BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 15-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 15-G- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service	Case 15-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service	Case 15-G- ____

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DIRECT TESTIMONY OF
THE REVENUE REQUIREMENTS PANEL

Steven R. Adams
Peter C. Cohen
Fausto Gentile
Maureen A. Gray
Joseph J. Syta

May 20, 2015

DIRECT TESTIMONY OF REVENUE REQUIREMENTS PANEL

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DIRECT TESTIMONY OF REVENUE REQUIREMENTS PANEL

I. INTRODUCTION

Q. Please state the names of the members on this Revenue Requirements Panel (the "Panel").

A. We are Steven R. Adams, Peter C. Cohen, Fausto Gentile, Maureen A. Gray, and Joseph J. Syta.

Q. Mr. Adams, please state your title and business address.

A. I am the Vice President – Regulatory Strategy. My business address is 52 Farm View Drive, New Gloucester, Maine 04260.

Q. Please summarize your work experience and educational background.

A. I have been with Iberdrola USA Networks ("IUSA") or its operating company subsidiaries for 20 years and assumed my current position in 2004. I began my career at IUSA with New York State Electric & Gas Corporation ("NYSEG" or the "Company") in 1995 and moved to Energy East Management Corporation ("Energy East") in 2001. Prior to joining NYSEG, I was an employee of the Virginia State Corporation Commission for over seven years. I hold a Bachelor of Business Administration from James Madison University and I am a Certified Public Accountant. My Curriculum Vitae ("CV") is set forth in Exhibit __ (RRP-9).

Q. Have you previously testified in other proceedings before the New York State Public Service Commission ("PSC" or the "Commission") or any other state or federal regulatory agency or court?

A. Yes, I have testified on several occasions before the PSC, including the last rate proceedings for NYSEG and Rochester Gas and Electric Corporation ("RG&E"

and together with NYSEG, the "Companies" and individually, the "Company"), Cases 09-E-0715 et al. In addition, I have testified before regulatory commissions in Connecticut, Maine, New Hampshire and Virginia.

Q. Mr. Cohen, please state your title and business address.

A. I am the Director – Regulatory. My business address is 52 Farm View Drive, New Gloucester, Maine 04260.

Q. Please summarize your educational background and work experience.

A. I have been with IUSA, formerly Energy East, for 11 years. I hold a Bachelor of Business Administration from the University of Denver. My CV is set forth in Exhibit __ (RRP-9).

Q. Have you previously testified in other proceedings before the PSC or any other state or federal regulatory agency or court?

A. I previously testified before the PSC in the Companies' last rate proceedings, Cases 09-E-0715 et al. In addition, I have testified before regulatory commissions in Maine and Connecticut.

Q. Mr. Gentile, please state your title and business address.

A. I am the Tax Controller. My business address is 70 Farm View Drive, New Gloucester, Maine 04260.

Q. Please summarize your educational background and work experience.

A. I have worked for IUSA and its subsidiaries since 1985, assuming my current position in 2010. I hold a Bachelor of Science degree in Accounting from LeMoyne University in Syracuse, New York. My CV is set forth in Exhibit __ (RRP-9).

Q. Have you previously testified in other proceedings before the PSC or any other state or federal regulatory agency or court?

A. I have testified on several occasions before the PSC, including the Companies' last rate proceedings, Cases 09-E-0715 et al. In addition, I have testified before the Maine Public Utilities Commission in Docket No. 2013-00068.

Q. Ms. Gray, please state your title and business address.

A. I am the Manager, New York Revenue Requirement. My business address is 89 East Avenue, Rochester, New York 14649.

Q. Please summarize your educational background and work experience.

A. I have been with IUSA or its operating company subsidiaries for 20 years and assumed my current position in 2013. I began my career at IUSA with NYSEG in 1995 and moved to Utility Shared Services in 2003. I hold a Masters of Business Administration from Lemoyne College, a Bachelor of Business Administration from Niagara University and I am a Certified Public Accountant. My CV is set forth in Exhibit __ (RRP-9).

Q. Have you previously testified in other proceedings before the PSC or any other state or federal regulatory agency or court?

A. No, I have not testified previously.

Q. Mr. Syta, please state your title and business address.

A. I am the Vice President, Controller and Treasurer. My business address is 89 East Avenue, Rochester, New York 14649.

DIRECT TESTIMONY OF REVENUE REQUIREMENTS PANEL

Q. Please summarize your educational background and work experience.

A. I started my career at RG&E in 1985 and became responsible for NYSEG as well after the 2002 merger of RG&E and NYSEG under Energy East. I assumed my current positions in 2004. Prior to joining RG&E, I was a consultant specializing in the utility industry. I hold a Bachelor of Science degree from the Rensselaer Polytechnic Institute in Troy, New York and a Master of Business Administration degree from the William E. Simon School at the University of Rochester. My CV is set forth in Exhibit __ (RRP-9).

Q. Have you previously testified in other proceedings before the PSC or any other state or federal regulatory agency or court?

A. I have testified before the PSC in numerous cases dating back to 1989. Most recently I testified in support of the Companies' September 2009 rate filings in Cases 09-E-0715 et al. as a member of both the Policy Panel and the Revenue Requirements Panel.

Q. What is the overall purpose of the Panel's testimony?

A. This Panel discusses the revenue requirement for both NYSEG and RG&E. The purpose of this testimony is to: 1) present the historical statements for the previous four calendar years and the Test Year ended December 31, 2014; 2) present the revenue requirements for the Rate Year Ended March 31, 2017 for the Companies; 3) describe the ratemaking adjustments proposed in the filing; and 4) describe requested accounting and ratemaking proposals. As the starting point for the Rate Year revenue requirement, we present the historic rate of return results for the Test Year, i.e., the twelve months ended December 31, 2014. The forecast Rate Year is the twelve month period from April 1, 2016 to March 31, 2017.[1] In addressing both the historic and forecasted results, we describe the significant adjustments to those results. In that process, we present the historic and Rate Year Operating and Maintenance ("O&M") expenses, operating taxes, income taxes, depreciation, Rate Base, and the forecast Rate Year capital structure and cost rates, all of which are summarized and included in the forecasted Rate Year revenue requirement.

II. SUMMARY AND IDENTIFICATION OF EXHIBITS

Q. Is this Panel sponsoring any exhibits?

A. Yes. This Panel sponsors the following exhibits:

1) Exhibit __ (RRP-1) provides historical financial statement information for each Company;
2) Exhibit __ (Elec. RRP-2) and Exhibit __ (Gas RRP-2) include the Rate of Return and revenue requirement schedules for each Company;
3) Exhibit __ (Elec. RRP-3) and Exhibit __ (Gas RRP-3) provide the adjustments made from the historic Test Year to the Rate Year for each Company;
4) Exhibit __ (Elec. RRP-4) and Exhibit __ (Gas RRP-4) include the Rate Base schedules for each Company;
5) Exhibit __ (Elec. RRP-5) and Exhibit __ (Gas RRP-5) includes the plant schedules for each Company ;

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[1] The Companies prepared their forecasts based on the Rate Year beginning April 1, 2016. As a result of making this filing on May 20, 2015 and assuming the full approximately 11-month statutory review period, the Companies recognize that new rates will not become effective until April 20, 2016.

6) Exhibit __ (RRP-6) includes the capital structure schedules for each Company;
7) Exhibit __ (RRP-7) provides an index of the Panel's workpapers. A copy of the workpapers will be provided to New York State Department of Public Service Staff ("Staff");
8) Exhibit __ (RRP-8) includes Moody's and Standard & Poor's ("S&P") Rate Year credit ratio calculations; and
9) Exhibit __ (RRP-9) includes the CVs of the members of the Panel.

III. SUMMARY AND OVERVIEW OF DELIVERY REVENUE REQUIREMENT

Q. Briefly describe the Delivery revenue requirement changes that the Companies are requesting for the Rate Year.

A. The Companies are requesting Delivery rate increases for three businesses (NYSEG Electric, NYSEG Gas and RG&E Gas). We are proposing a Delivery rate decrease for RG&E Electric. The rate changes are presented in the table below and reflect the rate request levels for these one-year rate filings. The Companies are requesting Delivery revenues to be based on a 10.06% return on equity ("ROE") and 50% equity ratio. The Companies will also be providing parties a multi-year rate plan for their consideration as part of a Joint Proposal whereby the Rate Year 1 rate changes are moderated over the multi-year period.

Table 1: Rate Increases / (Decrease)
($ thousands)

Company	Requested Increase / (Decrease)	Delivery Percentage	Overall Percentage
NYSEG Electric	$ 126,291	17%	7%
RG&E Electric	(10,160)	(2%)	(1%)
NYSEG Gas	37,810	20%	8%
RG&E Gas	20,318	12%	5%

Q. What are the primary financial drivers for the proposed rate increases?

A. The rate increase for NYSEG Electric is primarily driven by the need to recover deferred storm restoration costs, the movement to a full-cycle distribution vegetation management program, and cost increases associated with property taxes, Pension, and the return on Rate Base. Conversely, the rate decrease for RG&E Electric is driven by the amortization of regulatory liabilities, partially offset by the cost increases for Pension and return on Rate Base.

The rate increases at NYSEG Gas and RG&E Gas are driven by similar factors including cost increases associated with property taxes, Pension and the return on Rate Base.

Q. Please explain how you developed the Rate Year Delivery revenue requirement for each Company.

A. The Rate Year Delivery revenue requirement for NYSEG Electric, RG&E Electric, NYSEG Gas, and RG&E Gas, as well as the supporting exhibits and associated workpapers, were prepared in a manner consistent with Commission's Statement of Policy on Test Periods in Major Rate Proceedings issued in Case 26821. The revenue requirement forecast started from actual historic Test Year results. Various adjustments were then made to normalize the historic Test Year results and to create a verifiable link from the historic Test Year to the forecast Rate Year.

IV. DESCRIPTION OF EXHIBIT 1 – HISTORICAL FINANCIALS (RRP-1)

Q. Please describe the format of the NYSEG Electric, RG&E Electric, NYSEG Gas and RG&E Gas Exhibits __ (RRP-1).

A. Each Company has a separate Exhibit __ (RRP-1) which provides historical financial statement information and includes the following schedules:

1) Schedule A: Balance Sheet;
2) Schedule B: Income Statements;
3) Schedule C: Retained Earnings;
4) Schedule D: Operating Income;
5) Schedule E: Plant; and
6) Schedule F: Cash Flow.

Q. Please indicate whether the Companies had any Merchandising or Jobbing Revenues in the historic Test Year.

A. The Companies had Merchandising Revenues in the historic Test Year totaling $209,000 for NYSEG Electric and $64,000 for RG&E Electric. These amounts represent revenues associated with relay pulse and energy profiler systems.

V. DESCRIPTION OF EXHIBIT 2 – TEST YEAR AND REVENUE REQUIREMENT (RRP-2)

Q. Please describe the format of Exhibits __ (Elec. RRP-2) and Exhibits __ (Gas RRP-2) (collectively "Exhibit __ (RRP-2)").

A. Exhibit __ (RRP-2) is provided for each Company and includes the Rate of Return and revenue requirement schedules as follows:

1) Schedule A: Rate of Return Statement;
2) Schedule B: Revenue;
3) Schedule C: Operation and Maintenance Expense;
4) Schedule D: Depreciation and Amortizations;
5) Schedule E: Operating Taxes;
6) Schedule F: Income Taxes;
7) Schedule G: Capital Structure;
8) Schedule H: Regulatory Amortizations; and
9) Schedule I: Rate Change.

