELEC, Page 40	
(E)	Schedule MDL-3-ELEC, Page 44	
(F)	Schedule MDL-3-ELEC, Page 45	
(G)	Division 8-5-ELEC, 8-6 ELEC, Schedule MDL-3-ELEC, Page 8	
	(7464+1811+2905+4605+3051)/5-(7464-2385)	
(H)	Proposed Storm Fund Accrual - Division	1,800
	Base Rate Storm Fund Accrual - Company	1,041
	Difference	759

NATIONAL GRID - RI ELECTRIC
ADJUSTMENTS TO DEPRECIATION EXPENSE
($000)

Adjustment to Plant in Service	(A)	$	(3,986)
Composite Book Depreciation Rate	(B)		3.40%
Adjustment to Pro Forma Depreciation Expense		$	(136)

Sources:
(A) Schedule DJE-E-8.1
(B) Schedule MDL-3-ELEC, Page 52

NATIONAL GRID - RI ELECTRIC
ADJUSTMENTS TO TAXES OTHER THAN INCOME TAXES
($000)

Payroll Taxes:

Variable Pay - DSM	$ (400)
Consumer Advocate	(158)
Foundation Support Staff	(240)
Total	(798)
Payroll Tax Rate	7.65%
Adjustment to Taxes Other Than Income Taxes	$ (61)

Source: Schedule DJE-E-2

NATIONAL GRID - RI ELECTRIC
INCOME TAX EXPENSE
($000)

Rate Base	DJE-E-8	$ 542,040
Weighted Return on Equity	DJE-E-9	4.45%
Preliminary Taxable Income Base		24,110
Tax Reconciling Items	MDL-3-ELEC, p. 60	346
Taxable Income Base		24,456
Taxable Income	Taxable Income Base/.65	37,624
Income Tax Rate		35%
Current and Deferred Income Tax Expense		13,168
Unfunded Deferred Tax Catch-up	MDL-3-ELEC, p. 60	650
Amortization of ITC	MDL-3-ELEC, p. 60	(304)
Total Rate Year Income Tax Expense		$ 13,514

NATIONAL GRID - RI ELECTRIC
RETURN ON RATE BASE
($000)

	(A) Company Position	Adjustments		Division Position
Electric Plant in Service	$ 1,338,779	(3,986)	(B)	$ 1,334,793
Contributions in Aid of Construction	(103)			(103)
Accumulated Depreciation	(596,863)	(476)	(B)	(597,339)
Net Plant	741,813	(4,462)		737,351
Materials and Supplies	5,357			5,357
Prepaid Expenses	1,514			1,514
Loss on Reacquired Debt	3,065			3,065
Cash Working Capital	4,975	-		4,975
Sub-total	14,911	-		14,911
				-
Accumulated Deferred FIT	174,430	23,678	(D)	198,108
Customer Deposits	7,206			7,206
Injuries and Damages Reserve	-	4,908	(E)	4,908
Sub-total	181,636	28,586		210,222
Net Rate Base	$ 575,087	$ (33,048)		$ 542,040
Rate of Return	7.85%	-0.74%	(F)	7.11%
Return on Rate Base	$ 45,160	$ (6,632)		$ 38,528

Sources

(A)	Schedule MDL-3-ELEC, Page 39		
(B)	Schedule DJE-E-8.1		
(C)	ARO	(570)	Division 8-3-ELEC, Pages 7,2
	Plant Adjustment	94	Schedule DJE-E-8.1
	Net Adjustment	(476)	
(D)	Schedule DJE-E-8.2		
(E)	Division 8-3-ELEC, Page 7	6,147	Div. 8-3-E, p. 7
	Jurisdictional Allocator	79.84%	WP MDL-1, P. 3
	Adjustment to Distribution Rate Base	4,908	
(F)	Schedule DJE-E-9		

Schedule DJE-E-8.1

NATIONAL GRID - RI ELECTRIC
ADJUSTMENT TO RATE YEAR PLANT IN SERVICE AND ACCUM DEPRECIATION
($000)

Actual Non-ISR Capital Investment, Jan-June 2012	(A)	$	317
Projected Non-ISR Capital Investment, Jul-Dec 2012			317
Total Non-ISR Capital Investment - 2012			634
Projected Non-ISR Capital Investment, Jan 2013			53
Projected Non-ISR Capital Investment Feb 2013 - Jan 2014			634
Adjustment to Test Year Plant in Service for Non-ISR Plant Adds	(B)	$	1,004
Co. Adjustment to Test Year Plant in Service for Non-ISR Plant	(C)		4,990
Adjustment to Company Rate Year Plant		$	(3,986)
Adjustment to Accumulated Depreciation		$	(94)
Adjustment to Deferred Taxes		$	(389)

