BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

APPLICATION FOR APPROVAL OF CHANGE IN
ELECTRIC AND GAS DISTRIBUTION RATES

RIPUC DOCKET NO. 4770

TESTIMONY AND EXHIBITS
OF MICHAEL R. BALLABAN & DAVID J. EFFRON

ON BEHALF OF THE
DIVISION OF PUBLIC UTILITIES AND CARRIERS

APRIL 6, 2018

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DIRECT TESTIMONY
OF MICHAEL R. BALLABAN AND DAVID J. EFFRON

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael R. Ballaban. My business address is 370 Main Street, Suite 325, Worcester, Massachusetts, 01608.

Q. What is your present occupation?

A. I am a Managing Consultant for Daymark Energy Advisors specializing in pricing, cost-of-service, cost allocation, competitive market development, resource procurement and financial forecasting.

Q. Please summarize your professional experience.

A. Prior to working at Daymark, my professional experience includes employment with both New England Electric System (National Grid USA) and Boston Edison (Eversource Energy) where I gained extensive experience assisting utilities with all phases of rate filings before state commissions and at Federal Regulatory Energy Commission (FERC), including preparation, discovery, litigation, settlement and implementation. Most recently I was Senior Manager in the Power & Utility Advisory Services practice at Ernst & Young.

Q. What relevant experience do you have to rate case proceedings?

A. My recent experience includes leading a review a utility's allocation of certain service company costs to operating companies, co-leading a study to verify the electric and gas distribution assets in a utility's rate base were appropriate to support upcoming base rate filings, leading a review of significant deferred storm costs to verify that there were appropriate for a utility to include in cost recovery submissions, reviewing elements of utility's cost accounting structure and associated compliance program, and leading a regulatory transformation initiative to establish a regulatory organization within the finance function for a large multi-state utility.

I also have extensive experience assisting utilities with all phases of rate filings before state commissions and at Federal Regulatory Energy Commission (FERC), including preparation, discovery, litigation, settlement and implementation. In addition, while I was employed by New England Electric System, I developed financial forecasts and revenue requirements for the Company's subsidiary New England Power Company. I also testified to the FERC jurisdictional revenue requirement in the W-92 rate case before the FERC.

Q. Please describe your other work experience.

A. Following my employment with both New England Electric System, now National Grid, and Boston Edison, now Eversource, I was a consultant for Navigant Consulting where I specialized in utility rate and regulatory consulting. I then joined Black & Veatch as a principle consultant specializing in utility pricing, cost allocation and revenue requirements before becoming a senior manager in the power & utility advisory services practice at Ernst & Young. I have been with Daymark Energy Advisors for 9 months as a managing consultant.

Q. Please describe your educational background.

A. I received my Bachelors of Science in Transportation and Public Utilities from Indiana University and my M.B.A. in Finance from Babson College.

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. We are testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("the Division").

Q. What is the purpose of your testimony?

A. Our testimony examines the reasonableness of the Company's proposed revenue requirement. Specifically, our testimony supports an updated revenue requirements schedule provided below showing the impacts of recommended adjustments addressing the following key areas:

1. Tax Cuts and Jobs Act (TCJA) and Accumulated Deferred Income Taxes (ADIT);
2. Uncollectible accounts expense;
3. Proposed return on equity for Service Company Rents;
4. Utility plant in service;
5. Return on equity recommendation of Division Witness Kahal;
6. Depreciation recommendation of Division Witness McCullar;
7. Prudency of new Information System (IS) and Gas Business Enablement; (GBE) investments;
8. Appropriateness of the Company's proposed increase in labor expenses; and
9. Power Sector Transformation (PST) adjustments to revenue requirements due to the following:

- Cost allocation of Advanced Metering Infrastructure (AMI) Study recommended by Division Witness Woolf; and
- Cost allocation of Geographic Information System (GIS) upgrade and upgrade of the Systems Data Portal recommendations of Division Witness Booth.

Our testimony also comments on the allocation methodologies used by the Company, its affiliates, and the National Grid Service Company to allocate costs of certain services, projects, and systems that benefit or will benefit multiple affiliates. In particular, we make observations and recommendations related to the inconsistent way in which the gas distribution business allocated the costs of the GBE program, compared to the proposed method of allocating costs of the initiatives that have been categorized as grid modernization and PST by the Company.

Q. Please summarize your recommendations to the Commission regarding the Company's electric cost of service and revenue deficiency.

A. Our proposed modifications to Company's electric distribution cost of service and revenue deficiency are summarized in the table below (copy of Schedule RRP-E-1). The Company originally calculated a total revenue deficiency for Narragansett Electric of about $41.3 million. As described below, this was later revised by the Company to be about $27.4 million. The comparable total revenue deficiency that we have calculated is about $8.9 million.

Table 1: Narragansett Electric Rate Year Revenue Requirement

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

	(A) Original Company Position	(B) Revised Company Position	Adjstmts		Division Position
Total Cost of Service	$320,488	$ 306,627	$(18,497)	(C)	$288,131
Other Miscellaneous Revenues	8,531	8,531	-		8,531
Base Rate Revenue Requirement	$311,957	$ 298,096	$(18,497)		$279,600
Base Rate Revenues, Present Rates	270,662	270,662	-		270,662
Base Rate Revenue Deficiency	$ 41,295	$ 27,434	$(18,497)		$ 8,938

Notes:
(A) Schedules MAL-1&2-ELEC
(B) Schedules MAL-1&2-ELEC (REV-1)
(C) Schedule RRP-E-2

Q. Please summarize your recommendations to the Commission regarding the Company's gas cost of service and revenue deficiency.

A. Our proposed modifications to Company's gas distribution cost of service and revenue deficiency are summarized in the table below (copy of Schedule RRP-G-1). The Company originally calculated a total revenue deficiency for Narragansett Gas of about $30.3 million. As described below, this was later revised by the Company to be about $18.4 million. The comparable total revenue deficiency that we have calculated is about $2.4 million.

Table 2: Narragansett Gas Rate Year Revenue Requirement

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

	(A) Original Company Position	(B) Revised Company Position	Adjstmts		Division Position
Total Cost of Service	$ 244,846	$ 232,932	(16,001)	(C)	$ 216,930
Non-Firm Margin	1,388	1,388			1,388
Special Contract	225	225	-		225
Other Miscellaneous Revenue	38,170	38,170	-		38,170
Base Rate Cost of Service	$ 205,064	$ 193,149	$ (16,001)		$ 177,148
Base Rate Revenues, Present Rates	174,741	174,741	-		174,741
Base Rate Revenue Deficiency	$ 30,323	$ 18,408	$ (16,001)		$ 2,407

Notes:
(A) Schedules MAL-1&2-GAS
(B) Schedules MAL-1&2-GAS (REV-1)
(C) Schedule RRP-G-2

In addition to Schedules RRP-E-1 and Schedule RRP-G-1, the common Narraganset Electric and Narragansett Gas revenue requirement schedules include the following:

- Schedule RRP-E/G-2 presents the comparison for each element of the cost of service;
- Schedule RRP- E/G -3 presents details of our recommended adjustment to the uncollectible accounts expense;

- Schedule RRP- E/G -4 presents details of our recommended adjustments to operation and maintenance expense;
- Schedule RRP- E/G -4.1 presents details of our recommended adjustments to Service Company rents return on equity;
- Schedule RRP- E/G -5 presents details of our recommended adjustments to depreciation expense;
- Schedule RRP- E/G -6 presents details of our recommended adjustments to taxes other than income taxes;
- Schedule RRP- E/G -7 presents the income tax expense calculation;
- Schedule RRP- E/G -8 presents the return on rate base calculation; and
- Schedule RRP- E/G -9 presents the rate of return calculation.

Finally, there are two schedules that are specific to Narragansett Gas:

- Schedule RRP-G-4.2 presents details of our recommended adjustments to the average gas write-off rate; and
- Schedule RRP-G-8.1 presents details of our recommended adjustments to Rate Year plant in service.

III. REVENUE REQUIREMENT

Q. Please summarize the Company's revenue requirement.

A. In its application filed on November 27, 2017, the Company put forth the following revenue requirement values. Narragansett Electric's cost of service is approximately $320.5 million and Narragansett Gas' cost of service is approximately $244.8

million. The Company asserts that an increase in base distribution revenue of $41.3 million is needed on the electricity side and $30.3 million on the gas side to meet these values.[1]

Q. Please describe your analysis and review of the revenue requirement.

A. We looked to verify that rate base and operating expenses related to routine operation and maintenance (O&M) and capital expenditures are reasonable and appropriate. We reviewed and analyzed the filed revenue requirements, which included testimony, exhibits and workpapers. Additionally, we issued Data Requests and reviewed Data Requests by others, many of which were necessary to obtain supporting data and documentation not initially filed.

Q. What initial issues were identified with the Company's revenue requirement?

A. Through the discovery process, the Commission, the Division, and the Company identified the following issues the Company needed to address in its filed revenue requirement:

- The Company needed to update its revenue requirement to reflect the impacts of the Tax Cuts and Jobs Act[2] (TCJA), and
- Accumulated deferred income taxes were miscalculated[3].

[1] Direct Testimony of Melissa A. Little, pp.11-12, lines 21-22 and 1-10.
[2] Data Request PUC 4-1.
[3] Company Responses to Data Requests DIV 2-14, 31-1, and 31-2.

Q. Has the Company filed exhibits incorporating the effect of the TCJA and correction to the accumulated deferred income tax errors on its revenue requirement?

A. Yes. The Company's original filing did not incorporate the effects of the TCJA. However, the Company acknowledged that adjustments to the proposed revenue requirement to account for the TCJA would be appropriate, and on March 2, 2018, the Company submitted revised revenue requirements for Narragansett Electric and Narragansett Gas. The revised revenue requirements reflected the impact of the reduction in the federal income tax rate from 35% to 21% on the income tax expenses included in the costs of service and the effects of the elimination of bonus deprecation and the income tax rate reduction on the Rate Year balances of ADIT. The Company also corrected the errors in the computation of ADIT in its original filing, which further reduced the revenue requirements for Narragansett Electric and Narragansett Gas from the revenue requirements in the original filing.

1. Tax Cuts and Jobs Act and Accumulated Deferred Income Taxes

Q. Did the Company's filing of March 2 incorporate all the effects of the TCJA?

A. No. The reduction in the federal income tax rate created an excess in the balance of ADIT. The liabilities for deferred taxes were accrued under the assumption that the federal income rate would be the same when those liabilities are paid as when they were accrued. Thus, a reduction in the federal income tax rate creates an excess in the balance of ADIT. The Company's filing of March 2 did not address the treatment of the excess deferred federal income taxes (EDFIT) created by the reduction in the federal income tax rate. However, in response to Division Data Requests in Set 31 and in its supplemental response to Data Request PUC 4-1 on March 28, 2018, the Company presented its quantification of EDFIT and its proposal to flow the benefits of the EDFIT to ratepayers in the determination of the revenue requirements for Narragansett Electric and Narragansett Gas.

Q. How did the Company propose to deal with the EDFIT balances in its responses of March 28, 2018?

A. The Company calculated EDFIT balances of approximately $116 million for Narragansett Electric and $51 million for Narragansett Gas. These balances include both property related EDFIT (related mainly to accelerated depreciation, bonus depreciation, and capital repairs deductions for utility plant in service) and non-property related EDFIT. The property related EDFIT consist of "protected" balances and "unprotected" balances. The flow back of the protected balances of EDFIT (related mainly to accelerated depreciation and bonus depreciation) to ratepayers is restricted by the Internal Revenue Code, which specifies that any flow-back must be no more rapid than the flow-back pursuant to the average rate assumption method (or ARAM). There are no restrictions on the flow-back of unprotected balances of property related EDFIT or non-property related EDFIT.

The Company is proposing to flow back all property related EDFIT, both protected and unprotected, over 30 years, which approximates the average life of its plant in service. The Company is proposing to flow back the non-property related EDFIT over the average remaining life of its plant in service, which is approximately 22 years for Narragansett Electric and 25 years for Narragansett Gas. The total annual amortization of EDFIT, as calculated by the Company, is approximately $4.8 million for Narragansett Electric and about $1.8 million for Narragansett Gas. These proposed amortizations of EDFIT would result in further revenue requirement reductions of approximately $6.2 million for Narragansett Electric and $2.3 million for Narragansett Gas.

The Company has stated that "[p]rior to the commencement of hearings in this docket, the Company will update its Narragansett Electric and Narragansett Gas revenue requirements reflecting the excess deferred tax amortization of $4.1 million and $1.8 million for Narragansett Electric distribution and Narragansett Gas, respectively".[4] As these amortizations are estimates, the Company is proposing "to true up these estimates in a supplemental compliance filing to be filed with the Commission in Docket No. 4770 after the Company files its Fiscal Year 2018 federal income tax return in December 2018."[5] Any necessary true-up of the estimates would be reflected in the annual target revenue for Narragansett Electric and target revenue per customer for Narragansett Gas in the next electric and gas Revenue Decoupling Mechanism (RDM) reconciliation filings. The Company also stated that, as soon as possible, it would supplement its EDFIT calculations to incorporate the effect of the allocation of net excess deferred taxes of National Grid USA Service Company, Inc., which were not included in the responses on March 28, 2018.

[4] Company Response to PUC 4-1 Supplemental.
[5] *Id*.

Additionally, the Company has created a regulatory liability account for the excess deferred tax liability it has recorded to offset the net reduction to its net deferred tax liability balances.[6] The regulatory liability account represents the balance of excess deferred income taxes owed to customers.

Q. Is the Company's proposal for the treatment of EDFIT reasonable?

A. We believe that the general framework is reasonable. At the time of the preparation of this testimony, the Division had outstanding Data Requests on the Company's calculations of the EDFIT balances and the amortization of those balances. Pending receipt of the responses to those data requests, we would propose one modification to the Company's proposed treatment of EDFIT.

As noted above, the Company is proposing to flow back the non-property related EDFIT over the average remaining life of its plant in service, which is approximately 22 years for Narragansett Electric and 25 years for Narragansett Gas. There is no particular logic to amortizing the non-property related EDFIT over the average remaining life of plant in service, as the non-property related EDFIT are, by definition, not related to book plant. The turn-around for non-property related EDFIT can generally range from one year to perhaps twenty years. In this regard, we believe that a ten-year amortization period for non-property related EDFIT would be reasonable and is also equitable to the Company and its ratepayers.

[6] *Id*.

Q. Have you reflected the amortization of EDFIT in your calculation of the Company's revenue requirement?

A. Yes. We have included annual EDFIT amortization of $5,066,000 in the calculation of the pro forma electric federal income tax expense (Schedule RRP-E-7) and $1,998,000 in the calculation of the pro forma gas federal income tax expense (Schedule RRP-G-7).

2. Uncollectible Accounts Expense

Q. How did the Company determine the uncollectible accounts expense that it includes in pro forma test year operation and maintenance expenses?

A. The Company calculated the average of net write-offs as a percentage of total revenues for the five years ended June 30, 2017 and applied those percentages to the Rate Year revenues to calculate the pro forma Rate Year uncollectible accounts expenses (Schedule MAL-22 (REV-1), Pages 6 and 7).