Q. What is the source of the data set forth by each Company in Schedule A of Exhibit __ (RRP-2)?

A. Schedule A, Column A includes the actual Delivery operating results for the historic Test Year ended December 31, 2014. This column primarily reflects operating revenues and costs as presented in the 2014 Annual Compliance Filings ("ACF") and supported by the RRP-2 WP-08 ACF to RRP-2 ROR reconciliation workpapers. The amounts in this column have not been adjusted to exclude non-operating, non-recurring or out-of-period revenues and costs that were booked during the year. Column B represents the adjustments detailed in Exhibit __ (RRP-3), Schedule A and includes: 1) normalizing adjustments to exclude non-recurring and out-of-period revenues and costs; and 2) adjustments to reflect the forecast changes in revenues and costs through the Rate Year. These adjustments, when added to Column A, produce the forecast Rate Year operating results at existing rates, set forth in Column C. The adjustments in Exhibit __ (RRP-3), Schedule A are supported either by this Panel or by the Companies' other witnesses or panels. Schedule A, Column D presents the rate relief / return and associated taxes and other costs needed to earn the requested return as calculated on Exhibit __ (RRP-4), Schedule A. Column E sets forth the forecasted operating results, including rate relief / return, for the Rate Year.

Q. What other items does this Panel support?

A. This Panel and the other panels providing testimony in this proceeding support and address the following:

1) Revenues detailed on Schedule B are supported by this Panel and by the Deliveries and Revenue / Revenue Decoupling Mechanism Panels;
2) O&M Expenses detailed on Schedule C are supported by this Panel and by many of the Companies' other panels as noted throughout this testimony;
3) Depreciation expense is based on the Companies' proposed service lives and salvage rates, applied to the anticipated plant in service for each business. The proposed service lives and salvage rates are supported by the testimony of John Spanos of Gannett Fleming Valuation and Rate Consultants, LLC and the anticipated plant in service for each business is supported by the capital

expenditures presented by the Electric and Hydro Capital Expenditures Panel, the Gas Engineering, Delivery and Operations Panel, and this Panel. The amortization of the excess and deficient depreciation reserves at NYSEG Electric and Gas, respectively, is supported by this Panel. Depreciation expense amounts are shown on Schedule D;

4) Operating Taxes, as set forth on Schedule E, are supported by this Panel;
5) Income Taxes, as developed on Schedule F, are also supported by this Panel;
6) Rate Base is supported by this Panel, as developed on Exhibits __ (Elec. RRP-4) and Exhibits __ (Gas RRP-4);
7) This Panel calculated the Net Plant based on the actual plant balances at the end of the Test Year and forecast capital expenditures as set forth in the testimony and exhibits of the Electric and Hydro Capital Expenditures Panel and the Gas Engineering, Delivery and Operations Panel;
8) The Equity component of Rate Base, Interest Expense and Preferred Dividends are based on the above-referenced Rate Base and the Common Equity Ratio, average cost of debt and average cost of preferred stock; and
9) This Panel supports the projected equity, debt, and preferred stock amounts and costs and relies on the testimony of Ann E. Bulkley of Concentric Energy Advisors, Inc. to support the proposed capital structure, including equity percentages and recommended ROE.

Q. Please describe the adjustments to Interest Expense from the book amounts in Column A of Schedule A of Exhibit __ (RRP-2).

A. Detailed information about the cost of capital, including Interest Expense, can be found on Exhibit __ (RRP-2), Schedule G. Per book interest expense includes interest on debt and accruals of non-cash returns on certain regulatory assets and liabilities which are not included in Rate Base or provided for in the Joint Proposal approved in Cases 09-E-0715 et al. ("2010 JP"). These accruals are not part of the current revenue requirement and are, therefore, excluded from calculation of the revenue requirements. NYSEG and RG&E account for Interest Expense as Electric and Gas operating costs. However, part of the capital structure supports Interest-bearing Construction Work in Progress ("CWIP") and Non-Utility assets, neither of which is in Rate Base. Therefore, for regulatory purposes, it is necessary to synchronize (i.e., allocate) these costs of capital among Electric Rate Base, Gas Rate Base and Items Not in Rate Base in proportion to the amount of capital supporting each of these groups of assets. The Interest Expense for the historic Test Year and forecast Rate Year has been synchronized accordingly.

Q. What does Schedule A to Exhibit __ (RRP-2) demonstrate?

A. Schedule A summarizes the actual historical results and the forecasted Rate Year revenue requirement for Electric and Gas, respectively. The Companies utilized their 2014 Annual Compliance Filings as the starting point. Various adjustments are then included to forecast the Rate Year cost of services during the period April 1, 2016 through March 31, 2017.

Q. Can the Panel please explain the adjustments to Schedule H?

A. Schedule H sets forth the historic Test Year and the Rate Year Amortizations and positive benefit adjustment ("PBA") amounts.

Q. What is described in Schedule I?

A. Schedule I summarizes the components of the Rate Year rate change.

VI. DESCRIPTION OF EXHIBIT 3 – ADJUSTMENTS (RRP-3)

Q. Please describe the format of Exhibits __ (Elec. RRP-3) and Exhibits __ (Gas RRP-3) (collectively "Exhibit __ RRP-3)").

A. Exhibit __ (RRP-3) includes the Adjustments from the Historic Test Year to Rate Year, shown on Schedule A.

Q. What is included in Schedule A of Exhibit __ (RRP-3)?

A. Schedule A starts with the actual Historic Test Year Operating Results and projects across the page with the Companies' rate adjustments to get to the Rate Year revenue requirement before rate relief / return. The Adjustments on Schedule A are discussed in further detail below.

VII. DESCRIPTION OF EXHIBIT 4 – RATE BASE (RRP-4)

Q. Please describe the format of Exhibits __ (Elec. RRP-4) and Exhibits __ (Gas RRP-4) (collectively "Exhibit __ (RRP-4)").

A. Exhibit __ (RRP-4) includes the Rate Base schedules as follows:

1) Schedule A: Rate Base;
2) Schedule B: Plant, Non-Interest-Bearing CWIP, and Depreciation Reserve Forecast;
3) Schedule C: Materials and Supplies;

4) Schedule D: Prepayments;

5) Schedule E: O & M Working Capital Per FERC Formula;

6) Schedule F: Deferred Debits and Credits; and

7) Schedule G: Deferred Income Taxes and Investment Tax Credit ("ITC").

Q. Please describe what is included in Exhibit __ (RRP-4).

A. Each Schedule is consistent with the format of Exhibit __ (RRP-2). Column A sets forth the actual monthly average Rate Base for the historic Test Year ended December 31, 2014. The source of these amounts is the books and records of the respective Company. The adjustments set forth in Column B are detailed on Schedule A of Exhibit __ (RRP-3) and include: 1) adjustments to exclude items that are not supported by Delivery rates and 2) adjustments to reflect the forecast changes in plant and other balances through the Rate Year. These adjustments, when added to Column A, produce the forecast Rate Year Rate Base set forth in Column C.

Q. What is contained in Schedule A?

A. Schedule A is a summary that identifies the various components of Rate Base. Each component is further detailed on Schedules B through I.

Q. What does Schedule B set forth?

A. Schedule B sets forth the amount of Utility Plant, Depreciation Reserve and Non-Interest Bearing Customer Advances in Rate Base. As noted earlier, the historic Test Year amounts are the average of actual book balances for the 12 months ended December 31, 2014. Interest Bearing CWIP is excluded and will be added to Rate Base as the projects are placed in service. The changes to Rate Year are listed in Column B. The balance in Non-Interest Customer Advances is relatively stable and no change from the historic Test Year average has been projected.

Q. Please describe the adjustments to Utility Plant and Depreciation Reserve from the historic Test Year to the Rate Year.

A. The adjustments to Utility Plant and Depreciation Reserve are based on the forecast capital expenditures set forth in the testimony and exhibits of the Electric and Hydro Capital Expenditures Panel and the Gas Engineering, Delivery and Operations Panel. The workpapers accompanying this filing include a detailed calculation of the forecast Plant and Depreciation Reserve balances. These adjustments are posted forward to Column B on Schedule B of this exhibit.

Q. How were the forecast Gross Utility Plant shown on Schedule B of the Exhibit __ (RRP-4) calculated?

A. Gross Utility Plant is calculated in each Exhibit __ (RRP-5). The beginning Electric and Gas Plant balances on the associated workpaper are the sum of the actual per-book balances of Electric, Gas and allocated Common Gross Plant (account 101), Plant Held for Future Use (account 105), Complete Construction Not Classified (account 106) and CWIP (account 107) minus Interest-Bearing CWIP at December 31, 2014. The Electric and Gas Plant balances were increased through the Rate Year based on the forecast capital expenditures. For those projects with extended construction periods, the capital expenditure dollars projected to be spent on those projects were added to Plant on the anticipated in-service dates. The remainder of the capital forecast represents continuing expenditures on projects with relatively short construction periods. These expenditures were spread through each calendar year and added to Plant on a month-to-month basis.

Q. Please describe how the forecast Depreciation Reserve shown on Schedule B of each Exhibit __ (RRP-4) was calculated.

A. The forecast Depreciation Reserve was calculated in each Exhibit __ (RRP-5). The beginning Depreciation Reserve balances (account 108) are the actual per book balances of Electric, Gas and allocated Common accumulated depreciation at December 31, 2014. Depreciation Reserve has been adjusted by the amount of Depreciation Expense to be accrued through the Rate Year.

Q. Are there any adjustments to Materials and Supplies?

A. Schedule C provides a summary of Materials and Supplies that have been inflated from the historic Test Year to the Rate Year using the General Inflator (4.02%).[2] Gas Storage inventory has been removed from the historical Test Year because the return on gas storage inventory is recovered through the Merchant Function Charge ("MFC"). This gas storage inventory treatment is consistent with the Companies' 2010 JP.

Q. Please describe the adjustments to Prepayments.

A. Schedule D provides a summary of average historic balance of Prepaid Property Taxes, Insurance, PSC General Assessment, and other Prepayments that have been inflated using the General Inflator (4.02%).

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[2] The general inflator of 4.02% represents inflation from the midpoint of the 2014 Test Year to the midpoint of the Rate Year. The inflation values are based on the average GDP Chained Price Index from the Blue Chip Economic Indicators. The calculation is provided in the General Inflator section of this testimony.

Q. What does Schedule E set forth?

A. Schedule E sets forth the calculation of Cash Working Capital for O&M and Purchased Power Costs based on the Federal Energy Regulatory Commission ("FERC") formula.

Q. Would the Panel please describe the adjustment to O&M Working Capital?

A. O&M Working Capital has been adjusted to track the changes in O&M Expense set forth on Exhibit __ (RRP-3), Schedule A.

Q. Are you making adjustments to the Purchased Power Working Capital?

A. Yes, the Purchased Power Working Capital is being removed from the Electric Delivery Rate Base, subject to recovery in the MFC.

Q. Would the Panel please describe Schedule F?

A. Schedule F sets forth the average balances for the historic Test Year and the Rate Year of Deferred Debit and Credit accounts that are in Rate Base.

Q. Please describe Schedule G.

A. Schedule G sets forth the average balances for the historic Test Year and the Rate Year of Deferred Income Taxes and Deferred Investment Tax Credit. The historic Test Year amounts are averages per the Companies' books. The first section of the schedule is plant related. The Deferred Income Taxes in the second section titled "Regulatory Asset and Liability Related" track deferred debits and credits that are on Exhibit __ (RRP-2), Schedule H. Other items listed have a specific forecast, are being held constant or have been set to zero.

Q. How did the Companies calculate Deferred Income Taxes relating to Plant and the associated adjustments?

A. The Companies calculated Deferred Income Taxes related to Plant using historical and new plant data. The resulting deferred income taxes were used to adjust the December 31, 2014 actual book balance to arrive at the Rate Year balance as shown on Exhibit __ (RRP-4), Schedule A.

VIII. DESCRIPTION OF EXHIBIT 5 – PLANT (RRP-5)

Q. Please describe the format of Exhibits __ (Elec. RRP-5) and Exhibits __ (Gas RRP-5) (collectively "Exhibit __ (RRP-5)").