Sources

(A)	Division 1-20-ELEC	
(B)	2012 + Jan 13 + 1/2*12 Mos. Ended 1/14	
(C)	Schedule MDL-3-ELEC, Page 53	3447+326+2434/2

Schedule DJE-E-8.2

NATIONAL GRID - RI ELECTRIC
ACCUMULATED DEFERRED INCOME TAXES
($000)

Company Correction	(A)	$	11,935
Net Operating Loss	(B)		15,196
Jurisdictional Allocator	(C)		79.84%
Allocated to Distribution		$	12,132
Plant Adjustment	(D)	$	(389)
Net Adjustment to Accumulated Deferred Income Taxes		$	23,678

Sources:

(A)	Division 8-3-ELEC	
(B)	Division 8-3-ELEC, Page 1	
(C)	Workpaper MDL-1, Page 3	1-0.2016
(D)	Schedule DJE-E-8.1	

NATIONAL GRID - RI ELECTRIC
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	49.00%	5.11%	2.50%
Short Term Debt	1.20%	0.80%	0.01%
Preferred Stock	0.20%	4.50%	0.01%
Common Equity	49.60%	10.75%	5.33%
Total Capital	100.00%		7.85%

Division Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	51.79%	5.11%	2.65%
Short Term Debt	1.30%	0.80%	0.01%
Preferred Stock	0.17%	4.50%	0.01%
Common Equity	46.74%	9.50%	4.44%
Total Capital	100.00%		7.11%

Sources:
Schedule MDL-3-ELEC, Page 61
Testimony of Mr. Kahal

NATIONAL GRID - RI GAS
RATE YEAR REVENUE REQUIREMENT
($000)

	(A) Company Position	Adjustments		Division Position
Total Cost of Service	$173,128	(8,507)	(B)	$ 164,621
Non-Firm Margin	1,512	2,288	(C)	3,800
Gas Light & Special Contract	202	-		202
Other Miscellaneous Revenue	2,914	-		2,914
Company Use and LNG O&M	1,425	-		1,425
Base Rate Cost of Service	$ 167,075	$ (10,795)		$ 156,280
Base Rate Revenues, Present Rates	136,686	2,960	(D)	139,646
Base Rate Revenue Deficiency	$ 30,389	$ (13,755)		$ 16,634
Rate Increase by Element:				
Base Rate Revenue	$ 30,389	$ (13,755)		$ 16,634
Company Use and LNG O&M	376	-		376
ISR Factor	(6,924)	-		(6,924)
RDM Factor	(3,889)	-		(3,889)
Total	$ 19,952	$ (13,755)		$ 6,197

Notes:

- (A) Schedule MDL-3-GAS, Page 3
- (B) Schedule DJE-G-2
- (C) Testimony of Mr. Oliver
- (D) Schedule DJE-G-8

NATIONAL GRID - RI GAS
COST OF SERVICE
($000)

	(A) Company Position	Adjustments		Division Position
Uncollectible Accounts Expense	$ 6,001	$ (1,457)	(B)	$ 4,544
Other Op & Maint Expense	79,858	(1,454)	(C)	78,404
Depreciation and Amortization	29,811	-		29,811
Taxes Other Than Income Taxes	16,197	(32)	(D)	16,165
Interest on Customer Deposits	127	-		127
Income Taxes	10,639	(2,228)	(E)	8,411
Return on Rate Base	30,495	(3,335)	(F)	27,159
Total Cost of Service	$ 173,128	$ (8,507)		$ 164,621

Sources:

(A) Schedule MDL-3-GAS, Page 1
(B) Schedule DJE-G-3
(C) Schedule DJE-G-4
(D) Schedule DJE-G-5
(E) Schedule DJE-G-6
(F) Schedule DJE-G-7

NATIONAL GRID - RI GAS
ADJUSTMENTS TO UNCOLLECTIBLE ACCOUNTS EXPENSE
($000)

Total Cost of Service Excl. Uncollectible Accounts	(A)	$ 160,077
Other Miscellaneous Revenues	(B)	(2,914)
Total Revenues Subject to Write-offs		157,163
Grossed-up Write-off Rate	(C)	2.891%
Pro Forma Uncollectible Accounts Expense		$ 4,544

Sources:

(A)	Schedule DJE-G-2	
(B)	Schedule DJE-G-1	
(C)	Testimony of Mr. Gay	0.0281/(1-0.0281)

NATIONAL GRID - RI GAS
OPERATION AND MAINTENANCE EXPENSE
($000)

Variable Pay - DSM	(A)	$	(176)
Uninsured Claims	(B)		(223)
LNG Processing Terminal Labor	(C)		(453)
Advertising	(D)		(354)
Consumer Advocate	(E)		(156)
Foundation Support Staff	(F)		(92)
Total Adjustment to Operation and Maintenance Expense		$	(1,454)