Q. Did any of the years included in the five-year averages appear to be outliers?

A. Yes. As can be seen on Schedule MAL-22 (REV-1), Page 7, regarding the calculation of the gas net write-off rate, the net write-offs as a percentage of revenues were 2.56% in 2015 and 2.82% in 2013. These percentages are significantly higher than the write-off percentages in the other years.

Q. Has the Company explained why the write-off percentages were so much higher in those years?

A. Yes. In response to Division Data Request 2-40, the Company stated that "write-offs for the year ending June 2015 increased because of unfavorable weather in prior periods."

Regarding the twelve months ended June 30, 2013, the Company cited two reasons for the level of write-offs: The first reason was that "relatively high gas-supply costs occurred during the peak winter months of 2010/11, 2011/12, and 2012/13," which was "offset by significantly warmer weather during the winter of 2011/12 and slightly warmer than normal weather during the winter of 2012/13."[7]

The second reason was that "Narragansett Gas converted to the CSS billing system in January 2012" and that this conversion led to process improvements which in turn led to more field visits, and that this "accomplished terminations of older arrears that were accumulated at a time when gas-supply costs were much higher."[8]

Q. Based on these explanations, should the Company's calculation of the average gas write-off percentage be modified?

A. Yes. Regarding the experience in the twelve months ended June 30, 2015, the increase in write-offs was caused by colder than normal weather in previous months. Colder than normal weather is not an unusual or non-recurring phenomenon, so it is

[7] Company Response to DIV 2-40.
[8] *Id*.

not unreasonable to include that period in the calculation of the normalized write-off rate. However, based on the Company's explanation, it appears that the increase of the write-offs in the twelve months ended June 30, 2013 was caused by a one-time write-off of older arrearages that had accumulated in earlier periods. The effect of the write-off of accumulated older arrearages should not be a normal, recurring event and should be eliminated from the calculation of the gas write-off percentage.

Q. Was the Company able to quantify the terminations of older arrears (resulting from the conversion to the CSS billing system) that were accumulated at a time when gas-supply costs were much higher?

A. No. In response to Division Data Request 11-10, the Company stated that "it is not possible to compartmentalize the portion of terminations related to specific arrears." In that response the Company also noted that the write-off experience in the twelve months ended June 30, 2013 "would have been affected by Hurricane Sandy at the end of October 2012, when the Company had to suspend many collection activities, including field activity for the month of November 2012." This appears to be another reason the level of write-offs in that time frame was an outlier.

Q. Given that the quantification of the extent to which the terminations of accumulated older arrears affected the write-off experience in the twelve months ended June 30, 2013 is not possible, what do you recommend?

A. We recommend that the twelve months ended June 30, 2013 be eliminated from the calculation of the average write-off rate used in the calculation of pro forma gas uncollectible accounts expense.

Q. What is the effect of making this modification to the calculation of the average gas write-off rate?

A. The effect is to reduce the average gas write-off rate from 2.08% to 1.91%. Applying this write-off rate to the Rate Year revenue of $$178,075,000, the pro forma gas uncollectible accounts expense is $3,397,000, which is $310,000 less than the pro forma expense of $3,707,000 calculated by the Company (Schedule MAL-22 (REV-1), page 7, line 40). The effect of this adjustment is subsumed in the adjustment to pro forma uncollectible accounts expense on Schedule RRP-G-3

3. Proposed Return on Equity for Service Company Rents

Q. Have you analyzed the pro forma Service Company rents included in Rate Year operation and maintenance expenses by the Company?

A. Yes. The Service Company charges Narragansett for rental expense related to information systems and facilities. The rental expense consists of depreciation expense and a return on the Service Company's net investment in information systems and facilities. As shown on Schedule MAL-17 (REV-1), the pro forma Service Company rental expense included in the Rate Year electric cost of service is about $11.64 million, and the pro forma Service Company rental expense included in the Rate Year gas cost of service is $3.92 million.

Q. Are you proposing to modify the Service Company rents included in the Company's cost of service?

A. Yes. As stated above, one element of the Service Company rents is the return on the Service Company's net investment in information systems and facilities. In calculating the return on the Service Company's investment, the Company uses a rate of return of 8.80%, which includes the effect of income taxes on the equity component of the return. In calculating the rate of return, the Company uses a return on common equity of 10.10%, reflecting the Company's requested return on common equity in the present case.

The return on equity included in the rate of return on the investment in information systems and facilities should reflect the return on equity authorized by the Commission in this case. In this proceeding, the Division is recommending that the Commission authorize the Company a return on equity of 8.50% for Narragansett Electric and 9.00% for Narragansett Gas. We have included each return on equity in the calculation of the rate of return on the investment in information systems and facilities on Schedules RRP-E-4.1 and RRP-G-4.1.

Q. What is the effect of this modification to the rate of return used in calculating the pro forma Service Company rents?

A. The effect is to reduce the Service Company rate of return from 8.80% to 7.70% (Schedule RRP-E-4.1) for Narragansett Electric and from 8.80% to 8.04% for Narragansett Gas (Schedule RRP-G-4.1).

Q. What effect does this modification to the Service Company rate of return have on the Service Company rents included in the Company's cost of service?

A. The effect is to reduce the Service Company rents to Narragansett Electric by $328,000 (Schedule RRP-E-4.1) and to reduce the Service Company rents to Narragansett Gas by $77,000 (Schedule RRP-G-4.1).

Q. Does Schedule MAL-17 (REV 1) cover all Service Company Rents?

A. No. As described in the testimony of Division witnesses Bennett and Neale and further discussed in this testimony below, the Company has also included in its instant filing a proposal for the recovery of Service Company charges to Narragansett through rental expense related to the GBE program. The Company's proposal and the Division's recommendations (summarized later in the testimony) consists of return on and of certain capital and non-recurring O&M costs.

Q. Does the Company's proposal reflect the authorized rate of return that will be approved in this Docket by the Commission?

A. No. The Division recommends that the Company be required to recalculate the approved GBE program revenue requirement at the rate or return authorized in this proceeding.

4. Utility 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 of plant in service for the twelve months ending August 31, 2019, the Company's Rate Year. The Company began with the actual balance of plant as of June 30, 2017 the end of the test year, and then adjusted that balance for forecasted additions to and retirements from plant in service through August 31, 2019.

Q. Have you analyzed the Company's forecasts of gross utility plant through August 31, 2019?

A. Yes. We have reviewed the budgeted additions to plant. We have also compared the Company's forecasts of additions and retirements to actual additions and retirements in recent years, and we have analyzed the forecasts by plant function.

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

A. Yes. The forecast of Infrastructure, Reliability, and Safety (ISR) plant will, 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 forecast of certain of those additions; in particular, the forecasted spending on gas plant related to "growth," is significantly higher than the actual rate of plant additions in recent periods. Therefore, we are proposing to adjust the forecast of gas plant additions related to "growth" included in the Company's Rate Year rate base.

Q. How much higher are the Company's forecasts of spending on gas plant related to growth than the actual rate of plant additions in recent periods?

A. The actual gas plant additions for growth were approximately $21.0 million in Fiscal Year 2016 and approximately $18.9 million in Fiscal Year 2017 (response to Division Data Request 20-4). Thus, the average of plant additions was approximately $20 million for these two years. By contrast, the Company is forecasting growth related gas plant additions of $25.7 million for the twelve months ending August 2018 and $24.0 million for the twelve months ending August 2019 (response to Division Data Request 20-4). Thus, there is a forecasted increase of over 20% in these future plant additions from the actual level of such additions experienced in recent years. The Company has not presented any change in circumstances that would support increases of this magnitude.

In addition, in response to Division Data Request 28-4 the Company provided a comparison of budgeted to actual gas capital spending related to growth in Fiscal Year 2018 through January (in other words, in the ten months from April 2017 through January 2018). The actual capital spending in this ten-month period was about $15.9 million as compared to budgeted spending of about $21.3 million. The actual capital spending was about $5.4 million, or 25%, below budget in this time frame. Absent further clarification and justification by the Company for this increase, the forecast of gas plant additions for the twelve months ending August 2018 and the twelve months ending August 2019 should be modified for the purpose of determining the Company's Rate Year rate base.

Q. How do you propose to modify the forecasts of plant additions for the twelve months ending August 2018 and the twelve months ending August 2019?

A. The average of actual gas plant additions for Fiscal Years 2016 and 2017 was approximately $20 million. Absent further explanation and justification from the Company for the increase in the rate year, I believe that using this average is a reasonable estimate of the annual level of gas plant additions for growth for the twelve-month periods ending August 31, 2018 and August 31, 2019. (In fact, it is somewhat above the annualized rate of such capital spending experienced in Fiscal Year 2018 through January.)

Q. What is the effect of modifying the forecast of gas plant additions as you are recommending?

A. The effect is to reduce the plant in service in the average Rate Year rate base by $7,770,000 (Schedule RRP-G-8.1). In conjunction with this adjustment the average rate year deprecation reserve should be reduced by $193,000, and the average Rate Year balance of accumulated deferred income taxes should be reduced by $952,000.

Thus, the net adjustment is a reduction of $6,625,000 to the average Rate Year gas rate base.

5. Return on Equity Recommendation

Q. What is your position on the Company's proposed return on equity?

A. Division Witness Kahal has recommended that the return on equity for the Company be modified to reflect the Discounted Cash Flow (DCF) analysis he performed, which resulted in a recommendation of 9.0 percent return on equity. He further adjusted his recommendation to 8.5 percent to reflect the additional earnings of 0.5 percent from performance based incentives (PIM) earnings, which is addressed in the testimony of Division Witness Woolf. This modification is included in our Schedules RRP-E-9 and RRP-G-9 and is represented in the calculated adjustments shown in the revenue requirement schedule provided above.

6. Depreciation Recommendation

Q. What is your position on the Company's proposed depreciation rates?

A. Division Witness McCullar has recommended revisions to the depreciation rates as filed by the Company in this Docket. For electric plant, these modifications, as shown in the revenue requirement schedule provided above, result in lower electric rate year depreciation expense of $1,678,000. Additionally, depreciation reserve is reduced by $839,000 and the balance of property related accumulated deferred tax reserve is increased by $176,000, respectively. Therefore, the net impact on the electric rate base is $663,000.

For gas plant these modifications, as included in the revenue requirement schedule provided above, result in lower gas book depreciation expense of $4,526,000. Additionally, depreciation reserve is reduced by $2,263,000 and the balance of property related accumulated deferred tax reserve is increased by $475,000, respectively. Therefore, the net impact on gas rate base is $1,788,000.

Q. What other modifications are you recommending in the Company's revenue requirement filing based on your review?

A. As stated above, we will be recommending other modifications based on further analysis and review of the Company's revised revenue requirement that includes: the prudency of the Company's IS investments; the appropriateness of the Company's increased labor costs; costs related to the AMI Study discussed in the testimony of Division Witness Woolf; costs related to the proposed GIS upgrade and the upgrade of the Systems Data Portal discussed in the testimony of Division Witness Booth; and the GBE modifications discussed in the testimony of Division Witnesses Bennett and Neale.

IV. PRUDENCY OF IS AND GBE INVESTMENTS

Q. Please explain and summarize the Service Company rents expense.

A. Service Company rents are defined as "costs related to IS and facilities used by the Company that are owned by the Service Company".[9] Narragansett Electric and

[9] Direct Testimony of Melissa A. Little, p. 41, lines 8-9.

Narragansett Gas, as well as other affiliated companies, are charged for their allocated shares of the depreciation and associated return on the Service Company information system and facility investments.[10]

Shown in the table below[11], Melissa Little provided a summary of the calculated Service Company rents expenses[12] for Narragansett Electric and Narragansett Gas for the Test Year, Normalizing Adjustments, Proforma Adjustments, and Rate Year. For Narragansett Electric, the calculated Test Year expense is about $13.98 million and the Rate Year expense in about $11.64 million including Normalizing and Proforma Adjustments. For Narragansett Gas, the calculated Test Year expense is about $3.08 million and the Rate Year expense in about $3.91 million, including Normalizing and Proforma Adjustments. The Normalizing Adjustments included in the Rate Year expense were to restate the allocations of the Service Company rents for "a true-up of the return on and of capital calculations for those charges".[13] Proforma Adjustments are for system additions and enhancements that are anticipated through the Rate Year, which are "offset by a reduction in the return paid to the Service Company on systems and facilities that were in-service calculated to the end of the Test Year."[14]

Table 3: Service Company Rents Expense Summary[15]

Company	Test Year Expense	Normalizing Adjustment	Proforma Adjustment	Rate Year Expense

[10] *Id*., p. 41, lines 9-11.
[11] *Id*., p. 41, Table 8.
[12] The calculations for Service Company rents expense are provided in Schedule MAL-17 (REV-1).
[13] *Id*., p. 41, lines 15-16.
[14] *Id*., p. 42, lines 3-5.
[15] Schedule MAL-17 (REV-1), p. 1, line 4, Columns (j), (l), (p), and (r), and p. 2, line 4, Columns (p), (r), (v), and (x).

Narragansett Electric	$13,985,369	($6,011,767)	$3,664,531	$11,638,133
Narragansett Gas	$3,077,583	($350,899)	$1,189,335	$3,916,018

The Company provided details for each existing and new IS project and facility investment for the Rate Year and Data Years in Workpapers MAL-6a to MAL-6c (REV-1) and Workpapers MAL-6d to MAL-6f (REV-1), respectively. Collectively, the workpapers provided the following information on the projects: name of the project, program in which the project was developed, the total investment amount, date the project is expected to be in-service, and the total rent charged to Narragansett Electric and Narragansett Gas.

Q. Please describe the analysis you preformed to review the prudency of the Company's Service Company rents.

A. We performed a three-phase analysis that focused on existing and new IS projects. First, we looked to confirm that the Company is selecting the most value-added, least-cost path to execute projects. This was accomplished by verifying controls are in place to appropriately justify projects and that there is not a pattern of budget creep over time. Specifically, we examined the documentation for IS projects and the Company's sanctioning process. IS project documentation was provided in response to Division Data Requests 2-46 and 9-2 through 9-5 and explanations of various parts of the Company's sanctioning process was provided in response to Division Set 22 Data Requests. Additionally, we examined Workpapers MAL-6a to MAL-6c (REV-

1) and asked and reviewed Data Requests[16] to ensure that the Company did not include any costs related to the U.S. Foundation Project (USFP) SAP software implementation problems and corrective stabilization efforts.

Second, we performed analysis to verify that the Company can efficiently undertake the scope of activities planned for the Rate Year by confirming it has the capability to execute projects as planned. This analysis involved using Workpapers MAL-6a to MAL-6c (REV-1) to create a yearly comparison of IS projects currently in-service from 2010-2017 and IS projects forecasted to close to plant during the Rate Year, i.e. during 2018-2019. Specifically, we analyzed the number of IS projects in-service each year and the close-out spending by year to post-Test Year activity.

Lastly, we completed a budget analysis of IS projects with post-Test Year in-service dates from 7/1/2017 through 8/31/2019. This analysis compared the IS project budget values provided in response to the IS project sanctioning documentation Data Requests[17] to the IS project budget values provided in Workpapers MAL-6a to MAL-6c (REV-1).