A. Exhibit __ (RRP-5) includes the Plant schedules for each Company as follows:

1) Schedule A: Post-2014 Capital Expenditures;
2) Schedule B: Post-2014 Plant Additions by Calendar Year;
3) Schedule C: Depreciation Lives and Rates for Plant Additions, by Asset Type;
4) Schedule D: Post-2014 Plant Additions by Rate Year;
5) Schedule E: Average Gross Plant from Post-2014 Plant Additions;
6) Schedule F: Book Depreciation from Post-2014 Plant Additions;
7) Schedule G: Average Depreciation Reserve from Post-2014 Plant Additions;
8) Schedule H: Tax Depreciation from Post-2014 Plant Additions;
9) Schedule I: Average Rate Base Contribution from Post-2014 Plant Additions;
10) Schedule J: Total Book and Tax Depreciation from Plant;
11) Schedule K: Total Net Plant;

12) Schedule L: Total Deferred Income Taxes from Plant; and

13) Schedule M: Total Average Rate Base Contribution from Plant.

Schedules A, B and C present detailed inputs associated with post-2014 plant additions through 2021. Schedules D through I present the calculation of the components of incremental Rate Base associated with post-2014 plant additions. Schedules J through M combine the components of incremental Rate Base from post-2014 plant additions and plant in-service as of December 31, 2014 to provide total plant-related Rate Base.

Q. Can the Panel describe the Schedules included in Exhibit __ (RRP-5)?

A. Schedule A of Exhibit __ (RRP-5) provides a detailed calendar-year forecast of post-2014 capital projects and programs and their associated capital expenditures. The forecast is, with the exception the updates in this filing reflecting the most recent information, consistent with the Companies' Five Year Capital Expenditure Plan that was submitted to the PSC on April 1, 2015. Schedule A also specifies an asset type for each entry which is subsequently used to assign book and tax lives and depreciation rates. Schedule B specifies the amounts and timing of plant additions by calendar year associated with the capital expenditures provided in Schedule A. Programs that are characterized by plant additions throughout the year are assigned a mid-calendar year (July) in-service date. Schedule C is a table with supporting book and tax depreciation lives and rates by asset type, and common plant allocations. The depreciation rates (which reflect book lives and net salvage percentages) by asset type are derived by mapping individual FERC account book depreciation rates to higher level summary rates. The book lives and net salvage rates utilized for the period prior to the start of the Rate Year are consistent with those lives and net salvage rates previously approved by the PSC. The Rate Year depreciation is based on the book lives and net salvage rates proposed by Company Witness Spanos. Schedule D takes the plant additions provided on a calendar year basis on Schedule B and converts them to a Rate Year basis. Schedules E through G provide the Rate Year calculation of average gross plant, book depreciation, and average depreciation reserves associated with plant additions from Schedule D, asset types from Schedule A and book depreciation rates from Schedule C. Schedule H calculates the federal and New York State tax depreciation associated with plant additions from Schedule D, asset types from Schedule A and tax depreciation rates from Schedule C. The resulting Rate Year values are weighted averages of calendar year amounts. Schedule I takes the Rate Year totals for average gross plant, average depreciation reserve, and book and tax depreciation from Schedules D through H to calculate average Rate Year net plant and average Rate Year Accumulated Deferred Income Taxes ("ADIT"). Schedule J sums Rate Year book and tax depreciation from plant in-service as of December 31, 2014, as provided from the Companies' books of accounts, with Rate Year book and tax depreciation associated with post 2014 plant additions as calculated in Schedules F and H. Schedule K then utilizes the book depreciation projections from Schedule J and gross plant and depreciation reserve balances as of December 31, 2014 to project total Rate Year gross plant, depreciation reserve and net plant. Schedule L uses Rate Year book and tax projections from Schedule J to calculate Rate Year deferred federal and

New York State income taxes, based on the Companies' proposal to change to full normalization. Those values are added to the accumulated deferred income tax balance as of December 31, 2014 to derive average Rate Year ADIT. Finally, Schedule M summarizes the calculation of total average Rate Base attributable to plant in-service as of December 31, 2014 and post-2014 plant additions.

Q. Are the Companies proposing changes to the factors that are used to allocate common plant?

A. Yes, the Companies are proposing small modifications to the factors used to allocate plant. The Companies have calculated new allocation factors based on the ratio of the balances for Electric and Gas Test Year Plant In-service and Completed Construction Not Classified, less Production Facilities. A comparison of the current allocation factors to the proposed new allocation factors is provided in the following table:

Table 2: Electric and Gas Common Allocation Factors – Rate Year Plant

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	79.20%	0.47%	79.67%
NYSEG Gas	20.80%	-0.47%	20.33%
RG&E Electric	68.60%	0.88%	69.48%
RG&E Gas	31.40%	-0.88%	30.52%

Q. What is the impact of adopting the proposed plant allocation factors?

A. The following table demonstrates the impact of the proposed plant allocation factors on Rate Year Rate Base and book depreciation for the Electric and Gas businesses of NYSEG and RG&E:

Table 3: Electric and Gas Common Allocation Adjustments
Rate Year Plant ($ thousands)

Allocation Adjustment	Current Allocations	Adjustment	Proposed Allocations
NYSEG Electric			
Rate base	$1,606,829	$ 1,086	$ 1,607,915
Book depreciation	116,261	92	116,354
NYSEG Gas			
Rate base	$ 485,384	$ (1,086)	$ 484,298
Book depreciation	30,700	(92)	30,607
RG&E Electric			
Rate base	$1,277,045	$ 1,209	$ 1,278,254
Book depreciation	59,021	111	59,132
RG&E Gas			
Rate base	$ 405,613	$ (1,209)	$ 404,404
Book depreciation	24,465	(111)	24,354

IX. DESCRIPTION OF EXHIBIT 6 – CAPITAL STRUCTURE (RRP-6)

Q. Please describe the format of Exhibit __ (RRP-6).

A. Exhibit __ (RRP-6) includes the Capital Structure schedules for each Company as follows:

1) Schedule A: Weighted Pre-Tax Cost of Capital;
2) Schedule B: Capital Structure Supporting Rate Base and Associated Costs;
3) Schedule C: Common Equity Balance;
4) Schedule D: Cash Flows and Short-Term Debt;
5) Schedule E: Long-Term Debt Detail; and
6) Schedule F: Long-Term Debt Expense.

Q. Can the Panel describe the Schedules included in Exhibit __ (RRP-6)?

A. Exhibit __ (RRP-6) consists of Schedules A though F. Schedule A is a summary of the capital structure and costs rates forecast for the Rate Year. Schedule B is a further breakdown of the short-term and long-term debt, customer deposits and common equity components. Schedule B also contains a projected cash flow schedule in the Rate Year. Schedules C through E provide the underlying details of the common equity balances, cash flows and long-term debt component. Schedule F identifies unamortized debt discount and expense. Company Witness Bulkley provides testimony supporting the Companies' request for a 50% Equity Ratio for all businesses.

X. DESCRIPTION OF EXHIBIT 7 – WORKPAPER INDEX (RRP-7)

Q. Please describe Exhibits __ (RRP-7).

A. Exhibits __ (RRP-7) include an index of workpapers for each Company. Copies of the workpapers will be provided to Staff and parties and made available in an electronic or CD format.

XI. DESCRIPTION OF EXHIBIT 8 – CREDIT METRICS (RRP-8)

Q. Please describe Exhibit __ (RRP-8).

A. Exhibit __ (RRP-8) provides the credit metrics for the Companies using Moody's credit ratios as well as S&P's core and supplemental credit ratios.

XII. DESCRIPTION OF EXHIBIT 9 – REVENUE REQUIREMENTS PANEL CVS (RRP-9)

Q. Please describe Exhibit __ (RRP-9).

A. Exhibit __ (RRP-9) includes the CVs for each member of the Panel.

XIII. SPECIFIC RATE ADJUSTMENTS

A. Revenues

Q. What are the Companies' major normalizing and forecast adjustments on Schedule A of Exhibit __ (RRP-3) for revenues?

A. The revenue adjustments are primarily associated with the forecast Electric and Gas customer and sales usage Delivery values as set forth by the Deliveries and Revenue / Revenue Decoupling Mechanism Panels. The Companies are providing a new sales forecast, which has been used to calculate new Delivery revenues. The final approved Delivery revenues by service class will form the basis for the future revenue decoupling targets.

Q. Is the Panel proposing to adjust the level of wholesale transmission revenues included in base Delivery rates at NYSEG?

A. Yes, the Company proposes a slight decrease in the average wholesale transmission revenue level embedded in NYSEG's electric rates. In the 2010 JP, NYSEG Electric had embedded \$55.0 million of wholesale transmission revenues in rates. Any difference between actual transmission revenues and the level embedded in Delivery rates is recovered or returned through the non-bypassable wires charge ("NBC"). NYSEG proposes to update the level embedded in base rates to \$53.4 million which reflects the most recent two year average of wholesale transmission revenues. The table below illustrates the past five years of wholesale transmission revenues and the two-, three- and five-year averages. As can be seen in the table below, transmission revenues remain volatile ranging from \$22.6 million in 2012 to \$56.0 million in 2014. The primary source of transmission revenue comes from the New York Independent System Operator and is associated with Transmission Congestion Charges ("TCC").

Table 4: Wholesale Transmission Revenue – NYSEG Electric
Historical Values ($ thousands)

Year	Amount
2010	$45,325
2011	$34,028
2012	$22,642
2013	$50,844
2014	$56,009
5 yr avg	$41,770
3 yr avg	$43,165
2 yr avg	**$53,426**

Q. Is the Panel proposing any adjustment to NYSEG electric pole attachment revenues and investment?

A. Yes, the Company is currently in discussions regarding the sale of one-half interest in certain joint use poles. NYSEG Electric has reflected lower pole attachment revenue and reflected a concomitant reduction in Rate Base for an expected sale of one-half interest in certain joint use poles that is expected to be concluded before the start of the Rate Year. To the extent an agreement is reached on the sale, the Company will submit a separate petition to the Commission for approval of the sale. The Company expects the regulatory treatment of the proceeds from the sale to be determined in that separate proceeding.

B. Operations and Maintenance Expense Adjustments

1. Labor and Payroll

Q. Please describe the adjustment for Labor and Payroll.

A. The Companies' forecast of labor and payroll expense begins with the compensation associated with actual employees as of December 31, 2014 allocated to O&M expense. Adjustments to this base level are made for three different activities: merit increases; changes in staffing levels; and annual lump-sum distributions made to union employees in accordance with their labor contracts (RG&E) or anticipated contract (NYSEG). Estimates and additional information associated with these factors are supported by the Workforce, Compensation and Benefits Panel.

During 2015, the Companies are transitioning the timing of their annual non-union merit increases so that they become effective as of January 1 of each year. The most recent merit increases occurred in July 2014 and the Companies have forecasted a smaller, half-year increase of 1.75% in July 2015 to effectuate this transition. Starting in 2016, 3.50% non-union merit increases are forecast to occur each January. With respect to union compensation changes, the following table summarizes the anticipated union employees' adjustments and reflects two-thirds of the total variable increase, which is associated with factors benefiting customers.

Table 5: Labor and Payroll

Date	Fixed Portion of Increase	+	Variable Portion of Increase	=	Total Increase
NYSEG					
July 2015	3.00%		n/a		3.00%
July 2016	2.75%		0.17%		2.92%
RG&E					
June 2015	2.75%		0.17%		2.92%
June 2016	2.50%		0.33%		2.83%

The Companies are very cognizant of the need to appropriately manage their workforce and are forecasting a decrease in the labor force between the Test Year and the Rate Year at NYSEG and an increase at RG&E. As of December 31, 2014, NYSEG had 1,926 employees and RG&E had 848 employees. In the Rate Year, NYSEG is forecasting an average of 1,891 employees, a reduction of 35 employees or 1.8%. RG&E is forecasting an average Rate Year employee level of 877, an increase of 29 employees. Embedded in the forecast average Rate Year level of employees is the inclusion of Iberdrola Energy Projects ("IEP") employees into NYSEG (15) and RG&E (31), which began at the end of 2014. Forecasted changes in the number of employees within functional groups are multiplied by the average salaries for those groups to determine the labor savings. The projected staffing increase and associated costs at each Company are summarized in the table below.