Sources

(A)	Division 2-7-GAS
(B)	Division 2-13-GAS
(C)	Division 9-2-GAS
(D)	Schedule MDL-3-GAS, Page 44
(E)	Schedule MDL-3-GAS, Page 42
(F)	Schedule MDL-3-GAS, Page 43

NATIONAL GRID - RI ELECTRIC
ADJUSTMENTS TO TAXES OTHER THAN INCOME TAXES
($000)

Payroll Taxes:

Variable Pay - DSM	$ (176)
Consumer Advocate	(156)
Foundation Support Staff	(92)
Total	(424)
Payroll Tax Rate	7.65%
Adjustment to Taxes Other Than Income Taxes	$ (32)

Source: Schedule DJE-G-2

NATIONAL GRID - RI GAS
INCOME TAX EXPENSE
($000)

Rate Base	DJE-G-7	$ 367,512
Weighted Return on Equity	DJE-G-9	4.44%
Preliminary Taxable Income Base		16,318
Tax Reconciling Items	Division 2-25-GAS	(697)
Taxable Income Base		15,621
Taxable Income	Taxable Income Base/.65	24,032
Income Tax Rate		35%
Income Tax Expense		$ 8,411

Schedule DJE-G-7

NATIONAL GRID - RI GAS
RETURN ON RATE BASE
($000)

		(A) Company Position	Adjustments		Division Position
Gas Plant in Service		$ 773,552	-		$ 773,552
CWIP		66,070			66,070
Contributions in Aid of Construction		(5,584)			(5,584)
Accumulated Depreciation		(338,627)	(2,623)	(B)	(341,250)
Net Plant		495,411	(2,623)		492,788
Materials and Supplies		3,257			3,257
Prepaid Expenses		-			-
Deferred Debits		404			404
Cash Working Capital		8,974	-		8,974
Sub-total		12,635	-		12,635
					-
Accumulated Deferred FIT		108,004			108,004
Merger Hold Harmless Deferred FIT		25,475			25,475
Customer Deposits		4,621			4,621
Injuries and Damages Reserve		-	(190)	(C)	(190)
Sub-total		138,100	(190)		137,910
Net Rate Base		369,945	(3,003)		367,512
Rate of Return	(C)	8.24%	-0.85%		7.39%
Return on Rate Base		$ 30,495	$ (3,335)		$ 27,159

Sources

(A)	Schedule MDL-3-GAS, Page 58		
(B)	Account 230	(3,129)	DIV 2-23 GAS, Att. p. 7
	Account 101	506	DIV 2-23 GAS, Att. p. 1
	Net Adjustment	(2,623)	
(C)	DIV 2-23 GAS, Att. p. 7	(180+265+195+195+115)/5	

Schedule DJE-G-8

NATIONAL GRID - RI GAS
ADJUSTMENT TO SALES AND REVENUES
($000)

		RES-H	MED C&I	MED C&I FT-2	Total
1	Avg. Customers 12 Mos. 6/12	200,133	2,938	1,055	
2	Annual Growth	2,270	-	123	
3	Growth to Rate Year	3,594	-	195	
4	Average Customers - Rate Year	203,728	2,938	1,250	
5	Rate Year Customers per Company	202,140	2,832	1,030	
6	Adjustment to Customer Count	1,588	106	220	
7	Revenue per Customer	0.439	3.442	3.826	
8	Adjustment to Revenues	$ 697	$ 365	$ 842	$ 1,903
9	Actual 2011 HLF XL FT-1 Revenues				$ 4,947
10	Rate Year HLF XL FT-1 Revenues, per Company				3,890
11	Adjustment to Rate Year HLF XL FT-1 Revenues				$ 1,057
12	Total Adjustment to Base Rate Year Revenues				$ 2,960

Notes:

1 Workpaper WP_DJE-8-GAS
2 Workpaper WP_DJE-8-GAS
3 19/12*Line 2
4 Line 3 + Line 4
5 Company Workpaper AEL-3, Page 2
6 Line 4 - Line 5
7 Company Workpaper AEL-3, Pages 1 and 2
8 Line 6 * Line 7
9 Company Workpaper AEL-2, Page 1
10 Company Workpaper AEL-3, Page 1
11 Line 9 - Line 10
12 Line 8 + Line 11

Schedule DJE-G-9

NATIONAL GRID - RI GAS
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	49.00%	5.90%	2.89%
Short Term Debt	1.20%	0.80%	0.01%
Preferred Stock	0.20%	4.50%	0.01%
Common Equity	49.60%	10.75%	5.33%
Total Capital	100.00%		8.24%

Division Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	51.79%	5.65%	2.93%
Short Term Debt	1.30%	0.80%	0.01%
Preferred Stock	0.17%	4.50%	0.01%
Common Equity	46.74%	9.50%	4.44%
Total Capital	100.00%		7.39%

Sources:
Attachment MDL-1, GAS Page 56
Testimony of Mr. Kahal