Q. What are your Phase I findings from review of the Company's Service Company rents?

A. Based on our review of the IS project documentation, we conclude that there is sufficient IS project documentation/justification for the IS projects included in the

[16] Specifically, Data Requests DIV 9-4, 12-11, and 12-12.
[17] Specifically, the Company's Response to DIV 9-5.

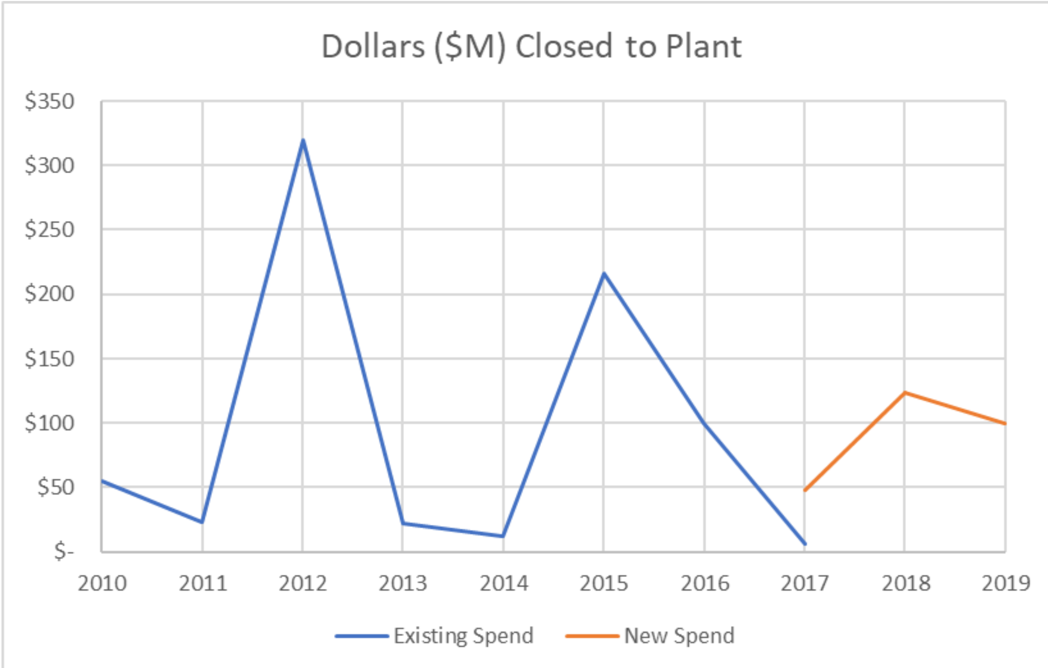
Filing. The sanctioning process explanations provided by the Company, which further detailed its budgeting and cost control procedures for all IS projects, is reasonable and appears to be followed for the IS projects under review in this Filing. Additionally, we note that the Company stated that it "not seeking recovery of any stabilization costs [related to the USFP SAP software implementation]. These costs were charged to National Grid USA, not to customers; therefore, they are not included in the cost of service in this proceeding."[18]

Q. What are your Phase II findings from review of the Company's Service Company rents?

A. Results from analyzing the Company's capability to undertake the scope of activities planned for the Rate Year are provided in the figures below. Figure 1 below shows the dollars closed to plant (i.e. in-service date) for existing and new projects by year from 2010 through 2019. The analysis shows spending peaks every three years and a downward trend in spending since 2012.

[18] Company Response to DIV 12-12.

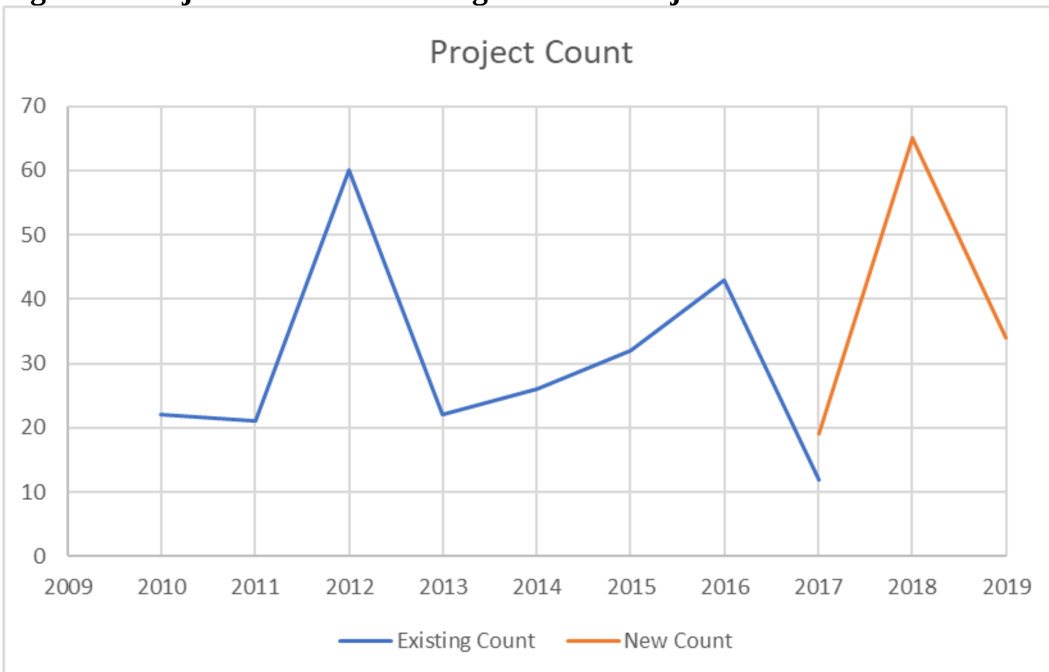
Figure 1: Dollars Closed to Plant for Existing and New Projects from 2010-2019[19]



Additional analysis included yearly projects placed into service. Figure 2 below shows the count of projects placed into service each year from 2010 through 2019 for existing and new projects. The analysis shows peaks about every three years, like spending, but the trend of projects placed into service is slightly increasing over time. Additionally, the Company appears to be placing an increased number of projects into service in 2018 and 2019, which is an increase compared to the Test Year.

[19] See Workpaper titled "RRP IS Project Analysis Workpapers", tab "IS Existing Proj RY Analysis".

Figure 2: Project Count for Existing and New Projects from 2010-2019[20]



While this analysis is informative, we completed an additional step that removed existing USFPs from the analysis. Figures 3 and 4 below show the results of removing these projects. Figure 3, which shows the dollars closed to plant for existing and new projects, less the USFPs, each year from 2010-2019, illustrates that since 2014 the Company had been increasing the amount of spend on projects placed into service up to the Test Year. After the Test Year, the expected amount of spend on new projects placed into service increases to back to the spend level prior to the Test Year.

[20] See Workpaper titled "RRP IS Project Analysis Workpapers", tab "IS Existing Proj RY Analysis".

Figure 3: Dollars Closed to Plant for Existing and New Projects (less USFPs) from 2010-2019[21]

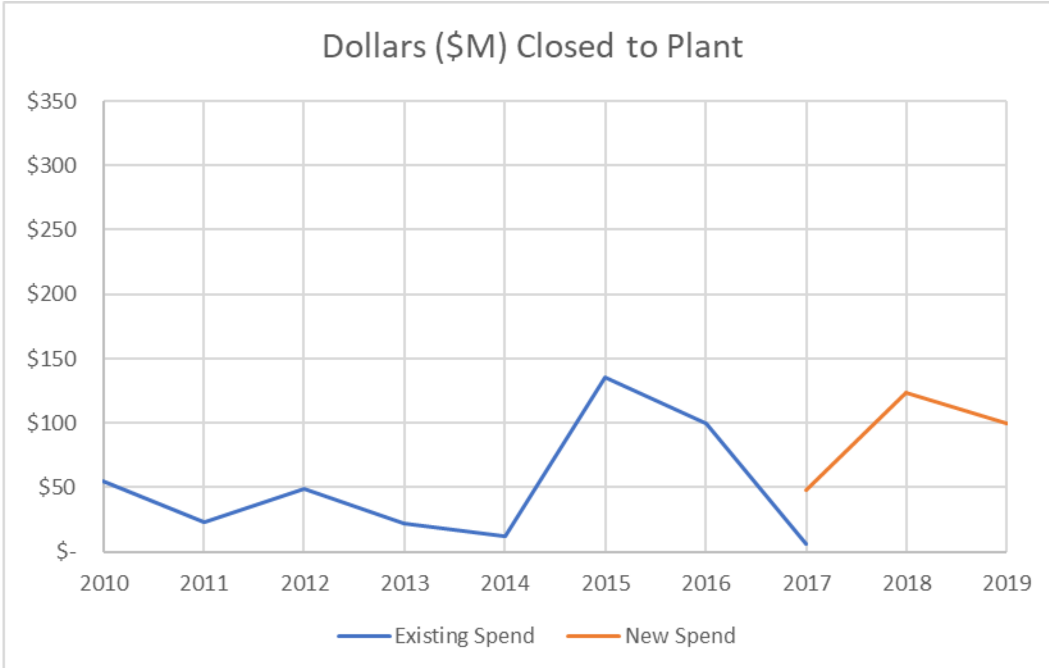
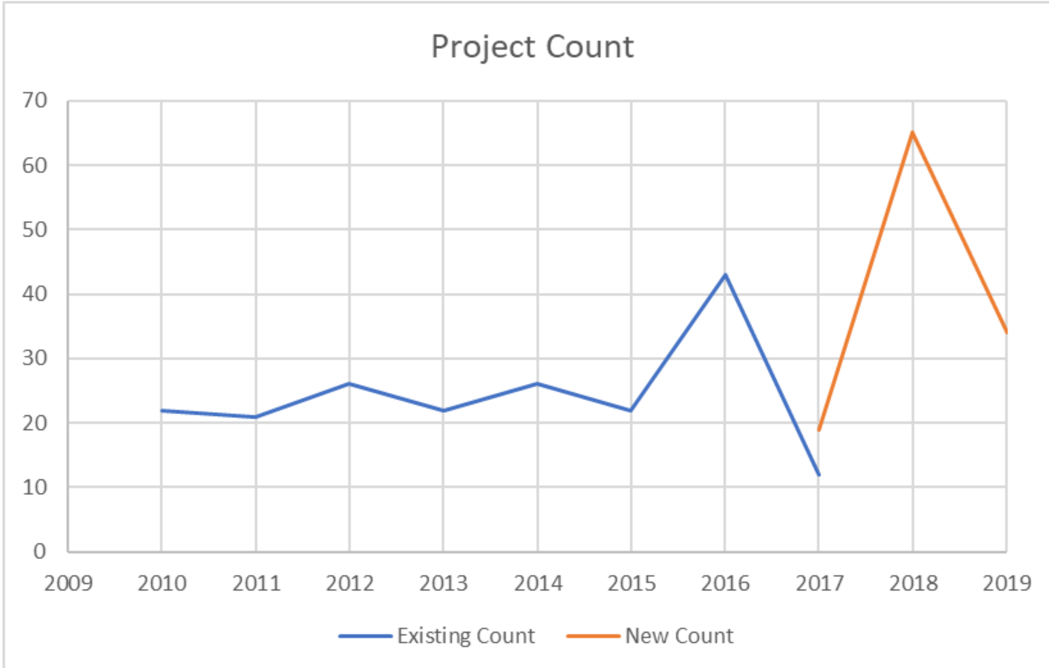


Figure 4, which shows the count of project placed into service by year from 2010 through 2019 for existing and new projects less the USFPs, shows a clearer defined increase in projects placed into service after 2015. However, like Figure 3, Figure 4 also shows that projects placed into service during the Test Year decreased, only to increase back to and even exceed the pre-Test Year level.

[21] See Workpaper titled “RRP IS Project Analysis Workpapers”, tab “IS Existing Proj RY sans USFP”.

Figure 4: Project Count for Existing and New Projects (less USFPs) from 2010-2019[22]



Q. What are your Phase III findings from review of the Company's Service Company rents?

A. Our budget analysis, which compared the initial budget values from the IS project documentation provided by the Company to the budget values provided in Workpapers MAL-6a to MAL-6c (REV-1), focused on IS projects placed into service post-Test Year from 7/1/2017 through 8/31/2019, revealed that the IS project budgets fluctuate during the planning and execution phases prior to implementation. Initially, we completed a budget analysis on a random sample of IS projects placed into service from 7/1/2017 through 8/31/2019 by examining ten (10) IS projects with a "Total Spend" value, budget value provided in Workpapers MAL-6a to MAL-6c (REV-1), less than $1 million and ten (10) IS projects with a "Total Spend" value

[22] See Workpaper titled "Daymark IS Project Analysis Workpapers", tab "IS Existing Proj RY sans USFP".

greater than $1 million. This initial IS project budget analysis showed wide variation between the values reported in Workpapers MAL-6a to MAL-6c (REV-1) and the IS project documentation.

Based on these initial results, we completed a more robust analysis to verify that our initial observations were consistent across all IS projects with in-service dates between 7/1/2017 and 8/31/2019. Results from our more robust analysis show that there is still a wide budgeting variation for IS projects. The table below provides the results of our analysis that compared each the budgeted capital expenditures (CAPEX) and budgeted total project expenditures (CAPEX plus operational expenditures or OPEX) from the IS project documentation to the "Total Spend" or budget for each project that the Company provided in Workpapers MAL-6a to MAL-6c (REV-1).[23] We note that our project total budget analysis compares IS capital expenditures as provided in Company workpapers to sanctioning documentation for IS projects, and, therefore does not distinguish between capital and operating expenditures. However, without further clarity from the Company, this analysis is a reasonable way to gain insight as to how project budgets varied from initial design to implementation.

[23] The percent delta from our analysis represents the difference between the budget value in Workpapers MAL-6a to MAL-6c (REV-1) and the budget value from the IS project sanctioning documentation.

Table 4: New IS Project Rate Year Budget Variance Analysis[24]

	Project Count	Project $ (Initial Budget)	Project $ (Final Budget)	Mean $ (Initial Budget)	Mean $ (Final Budget)	Average
CAPEX						
All projects	101	$343,046,339	$270,874,003	$3,396,498	$2,295,542	-8.13%
Projects Decreasing from Initial	43	$220,596,847	$116,130,207	$5,130,159	$2,700,702	-51.42%
Projects Increasing from Initial	38	$96,736,653	$114,518,114	$2,545,701	$3,013,635	36.58%
Average of Inc and Dec						-7.42%
Total (CAPEX + OPEX)						
All projects	101	$343,046,339	$270,874,003	$3,396,498	$2,295,542	-55.05%
Projects Decreasing from Initial	75	$263,959,847	$147,398,153	$3,519,465	$1,965,309	-83.10%
Projects Increasing from Initial	21	$67,921,653	$94,974,168	$3,234,364	$4,522,579	32.01%
Average of Inc and Dec						-25.55%

Our analysis separated projects with deltas that were decreasing and increasing into separate buckets, as well as a bucket for all projects.[25] For each bucket, we calculated the following: total that was initially budgeted from the project documentation; total that was finally budgeted or provided in the Company's workpapers; the mean of each total; the average of all projects included in each bucket; and the average of the average increasing and average decreasing projects. This analysis shows that there is significant budget fluctuation between the project documentation and the Company's workpapers whether only the capital expenditures or total project costs are considered.