Table 6: Actual and Projected Staffing Levels
Full-Time Equivalent Positions ($ thousands)

Company	Actual Staffing at 12/31/14	Average Rate Year Staffing	Staffing Change from 12/31/14 to Avg. Rate Year	Total Value of Change in Staffing	O&M Value of Change in Staffing
NYSEG Electric	1,474.7	1,425.0	(49.8)	$ (3,889)	$ (2,812)
NYSEG Gas	451.3	466.2	14.9	1,491	1,078
TOTAL NYSEG	**1,926.0**	**1,891.1**	**(34.9)**	**$ (2,398)**	**$ (1,734)**
RG&E Electric	531.6	539.4	7.7	$ 724	$ 516
RG&E Gas	316.4	337.9	21.5	1,858	1,325
TOTAL RG&E	**848.0**	**877.3**	**29.3**	**$ 2,582**	**$ 1,841**
TOTAL	**2,774.0**	**2,768.4**	**(5.6)**	**$ 184**	**$ 107**

2. Other Post-Employment Benefits ("OPEBs") and Pensions

Q. How were the OPEB and Pension adjustments developed?

A. The Companies' forecast of Pension and OPEB expenses are based on the average of five-year annual forecast cost estimates prepared by the Companies' actuary, AON Hewitt. The total annual cost estimates are pro-rated to a Rate Year view, and the total costs are reduced by the anticipated allocations to capital and to affiliates to arrive at the O&M amounts of Pension costs and OPEB costs attributable to NYSEG and to RG&E. These calculations are provided in the workpapers. The adjustments from the historic Test Year to the Rate Year are provided in the following table:

Table 7: Pension and OPEB Expense
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
Pension Expense			
NYSEG Electric	$ 23,000	$ 10,300	$ 33,300
RG&E Electric	7,400	200	7,600
NYSEG Gas	6,100	2,400	8,500
RG&E Gas	4,600	200	4,800
Total Cost	**$ 41,100**	**$ 13,100**	**$ 54,200**
OPEB Expense			
NYSEG Electric	$ (600)	$ 2,000	$ 1,400
RG&E Electric	1,000	700	1,700
NYSEG Gas	(200)	500	300
RG&E Gas	600	500	1,100
Total Cost	**$ 800**	**$ 3,700**	**$ 4,500**

As noted above, the forecast Pension and OPEB expenses are based on the actuarial calculations done by the Companies' actuaries, AON Hewitt, which are provided as part of the testimony, exhibits and workpapers of the Workforce, Compensation and Benefits Panel. The Workforce, Compensation and Benefits Panel also describes the efforts undertaken by the Companies to manage Pension and OPEB expenses, including the elimination of defined benefit plans to new employees.

The Companies are proposing to reset the Pension and OPEB targets based on the proposed average and to continue reconciliation of actual costs consistent with the Statement of Policy Concerning the Accounting and

Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions ("Pension Policy Statement") adopted in Case 91-M-0890.

3. Variable Compensation

Q. Please describe the adjustment for Variable Compensation.

A. The forecast of Variable Compensation proposed to be included in revenue requirements is based on a historical three-year average of Group and Executive Incentive actual costs. Those costs were increased to reflect the percentage growth in payroll expense and then reduced to reflect the level associated with customer benefits. This level associated with customer benefits is discussed in the testimony of the Workforce, Compensation and Benefits Panel. Variable Compensation adjustments for NYSEG and RG&E employees from the historic Test Year to the Rate Year are provided in the following table. Variable Compensation for Iberdrola USA Management Corporation ("IUMC") employees has been calculated on the same basis, using the level associated with customer benefits, and is included as part of the IUMC costs allocated to NYSEG and RG&E, which is covered later in this Panel's testimony.

Table 8: Variable Compensation for NYSEG and RG&E Employees
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 2,056	$ (673)	$ 1,383
RG&E Electric	1,871	(724)	1,147
NYSEG Gas	490	(144)	346
RG&E Gas	1,101	(404)	697
Total Costs	**$ 5,518**	**$ (1,945)**	**$ 3,573**

4. 401(k)

Q. Please describe the adjustment for 401(k) costs.

A. The Companies' forecast of 401(k) costs is based on the estimates prepared by the Companies' actuary, AON Hewitt. Adjustments for 401(k) costs from the historic Test Year to the Rate Year are provided in the following table:

Table 9: 401(k) Expense
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 1,744	$ 261	$ 2,005
RG&E Electric	1,095	120	1,215
NYSEG Gas	580	87	667
RG&E Gas	718	78	796
Total Cost	**$ 4,137**	**$ 546**	**$ 4,683**

These adjustments and the associated actuarial information are addressed further in the testimony of the Workforce, Compensation and Benefits Panel.

5. Uncollectibles

Q. How have the Companies reflected Delivery Uncollectible expenses in the Rate Year?

A. The adjustments on Schedule A for Uncollectibles are based on a net write-off percentage using a historical three-year average, which is then applied to proposed Delivery revenues. As discussed in the Customer Services, Energy Efficiency, and Retail Access Panel's testimony, despite continuing efforts to control the level of Uncollectible write-offs, the Uncollectible expense has increased, with 2014 being a peak year. While the Companies are not proposing to use only the Test Year experience in forecasting the Uncollectible expense for the Rate Year, we are proposing to appropriately account for the volatility in this cost area by proposing a symmetrical true-up of Delivery Uncollectible expense. If the Companies were to use only the Uncollectible percentage from the Test Year in forecasting Uncollectible expense, the annual amount of Uncollectible expense being requested would be higher by a cumulative total of $2.9 million across the four businesses. The proposed Uncollectible percentages as compared to the historic Test Year are decreases for all Companies, as presented in the table below.

Table 10: Uncollectibles Percentages

Company	Historical Test Year	Rate Year Ended 3/31/17
NYSEG Electric	1.15%	1.01%
RG&E Electric	1.71%	1.45%
NYSEG Gas	1.34%	1.24%
RG&E Gas	2.27%	1.93%

6. Insurance

Q. Please describe the adjustment for Insurance costs.

A. The Insurance adjustments on Schedule A for general liability are based on specific historic Test Year invoice amounts, adjusted for an Energy Insurance Mutual Policy Holder Distribution and a calculated increase Rate Based on the combined Companies' historical three-year average increase rate of 10.44%. The use of a combined percentage is proposed since the Companies general liability insurance is underwritten on a consolidated basis in New York. We have also included a forecast for Cyber Liability insurance for all Companies totaling $191,000 based on a recent premium for the term beginning in 2015. Workers' compensation costs are primarily driven by annual cost of living adjustments ("COLA") and medical cost increases and are based on an actuarial forecast with growth rates of 5% for NYSEG and 3% for RG&E applied to historical Test Year amounts. Other insurance adjustments including property, automobile, and fiduciary have been estimated using a general inflation factor applied to historic Test Year amounts. In addition, an adjustment has been made at RG&E Electric to remove the Nuclear Electric Insurance Limits ("NEIL") distribution received during the Test Year due to the uncertainty of the timing and receipt of any refund or amount. To the extent that any NEIL refunds are received, the Companies will set those funds aside as a regulatory liability for the future benefit of customers. The adjustments from the historic Test Year to the Rate Year as provided in the following tables:

Table 11: Insurance – NYSEG Electric
Rate Year Costs ($ thousands)

Insurance	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
General Liability	$ 1,629	1,014	$ 2,643
Cyber	95	7	101
All Other Insurance[1]	1,093	121	1,214
Worker's Compensation	1,490	801	2,291
Injury / Damages[1]	649	(383)	267
NYSEG Electric	**$ 4,956**	**$ 1,560**	**$ 6,516**

Table 12: Insurance – RG&E Electric
Rate Year Costs ($ thousands)

Insurance	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
General Liability	$ 744	$ 459	$ 1,203
Cyber	37	8	44
All Other Insurance[1 2]	(1,003)	1,623	621
Worker's Compensation	893	522	1,415
Injury / Damages[1]	644	28	672
RG&E Electric	**$ 1,316**	**$ 2,639**	**$ 3,955**

Table 13: Insurance – NYSEG Gas
Rate Year Costs ($ thousands)

Insurance	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
General Liability	$ 236	$ 156	$ 391
Cyber	14	11	25
All Other Insurance[1]	167	273	440
Worker's Compensation	402	55	457
Injury / Damages[1]	(324)	396	72
NYSEG Gas	**$ 495**	**$ 890**	**$ 1,384**

Table 14: Insurance – RG&E Gas
Rate Year Costs ($ thousands)

Insurance	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
General Liability	$ 378	$ 231	$ 609
Cyber	19	3	21
All Other Insurance[1]	238	42	280
Worker's Compensation	561	280	841
Injury / Damages[1]	165	5	170
RG&E Gas	**$ 1,361**	**$ 560**	**$ 1,921**

Table 15: Insurance – Total
Rate Year Costs ($ thousands)

Insurance	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 4,956	1,560	$ 6,516
RG&E Electric	1,316	2,639	3,955
NYSEG Gas	495	890	1,384
RG&E Gas	1,361	560	1,921
Total	**$ 8,128**	**$ 5,649**	**$ 13,777**

[1] Adjustments for All Other Insurance and Injury/Damages include reallocation of costs between Electric and Gas businesses based on proposed allocation percentages.

[2] Adjustment includes removal of NEIL distribution from historic test year of $1,107.

7. IUMC Costs

Q. How were the IUMC Costs adjustments developed and what costs are included?

A. The IUMC costs include costs directly assigned to NYSEG or RG&E by IUMC or allocated (based on the Massachusetts formula) from IUMC to NYSEG or RG&E for shared services such as Accounting, Finance and Tax, Accounts Payable, Supply Chain, Human Resources, Information Technology, Governance and Security. The types of costs incurred by IUMC include labor, external services and other internal company costs, as reflected on Schedule A and the IUMC Cost workpapers.

The IUMC transaction costs were reviewed extensively in the 2011 management audit, which found that the Companies' financial system and processes provide adequate capability to trace financial transactions, identify the sources of charges, and document cost assignments and allocations. The management audit contained five recommendations regarding service company transactions (Chapter III of the management audit report) and, as noted by the Management Audit Panel's testimony in this case, all those recommendations have been completed by the Companies and Staff has confirmed their completion.

The adjustments on Schedule A primarily represent amounts based on either a general inflator or payroll inflator of historical Test Year costs. Also reflected in Schedule A is the use of revised Electric / Gas allocation factors described later in this testimony.

8. Legal / Regulatory

Q. Is the Panel proposing any adjustment to Legal and Regulatory costs?

A. Yes, the Legal / Regulatory adjustments on Schedule A reflect outside Legal and Regulatory costs based on historical Test Year data with normalizing adjustments to reflect additional costs associated with the preparation and processing of these rate cases. For the Rate Year, the total Legal and Regulatory costs for all Companies, excluding rate case costs, are $2.2 million. These costs are a significant decrease over the historical Test Year, primarily due to Legal costs incurred in 2014 at RG&E Electric for several cases, including the Ginna proceeding and related litigation – cases that the Companies have not included in the forecast for the Rate Year. The Companies propose to recover the incremental costs associated with the rate cases, totaling $7.2 million, over two years, at $3.6 million per year. The Rate Year total for all Legal and Regulatory costs is therefore $5.8 million. Further detail is provided in the supporting workpaper and summarized in the table below.

Table 16: Legal/Regulatory
Rate Year Costs ($ thousands)

Expense	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric:			
Rate Case	$ 567	$ 1,048	$ 1,615
Non-Rate Case	1,995	(823)	1,172
Total	**$ 2,562**	**$ 225**	**$ 2,787**
RG&E Electric:			
Rate Case	$ 264	$ 832	$ 1,096
Non-Rate Case	1,601	(1,206)	395
Total	**$ 1,865**	**$ (374)**	**$ 1,491**
NYSEG Gas:			
Rate Case	$ 21	$ 356	$ 377
Non-Rate Case	687	(113)	574
Total	**$ 708**	**$ 243**	**$ 951**
RG&E Gas:			
Rate Case	$ 27	$ 502	$ 529
Non-Rate Case	340	(318)	22
Total	**$ 367**	**$ 184**	**$ 551**
Grand Total Cost	**$ 5,502**	**$ 278**	**$ 5,780**
Rate Case	879	2,738	3,617
Non-Rate Case	4,623	(2,460)	2,163

9. Storms

Q. Are the Companies proposing to continue to utilize reserve accounting for Major Storm costs?

A. Yes, the Companies propose to continue to utilize reserve accounting with symmetrical deferral treatment for major storms. However, the Companies are also proposing a Rate Adjustment Mechanism (positive or negative) if the storm reserve balance exceeds certain thresholds as measured on March 31 of each applicable year. The proposed thresholds are $20 million at NYSEG Electric and $10 million at RG&E Electric. The Companies' proposed Rate Adjustment Mechanism is explained in further detail later in this testimony.

Q. What is the Companies' proposal for Major Storm reserve costs?

A. NYSEG is proposing to keep the NYSEG Electric major storm reserve amount at the $12 million annual amount currently included in revenue requirements, despite significant evidence supporting a major increase to the reserve. RG&E is proposing a small decrease in the RG&E Electric Major Storm reserve amount to $2.52 million.

Q. What is the Companies' proposal for minor storm costs?

A. With respect to minor storm costs, NYSEG Electric is proposing a small reduction from current levels included in rates to $4.0 million per year and RG&E Electric is proposing to initiate a specific collection of $2.1 million per year.

Q. Do the Companies have any proposal related to the effect of storms on their gas systems?

A. Yes. In addition to the Electric storm amounts proposed by the Companies, both NYSEG and RG&E are proposing to include in rates a Gas Storm reserve which would be used to cover any costs associated with major storm restoration work associated with Company gas facilities.

Q. What does the five-year history support with respect to NYSEG Electric and RG&E Electric major storm costs?

A. As shown on Schedule A for NYSEG Electric, there are several potential approaches to calculating proposed major storm reserve allowances to be included in revenue requirements for NYSEG Electric. If the Company were to simply use a historical five-year average of major storm costs, the Company would have proposed a storm reserve amount of nearly $50 million per year. Even if NYSEG were to remove from the five-year average calculation the storm costs associated with Hurricane Irene, Tropical Storm Lee, and Superstorm Sandy, the Company would be proposing nearly $25 million per year in its storm reserve. Because of the pressure that such increases would place on customers' rates, NYSEG has opted to keep its major storm reserve amount at $12 million and implement a Rate Adjustment Mechanism. If the Commission does not approve the Rate Adjustment Mechanism, then the Companies request that the storm reserve allowance for NYSEG be increased to $25 million.

For RG&E Electric, the five-year historical average without any exclusions was about $2.59 million per year, which is approximately the same as what is currently included in revenue requirements. The major storms that impacted NYSEG Electric did not have as significant an impact on RG&E, so a small decrease in the amount requested for the major storm reserve at RG&E is appropriate.

Q. Please describe the Companies' proposal with respect to storm reserve amounts for the Gas businesses.

A. The Companies propose reserve accounting for restoration of Gas facilities due to major storms, with levels to be set in rates for NYSEG Gas at $1.5 million and RG&E Gas at $0.5 million. The Companies have never had a Gas Storm reserve before, but there was a major impact (over $8 million) in the Gas business at NYSEG as a result of Tropical Storm Lee in 2011. This reserve accounting would accommodate a repeat of this type of event. As with the electric storm reserve, there would be full symmetrical deferral around the annual Gas Storm reserve amounts.

Q. What are the Companies proposing for minor storm costs?

A. The Companies are not proposing reserve accounting for minor storm costs. The Companies are proposing a consistent presentation approach for NYSEG and RG&E, whereby minor storm costs are shown as a separate line item in the O&M schedules of costs, and the O&M presentation will remove the incremental costs associated with minor storms from the corresponding line items (e.g., overtime labor, outside services, and materials). Schedule B for each Company shows the calculation of a three year average of incremental costs associated with minor storms. The three-year average minor storm costs at NYSEG Electric and

RG&E Electric, net of pre-staging costs being proposed to be collected from the major storm reserve, are about $4.0 million and $2.1 million, respectively.

Q. Are the Companies addressing Storm Preparedness?

A. Yes, a detailed discussion is included the Emergency Preparedness / Storm Panel. As part of that testimony, the Companies are proposing to recover from the major storm reserve certain pre-staging costs associated with anticipated major storms that do not materialize.

Q. Are there any other proposals associated with major storm accounting that the Companies want to mention?

A. Yes. The Companies have reviewed the current Rate Plan language associated with major storm accounting, particularly Appendix G, paragraph 24 of the 2010 JP, and have the following proposals:

1) The Companies support the continued definition of major storms indicated in section 24.a.i, including the concept that "a major storm is not limited by operating district." The Companies propose the following clarifying language on this last point: "the incremental storm costs associated with a particular major storm are those incremental costs incurred in all affected operating districts, which must accumulate to the $300,000 threshold in order to qualify for reserve accounting;"

2) The Companies propose to add "Stores Loader" to the list as non-incremental; and

3) The Companies would propose that paragraph 24.e is no longer relevant in the definition of major storms, as it dealt strictly with a transition period covering 2009 and 2010.

10. Emergency Preparedness

Q. Have the Companies made adjustments related to Emergency Preparedness?

A. Yes, the Companies have made Emergency Preparedness adjustments on Schedule A, which represent amounts for continued development of emergency preparedness functions, technology and facility improvements, a storm prediction model and incremental weather services in the amount of $1.2 million for NYSEG Electric and $0.8 million for RG&E Electric. These costs are testified to separately in the testimony of the Emergency Preparedness / Storm Panel.

11. Incremental Maintenance

Q. Please describe the Incremental Maintenance costs currently in revenue requirements based on the Companies' current Rate Plan.

A. In Appendix M of the 2010 JP, certain O&M expenses associated with a number of new initiatives were identified as Incremental Maintenance and were incorporated into rates. The Companies' actual spending for these Incremental Maintenance activities has been reported each year to the PSC as part of the Companies' ACF and is subject to a one-way, downward-only reconciliation. The table below provides the level of Incremental Maintenance costs currently included in revenue requirements, and the level of actual spending during the historic Test Year.

Table 17: Incremental Maintenance Costs
Historic Test Year Costs ($ thousands)

Company	Annual Amount Built into Existing Tariffs	Actual Historic Test Year Expenditures
NYSEG Electric	$ 4,895	$ 4,930
RG&E Electric	2,279	2,398
NYSEG Gas	577	810
RG&E Gas	1,060	1,007
Total Cost	**$ 8,811**	**$ 9,145**

Q. How do the Companies propose to reflect any costs associated with the specific Incremental Maintenance activities started during the term of the current Rate Plan that will continue to be performed?

A. Many of the projects and programs that were new to the Companies during the previous rate case are now considered normal practices to adequately serve customers. Therefore, Companies no longer consider these activities as Incremental Maintenance in this rate case filing. The Companies have reflected these continuing costs in the Outside Services cost category, as described later in this testimony.

Q. Please describe the new Incremental Maintenance costs proposed by the Companies in this filing.

A. Similar to its last rate filing, the Companies have identified several new Incremental Maintenance programs and activities that they propose to undertake and recover in rates. The tables below provide an overview of these costs for the Companies' electric and gas businesses, respectively.

Table 18: Electric Incremental Maintenance Programs
Rate Year Costs ($ thousands)

Program	NYSEG Electric	RG&E Electric
Steel Transmission Pole Inspection & Maintenance	$ 441	$ 118
Aluminum Base Insulator Replacement	1,000	-
Wood Pole Inspection & Treatment to 10-Year Cycle	1,050	-
All Other (additional details provided in workpapers)	1,044	138
Total Cost	**$3,535**	**$ 256**

Table 19: Gas Incremental Maintenance Programs
Rate Year Costs ($ thousands)

Program	NYSEG Gas	RG&E Gas
Damage Prevention (Enhanced Damage Prevention - Vehicle)	$ 948	$ 948
Public Awareness (Fire Department Outreach)	200	200
Distribution Integrity Management (Data Automation)	200	200
All Other (additional details provided in workpapers)	374	380
Total Cost	**$1,722**	**$1,728**

Additional information regarding these programs is provided in the testimonies of the Electric Reliability and Operations Panel and Gas Engineering, Delivery and Operations Panel. The Companies propose to treat these new incremental expenses in similar fashion as the prior incremental maintenance programs adopted in the previous Rate Plan. Specifically, the Companies propose that the costs be subject to a downward-only reconciliation whereby if the Companies do not expend the requested expenses any shortfall will be deferred for the benefit of customers.

12. Vegetation Management

Q. How have you adjusted costs for Electric Distribution Vegetation Management?

A. For NYSEG, the Distribution Vegetation Management adjustments on Schedule A represent the incremental costs associated with implementing a five-year vegetation management full-cycle trim program at NYSEG on a phased-in basis. NYSEG has already started implementing a full-cycle trim on a limited basis in two divisions (Brewster and Liberty), consistent with the Commission's October 1, 2013 Order Denying Petition and Establishing Further Proceedings in Case 13-E-0117. NYSEG incurred incremental costs not currently included in revenue requirements in 2013 and 2014 to start the full-cycle efforts and will incur incremental costs in 2015 as well. The costs for the Rate Year reflect a ramping up of activities and costs, with the full annual cost for moving NYSEG to a full-cycle trim being incurred after the Rate Year. RG&E Electric distribution is already on a five-year cycle trim and will continue that practice. The RG&E Electric costs for the Rate Year reflect the most current competitively bid contract prices for line clearing. The Rate Year amounts and associated adjustments are testified to by the Vegetation Management Panel and are reflected in the table below.

Table 20: Vegetation Management – Distribution
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric Distribution	$ 24,259	$ 15,689	$ 39,948
RG&E Electric Distribution	6,563	1,174	7,737
Total Costs	$ 30,822	$ 16,863	$ 47,685

Q. Are the Companies requesting reconciliation of Distribution Vegetation Management costs?

A. Yes, NYSEG Electric and RG&E Electric request full reconciliation of Distribution Vegetation Management costs. In the 2010 JP, distribution vegetation management expenses were subject to a downward only reconciliation mechanism. In this case, the Companies have retained Environmental Consultants, Inc. ("ECI") to assist with providing costs estimates to determine the forecast Distribution Vegetation Management reclamation plan expenses. However, actual amounts are likely to differ from the forecast because the Companies intend to request competitive bidding for the proposed contractor vegetation management work. In order to protect customers and equitably treat the Companies for these costs, the Companies propose to fully reconcile the actual costs with the amount provided in rates.

Q. How have the Companies adjusted costs for Transmission Vegetation Management?

A. The Transmission Vegetation Management Rate Year costs and adjustments on Schedule A represent the costs needed to continue the current Transmission Vegetation Management programs at both NYSEG and RG&E and to incorporate compliance with all current standards and requirements. The adjustments are addressed in the testimony of the Vegetation Management Panel. The impact of these adjustments is detailed in the table below.

Table 21: Vegetation Management – Transmission
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric Transmission	$ 4,835	$ 1,665	$ 6,500
RG&E Electric Transmission	965	305	1,270
Total Costs	$ 5,800	$ 1,970	$ 7,770

13. Site Investigation and Remediation

Q. Please provide a summary of the NYSEG's Site Investigation and Remediation ("SIR") program.

A. NYSEG entered into an Order on Consent with New York State Department of Environmental Conservation ("NYSDEC") in March 1994 ("Consent Order") to investigate and, where necessary, remediate 33 manufactured gas plant ("MGP") sites. Four MGP sites were subsequently added to the Consent Order or covered by separate agreements with the NYSDEC and two more MGP sites are planned to be added in 2015. NYSEG has a comprehensive program utilizing knowledgeable Company staff and contractors to meet the obligations of the Consent Order with the review and approval of the NYSDEC.