Q. Have you performed any other analysis regarding the Company's Service Company rents?

[24] See Workpaper titled "RRP IS Project Analysis Workpapers", tab "IS New Proj RY Var Analysis".

[25] Two projects were excluded due to readability of the project documentation for one and lack of documentation for the other project. Additionally, the Cyber Security Phase 2 projects were not broken out, so they were consolidated into one for the variance analysis.

A. Yes. We have reviewed testimony from the New York Public Service Commission (NYPSC) staff regarding IS investments.[26] NYPSC staff appeared to perform thorough analysis, since they had a panel of people analyzing all aspects of the IS cost portion of the Niagara Mohawk's Filing. In testimony, NYPSC staff made recommendations to remove a few discrete projects from the Rate Year revenue requirement. Based on our review, only one IS project, Customer Bill Redesign, is also included in this docket. Other projects recommended for removal were not found when reviewing the filed workpapers. This was confirmed by the Company in its response to Division Data Request 29-2.

Besides removing specific projects, NYPSC staff made other suggestions regarding rate recovery that included: "(2) a slippage adjustment to capital expenditures and associated operating and run the business expenses; (3) an adjustment to operating expenses to reflect a normalized level of operating expenses as a percentage of capital spending; and (4) an adjustment to the National Grid USA Service Company (National Grid or Service Company) return on IS capital investments."[27] Division Witnesses Bennett and Neale discusses similar adjustments with respect to GBE investments that include a cap on recovery.

Q. What recommendations do you have for the Commission based on your findings?

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[26] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Information Services Panel.
[27] *Id.*, p. 6, lines 12-21.

A. Innovative cost recovery solutions, such as those recommended by NYPSC staff and largely adopted by the settlement in that proceeding, may be appropriate to consider in the instant Filing for all new IS projects and GBE investments. One example is NYPSC staff's recommendation for a slippage adjustment to "protect customers from unreasonable or inaccurate rate year forecasting which may occur due to the combined effects of an unclear estimating process and a significant increase in capital spending that may not be achievable."[28]

As demonstrated by Phase III of our analysis, IS project budgets fluctuate during the planning and execution phases prior to the IS projects being implemented. Given the scale of proposed IS projects entering service after 6/30/2017 through the Rate Year, the final number of projects completed and their associated costs, may deviate from the Company's estimates. Additionally, our observations from the Company's execution of existing investments (see Figures 3 and 4 above), suggest that the Company is looking to undertake an increased scope of work from its post-Test Year history (both in terms of number of projects and total project costs).

This increased scope of work is significant and we are not fully confident the Company can execute the project work in the timeline provided in the Filing. In the interest of conservatism, the allowed total budget for all new IS projects that is included in the revenue requirement for the Rate Year should be reduced. Therefore,

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[28] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Information Services Panel, pp. 38 and 39, lines 20-24 and 1.

it is appropriate to impute a downward adjustment to the revenue requirement based upon the average variance of budgets reported by the Company in project documentation compared to Workpapers MAL-6a to MAL-6c (REV-1).

As a result of our analysis and the NorthStar Report[29] provided in response to Commission Data Request 5-23, we recommend that a downward adjustment of 15 percent[30] for both new IS be adopted to reflect that there are several planned projects in the spending plan that the Company may not complete before the next rate case and that the analysis here has demonstrated that the company does not often spend 100 percent of its budget.

Q. Do you have any observations related to the Gas Business Enablement Program proposed by the Company that is addressed in the testimony of Division witnesses Bennett and Neale?

A. Yes, we do. In their joint testimony, witnesses Bennett and Neale express significant concerns about the GBE program before the Commission, specifically relating to:

- The Company's ability to carry out the full scale of its planned GBE implementation as filed;
- The additional burden associated with implementing first in Rhode Island; and

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[29] Page 87 of the NorthStar Report states that "[o]ver the last three years, budget expenditures in NY were generally underrun and cover other functional area overruns".

[30] Since the project budgeting varied widely, we arrived at 15 percent by taking the average of (7.42) and (25.55), which represent the averages of projects increasing and decreasing when looking at initial budgets that just include CAPEX and initial budgets that include CAPEX and OPEX. This approach is reasonable do to the wide variance in project budgets between the project documentation and the Company's workpapers. See Workpaper titled "RRP IS Project Analysis Workpapers", tab "IS New Proj RY Var Analysis".

- Lack of customer protections.

Therefore, the recommendations that we describe below should apply to both GBE and Service Company new IS investment revenue requirements allocated to Narragansett Electric and Gas.

Q. Do you have any additional recommendations relating to the IT services being provided to the Company by the National Grid Service Company?

A. Yes. The size of the investments being made at this time is quite large. A large part of the reason has to do with the fact that National Grid has gone through a long period of underinvestment in IT. This was clear from the attachment to the response to Division Data Request 3-23.[31] Our review of this "big bang" of IT investments, which includes many programs and cybersecurity, was limited to budgetary analysis and review of the rate case information in New York. But the Division is limited in staff and budget. It was not possible within the limited period of the rate case for the Division to hire a consultant firm with expertise in IT technologies, cybersecurity, and management of IT systems to make a determination as to the effectiveness and prudency of the overall IT services being provided and proposed for the future. For that reason, the Division recommends to the Commission that it order the Company to hire an independent consulting firm with appropriate expertise to perform an audit of the IT function and services, including without limitation cybersecurity services and the GBE program, being provided to the Company. The selection of the independent firm and scope of the audit should be subject to the consent of the

[31] Company Response Data Request DIV 3-23, Attachment DIV 3-23, p. 5 of 43.

Division and filed with the Commission for approval. The audit should be conducted by the independent firm and a report filed with the Division and the Commission within one year from the issuance of the Commission's order. Given the apparent poor management of investments in the past as indicated in Division Data Request 3-23, the cost of the audit should be borne by the shareholders. By performing this audit, both the Division and the Commission can obtain assurance that the substantial investments being made and paid for by ratepayers is appropriate and prudent.

Q. Please summarize your recommendations.

A. We recommend the Commission adopt the following customer protections:

- Limit cost recovery of and on capital in the Rate Year to 85% of the allocated Service Company Rents revenue requirement to Narragansett Electric and Gas as filed by the Company in Docket 4770 for IS and GBE investments placed in-service after the Test Year;
- Limit the cost recovery of non-recurring GBE operating expenses in the Rate Year to 85% of the Rate Year non-recurring operating expenses as provided by the Company in response to DIV 3-58;
- In the event actual IS and GBE costs related to these investments are greater than 85%, but do not exceed filed amounts, allow the Company to create a regulatory asset to defer the balance of charges for future recovery subject to the Company's demonstration of cost and implementation results;
- Cap recovery of the GBE implementation program at the Company's allocated cost of \$37.1M (\$33.3M for Narragansett Gas and \$3.8M for Narragansett Electric) less pre-rate year expenses[32]; and

[32] Joint Testimony of Division witnesses Bennett and Neale.

- In the event actual IS and GBE costs related to these investments are less than 85%, require the Company to create a regulatory liability to defer the balance of charges for the benefit of customers.

The Rate Year revenue requirement impact from our proposed downward adjustment of 15 percent will reduce the Company's rate request relating to Service Company new IS invests for Narragansett Electric and Narragansett Gas by about an incremental $439,705 and $175,00, respectively.[33] The Rate Year revenue requirement impact from our proposed downward adjustment of 15 percent will reduce the Company's rate request relating to the GBE investments for Narragansett Electric and Narragansett Gas by about an incremental $83,599 and $977,286.[34]

In addition, we recommend the independent audit of IT services and cybersecurity.

It should also be noted that at this time, we are awaiting a response from the Company to the Division Data Request 36-3 to determine if the Company was on schedule (target release date 3/31/18) in delivering its first release in Rhode Island associated with integrated Operations/CMS functionality, including:

- Corrosion and Instrument & Regulation;
- Collections; and
- Integrity Management (Corrosion & I&R).

We also requested any updates or currently anticipated updates to the High Level GBE Roadmap provided in Schedule GBE – 4.

[33] See Workpaper titled "RRP New IS Investments Rev Req", tab "Pivot Table Summary".
[34] Joint Testimony of Division Witnesses Bennett and Neale.

Additionally, we are awaiting a response from the Company to Division Data Request 38-1, which is asking the Company to provide an update to the data provided in "Workpaper MAL 6a-6c Service Company Rents for all projects forecasted to close to plant after 6/30/17 to reflect updates for actual spending and/or changes to forecasted data that have occurred subsequent to the rate request filed November 27, 2017". This information is necessary to further examine the Company's ability to execute projects on schedule and in line with budget. Depending on the Company's responses to the two outstanding Data Requests, we may want to supplement this testimony and the Divisions recommendations herein.

V. APPROPRIATENESS OF INCREASED LABOR COSTS

Q. Please explain and summarize the Labor expenses.

A. Labor expenses are the costs to the Company for employment of its workers, both union and non-union. These expenses include annualized salaries of all employees who work for the Company or an affiliate providing services to the Company, annualized salaries for vacant positions, wages for seasonal and temporary employees, annualized salaries for incremental full time equivalent (FTE) employees, overtime pay and the non-financial component of variable pay, and adjustments to all wages based on projected wage rate increases.[35] For this instant Filing, the Company states that the Rate Year labor expense mostly includes the following:

> "(1) annualized salaries of all employees of record as of June 30, 2017 who work directly for the Company or work for an affiliate providing services to

[35] Direct Testimony of Melissa A. Little, p. 27, lines 15-22.

the Company; (2) annualized salaries for vacant positions as of June 30, 2017, wages for seasonal and temporary employees at the level incurred during the Test Year; (3) annualized salaries for incremental full time equivalent employees to be hired after the Test Year; (4) overtime pay and the non-financial component of variable pay at the level incurred during the Test Year; and (5) all adjusted as applicable by projected wage rate increases at the Test Year level of labor charged to O&M expense through the Rate Year."[36]

In her direct testimony and shown in the table below[37], Melissa Little provided a summary of the calculated Labor expenses[38] for Narragansett Electric and Narragansett Gas for the Test Year, Normalizing Adjustments, Proforma Adjustments, and Rate Year. For Narragansett Electric, the calculated Test Year expense is about $54.76 million and the Rate Year expense is about $54.83 million, including Normalizing and Proforma Adjustments. For Narragansett Gas, the calculated Test Year expense is about $36.02 million and the Rate Year expense is about $35.33 million, including Normalizing and Proforma Adjustments.

Table 5: Labor Expense Summary[39]

Company	Test Year Expense	Normalizing Adjustments	Proforma Adjustments	Rate Year Expense
Narragansett Electric	$54,756,249	($7,516,038)	$7,591,469	$54,831,680
Narragansett Gas	$36,022,308	($4,530,940)	$3,835,607	$35,326,975

The Company made several Normalizing Adjustments to Test Year O&M expenses that included: normalizing the costs related to Gas Cost Recovery-related O&M

[36] *Id*.
[37] *Id*., p. 28, Table 3. Numbers updated based on March 2 filed Schedule MAL-12 (REV-1).
[38] The calculations for Labor expense are provided in Schedule MAL-12 (REV-1).
[39] Schedule MAL-12 (REV-1), p. 1, line 4, Columns (j), (l), (p), and (r), and p. 2, line 4, Columns (p), (r), (v), and (x).

expenses[40] for Narragansett Gas out of the Labor and Other O&M expense line items[41]; applying an inflation adjustment so that the Test Year Labor expenses are reflected at pro forma levels in the Rate Year[42]; reducing variable pay in the Test Year for Narragansett Gas Electric and Narragansett Gas because it was paid above target levels[43]; and, due to the improper over- and under-statement of segments in the segment/regulatory account reporting in the Test Year segment applying reclassification adjustments to normalize out the reporting errors.[44]

Proforma Adjustments were made to union and non-union wages for salary and wage expenses for employees of the Company, Service Company, and other National Grid affiliates, as well as to reflect post-Test Year hires.[45] The Company explains that these post-Test Year hires are needed to fill established positions vacated as of the end of the Test Year and incremental new hires that are necessary for workload increases in several departments, as well as replacement of expected Customer Meter Service (CMS) staff retirements.[46] These retirements are netted out against the planned additions. The Company plans to make 107 new post-Test Year hires in the Rate Year that includes 32 employees for Narragansett Electric, 30 employees for Narragansett Gas, and 107 employees for the Service Company.[47]

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[40] Expenses related to local production and storage facilities recovered through the Gas Cost Recovery Factor.
[41] Direct Testimony of Melissa A. Little, p. 25, lines 6-13.
[42] *Id*., p. 27, lines 1-10.
[43] *Id*., p. 28, lines 17-18.
[44] *Id*., p. 29, lines 1-4.
[45] *Id*., p. 29, lines 7-10.
[46] *Id*., p. 29, lines 13-19. Departments include Electric and Gas Operations, Information Services, Customer Energy Integration, Consumer Advocate Staff, Customer Meter Services, and Solar Distributed Generation.
[47] Direct Joint Testimony of Raymond J. Rosario, JR., Alfred Amaral III, and Ryan M. Constable , pp. 31 and 32. Direct Testimony on Melissa Little, p. 29. Workpaper MAL-4 (REV-1).

Proforma Adjustments for salary and wage expenses in the Rate Year for Narragansett Electric were about $4.18 million and for Narragansett Gas were about $1.84 million.[48] For the Rate Year, the Company explained that the Proforma Adjustments were made using the following three step process:

> "(1) determining the "steady state" wages as of the end of the Test Year for employees as of June 30, 2017, plus post-Test Year hires; (2) applying proforma wage increases to union and non-union steady state wages; and (3) applying those same proforma increases to non-financial variable pay and overtime pay."[49]

In addition to the Company's Labor expenses, the Normalizing and Proforma Adjustments were made to the Service Company and All Other Companies (Affiliate Company). The Proforma Adjustments were calculated similarly to the Company's employees, except the steady state wages at the end of the Test Year are reduced to reflect only the percentage of the total salaries and wages charge to the Company.[50] Service Company proforma salary and wage adjustments to the Rate Year for Narragansett Electric are about $3.32 million and for Narragansett Gas are about $1.96 million.[51] Affiliate Company proforma salary and wage adjustments to the Rate Year for Narragansett Electric are about $91,778 and for Narragansett Gas are about $39,263.[52]

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48 Schedule MAL-12 (REV-1), pp. 6-7, line 42, Column (m).
49 *Id*., p. 30, lines 11-15.
50 Direct Testimony of Melissa A. Little, p. 34, lines 2-5.
51 Schedule MAL-12 (REV-1), p. 2, line 2, Columns (p) and (r).
52 Schedule MAL-12 (REV-1), p. 2, line 3, Columns (p) and (r).