NYSEG has also been identified as a Potentially Responsible Party ("PRP") at thirteen State and Federal Superfund sites as a result of off-site disposal of waste or property ownership. NYSEG has participated in PRP groups to limit the overall cost and the specific share of those costs allocated to NYSEG for these Superfund sites.

Lastly, the NYSEG SIR program includes the investigation and remediation of eight company owned non-MGP sites with "legacy" environmental impacts that required action to meet NYSDEC requirements.

Q. Please describe RG&E's SIR program.

A. RG&E entered into a Voluntary Cleanup Agreement ("VCA") with the NYSDEC in April 2003 to investigate and, where necessary, remediate seven MGP sites. The VCA was amended in December 2014 to include two additional sites in Geneseo, New York. Two other MGP sites are covered by separate agreements with the NYSDEC. RG&E has a comprehensive program utilizing Company staff and contractors to meet the obligations of the VCA under the review and approval of the NYSDEC.

RG&E has also been identified as a PRP at nine State and Federal Superfund sites as a result of off-site disposal of waste or property ownership. RG&E has participated in PRP groups to limit the overall cost and the specific share of those costs allocated to RG&E for these Superfund sites.

The RG&E SIR program has also included investigation and remediation of nine other Company-owned non-MGP sites with "legacy" environmental impacts that required action to meet NYSDEC requirements.

Q. Have the Companies recently filed a comprehensive report on their SIR activities under Case 11-M-0034?

A. Yes. The Companies submitted a filing on April 30, 2015 which provides a significant amount of detail on the Companies' SIR programs, including a review of the timetables for each project and the Companies' cost control efforts consistent with the best practices inventory developed as part of the proceeding. A copy of this filing is included as workpaper RRP-2-WP-30 to this testimony.

Q. What steps have the Companies taken to control SIR costs and liabilities?

A. The Companies follow the management/mitigation practices set forth in the Inventory of Best Practices for Utility SIR Programs adopted by the State's electric and gas utilities pursuant to the Commission's November 28, 2012 Order Concerning Costs for Site Investigation and Remediation in Case 11-M-0034 ("SIR Order"). Additionally, the Companies have proactively sought contributions toward SIR costs from parties who share the Companies' responsibility for environmental clean-up costs at different sites.

Q. Have the Companies been successful in obtaining contribution from other parties for SIR costs?

A. Yes. The Companies have received substantial damage awards in separate lawsuits brought against FirstEnergy Corporation ("FirstEnergy") seeking contribution for environmental clean-up costs. In both cases, the United States District Court found, in decisions affirmed by the United States Court of Appeals for the Second Circuit, that FirstEnergy was liable for a portion of the clean-up costs at several of the Companies' MGP Sites based on FirstEnergy's status as a corporate successor to Associated Gas & Electric Company, which at one time in the past dominated the operation of the Companies.

Q. What portion of clean-up costs at the Companies' MGP sites is FirstEnergy required to contribute?

A. Pursuant to the judgments entered in favor of NYSEG and RG&E by the District Courts, FirstEnergy must contribute to clean up costs at nine NYSEG and two RG&E MGP sites, according to the percentages shown in the table below.

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Table 22: FirstEnergy Percentage Liability at SIR Sites

Site	Percentage
NYSEG	
Corning	15.0%
Cortland-Homer	44.8%
Goshen	23.5%
Granville	30.4%
Ithaca Court Street	30.4%
Ithaca First Street	100.0%
Mechanicville	24.8%
Oneonta	39.4%
Plattsburgh	19.4%
RG&E	
East Station	8.0%
West Station	8.0%

Q. To date, have the Companies recovered any costs from FirstEnergy pursuant to these judgments?

A. Yes. FirstEnergy has paid NYSEG $24.0 million in environmental clean-up costs to date, including interest. At RG&E, FirstEnergy has paid $0.38 million including interest in environmental clean-up costs. These payments from First Energy have been accounted for in the environmental reserve as a reduction to the regulatory liability on the Companies' books, reducing the future amounts that customers would otherwise have had to pay towards SIR.

Q. Do the Companies have any internal processes that review SIR procedures? If so, please describe how such controls affect SIR projects.

A. The Companies follow a Quality Management System ("QMS") approach to all key projects, including projects to remediate MGP Sites. The QMS approach is described in detail by the Gas Engineering, Delivery and Operations Panel, and involves milestones and stage gates that are quality checked at various points of a project timetable.

Q. Are the Companies in compliance with the Commission's SIR Order?

A. Yes, the Companies SIR processes are in compliance with existing timetables and NYSDEC requirements, are in compliance with the best practices inventory and subject to regular cost reviews, and are managed and controlled using the QMS approach.

Q. Please describe the adjustment for SIR (Environmental Remediation) costs.

A. The Environmental Remediation adjustments are shown on Schedule A and reflect the latest information available and the impacts of the requirements of the SIR Order.

Q. Do the Companies propose to reconcile these adjustments?

A. Yes. The Companies propose that these costs continue to be subject to reserve accounting and get reconciled annually. The Companies have used the prospective five year projection of annual SIR costs, and have levelized that total projected amount over five years. For the Rate Year, this five-year levelized amount is less than what is projected to be spent just during the Rate Year. The Companies propose annual amounts be reflected in the environmental reserve as follows: $10.1 million at NYSEG Electric; $8.0 million at RG&E Electric; $2.8 million at NYSEG Gas; and $4.1 million at RG&E Gas. The Companies have also tried to minimize the impact on Rate Year revenue requirements by proposing to utilize the existing environmental reserve balances (representing primarily amounts deferred on behalf of customers over the last several years) to reduce the amount being requested to be added to the reserve prospectively. The annual reserve amounts being requested are shown in the table below.

Table 23: Environmental Expense
Rate Year Costs ($ thousands)

Company	Current Rate Allowance	Adjustment	Proposed New 5 Year Average
NYSEG Electric	$ 18,087	$ (8,007)	$ 10,080
RG&E Electric	7,394	636	8,030
NYSEG Gas	4,411	(1,629)	2,782
RG&E Gas	3,717	397	4,114
Total Costs	**$ 33,609**	**$ (8,603)**	**$ 25,006**

14. Economic Development

Q. What does the adjustment for Economic Development represent?

A. The Economic Development adjustment on Schedule A reflect projected electric and gas assistance based on historical experience and future projections. These include assumptions that the business climate and economy in New York State will continue to strengthen and that the Companies will have a more robust natural gas program with higher annual spending targets. The Companies have attempted to moderate the impacts of anticipated Economic Development spending through the utilization of previously-deferred Economic Development underspent amounts. As shown on Schedule A for each Company, all four businesses have a regulatory liability amount deferred on behalf of customers through the end of the Test Year. NYSEG Electric is proposing to utilize a portion of its deferred amount to fund a portion of the Energy Smart Community Project ("ESC"), testified to in detail by the Reforming the Energy Vision Panel. The Economic Development programs proposed by the Companies are fully explained in the testimony of the Revenue Allocation, Rate Design, Economic Development, and Tariff Panel.

Additionally, all four businesses are proposing to utilize the remaining previously deferred amounts over a five year period to offset the amounts that would otherwise be requested to be included in revenue requirements for future years. Without any utilization of the previously deferred amounts, spending on Economic Development programs, including the ESC, during the Rate Year would total $12.6 million. The Companies proposal to moderate Economic Development expense in the Rate Year through the utilization of a portion of the available reserve balance results in a net O&M cost included in Rate Year revenue requirements of $2.4 million for NYSEG Electric, $0.8 million for RG&E Electric, $0.3 million for NYSEG Gas and $0.2 million for RG&E Gas. The adjustments are provided in detail in Schedule A and are summarized in the table below.

Table 24: Economic Development
Rate Year Costs ($ thousands)

Program Type	Historical Test Year	Adjustment	Rate Year Ended 3/31/17	Rate Year Revenue Requirement: O&M / Rate Discounts
NYSEG Electric:				
Rate Discounts	$ 33	$ (21)	$ 12	$ 12
Non-Rate O&M	6,238	(3,850)	2,388	2,388
Regulatory Deferral	(234)	234	-	-
Reserve Utilization	-	4,662	4,662	-
Total - NYSEG Elec	**$ 6,037**	**$ 1,025**	**$ 7,062**	**$ 2,400**
RG&E Electric:				
Rate Discounts	$ 563	$ (381)	$ 182	$ 182
Non-Rate O&M	2,474	(1,806)	668	668
Regulatory Deferral	1,727	(1,727)	-	-
Reserve Utilization	-	3,582	3,582	-
Total - RG&E Elec	**$ 4,763**	**$ (331)**	**$ 4,432**	**$ 850**
NYSEG Gas:				
Rate Discounts	$ 228	$ (171)	$ 57	$ 57
Non-Rate O&M	25	193	218	218
Regulatory Deferral	572	(572)	-	-
Reserve Utilization	-	382	382	-
Total - NYSEG Gas	**$ 825**	**$ (168)**	**$ 657**	**$ 275**
RG&E Gas:				
Rate Discounts	$ 23	$ (3)	$ 20	$ 20
Non-Rate O&M	-	190	190	190
Regulatory Deferral	190	(190)	-	-
Reserve Utilization	-	210	210	-
Total - RG&E Gas	**$ 213**	**$ 207**	**$ 420**	**$ 210**
Grand Total	**$ 11,838**	**$ 733**	**$ 12,571**	**$ 3,735**

15. Communication Outreach – Gas Odors

Q. What adjustments have been made for Communication Outreach – Gas Odors?

A. The adjustments on Schedule A reflect projected outreach and education costs associated with a more robust natural gas safety program, including radio advertising campaigns, educational services and contractor services for program coordination. The Companies recognize the importance of this outreach and have incorporated expenditures totaling $570,000 for NYSEG Gas and RG&E Gas. These costs are testified to separately in the testimony of the Gas Engineering, Delivery and Operations Panel.

16. Low Income Programs

Q. What adjustments have been made for the Low Income Programs?

A. The adjustments on Schedule A for the Low Income Programs are intended to capture the forecasted costs of continuing to provide assistance to eligible customers that meet established guidelines. The Companies recognize the importance of assisting low income customers and support the continuation of these types of programs. These costs, totaling $27.7 million, represent an increase of $8.5 million over past Low Income Programs' funding. Of this increase, $4.0 million relates to a proposed new program for budget balance forgiveness. The adjustments are testified to separately in the Customer Services, Energy Efficiency, and Retail Access Panel, provided in detail in the supporting workpapers, and are summarized in the table below.

Table 25: Low Income
Rate Year Costs ($ thousands)

Company	Amount in Rates	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 9,369	$ 1,705	$ 11,074
RG&E Electric	4,183	903	5,086
NYSEG Gas	2,961	4,913	7,874
RG&E Gas	2,724	985	3,709
Total Costs	**$ 19,237**	**$ 8,506**	**$ 27,743**

Q. Do the adjustments reflect any impacts related to Case 14-M-0565?

A. The revenue requirement adjustments do not reflect any impacts related to this on-going proceeding. Therefore, the Companies request that any such impacts be either part of a rate case filing update or be deferred for future resolution.

17. Customer Service Enhancements

Q. What adjustments have been made for the Customer Service Enhancements?

A. The adjustments on Schedule A for the Customer Service Enhancements are intended to capture the forecasted costs of new initiatives such as bill and outage alerts, educational Energy Summits, emergency preparedness and natural gas safety programs totaling $3.3 million for all Companies. The Companies also propose a trip charge and collection in revenues of costs associated with credit card payments. These new initiatives reflect the Companies' proposal to enhance customer service and are discussed in the testimony of the Customer Services, Energy Efficiency, and Retail Access Panel, the supporting workpapers and in the table below.

Table 26: Customer Service Enhancements
Rate Year Costs ($ thousands)

Company/Project	Rate Year Ended 3/31/17
NYSEG Electric:	
Common Projects	$ 597
Electric Only Projects	73
Total - NYSEG Elec	**$ 670**
RG&E Electric:	
Common Projects	$ 265
Electric Only Projects	25
Total - RG&E Elec	**$ 290**
NYSEG Gas:	
Common Projects	$ 177
Gas Only Projects	1,120
Total - NYSEG Gas	**$ 1,297**
RG&E Gas:	
Common Projects	$ 218
Gas Only Projects	820
Total - RG&E Gas	**$ 1,038**
Total Cost	**$ 3,295**

18. Security Costs

Q. What are the Companies proposing for Security Costs?

A. The Companies recognize the importance of security and have made adjustments on Schedule A that result in Rate Year amounts totaling $3.9 million for Physical and $2.6 million for Cyber Security Costs. These amounts are testified to separately in the testimony of the Electric Reliability and Operations Panel. The impact of these adjustments by Company and business is provided in detail in the supporting workpapers and summarized in the table below.

Table 27: Security Costs
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
Physical:			
NYSEG Electric	$ 737	$ 765	$ 1,502
RG&E Electric	1,000	462	1,462
NYSEG Gas	109	153	262
RG&E Gas	493	191	684
Cyber:			
NYSEG Electric	$ 1,138	$ 337	$ 1,475
RG&E Electric	461	147	608
NYSEG Gas	168	78	246
RG&E Gas	227	73	300
Total Cost	**$ 4,333**	**$ 2,206**	**$ 6,539**

19. Stray Voltage

Q. Please describe the adjustments that were made for Stray Voltage costs.

A. The adjustments on Schedule A for Stray Voltage result in total Rate Year costs for all Companies of $3 million for the inspection and testing requirements of Case 04-M-0159. The costs are higher than the historical Test Year by $0.7 million, primarily due to aggressive inspection efforts in the years prior to 2014 that left a relatively smaller amount of testing to be done during the historic Test Year to meet the cumulative five year requirements.

Q. How are the Companies supporting the costs projected for the Rate Year?

A. The Companies based the Rate Year costs on estimated costs of $2.9 million in 2015. The estimate for 2015 costs is based on actual contract terms with vendors providing testing and inspection services.

20. Management and Operations Audits

Q. Please discuss how the Companies developed the adjustment for Management and Operations Audits.

A. The Rate Year costs on Schedule A for Management and Operation Audits reflect known information regarding costs from the most recent Management and Operations Audits and estimated costs for future audits based on a general inflation factor. These costs are primarily for the Companies' share of costs to have the audits performed by the PSC-hired Consultant as well as other costs that could be incurred, dependent on each audit's process, results and recommendations. As described in the Management Audit Panel's testimony, benefits to customers are reflected in revenue requirements in several areas, including the Companies' proposal to utilize the 1% labor productivity offset as part of its initial filing. Rate Year costs, including adjustments from the Test Year amounts, associated with Management and Operations Audits are set forth in the table below.

Table 28: Management and Operations Audits
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 141	$ 299	$ 440
RG&E Electric	91	294	385
NYSEG Gas	35	75	110
RG&E Gas	39	126	165
Total Costs	**$ 306**	**$ 794**	**$ 1,100**

21. Decommissioning Of Russell Site; Decommissioning Of Beebee Site

Q. Please discuss the ongoing decommissioning of the RG&E Electric Russell and Beebee sites and RG&E's proposal to fund the costs of the decommissioning work.

A. The Beebee coal-fired generating station was closed down in 1999 and the Russell coal-fired generating station was closed down in 2008. RG&E has been doing decommissioning work at these two sites for a number of years and has continued to move forward with the decommissioning/demolition efforts at both the Beebee and Russell Stations, consistent with the requirements set forth under the Order Approving Acquisition Subject to Conditions issued on January 6, 2009 in Case 07-M-0906 and with the direction provided by the Commission in its subsequent July 25, 2011 Order Modifying Auction Plan and Establishing Further Procedures and its May 4, 2012 Order Denying Rehearing and Granting Clarification in Part, both issued in the same proceeding.

Q. Has the PSC been kept informed of the progress of the decommissioning efforts?

A. Yes. RG&E has filed quarterly progress reports with the Commission since 2012, and has shared various key documents with Staff, such as RFPs and contracts for work to be done.

Q. Has RG&E sought out the lowest cost qualified contractors to plan and perform the decommissioning work?

A. Yes, RG&E has shared its selection information with Staff and has contracted with a well-qualified contractor to complete the remaining decommissioning and demolition work over the 2014 to 2016 time frame.

Q. Taking into account all of the costs previously incurred and the estimates of costs to complete the decommissioning and demolition work, what are the latest estimates of the total costs necessary to fully decommission each site?

A. The latest estimate of cost to complete the decommissioning of the Beebee site is $27.27 million. The latest estimate of cost to complete the decommissioning of the Russell site is $17.63 million.

Q. Has RG&E previously collected money from its customers that has been or will be applied to the decommissioning of the sites?

A. Yes. For the Beebee site, through a combination of excess depreciation reserve and a specific collection from RG&E customers for a number of years, RG&E had collected approximately $15.2 million. For the Russell site, accumulated depreciation reserves in excess of the gross plant retired amounted to about $12.3 million. The previously collected costs have been accounted for as a decommissioning reserve for each site, which has been considered an offset to Rate Base.

Q. How has RG&E been accounting for the costs incurred to date for the decommissioning efforts at the two sites?

A. RG&E has charged those costs against the amounts previously collected from customers. Based on the cumulative amounts collected from customers, and the amounts spent on decommissioning through the end of 2014, approximately \$4.98 million remains in the Beebee decommissioning reserve, and approximately \$7.56 million remains in the Russell decommissioning reserve.

Q. How does RG&E propose to account for and collect or reflect the remaining estimated costs to complete with the Russell and Beebee decommissioning?

A. RG&E will continue to incur cost for the decommissioning/demolition of the Russell and Beebee sites based on the schedules and contracts shared with the Commission, including any future contractual costs that may increase or decrease from the current estimated amounts. RG&E proposes to transfer an amount from an already existing regulatory liability account into its current decommissioning reserves for each site such that the reserves will contain enough funds to fully cover the currently estimated remaining 2015 and 2016 costs to complete the decommissioning work. This approach will allow RG&E to complete the decommissioning work without asking customers for any additional incremental amount in revenue requirements to cover future costs.

Q. What regulatory liability account is RG&E proposing to use as a source for the amounts transferred into the decommissioning reserves?

A. RG&E is proposing to utilize amounts from the regulatory liability associated with the deferral of post-term Joint Proposal amortizations. Absent attribution of a portion of this regulatory liability toward the decommissioning reserves, it would have a balance of approximately a $42.4 million at the start of the Rate Year.

Q. What is RG&E's best estimate of the amounts to be transferred into the decommissioning reserves?

A. For Beebee, as noted above, the remaining 2015-2016 estimate to complete the decommissioning work is $27.27 million. When compared to the January 1, 2015 reserve amount of $4.98 million, this results in the need to transfer approximately $22.29 million into the Beebee decommissioning reserve. Similarly for Russell, as noted above, the remaining 2015-2016 estimate to complete the decommissioning work is $17.63 million. When compared to the January 1, 2015 reserve amount of $7.56 million, this results in the need to transfer approximately $10.1 million into the Russell decommissioning reserve. The total transfer from the post-term Joint Proposal amortization regulatory liability to the two decommissioning reserves will be a total of approximately $32.4 million.

Q. What is the Company proposing should the actual costs of decommissioning / demolition turn out to be different than the estimated costs?

A. The Company proposes that, if the final actual costs exceed the amount that is in the decommissioning reserves after the transfer described above, those additional costs be deferred in a regulatory asset account and addressed in a future rate proceeding. To the extent that the final actual costs are below the amount that is in the decommissioning reserves after the transfer described above, the Company proposes to move the remaining balance to a regulatory liability account that would be addressed in a future rate proceeding.

22. Regulatory Commission Assessment

Q. Please describe the adjustment to Regulatory Commission Assessment Fees.

A. The adjustments on Schedule A for Regulatory Commission Assessment Fees are based on the most recent Public Service Law ("PSL") § 18-a assessment estimate and increased using the general inflation factor. These costs, totaling $4.9 million for NYSEG and $3.1 million for RG&E represent the general assessment only.

23. Gas Pipeline Integrity Costs

Q. Please describe the adjustment for the Gas Pipeline Integrity Costs.

A. The Companies have made adjustments on Schedule A to reflect gas pipeline integrity costs including Distribution Integrity Management, Integrity Management, Data Management and other costs proposed at a total of $1.7 million for NYSEG Gas and RG&E Gas in the Rate Year. The adjustments from the historic Test Year to the Rate Year are provided in the following table and in detail in the supporting workpapers. These costs are also testified to separately in the Gas Engineering, Delivery and Operations Panel.

Table 29: Gas Pipeline Integrity
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Gas	$ 231	$ 281	$ 512
RG&E Gas	537	662	1,199
Total Cost	**$ 768**	**$ 943**	**$ 1,711**

24. Gas Research And Development

Q. What are the adjustments for Gas Research and Development ("R&D")?

A. The adjustments on Schedule A for Gas R&D are primarily driven by forecast changes associated with new internal R&D programs focused on technologies, automation and inspections. The costs for NYSEG Gas are $1.7 million, which is slightly lower than costs for the historical Test Year. The costs for RG&E Gas are $1.4 million, an increase over the historic Test Year primarily due to an increased focus on internal programs related to new technologies. These costs are also testified to separately in the Gas Engineering, Delivery and Operations Panel. The table below summarizes the adjustments from the historical Test Year to the Rate Year.

Table 30: Gas R&D
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Gas	$ 1,877	$ (138)	$ 1,739
RG&E Gas	1,025	332	1,357
Total Cost	**$ 2,902**	**$ 194**	**$ 3,096**

25. Gas Expansion

Q. What are the Rate Year costs being proposed for Gas Expansion?

A. The adjustments on Schedule A for Gas Expansion are all new costs not previously incurred in the Test Year associated with marketing, the rebate program and the Community Development Fund Pilot Program, which would be used to match funding provided by local, regional and state agencies for the construction of natural gas infrastructure in a community. The costs for NYSEG Gas are $0.8 million and for RG&E Gas are $0.6 million, which represent the Companies' commitment to natural gas expansion opportunities. These costs are also testified to separately in the Electric Supply and Natural Gas Supply and Expansion Panel. The proposed Rate Year amounts are summarized in the following table:

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Table 31: Gas Expansion
Rate Year Costs ($ thousands)

Program	Rate Year Ended 3/31/17
NYSEG Gas	
Marketing	$ 165
Rebate Program	380
Community Development Fund Pilot Program	300
Total	**$ 845**
RG&E Gas	
Marketing	$ 52
Rebate Program	240
Community Development Fund Pilot Program	300
Total	**$ 592**
Total Cost	**$ 1,437**

26. Energy Efficiency Program, SBC / RPS

Q. How are the Companies accounting for Energy Efficiency programs?

A. The Companies are proposing to continue to collect non-internal staff energy efficiency costs through a surcharge on customer bills. The amount to be collected in the surcharge is anticipated to be what was included in recent Commission orders. The costs of internal staff supporting energy efficiency programs are included in O&M costs and collected through base Delivery rates.

Q. Are the Companies proposing any changes to the System Benefits Charge ("SBC") and Renewable Portfolio Standard ("RPS") surcharges?

A. No. SBC and RPS information on Schedule A reflects their continued reconciliation with no effect on Delivery revenue requirement.

27. Distribution Level Demand Response

Q. Have the Companies made any adjustments for costs associated with the recently proposed Distribution Level Demand Response programs?

A. Yes. The Companies are anticipating expenditures in the Rate Year for Distribution Level Demand Response for NYSEG Electric and RG&E Electric totaling $1.1 million. The total Rate Year costs resulting from these adjustments are shown in the table below.