Q. Please describe the analysis you preformed to review the prudency of the Labor expenses.

A. Our analysis of the Labor expenses involved several steps. First, we reviewed the Company's testimony[53] on retirements, replacement FTEs, and additional FTEs, discovery responses related to labor expenses and personnel, and the Company's retirement model, including the results. Then, we examined the Company's historical head count. Lastly, we analyzed the impact of each FTE on the revenue requirement in the Rate Year. Collectively, the goal of our analysis was to determine if the timing of replacements for retirements and extent of additional FTEs are appropriate and necessary for inclusion in the post-Test Year adjustments.

Q. What are your findings regarding review of retirements, replacement FTEs, and incremental FTEs?

A. Our initial review and analysis of the Company's Labor expenses revealed that the increased labor costs are primarily due to workforce requirements to address anticipated retirements and workload at the Service Company to address Narragansett Electric's anticipated distributed generation (DG) related increases to interconnection applications and installations and Narragansett Gas' increased workload to address gas maintenance and construction projects.

After examining the Company's testimony on replacements needed to address anticipated workforce retirements, Schedule OPEX-1 (Rhode Island Workstate

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[53] Joint Direct Testimony of Raymond J. Rosario, JR., Alfred Amaral III, and Ryan M. Constable.

Employee Population 10-year chart and data), and related discovery responses[54], it appears that the age breakdown of the workforce in Rhode Island has only changed slightly since 2007; this is, the percentage of 55+ workers has remained relatively flat at 25%, and only risen slightly to 29% as of July 2017. As shown in the table below, while workforce aging has become more of an issue recently for the Company and the State of Rhode Island, the same trends have been evident for the last ten years for workers in the 50-59, 55+, and 60+ percentages. While it is true that the 40-49 percentage has decreased over time, the <40 percentage has increased at a similar pace.

Table 6: Rhode Island Workstate Employee Population from 2007-2017 (July)[55]

Rhode Island Workstate Employee Population	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017 (July)	2022 (July)
% <40	17%	17%	19%	20%	18%	18%	20%	24%	27%	28%	29%	39%
% 40-49	38%	38%	38%	37%	36%	33%	30%	27%	24%	23%	23%	18%
% 50-59	40%	39%	36%	38%	39%	40%	42%	41%	41%	40%	40%	32%
% 60+	5%	5%	7%	6%	7%	9%	8%	8%	9%	8%	8%	11%
% 55+	25%	23%	23%	24%	25%	27%	28%	26%	28%	28%	29%	30%

Q. What are your findings regarding review of new hire relating to gas maintenance and construction?

A. After review of the Company provided documentation[56], it appears that gas maintenance and construction-related head count increases are reasonable.

Q. What are your findings and recommendations regarding review of incremental FTEs relating to DG applications?

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[54] Company Responses to Data Requests DIV 3-1 to 3-7, 9-7, 9-8, 21-16, and 29-3; PUC 3-38.
[55] See Workpaper titled "Book 4. (Schedule OPEX-1-RI 10 yr chart and data) – RRP".
[56] Joint Direct Testimony of Raymond J. Rosario, JR., Alfred Amaral III, and Ryan M. Constable, Section VI.

A. As discussed by Division Witness Booth, the Division supports a reduction in the additions requested by the Company to support increased DG applications from 19 to 3 incremental FTEs in the Rate Year. In support of this recommendation, we are recommending a downward adjustment in labor costs of about $765,268.[57]

Q. What are your findings regarding employee head count?

A. After reviewing the Company's testimony and several discovery responses[58] related to employee head count, we have created three tables that illustrate employee head count as of the end of the Test Year through the Rate Year. The first table, provided below, shows head count for Narragansett Electric and Narragansett Gas as of the end of the Test Year through the Rate Year. It captures vacancies during the post-Test Year period, incremental new hires in the Rate Year, and Rate Year attritions. For this table, we assume 100% direct assignment for the incremental Service Company employees assigned to Narragansett Electric and Narragansett Gas. The table shows that head count additions through the Rate Year are significant. When 100% direct assignment Service Company new hires are included, on a percentage basis, staff head count is up 14% from Test Year levels.

[57] See Workpaper titled "RRP Labor Expenses Workpapers", tab "DG Reduction".

[58] Company Responses to Data Requests Division 3-8, 9-6 to 9-8, 20-5 to 20-9, 21-13 to 21-15, 21-17, 21-18, 29-4; PUC 3-30 to 3-37, and 4-10 to 4-12.

Table 7: Head Count Summary[59]

Head Count	As of 6/30/17	Vacancies Filled Post-Test Period	Steady State (a)	Rate Year Incremental New Hires	Rate Year Attritions	Rate Year Total (b)	% Change (b)/(a)-1
Electric	396	22	418	32	-3	447	7%
DG Applications(*)				*19*		*19*	
Total Electric	396	22	418	51	-3	466	11%
Gas	342	9	351	36	-6	381	9%
Gas Maint. & Const.(*)				*23*		*23*	
Total Gas	342	9	351	59	-6	404	15%
Total Electric and Gas	738	31	769	110	-9	870	13%

(*) Incremental Service Company employees 100% direct assigned to Narragansett Electric and Gas

The last table, provided below, shows the incremental impact of head count changes to the post-Test Year period. It captures counts and labor costs of new hires and attritions broken out by Narragansett Electric, Narragansett Gas, and the Service Company for the Rate Year. Note that the Service Company number of employees includes the direct assigned Narragansett Electric and Narragansett Gas employees for DG applications and gas maintenance and construction. The table shows that head count additions for the Company and Service Company increase Rate Year O&M costs by $3.99 million. Rate Year O&M costs are largely due to anticipated retirements beyond the Rate Year. As shown below, O&M costs for new hires, net of attritions, results in a cost of $3.85 million.

59 See Workpaper titled "RRP Labor Expenses Workpapers", tab "Head Count Summary".

Table 7: Incremental Impact of Head Count Changes Post-Test Year[60]

	Rate Year (9/1/18 - 8/31/19)	
	# Employees	Labor Costs O&M
New Hires		
Electric	32	$1.53M
Gas	30	$1.48M
Service Company(*)	107	$.97M
Total	169	$3.99M
Attritions		
Electric	(3)	-$.08M
Gas	(6)	-$.32M
Service Company	0	
Total	(9)	-$.4M
Net	160	$3.58M

(*) Inclusive of the following:

DG Applications	19
Gas Maint. & Const.	23

Q. What are your findings regarding the impact of incremental FTEs on the revenue requirement?

A. Using the Melissa Little's Workpaper MAL-4 (REV-1) Labor Expenses as a starting point, we added additional columns for Title, O&M%, % Elec, and % Gas to tab "Incremental FTEs". We populated these columns with data from the Company's response to Division Data Request 3-9, which requested information on the 204 incremental post-Test Year new hires. In addition to this analysis, the Company was requested to update Workpaper MAL-4 (REV-1) Labor Expenses, tab "Incremental FTEs", with "additional columns for Rate Year, Data Year 2020, and Data Year 2021 in dollars ($) for each type of benefit (e.g. health insurance) for each Position, including positions that are retiring in each year".[61] Using the data provided in

[60] See Workpaper titled "RRP Labor Expenses Workpapers", tab "Inc FTE Labor Cost".
[61] Data Request DIV 29-6.

response to Division Data Request 29-6, we could fully examine the impacts of each FTE on the revenue requirement. The "Summary" tab of the Company's response to Division Data Request 29-6, provides a summary of Rate Year impacts of the incremental FTEs broken out by Narragansett Electric, Narragansett Gas, and Service Company for Union and Non-union. In addition, the Company included the Rate Year impacts of the 26 vacancies at Narragansett Electric and 9 vacancies at Narragansett Gas. We added lines to calculate the average Rate Year Incremental FTE for Narragansett Electric (union and non-union), the average Rate Year Incremental FTE for Narragansett Gas (union and non-union), the average Rate Year Incremental FTE for Service Company (union and non-union), and average Rate Year vacancies.[62] We also added a total to capture the average O&M impact of the average Incremental FTE and Vacancy for Narragansett Electric, Narragansett gas, and the Service Company.

Q. What recommendations do you have regarding the appropriateness of the Company's proposed labor cost increases?

A. Based on the findings of our analysis on retirements, replacement FTEs, and incremental FTEs, we conclude that the timing of head count additions related to retirements may be driven more by the timing of the instant Filing rather than good business practice. While the Company's retirement model analysis is reasonable, the age trend has not changed significantly for workers over 50 years of age. Additionally, while the Company is showing a need for the incremental FTEs to

[62] See Workpaper titled "Attachment DIV 29-6 – RRP", tab "Summary".

handle increased workload from DG applications and gas maintenance and construction; the ability of the Company to attract qualified, capable employees in the current competitive marketplace is unclear. Rate payers should not have to cover expenses related to these incremental FTEs until the Company is able to successfully hire and retain these post-Test Year new hires. Therefore, we recommend a downward adjustment in labor costs of about $935,548 to reflect a smooth hiring pattern over the course of the year for all Narragansett Gas & Narragansett Electric incremental hires requested, but not filled.[63] This adjustment is consistent with the Company's recent hiring practices shown in the Company's response to Attachment DIV-20-5.

Q. Do you have any other findings based on your review of the Company's Labor expenses?

A. Yes. During our review of understanding each incremental FTE's impact on the revenue requirement, we noticed that the Company is proposing wage increases that are higher for non-union employees than union employees.[64] While it is reasonable for the non-union employees to experience wage increases, the Company's proposed increases appear to be too high. After analyzing the impacts of the proposed wage increase for non-union employees, we determined that applying the average of the wage increases for union employees during the periods 7/1/2017-6/30/2018, 7/1/2018-6/30/2019, and 7/1/2019-8/31/2019, to each of those periods for non-union

[63] See Workpaper titled "RRP Labor Expense Workpapers", tab "Retirement Labor Reduction".

[64] Wage increases for the Rate Year are shown in Schedule MAL-12 (REV-1), pp. 6-7, lines 17-18, 22-23, 27-28 and p. 8, lines 21-22, 26-27, and 31-32.

employees provided more reasonable non-union wage increases. The reason for using the average of the wage increases for union employees is because non-union wage increases are typically steadier and should not be front or back-loaded. In the table below, which was created by adjusting the non-union wage increases in Schedule MAL-12 (REV-1) as previously described, we show the impact of using the average union wage increases on the Rate Year revenue requirement is an increase of about $976,005.

Table 8: Rate Year Impact of Higher Non-Union Wage Increase[65]

Rate Year Impact of Higher Non-Union Wage Increase								
	Narragansett Electric		Narragansett Gas		Service Company		Total	
	As Proposed	Average Union	As Proposed	Average Union	As Proposed	Average Union	As Proposed	Average Union
7/1/2017-6/30/2018	$206,664	$106,171	$66,856	$30,122	$1,823,509	$1,077,052	$2,097,029	$1,213,344
7/1/2018-6/30/2019	$176,527	$108,156	$57,107	$30,616	$1,557,597	$1,100,954	$1,791,231	$1,239,726
7/1/2019-8/31/2019	$30,892	$18,719	$9,993	$5,287	$272,575	$191,206	$313,460	$215,213
Rate Year 8/31/2019 O&M Wages	$2,729,067	$2,647,963	$711,801	$687,264	$36,172,152	$35,301,788	$39,613,020	$38,637,015
Difference	**$81,105**		**$24,537**		**$870,363**		**$976,005**	

When the Company was questioned about the reasonableness of the higher non-union wage increase, it replied:

> "Wage increases for non-union employees are properly based on employment market data and reasonable consistency with the Company's financial plan. To attract qualified, capable nonunion employees, National Grid must maintain compensation packages for non-union personnel that are competitive with other options available to those employees in the marketplace. National Grid continually monitors the marketplace to ensure that the compensation package is competitive. An annual review is conducted to review and analyze both salary structure and the level of annual merit increases to assure that these two components remain aligned with market offerings and fit within National Grid's financial plan. National Grid needs to keep pace with the market; otherwise, the Company will be at risk in terms of attracting and retaining the caliber of qualified employees needed to provide safe, reliable, and efficient utility service to customers.
>
> Wage increases for union employees are a different matter because wage increases are Determined as part of a comprehensive, negotiated arrangement put in place for a multi-year term. These arrangements encompass items beyond compensation matters (such as operational matters) so that there are

[65] See Workpaper titled "OM-Exp Labor – RRP", tab "Exhibit for Testimony".

tradeoffs embodied in the arrangement that preclude a direct comparison to non-union payroll increases."[66]

This data request response by the Company is not inconsistent with our recommendation that use of the three-year average better reflects the expectations of non-union staff regarding wage increases and better reflects a more stable application of wage increases than those in negotiated agreements.

VI. POWER SECTOR TRANSFORMATION ADJUSTMENTS TO THE REVENUE REQUIREMENT

Q. Are there any other aspects of the revenue requirement you wish to address in your testimony?

A. Yes. The Division is recommending that certain initiatives that were initially segregated by the Company as "PST" programs and treated separately under a proposed PST tracker be undertaken by the Company during the rate year and the costs included in the rate year revenue requirement. The testimony of Division Witnesses Woolf and Booth specifically address these programs in detail, which include the Company's proposed AMI Study, GIS Upgrade and update of the Systems Data Portal. We will discuss the impact of these additions to the rate year revenue requirement.

Q. Please summarize the Company's proposal regarding the AMI Study.

A. The Company is currently requesting $2 million for incremental costs for Advanced Metering Functionality (AMF) design work in Fiscal Year 2019.[67] Regarding the

[66] Company Response to Data Request Division 3-10.

AMI study, New York has already approved the study and is estimating costs at $2.988 million.[68] The Company is proposing to combine the Rhode Island piece of the study with the New York study and estimates that total cost of the combined study will be about $4.045 million.[69]

Q. Is Niagara Mohawk authorized to recover any portion of the costs associated with the New York AMI Study?

A. Niagara Mohawk is authorized to recover $2 million of the estimated $2.988 million study costs.[70]

Q. Do you believe the Company's allocation of costs between Rhode Island and New York for the combined study is appropriate?

A. No. In its response to Division Data Request 30-1, the Company states:

> "Niagara Mohawk received $2 million in base distribution rates to conduct the study. The Company used the $2 million Niagara Mohawk rate allowance as the basis for the $2 million Rhode Island AMI study funding request."

As noted in its response to Division Data Request 23-5, the estimated cost of the Niagara Mohawk-only AMI study was about $2.988 million. So, the incremental costs of including Rhode Island in the study would be approximately $1.057 million ($4.045 million minus $2.988 million), or about half of what the Company is requesting and about 25 percent of the total costs.[71]

[67] RIPUC Docket No. 4780, Filing Letter dated 1-12-18, p. 2.
[68] Company Response to Data Request DIV 23-5.
[69] *Id*.
[70] Company Response to Data Request DIV 30-3.
[71] Company Responses to Data Requests DIV 30-1 and 30-2.

The Company also has stated that when it provided its estimates for the full multi-jurisdictional AMI deployment with New York, the Company used an allocator from its Service Company Allocation Manual that was 25.12 percent. (See Division Data Request 23-3).

The Company asserts that the allocation of 25 percent of the costs would be incorrect because that allocation methodology is used for multi-jurisdictional scenarios, whereas the AMI studies are specific to the individual jurisdictions; "therefore it is appropriate to charge the AMI study costs by company".[72] However, given the actual estimated budget for the combined study and the breakdown of costs between Niagara Mohawk and Narragansett Electric, we believe the 25 percent allocation is the most reasonable allocation to use when distributing costs for the AMI study to Rhode Island ratepayers. This is appropriate because, otherwise, Rhode Island ratepayers would be picking up the $1 million of cost that New York ratepayers were avoiding from the settlement that approved the New York rate allowance of only $2 million.

Further, the AMI study is a combined study, it is not two separate studies and the New York affiliate has a much larger deployment of AMI than Rhode Island.

[72] Company Response to Data Request DIV 30-2.

Q. What is your recommendation on the cost recovery applicable to Rhode Island for the Company's proposed AMI Study?

A. As discussed by Division Witness Woolf, the Division supports the AMI study and believes the Company should conduct the study as soon as possible. In addition, Rhode Island should only pay for its fair share of the costs. As noted above, there are several reasons why it is appropriate for Rhode Island to be allocated only 25 percent of the combined study cost. In any case, as already explained, the New York study has been approved with the budget of approximately $2.988 million. Therefore, Rhode Island should only be responsible for the approximately $1.057 million difference, or about 25 percent of the total costs. Further, due to the timing of the investment being in between rate cases, the Investment should be amortized over three years or approximately $352.3 thousand per year in base rates. This will ensure that there is no risk of overcollection until the next time base rates are changed.

Q. Please summarize the Company's proposed GIS upgrade.

A. National Grid indicates it is to increase granularity, accuracy, and timeliness of data associated with advanced systems functionality, the Company is proposing upgrades in both New York and Rhode Island that together total about $3.05 million.[73] In a response just received by the Division on March 27, the Company has indicated that the New York Public Service Commission approved the project

[73] Direct testimony of the National Grid Power Sector Transformation Panel, RIPUC Docket No. 4780, Schedule PST - 1, Chapter 3 - Modern Grid, p. 15-17.

for New York.[74] The Company stated that it is proposing "to move forward with a Multi-Jurisdictional deployment and is seeking approval of $427,000 in its first year revenue requirements for the GIS Data Enhancement project presented in the table on Page 1 of 2 of Attachment DIV 19-8-3

Q. What is your position on the Company's proposed GIS upgrade?

A. Division Witness Booth has provided testimony on the GIS enhancements. I agree with Witness Booth and the Division that the Company should move forward immediately with the GIS enhancements. The Company was proposing for the six months ending March 2019 a cost of $3.05 million for GIS data system enhancements.[75] As mentioned above, the Company allocated to Rhode Island $427,000. However, there are some follow up questions that still need to be answered through Division Data Request Set 41. Subject to being able to review the responses to those follow up questions, we have assumed that the $427 thousand allocation is appropriate. However, similar to the treatment of the AMI Study costs, we would recommend that the GIS upgrade costs be amortized over three years (approximately $142,300 per year) in base rates to ensure there is no risk of over-collection until the next time base rates are changed.

Q. Please summarize the Company's proposed upgrade of its Systems Data Portal.

[74] Company Response to Data Request DIV 32-23.
[75] Company Response to Data Request Division 19-8, Attachment DIV 19-8-1.

A. The Systems Data Portal will be a web-based application that would provide relevant distribution planning information and distribution system data to stakeholders during the engagement process of the power sector transformation.[76] To complete the Systems Data Portal, the Company proposes to fund two distribution planning engineers and an analyst for an estimated $700 thousand in incremental annual O&M costs.[77] About $80,000 of these costs, which would begin work on the portal and reflect an initial year of effort, have been proposed in the System Reliability Project (SRP) 2018 Report.[78]

Q. What is your position on the Company's proposed upgrade of their Systems Data Portal?

A. We agree with the Company's assertion that these upgrades are necessary. However, we also agree with the Division Witness Booth's assertion that the costs proposed by the Company for the upgrades are excessive and support his recommendation of reducing the costs by one third. Additionally, we are netting $80,000 of costs of the initial work effort as described in the SRP 2018 Report. The revenue requirement impact would then be $700,000 less $80,000 divided by three, or about $205,000 added to base rates for the Rate Year.

[76] Direct testimony of the National Grid Power Sector Transformation Panel, RIPUC Docket No. 4780, Schedule PST - 1, Chapter 3 - Modern Grid, pp. 6-7.
[77] *Id.*, p. 8.
[78] *Id*.

VII. COST ALLOCATIONS AND COST RECOVERY CONDITIONS RELATING TO GBE AND PST INITIATIVES

Q. Did you review how the Company generally allocated the costs of the Gas Business Enablement program and compare it generally to what the Company was proposing for the allocation of projected costs of the various initiatives categorized as "PST" in the Company's PST filing?

A. Yes. We did.

Q. Do you agree with the way the Company has treated and proposed to allocate the shared costs in the context of those two programs?

A. No. There is a major inconsistency.

Q. Please briefly explain how the costs were allocated for GBE.

A. As described in the testimony of Division witnesses Bennett and Neale, the Company used allocators from its Service Company Allocation Manual to allocate the GBE program costs to its operating companies. The resulting allocations to each operating company were provided in Response to Division Data Request 17-11, Attachment DIV 17-11. We have not objected to these allocations in the context of GBE. The allocations are charged to the operating companies in the form of rent expense allocated to Narragansett Gas and Narragansett Electric.

Q. Has the National Grid Service Companies recovered all their up-front costs for Gas Business Enablement that were allocated to the affiliates?

A. No. In fact, it is quite revealing to see how much foundational work the National Grid companies have been willing to do for Gas Business Enablement and allocate to the affiliates without either obtaining cost recovery or being assured of cost recovery in the manner in which they are seeking assurance of cost recovery for their proposed PST initiatives.

Q. What was the aggregate total of costs the National Grid Companies incurred from the inception of the initiative through the end of December 2017 for GBE?

A. The Company's response to Division Data Request 32-52 indicates that the National Grid companies have incurred approximately $39 million in costs during that period that was allocated to numerous affiliates across National Grid.[79]

Q. How much of the $39 million was allocated and charged to New York regulated distribution affiliates during that period?

A. Taking the data from Division Data Request 32-52, if we add up the New York regulated utilities share from Brooklyn Union Gas KEDNY, KS Gas East KEDLI, and Niagara Mohawk, the total of costs allocated and charged to these New York regulated distribution affiliates in that period was approximately $24 million. Of

[79] Company Response to Data Request DIV 32-52, Attachment DIV 32-52.

that amount, approximately $5.8 million was incurred by Niagara Mohawk, of which it did not seek any recovery. The other two regulated entities incurred approximately $11.2 million and $7.2 million, respectively.

Q. Did the Brooklyn Union and KS Gas East affiliates obtain recovery?

A. No. The response identifies the cost recovery for these two allocations of costs as "To Be Decided – no pending base rate request." While this answer seems to suggest that those affiliates have not yet decided whether to seek recovery in rates, that label seems misleading in light of the Company's explanation about how the ratemaking rules in New York resulted in Niagara Mohawk not seeking any of the recovery.[80] There is no rate case pending for those gas companies. By the time these other affiliates presumably file rate cases again, the costs will be in the distant past, well beyond any 12-month historical test year period. For that reason, we believe that the $24 million will not be recovered from any New York ratepayers. This is significant when considering that the ratio of benefits to costs is higher for New York ratepayers than for Rhode Island ratepayers, as described in the testimony of Division Witnesses Bennett and Neale.

Q. What about Massachusetts?

A. The response indicates that there was an aggregate total of $10.8 million of costs incurred by the two gas distribution affiliates and two electric distribution

[80] Company Response to Data Request DIV 24-4.

affiliates. Apparently, the gas distribution companies have made a request in a pending rate case to recover approximately $9.8 million of those past costs.

Q. What about Rhode Island?

A. The same schedule indicates that Narragansett Electric's gas, electric distribution, and electric transmission business was charged approximately $3 million during that period and the Company is seeking 100% of that recovery.

Q. Is this treatment fair to Rhode Island in light of the fact that a higher proportion of the benefits will be incurred by the New York affiliates?

A. No. It is not reasonable for the National Grid affiliates in New York to absorb the $24 million in past costs, while the New England companies, including Narragansett Electric's ratepayers, are asked to pay 100% of their allocated share of past costs incurred during that same past period. In the revenue requirement, we have excluded all of these past non-recurring costs that were allocated to the Company's gas and electric businesses.

Q. Does the way the Company allocated the Gas Business Enablement costs have implications for how the National Grid companies are allocating costs on the electric side of the business for grid modernization initiatives?

A. Yes. The National Grid companies launched a massive initiative to transform the gas business through the Gas Business Enablement program. By all indications, none of the affiliates sought prior approval from any regulator before commencing the initiative. Yet, the project started, the costs were incurred, and the costs are being allocated using one of the allocators typically used for similar activities from the Service Company Allocation Manual. There was no waiting for all jurisdictions to give pre-approval before the companies began. They just did what they believed was important and prudent to do and dealt with cost recovery issues after the fact. Further, the allocation was not based on the amount of benefit, nor was it based on whether a particular jurisdiction pre-approved a cost recovery mechanism in advance. Rather, it was just implemented by allocating the costs in the ordinary course. This is in stark contrast to how the Company in this rate case is treating important transformational initiatives on the electric side of the business.

Q. How does it differ on the electric side?

A. Numerous initiatives included in the menu of PST programs identified by the Company in its PST filing have systems or projects that will eventually benefit companies across jurisdictions, much like the costs that were allocated for the transformational GBE program. But the Company has waited and proposed that its actions be contingent upon regulatory approval of cost recovery with no regulatory lag.

Q. What are the implications for cost allocations?

A. There is a glaring inconsistency. In the instance of the Gas Business Enablement, the Company accepts an allocation of costs that is not in line with the benefits and is not conditioned on cost recovery assurance. In contrast, when the Company addresses the PST initiatives – as the Company has defined them – the Company takes the position that Rhode Island must agree to pay for 100% of the cost for any initiative that has not obtained pre-approval of cost recovery in other jurisdictions. As a result, even though initiatives such as Distribution Supervisory Control and Data Acquisition (DSCADA) and the GIS Enhancements would benefit affiliates at some point in the near future, the Company told the Commission that Rhode Island must pick up 100% of the cost or wait until Massachusetts and/or New York approves the project too. Fortunately, New York has approved the GIS Enhancements and the Company is now proposing that Rhode Island only pay an allocated share. But that is not the case with DSCADA and some of the other PST initiatives proposed by the Company with multi-jurisdictional cost scenarios. Specifically, the Company appears to be holding Rhode Island hostage to the willingness of the Department of Public Utilities and/or the New York Public Service Commission to provide advance cost recovery approval before moving forward with some important foundational projects. Witness Greg Booth testifies that DSCADA is an important part of the business that should be moving forward now, among some other foundational grid modernization projects. To be consistent with the GBE initiative, there is no basis for the Company to be conditioning the allocation of costs to all affiliates on obtaining advance cost recovery approval from either Massachusetts or New York. The projects will eventually benefit one or more of the other affiliates, in the same way that the foundational GBE costs that were incurred will eventually benefit other operating companies. As Booth testifies, to the extent the projects are core business or foundational to advancing grid modernization they should move forward. Thus, when the costs are incurred, those costs should be allocated to all affiliates that will eventually receive a benefit, applying an appropriate allocator from the Service Company Allocation Manual that charges all those affiliates.

Q. Have you included the costs of DSCADA or other foundational grid modernization initiatives identified by Booth in the rate year revenue requirement?

A. No. That is because the Company has not projected that it will be incurring any costs on DSCADA or the other foundational initiatives until the year following the rate year, under any scenario.[81] But, based on Division Witness Booth's testimony, the Company should be moving forward on a reasonable schedule

[81] Company Response to Data Request DIV 19-8.

without waiting for regulatory cost approvals. As such, the costs should be treated in the same way the Gas Business Enablement costs were treated. Specifically, each affiliate that will eventually benefit from the shared system enhancement should receive its allocated share of cost and the Company should then seek recovery of its allocated share in the next respective rate case, as appropriate, in same manner that cost recovery has been sought for Gas Business Enablement, without the benefit of a fully reconciling PST cost tracker, as explained by Division Witness Tim Woolf in his testimony.

Q. Does this conclude your direct testimony?

A. Yes.

DAYMARK
ENERGY ADVISORS

Michael R. Ballaban

Managing Consultant

Michael Ballaban is a management consultant with wide-ranging experience serving electric and gas industry stakeholders performing financial advisory, pricing, cost-of-service, cost allocation, competitive market development, resource procurement and financial forecasting services.

He has worked for two of the largest investor-owned utilities in New England — New England Electric System (National Grid USA) and Boston Edison (Eversource Energy) — and has served electric, gas and water investor-owned and municipal clients throughout the United States and Canada and outside North America.

In the United States, Michael has worked at both the state and federal levels, testified at the Federal Energy Regulatory Commission (FERC) and participated in the restructuring of retail electric markets in the Northeast.

Recent experience includes leading a review a utility's allocation of certain service company costs to operating companies, co-leading a study to verify the electric and gas distribution assets in a utility's rate base were appropriate to support upcoming base rate filings, leading a review of significant deferred storm costs to verify that there were appropriate for a utility to include in cost recovery submissions, reviewing elements of utility's cost accounting structure and associated compliance program, and leading a regulatory transformation initiative to establish a regulatory organization within the finance function for a large multi-state utility.

Michael also has extensive experience assisting utilities with all phases of rate filings before state commissions and at Federal Regulatory Energy Commission (FERC), including preparation, discovery, litigation, settlement and implementation.

SELECTED PROFESSIONAL EXPERIENCE

Rate and Regulatory

- Managed a project team assisting a large state power authority with the assessment and redesign of the government customer segment electric rate structure and pricing. The customer segment comprised more than 100 entities and generated $1.3 billion in revenue to the authority. The project scope included the analysis and redesign of the utility's production and delivery rates so that the rates charged to the customers are aligned with costs, all on a basis that is revenue neutral to utility. The project was undertaken with customers in a collaborative outreach and feedback process to achieve agreement on recommended rate redesign solutions.

- Performed a review of the revenue requirement to support a rate case filing for an electric utility with revenues in excess of $3 billion. Reviewed each of the expense and capital components of the study to confirm that results are reasonable, underlying assumptions are verifiable and defensible, appropriate levels of documentation are established and elements are appropriately linked to the files reporting summary results.

- Managed project teams that prepared the revenue requirements, allocated cost-of-service and rate design, and coordinated the post-filing discovery activities for five rate cases across multiple jurisdictions for a western gas utility.

- Performed a comprehensive review of a major Asian investor-owned utility's existing rate structure and recommended tariff redesign strategies that addressed key marketing and financial goals in light of an evolving competitive environment. Recommended redesign strategies that addressed key customer retention and profitability goals. Also introduced an enhanced rate modeling package that allowed the client to better evaluate functionalization and allocation methods for developing alternative rate plans.
- Managed a project team that prepared multiyear natural gas rate studies for a city-owned gas utility. The comprehensive studies included a five-year projection of the utility's financial position, a cost-of-service analysis to evaluate the cost responsibility for each of the various classes of customers served, and the development of recommended rate charges to recover the costs of providing service from the respective classes of customers.
- Reviewed a Canadian regulatory agency's existing cost-of-service and rate design models to assess their accuracy, usability, flexibility and expandability in conforming to business and regulatory needs associated with electric retail restructuring. Recommended changes that enhanced the models' capabilities to unbundle lines of business in support of functional profitability analysis and rate redesign requirements. Also authored a user's guide to help model users apply fundamental principles of cost functionalization, classification and allocation to the cost-of-service development process.
- Prepared reports describing load management initiatives and large/industrial rate options offered by utilities throughout North America for a Canadian utility. Gathered data by developing and conducting surveys of large utilities and regulatory agencies, performing follow-on research and conducting follow-up interviews as necessary to complete these assignments. Research and interviews focused on determining each utility's motivation for offering specialized tariffs, the cost basis for tariffs developed and the cost-shifting implications associated with implementing the special tariffs.
- Reviewed the revenue requirement model for a major Midwestern utility intended to support an upcoming state-level rate filing to verify consistency and completeness of information spanning data input, model compilation, scenario analysis and reporting; identified source system data requirements and verified information was retrieved in optimum format utilizing full system functionality; and, identified pain points of the current process and addressed via suggested improvement opportunities.
- Participated in an assessment of a financial model for a private equity client intended as support when they sought financing in the market for a major FERC regulated transmission investment. The model estimated the income and cash flow that the investment was forecasted to generate over its useful life based on FERC Section 205 revenue requirement methodology.
- Subject matter resource to a team performing a review of a large electric utility's FERC jurisdictional formula rate model used to develop the transmission service charge to wholesale customers. The review addressed all procedures and controls, calculations, and inputs to the process.
- Led a review of several hundred million in deferred storm costs for a major multi-state Northeast utility to confirm charges as captured in the Company's financial systems by regulatory jurisdiction were reasonable and appropriate to include in cost recovery submissions to state regulatory agencies. The Company filed to seek recovery of all eligible reviewed costs at the conclusion of the engagement.
- Held various positions in pricing, financial planning, revenue requirements, and business strategy at New England Electric System and Boston Edison Company. Experience highlights include developing financial plans for company subsidiaries generating $1.6 billion in revenues, preparing and testifying to financial projections supporting proposed combined generation and transmission FERC rate requests during the period 1992 through 1994, participating in customer negotiations that resulted in

the retention of $30 million in at risk revenue, and leading the development of performance-based rate initiatives.

Costing

- Co-led a study for a major New England utility to review and verify the electric and gas distribution assets and reserves included in the Company's rate base as well as verify annual returns filed with its Commission. The examination of rate-base accounts included plant-in service, construction work in progress, and depreciation and deferred tax reserves
- Managed a study of the cost accounting structure for a large state power authority's Energy Efficiency organization Recommended changes/modifications to existing policy, documentation, and compliance efforts and provided an evaluation as to whether existing methods should be the basis for future allocation methods for new programs as the organization gains scale over time
- Led a review of a major utility's allocation of certain Service Company costs to operating companies by determining whether these costs were direct charged or allocated using appropriate procedures. Performed analyses specific to vendor costs, payroll expenses, employee expenses and general ledger journal entries. Calculated any proposed adjustments and confirmed whether there were any other pertinent facts indicating that the cost should be allocated differently or excluded.
- Prepared cost benefit analyses for investments in advanced meter reading and other proposed delivery infrastructure capital programs in support of regulatory submissions made across a utility's multi-state retail jurisdictions.

Regulatory Transformation

- Regulatory work stream leader for a transformation initiative for a large Midwestern multi-state electric and gas utility to develop a 5-year strategy roadmap of prioritized improvement opportunities that enables the client to:
  - collaborate across jurisdictions, financial planning and regulatory functions to better align regulatory objectives to business strategy
  - enhance scenario planning and analytics capability to effectively model and predict the need for rate actions, consider alternative regulatory mechanisms and develop regulatory strategies in light of market trends
  - Increase efficiency in development of regulatory filings to allow more emphasis on the content and less on process.
- Rates and Regulatory work stream leader for a focused finance transformation initiative to establish a Rates organization within the Finance function for a large multi-state utility. Advised the client on the design of a new operating model (including the development of a gap analysis and maturity model assessment, creation of an activity taxonomy, identification of delivery locations, and establishment of Centers of Expertise); the development of a roadmap of future initiatives and continuous improvement opportunities; and the design of a future state organization structure.

Financial Advisory

- Performed due diligence activities for utility asset sell-side transactions with a market value of more than $5 billion. Worked closely with clients and bidders to facilitate due diligence efforts relating to site visits, administration and response to questions, satisfying documentation needs and preparation of bid responses. Prepared employee asset documents that were used as the primary vehicles for the targeted marketing of employees to bidders. Also assisted in the development of transaction agreements. Participated in bid evaluation teams and performed comparative analyses of bid responses, both in terms of price and terms of sale, in support of selecting the highest value offers. Provided regulatory support to clients in both pre- and post-divestiture filings required to satisfy state regulatory requirements.

- Participated in a due diligence engagement to support a client's bid to acquire a medium-sized electric utility. Evaluated the unbundled rate structure and load profile of the target company to assess potential risks associated with existing power supply arrangements with an affiliated company.
- Led the comprehensive review of bidders' proposals to purchase electric assets from the federal government in a privatization initiative. Factors considered in the evaluations included pricing and other key contract terms, buyers' abilities to meet major service requirements, and the buyers' operating histories and financial capabilities.
- Co-managed an engagement to assist a major utility in auctioning its load and supply obligations. The key activities performed included marketing, due diligence and bid negotiations on the client's behalf. The auction resulted in the successful transferring of the client's load and supply obligations to third parties.
- Served as project manager on three engineer's reports developed for a utility's bond issuances totaling more than $500 million. The reports summarized the findings of studies of the utility's facilities, management, operations, gas supply, rates and marketing, and customer service, and assessed the financial feasibility of the bond issuances.

Resource Planning and Procurement

- Conducted an energy solicitation for this municipal agency to procure a retail electric power contract on behalf of its member organizations. Duties included advising the agency and its members on market entry strategies to obtain the best pricing and terms of service from suppliers; conducting the solicitation; reviewing supplier bids; and assisting the agency in negotiating and contracting with the selected vendor. This engagement resulted in providing the client with significant savings as compared to default service options available in the state.
- Assisted a large municipal electric utility with developing a comprehensive energy plan encompassing supply, demand-side, delivery and renewable energy components. Tasks during the engagement included helping to prepare the five-volume plan; assisting the utility with gathering, analyzing and preparing responses to comments received during a public hearing process regarding its proposed plan; assisting the utility in developing negotiating positions regarding certain plan elements; and conducting special analyses as needed to support plan initiatives.

Competitive Market Development

- Assisted clients in forming business strategy and establishing plans in anticipation of deregulation of the US electric energy markets. Primary focus included policy analyses for competitive positioning, tariff redesign recommendations, and cost-of-service and financial analyses. Client base included investor-owned utilities, municipal agencies, regulatory authorities, and customers entering competitive market

SELECTED EMPLOYMENT HISTORY

Daymark Energy Advisors Inc. *(formerly La Capra Associates)* Worcester, MA
Managing Consultant *June 2017 – Present*

Ernst & Young LLP Miami, FL
Senior Manager Power & Utility Advisory Services *2011-2017*

Black & Veatch Overland Park, KN
Principal Consultant Enterprise Management Solutions *2004-2011*

Navigant Consulting, Stone & Webster Management Consulting *MA*
Various utility rate and regulatory consulting roles *1997-2004*

Boston Edison Company *(currently Eversource)* Boston, MA
Principal, Pricing *1994 – 1997*
New England Electric System *(currently National Grid)* Westboro, MA
Principal, Economic Planning/Financial Forecasting/Revenue Requirements *1982 – 1994*

EDUCATION

Babson College Wellesley, MA
M.B.A., Finance

Indiana University Bloomington, IN
B.S., Transportation and Public Utilities
Concentration in accounting

PUBLICATIONS, PRESENTATIONS & CONFERENCES

"Innovative Approaches to Align LDC Rates to Fixed Cost Structures," 16th National Energy Services Conference and Exposition, February 2006
"Performance Based Ratemaking," Association of Energy Service Professional/EPRI Pricing Conference, May 2004.

Michael R. Ballaban

Managing Consultant

Michael Ballaban is a management consultant with wide-ranging experience serving electric and gas industry stakeholders performing financial advisory, pricing, cost-of-service, cost allocation, competitive market development, resource procurement and financial forecasting services.

He has worked for two of the largest investor-owned utilities in New England — New England Electric System (National Grid USA) and Boston Edison (Eversource Energy) — and has served electric, gas and water investor-owned and municipal clients throughout the United States and Canada and outside North America.

In the United States, Michael has worked at both the state and federal levels, testified at the Federal Energy Regulatory Commission (FERC) and participated in the restructuring of retail electric markets in the Northeast.

Recent experience includes leading a review a utility's allocation of certain service company costs to operating companies, co-leading a study to verify the electric and gas distribution assets in a utility's rate base were appropriate to support upcoming base rate filings, leading a review of significant deferred storm costs to verify that there were appropriate for a utility to include in cost recovery submissions, reviewing elements of utility's cost accounting structure and associated compliance program, and leading a regulatory transformation initiative to establish a regulatory organization within the finance function for a large multi-state utility.

Michael also has extensive experience assisting utilities with all phases of rate filings before state commissions and at Federal Regulatory Energy Commission (FERC), including preparation, discovery, litigation, settlement and implementation.

SELECTED PROFESSIONAL EXPERIENCE

Rate and Regulatory

- Managed a project team assisting a large state power authority with the assessment and redesign of the government customer segment electric rate structure and pricing. The customer segment comprised more than 100 entities and generated $1.3 billion in revenue to the authority. The project scope included the analysis and redesign of the utility's production and delivery rates so that the rates charged to the customers are aligned with costs, all on a basis that is revenue neutral to utility. The project was undertaken with customers in a collaborative outreach and feedback process to achieve agreement on recommended rate redesign solutions.
- Performed a review of the revenue requirement to support a rate case filing for an electric utility with revenues in excess of $3 billion. Reviewed each of the expense and capital components of the study to confirm that results are reasonable, underlying assumptions are verifiable and defensible, appropriate levels of documentation are established and elements are appropriately linked to the files reporting summary results.
- Managed project teams that prepared the revenue requirements, allocated cost-of-service and rate design, and coordinated the post-filing discovery activities for five rate cases across multiple jurisdictions for a western gas utility.

- Performed a comprehensive review of a major Asian investor-owned utility's existing rate structure and recommended tariff redesign strategies that addressed key marketing and financial goals in light of an evolving competitive environment. Recommended redesign strategies that addressed key customer retention and profitability goals. Also introduced an enhanced rate modeling package that allowed the client to better evaluate functionalization and allocation methods for developing alternative rate plans.
- Managed a project team that prepared multiyear natural gas rate studies for a city-owned gas utility. The comprehensive studies included a five-year projection of the utility's financial position, a cost-of-service analysis to evaluate the cost responsibility for each of the various classes of customers served, and the development of recommended rate charges to recover the costs of providing service from the respective classes of customers.
- Reviewed a Canadian regulatory agency's existing cost-of-service and rate design models to assess their accuracy, usability, flexibility and expandability in conforming to business and regulatory needs associated with electric retail restructuring. Recommended changes that enhanced the models' capabilities to unbundle lines of business in support of functional profitability analysis and rate redesign requirements. Also authored a user's guide to help model users apply fundamental principles of cost functionalization, classification and allocation to the cost-of-service development process.
- Prepared reports describing load management initiatives and large/industrial rate options offered by utilities throughout North America for a Canadian utility. Gathered data by developing and conducting surveys of large utilities and regulatory agencies, performing follow-on research and conducting follow-up interviews as necessary to complete these assignments. Research and interviews focused on determining each utility's motivation for offering specialized tariffs, the cost basis for tariffs developed and the cost-shifting implications associated with implementing the special tariffs.
- Reviewed the revenue requirement model for a major Midwestern utility intended to support an upcoming state-level rate filing to verify consistency and completeness of information spanning data input, model compilation, scenario analysis and reporting; identified source system data requirements and verified information was retrieved in optimum format utilizing full system functionality; and, identified pain points of the current process and addressed via suggested improvement opportunities.
- Participated in an assessment of a financial model for a private equity client intended as support when they sought financing in the market for a major FERC regulated transmission investment. The model estimated the income and cash flow that the investment was forecasted to generate over its useful life based on FERC Section 205 revenue requirement methodology.
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Concentration in accounting

PUBLICATIONS, PRESENTATIONS & CONFERENCES

"Innovative Approaches to Align LDC Rates to Fixed Cost Structures," 16th National Energy Services Conference and Exposition, February 2006

"Performance Based Ratemaking," Association of Energy Service Professional/EPRI Pricing Conference, May 2004.

Schedule RRP-E-1

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

	(A) Original Company Position	(B) Revised Company Position	Adjstmts		Division Position
Total Cost of Service	$ 320,488	$ 306,627	$ (18,497)	(C)	$ 288,131
Other Miscellaneous Revenues	8,531	8,531	-		8,531
Base Rate Revenue Requirement	$ 311,957	$ 298,096	$ (18,497)		$ 279,600
Base Rate Revenues, Present Rates	270,662	270,662	-		270,662
Base Rate Revenue Deficiency	$ 41,295	$ 27,434	$ (18,497)		$ 8,938

Notes:
(A) Schedules MAL-1&2-ELEC
(B) Schedules MAL-1&2-ELEC (REV-1)
(C) Schedule RRP-E-2

Schedule RRP-E-2

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

	(A) Original Company Position	(B) Revised Company Position	Adjstmts		Division Position
Uncollectible Accounts Expense	$ 4,660	$ 4,459	$ (824)	(C)	$ 3,635
Other Operation & Maintenance Expense	150,797	150,775	(2,024)	(D)	148,751
Depreciation and Amortization	51,265	51,265	(1,678)	(E)	49,587
Taxes Other Than Income Taxes	35,185	35,185	(127)	(F)	35,058
Interest on Customer Deposits	132	132			132
Income Taxes	22,111	10,837	(7,986)	(G)	2,851
Return on Rate Base	56,338	53,974	(5,856)	(H)	48,118
Total Cost of Service	$ 320,488	$ 306,627	$ (18,497)		$ 288,131

Sources:
- (A) Schedule MAL-1-ELEC
- (B) Schedule MAL-1-ELEC (REV-1)
- (C) Schedule RRP-E-3
- (D) Schedule RRP-E-4
- (E) Schedule RRP-E-5
- (F) Schedule RRP-E-6
- (G) Schedule RRP-E-7
- (H) Schedule RRP-E-8

Schedule RRP-E-3

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

Total Cost of Service Excl. Uncollectible Accounts	(A)	$ 284,496
Other Miscellaneous Revenues	(B)	(8,531)
Total Revenues Subject to Write-offs		275,965
Grossed-up Write-off Rate	(C)	1.317%
Pro Forma Uncollectible Accounts Expense		$ 3,635

Sources:

(A)	Schedule RRP-E-2	
(B)	Schedule RRP-E-1	
(C)	Schedule MAL-22 (REV-1), Page 6	0.013/(1-0.013)

Schedule RRP-E-4

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

Service Company Rents - ROE	(A)	$	(328)
New Service Company IS investments	(B)	$	(441)
GBE Investments	(C)	$	(84)
AMI Study	(D)	$	352
GIS Upgrade	(E)	$	142
Labor - Wage Increase	(F)	$	(772)
Labor - Incremental FTE	(G)	$	(335)
Labor - Systems Data Portal	(H)	$	205
Labor-DG Hires	(I)	$	(765)
Total Adjustment to Operation and Maintenance Expense		$	(2,024)

Sources
(A) Schedule RRP-E-4.1
(B) Workpaper titled “RRP New IS Investments Rev Req"
(C) Joint Testimony of Division Witnesses Bennett and Neale
(D) Testimony of Division Witnesses Woolf, Booth and Ballaban/Effron
(E) Testimony of Division Witnesses Booth and Ballaban/Effron
(F) Workpaper titled “OM-Exp Labor – RRP”,
(G) Workpaper titled “RRP Labor Expense Workpapers
(H) Testimony of Division Witnesses Booth and Ballaban/Effron
(I) Workpaper titled “RRP Labor Expenses Workpapers"

Schedule RRP-E-4.1

NATIONAL GRID - RI ELECTRIC
SERVICE COMPANY RENTS - ROE
($000)

Return Component at 8.80%:

Existing IS Projects	(A)	$ 1,596
New IS Projects	(A)	919
Existing Facilities	(B)	111
Total		2,625
Percent Reduction for Proposed ROE	(C)	-12.50%
Reduction to Rate Year Service Company Rents		$ (328)

Sources:

(A)	Workpaper MAL-6a (REV-1)	86.34%	*	1,848
(B)	Workpaper MAL-6a (REV-1)	86.34%	*	1,064
(C)	Workpaper MAL-6d (REV-1)	86.34%	*	128
(D)	Rate of Return			

	Ratio	Cost	Wtd. Cost	27.32% Pre-tax Cost
Debt	50.00%	3.70%	1.85%	1.85%
Equity	50.00%	8.50%	4.25%	5.85%
Total Capital	100.00%		6.10%	7.70%
Service Company Return per Company				8.80%
Percentage Reduction				-12.50%

Schedule RRP-E-5

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

Rate Year Depreciable Plant in Service	(A)	1,601,564
Proposed Composite Depreciation Rate	(B)	3.09%
Rate Year Depreciation Expense		49,501
Rate Year Depreciation Expense, per Company	(A)	51,179
Adjustment to Rate Year Depreciation Expense		(1,678)

Adjustment to Rate Year Depreciation Reserve	(839)
Adjustment to Rate Year Acumulated Deferred Income Taxes	176
Adjustment to Rate Year Rate Base	663

Sources:
(A) Schedule MAL-6-ELEC (REV-1), Page 2
(B) Workpaper RRP-E-5

Schedule RRP-E-6

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

Payroll Taxes:	
Labor - Wage Increase	(772)
Labor - Incremental FTE	(335)
Labor - Systems Data Portal	205
Labor-DG Hires	(765)
Total	(1,667)
Payroll Tax Rate	7.65%
Adjustment to Taxes Other Than Income Taxes	$ (127)

Source: Schedule RRP-E-2

Schedule RRP-E-7

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

Rate Base	RRP-E-8	$	726,438
Weighted Return on Equity	RRP-E-9		4.33%
Preliminary Taxable Income Base			31,490
Tax Reconciling Items	MAL 10-ELEC (REV-1)		705
Amortization of Excess Deferred Income Taxes	*		(5,066)
Taxable Income Base			27,129
Taxable Income	Taxable Income Base/.79		34,340
Income Tax Rate			21%
Current and Deferred Income Tax Expense			7,211
Unfunded Deferred Tax Catch-up	MAL 10-ELEC (REV-1)		650
Other Normalized Differences	MAL 10-ELEC (REV-1)		55
Amortization of Excess Deferred Income Taxes	*		(5,066)
Total Rate Year Income Tax Expense		$	2,851

*

Property Related	97,806	Attachment DIV 31-1
Amortization Period	30	PUC 4-1 Supplemental
Annual Amortization	3,260	
Non-Property Related	18,056	Attachment DIV 31-1
Amortization Period	10	See Testimony
Annual Amortization	1,806	
Total Annual Amortization	5,066	

Schedule RRP-E-8

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

		(A) Company Position			Division Position
Net Rate Base, per Company		$ 726,438			$ 726,438
Division Adjsutments:					
Depreciation Rates	(B)				663
Amortization of EDFIT	(C)				2,533
Adjusted Rate Base		726,438			729,634
Rate of Return		7.43%	-0.84%	(F)	6.59%
Return on Rate Base		$ 53,974	$ (5,856)		$ 48,118

Sources
(A) Schedule MAL-11-ELEC (REV-1)
(B) Schedule RRP-E-5
(C) Schedule RRP-E-7, Annual Amortization/2

Schedule RRP-E-9

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

Company Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	48.47%	4.69%	2.27%
Short Term Debt	0.45%	1.76%	0.01%
Preferred Stock	0.11%	4.50%	0.00%
Common Equity	50.97%	10.10%	5.15%
Total Capital	100.00%		7.43%

Division Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	47.85%	4.69%	2.24%
Short Term Debt	1.11%	1.76%	0.02%
Preferred Stock	0.09%	4.50%	0.00%
Common Equity	50.95%	8.50%	4.33%
Total Capital	100.00%		6.59%

Sources:
Schedule MAL-1-ELEC (REV-1), Page 4
Testimony of Mr. Kahal

Schedule RRP-G-1

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

	(A) Original Company Position	(B) Revised Company Position	Adjstmts		Division Position
Total Cost of Service	$ 244,846	$ 232,932	(16,001)	(C)	$ 216,930
Non-Firm Margin	1,388	1,388			1,388
Special Contract	225	225	-		225
Other Miscellaneous Revenue	38,170	38,170	-		38,170
Base Rate Cost of Service	$ 205,064	$ 193,149	$ (16,001)		$ 177,148
Base Rate Revenues, Present Rates	174,741	174,741	-		174,741
Base Rate Revenue Deficiency	$ 30,323	$ 18,408	$ (16,001)		$ 2,407

Notes:
- (A) Schedules MAL-1&2-GAS
- (B) Schedules MAL-1&2-GAS (REV-1)
- (C) Schedule RRP-G-2

Schedule RRP-G-2

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

	(A) Original Company Position	(B) Revised Company Position	Adjstmts		Division Position
Uncollectible Accounts Expense	$ 4,338	$ 4,090	$ (680)	(C)	$ 3,410
Other Op & Maint Expense	86,646	86,411	(2,035)	(D)	84,376
Depreciation and Amortization	43,163	43,163	(4,526)	(E)	38,637
Taxes Other Than Income Taxes	29,859	29,859	(62)	(F)	29,797
Interest on Customer Deposits	35	35	-		35
Income Taxes	21,483	10,532	(3,672)	(G)	6,860
Return on Rate Base	59,322	58,842	(5,027)	(H)	53,815
Total Cost of Service	$ 244,846	$ 232,932	$ (16,001)		$ 216,930

Sources:

(A) Schedule MAL-1-GAS
(B) Schedule MAL-1-GAS (REV-1)
(C) Schedule RRP-G-3
(D) Schedule RRP-G-4
(E) Schedule RRP-G-5
(F) Schedule RRP-G-6
(G) Schedule RRP-G-7
(H) Schedule RRP-G-8

Schedule RRP-G-3

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

Total Cost of Service Excl. Uncollectible Accounts	(A)	$ 213,521
Other Miscellaneous Revenues	(B)	(38,170)
Total Revenues Subject to Write-offs		175,351
Grossed-up Write-off Rate	(C)	1.945%
Pro Forma Uncollectible Accounts Expense		$ 3,410

Sources:

(A)	Schedule RRP-G-2	
(B)	Schedule RRP-G-1	
(C)	Schedule RRP-G-4.1	Rate/(1-Rate)

Schedule RRP-G-4

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

Service Company Rents - ROE	(A)	$	(77)
New Service Company IS investments	(B)	$	(175)
GBE Investments	(C)		(977)
Labor - Wage Increase	(D)		(205)
Labor - Incremental FTE	(E)		(601)
Total Adjustment to Operation and Maintenance Expense		$	(2,035)

Sources
- (A) Schedule RRP-G-4.2
- (B) Workpaper titled “RRP New IS Investments Rev Req"
- (C) Joint Testimony of Division Witnesses Bennett and Neale
- (D) Workpaper titled “OM-Exp Labor – RRP”,
- (E) Workpaper titled “RRP Labor Expense Workpapers"

Schedule RRP-G-4.1

NATIONAL GRID - RI GAS
SERVICE COMPANY RENTS - ROE
($000)

Return Component at 8.80%:

Existing IS Projects	(A)	$	489
New IS Projects	(A)		336
Existing Facilities	(B)		63
Total			888
Percent Reduction for Proposed ROE	(C)		-8.64%
Reduction to Rate Year Service Company Rents		$	(77)

Sources:
(A) Workpaper MAL-6a (REV-1)
(B) Workpaper MAL-6d (REV-1)
(C) Rate of Return

	Ratio	Cost	Wtd. Cost	27.32% Pre-tax Cost
Debt	50.00%	3.70%	1.85%	1.85%
Equity	50.00%	9.00%	4.50%	6.19%
Total Capita	100.00%		6.35%	8.04%
Service Company Return per Company				8.80%
Percentage Reduction				-8.64%

Schedule RRP-G-4.2

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

Year	Revenue	Write-Offs	%
2017	351,001	4,582	1.31%
2016	328,129	6,447	1.96%
2015	411,397	10,543	2.56%
2014	406,387	6,980	1.72%
Totals	1,496,914	28,553	1.91%

Total Rate Year Revenue	178,075
Pro Forma Uncollectible Accounts Expense	3,397
Pro Forma Uncollectible Accounts Expense, per Company	3,707
Adjustment Subsumed in Pro Forma Calculation	(310)

The effect of this adjustment is subsumed on Schedule RRP G-3

Source: Schedule MAL-22 (REV-1), Page 7

Schedule RRP-G-5

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

Rate Year Depreciable Plant in Service, per Company	(A)	1,284,030
Division Adjustment	(B)	(7,770)
Adjusted Depreciable Plant in Service		1,276,260
Proposed Composite Depreciation Rate	(C)	2.86%
Rate Year Depreciation Expense		36,503
Rate Year Depreciation Expense, per Company	(A)	41,029
Adjustment to Rate Year Depreciation Expense		(4,526)
Adjustment to Rate Year Depreciation Reserve		(2,263)
Adjustment to Rate Year Acumulated Deferred Income Taxes		475
Adjustment to Rate Year Rate Base		1,788

Sources:

(A) Schedule MAL-6-GAS (REV-1), Page 2
(B) Schedule RRP-G-8.1
(C) Workpaper RRP-G-5

Schedule RRP-G-6

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

Payroll Taxes:	
Labor - Wage Increase	$ (205)
Labor - Incremental FTE	(601)
	(806)
Payroll Tax Rate	7.65%
	$ (62)

Source: Schedule RRP-G-4

Schedule RRP-G-7

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

Rate Base	RRP-G-8	$ 767,170
Weighted Return on Equity	RRP-G-9	4.59%
Preliminary Taxable Income Base		35,213
Tax Reconciling Items	MAL 10-GAS (REV-1)	23
Amortization of Excess Deferred Income Taxes	*	(1,998)
Taxable Income Base		33,238
Taxable Income	Taxable Income Base/.79	42,074
Income Tax Rate		21%
Current and Deferred Income Tax Expense		8,835
Other Normalized Differences	MAL 10-GAS (REV-1)	23
Amortization of Excess Deferred Income Taxes	*	(1,998)
Total Rate Year Income Tax Expense		$ 6,860

*

Property Related	46,847	Attachment DIV 31-2
Amortization Period	30	PUC 4-1 Supplemental
Annual Amortization	1,562	
Non-Property Related	4,364	Attachment DIV 31-2
Amortization Period	10	See Testimony
Annual Amortization	436	
Total Annual Amortization	1,998	

Schedule RRP-G-8

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

		(A) Company Position		Division Position
Net Rate Base, per Company		767,170		767,170
Division Adjsutments:				
Forecasted Rate Year Plant	(B)			(6,625)
Depreciation Rates	(C)			1,788
Amortization of EDFIT	(D)			999
Adjusted Rate Base		767,170		763,332
Rate of Return	(C)	7.67%	-0.62%	7.05%
Return on Rate Base		$ 58,842	$ (5,027)	$ 53,815

Sources
(A) Schedule MAL-11-GAS (REV-1)
(B) Schedule RRP-G-8.1
(C) Schedule RRP-G-5
(D) Schedule RRP-G-7, Annual Amortization/2

Schedule RRP-G-8.1

NATIONAL GRID - RI GAS
ADJUSTMENT TO RATE YEAR PLANT IN SERVICE
($000)

Average Gas Plant Additions for Growth FY 2016 and FY 2017	(A)	$ 19,952
Company Forecasted Gas Plant Adds for Growth - 12 Mos. Aug-18	(B)	25,691
Adjustment to Gas Plant as of August 31, 2018		$ (5,739)
Average Gas Plant Additions for Growth FY 2016 and FY 2017	(A)	$ 19,952
Company Forecasted Gas Plant Adds for Growth - 12 Mos. Aug-19	(B)	24,014
Adjustment to Gas Plant as of August 31, 2019		(4,062)
Adjustment to Average Balance of Rate Year Gas Plant		$ (2,031)
Total Adjustment to Rate Year Gas Plant		$ (7,770)
Adjustment to Accumulated Depreciation	(C)	$ (193)
Adjustment to Deferred Taxes	(D)	$ (952)
Net Adjustment to Rate Base		$ (6,625)

Sources:

(A)	Attachment DIV 20-4	(20990+18914)/2
(B)	Attachment DIV 20-3	
(C)	Equal to 1 year depreciation on 2018 adjstmt + 1/2 year on 2019 adjstmt	
(D)	Workpaper RRP-G-8.1	

Schedule RRP-G-9

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

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	48.47%	5.18%	2.51%
Short Term Debt	0.45%	1.76%	0.01%
Preferred Stock	0.11%	4.50%	0.00%
Common Equity	50.97%	10.10%	5.15%
Total Capital	100.00%		7.67%

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	47.85%	5.10%	2.44%
Short Term Debt	1.11%	1.76%	0.02%
Preferred Stock	0.09%	4.50%	0.00%
Common Equity	50.95%	9.00%	4.59%
Total Capital	100.00%		7.05%

Sources:
Schedule MAL-1-GAS (REV-1), Page 4
Testimony of Mr. Kahal