Table 32: Distribution Level Demand Response
Rate Year Costs ($ thousands)

Company	Rate Year Ended 3/31/17
NYSEG Electric	$ 732
RG&E Electric	333
Total Costs	**$ 1,065**

Q. Have the Companies included these anticipated Distribution Level Demand Response costs in Delivery revenue requirements?

A. Not at this time. Consistent with the proposal made in their March 15, 2015 filing in Case 14-E-0423, the Companies have included these expenditures as adjustments to revenues and propose to collect those expenditures through the Non-Bypassable Charges (“NBC”). To the extent that these expenditures are not approved for collection through the NBC, then these costs would need to be recovered through Delivery rates.[3] These expenditures are further addressed in Case 14-E-0423.

28. Outside Services

Q. What adjustments have the Companies made for Outside Services?

A. The Companies have included adjustments for Outside Services based on actual forecast data or historical Test Year amounts adjusted by a general inflation factor. Total Outside Services costs in the Rate Year are $21.9 million for NYSEG Electric, $15.3 million for RG&E Electric, $7.9 million for NYSEG Gas and $8.7 million for RG&E Gas. As described earlier in this testimony, included in these costs are costs for certain programs that were considered Incremental Maintenance during the last rate plan, which are now established programs within each business. The total amount now reflected in Outside Services for these former Incremental Maintenance programs is $13.2 million. In addition to the recategorization of costs, the increase in costs for all Companies over the historical Test Year are primarily attributed to enhanced line security and safety programs, enhancements to the geographic information system ("GIS"), upgrades to telecommunications capabilities and mobile radio expansion and applying best practices to facilities maintenance activities, such as cleaning and repairs, which are all supported by the Outside Services detail workpapers provided by this Panel, as well as implementation of a new substation 3D tool and its related maintenance as described in the testimony of the Electric Reliability and

[3] As discussed in the testimony of the Electric Supply/Natural Gas Supply and Expansion Panel, the Companies are proposing to rename the NBC the "Monthly Adjustment Clause."

Operations Panel. The supporting workpapers provide detail for all costs and the tables below provide a summary of the historical Test Year to Rate Year costs.

Table 33: Outside Services – NYSEG Electric
Rate Year Costs ($ thousands)

Outside Service	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
Facilities and General Services (note 1)	$ 4,383	$ 1,292	$ 5,675
Current JP Incremental Maint (note 2)	-	5,086	5,086
Engineering	2,902	142	3,044
Construction and Maintenance	2,755	60	2,815
Customer Service	1,594	113	1,707
Oper Tech/Business Transformation (note 3)	545	767	1,312
Other (notes 4 and 5)	2,428	(193)	2,235
Total - NYSEG Electric	**$ 14,607**	**$ 7,267**	**$ 21,874**

Table 34: Outside Services – RG&E Electric
Rate Year Costs ($ thousands)

Outside Service	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
Customer Service	$ 3,822	$ 190	$ 4,012
Facilities and General Services (note 1)	1,982	718	2,700
Current JP Incremental Maint (note 2)	-	2,180	2,180
Construction and Maintenance	2,072	36	2,108
Corporate Services	1,354	(75)	1,279
Line Clearance	693	28	721
Other (note 5)	1,956	310	2,266
Total - RG&E Electric	**$ 11,879**	**$ 3,387**	**$ 15,266**

Table 35: Outside Services – NYSEG Gas
Rate Year Costs ($ thousands)

Outside Service	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
Current JP Incremental Maint (note 2)	$ -	$ 3,443	$ 3,443
Construction and Maintenance	2,146	(1,233)	913
Facilities and General Services (note 1)	808	199	1,007
Locational Services	653	26	679
Customer Service	471	26	497
Other (note 5)	785	600	1,385
Total - NYSEG Gas	**$ 4,863**	**$ 3,061**	**$ 7,924**

Table 36: Outside Services – RG&E Gas
Rate Year Costs ($ thousands)

Outside Service	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
Current JP Incremental Maint (note 2)	$ -	$ 2,462	$ 2,462
Construction and Maintenance	2,105	(350)	1,755
Customer Service	1,434	76	1,510
Facilities and General Services (note 1)	897	318	1,215
Asset Management and Planning	703	28	731
Other	982	27	1,009
Total - RG&E Gas	**$ 6,121**	**$ 2,561**	**$ 8,682**

Table 37: Outside Services – Total
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 14,607	7,267	$ 21,874
RG&E Electric	11,879	3,387	15,266
NYSEG Gas	4,863	3,061	7,924
RG&E Gas	6,121	2,561	8,682
Total	**$ 37,470**	**$ 16,276**	**$ 53,746**

Notes:
1) maintain infrastructure of facilities including cleaning and repairs; line safety
2) ongoing incremental maintenance costs transferred to Base Delivery Rates
3) O&M costs related to telecom project support and mobile radio expansion, resources to maintain GIS database and support for OMS/APLEX
4) primarily costs for 3D substation design tool and all employee mandatory HR training
5) includes adjustment related to Gas vs. Electric allocation adjustment

29. Reforming the Energy Vision - Incremental Costs

Q. How have the Companies reflected incremental costs associated with the Reforming the Energy Vision ("REV") proceeding, Case 14-M-0101?

A. The only REV-related direct impact on the Companies' proposed Electric Delivery rates is for the recovery of any REV-related incremental costs that have been deferred by the Companies under the terms of the current Rate Plan. Consistent with paragraph XI.K of the 2010 JP, the electric businesses are allowed to defer the incremental costs incurred as a result of new regulatory actions as long as the incremental pre-tax amount is in excess of $1.5 million for NYSEG Electric and in excess of $1.0 million for RG&E Electric. These costs are discussed separately in the testimony of the Reforming the Energy Vision Panel.

Q. Are there other REV-related costs that the Companies expect to incur?

A. Yes. As indicated in the testimony of the Reforming the Energy Vision Panel, the Companies are pursuing REV-related project called the Energy Smart Community, which will involve both capital and non-capital spending. The capital spending will occur over the next several years, as shown in Exhibit __ (REV-2). Certain incremental non-capital costs associated with the ESC will also be incurred. As described previously in this testimony, the Companies propose to utilize previously deferred Economic Development regulatory liability amounts to cover those costs.

Q. Have the Companies included any adjustments for Demonstration project costs associated with the REV proceeding?

A. No. The Companies will be making a separate filing in Case 14-M-0101 related to Demonstration projects on July 1, 2015. The Commission's Order Adopting Regulatory Policy Framework and Implementation Plan ("Track 1 Order") issued on February 26, 2015, provides direction on the recovery of incremental costs associated with these Demonstration projects, separate and distinct from the rate cases.

30. General Inflator

Q. Please describe how the General Inflator was calculated.

A. The General Inflator represents the forecasted change in the average Gross Domestic Product ("GDP") Chained Price Index as reported by 2014 Blue Chip

Economic Indicators. The table below provides the result of this calculation, which is utilized in the determination of a number of Rate Year O&M expenses.

Table 38: Calculation of General Inflator

Average GDP Chained Price Index					
Rate Year Ended 3/31/17	/	Historic Test Year Ended 12/31/14	-1	=	Historic Test Year to Rate Year Inflator
112.734		108.375			4.02%

Q. What Test Year costs were inflated utilizing the General Inflator?

A. The General Inflator is utilized to determine Rate Year O&M expense levels for a variety of costs that have not been specifically forecasted by the Companies. Categories of O&M costs that were forecasted using the General Inflator include Medical and Other Employee Benefits, Transportation, Materials & Supplies, Regulatory Assessment Fees, and Postage.

Q. How was the General Inflator applied to these Test Year costs?

A. The application of the General Inflator begins with the normalization of historic Test Year values to remove the impact of one-time items and adjusting for other known changes such as the updated O&M allocation factor, discussed later in our testimony. The General Inflator is then applied to the normalized historic Test Year amounts to calculate the forecasted Rate Year level of expense.

31. Common O&M Allocations to Electric and Gas

Q. Have the Companies included adjustments for Common O&M allocations to Electric and Gas?

A. Yes, the Companies make adjustments to update the Common O&M allocations to Electric and Gas. The Electric and Gas Common O&M allocations are primarily based on the traditional three-factor Massachusetts formula, utilizing historic Test Year information as reported in the FERC Form 1. In addition, a few O&M items utilize an allocation based on a customer count, which is more cost-causative in certain instances than the Massachusetts formula. The table below provides a summary of the adjustments to the Common O&M allocation percentages based on the Massachusetts formula, from the historic Test Year to the Rate Year.

Table 39: Common O&M Allocation Factors

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	87.1%	-6.7%	80.4%
NYSEG Gas	12.9%	6.7%	19.6%
RG&E Electric	66.4%	1.1%	67.5%
RG&E Gas	33.6%	-1.1%	32.5%

Q. For what types of Common O&M expenses have the Companies made adjustments using the proposed new Common O&M allocation percentages?

A. The Companies made Common O&M allocation adjustments to certain O&M expenses such as IUMC Costs, Outside Services, Insurance, Environmental, Legal/Regulatory and costs that utilized the application of a general inflator. This adjustment is included in the workpapers for any costs that were subject to a common allocation, and tracks through the normalization of historic Test Year values using the revised allocation factors and the calculated Rate Year level of expense based on the application of the general inflator or based on specific Rate Year forecasts.

Q. What are the estimated impacts of the application of the proposed Common O&M allocation percentages to Electric and Gas on the historic Test Year and the Rate Year?

A. The estimated impacts of the application of the new allocation percentages on the historic Test Year and the Rate Year are provided in the table below. As can be observed on the table, there is a significant shift of dollars (about $7.7 million) from NYSEG Electric to NYSEG Gas. The net effect on RG&E Electric and Gas was de minimis.

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<u>Table 40: Electric and Gas Common O&M Allocation Adjustments</u>
Rate Year Costs ($ thousands)

Allocation	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric (to) from NYSEG Gas			
IUMC cost	$ (3,870)	$ (154)	$ (4,024)
O&M Expenses with Gen. Infl.	(1,177)	(47)	(1,224)
Environmental	(1,118)	(580)	(1,698)
Outside Services	(450)	(18)	(468)
Insurance	(245)	(10)	(255)
Legal Regulatory Costs	(85)	89	4
Other	(588)	491	(97)
Total Allocation Adjustment - NYSEG	**$ (7,533)**	**$ (229)**	**$ (7,762)**
RG&E Electric (to) from RG&E Gas			
IUMC cost	$ 324	$ 7	$ 331
Environmental	124	(370)	(246)
O&M Expenses with Gen. Infl.	(118)	(4)	(122)
Other	49	(16)	33
Total Allocation Adjustment - RG&E	**$ 379**	**$ (383)**	**$ (4)**

32. Amortizations

Q. Please describe the change in amortization expense that the Companies have included in their filing.

A. The level of amortization expense in the historic Test Year was established in the Companies' most recent rate cases and was embedded in NYSEG's and RG&E's tariffs. Following the conclusion of the initial forty-month term of the rate plans, over which time the underlying regulatory deferrals were amortized consistent with the agreement denoted in Appendix O of the 2010 JP, the Companies continued to reflect the amortization amounts as a charge or credit to expense, while deferring these same amortization amounts for future recovery from or return to customers.

Q. Have the Companies identified any new deferred regulatory assets or liabilities that they are proposing to amortize?

A. Yes, during the term of the current rate plans, the Companies have accounted for a number of new deferred regulatory assets and liabilities. NYSEG and RG&E propose to begin amortizing the estimated new deferred balances in the Rate Year.

Q. Over what term are the Companies proposing to amortize these new regulatory assets and liabilities?

A. In general, the Companies propose to amortize the deferred balances over a period of five years, with a few exceptions noted below.

Table 41: Proposed Amortizations

Deferred Balance	Amortization
PowerTax Regulatory Asset and Unfunded Future Income ("IT") Taxes	Amortized over the estimated life of the underlying assets.
Electric PBAs	NYSEG Electric amortized fully during the Rate Year. RG&E Electric to be amortized over five years.
NYSEG Gas Pension and Property Tax	Continue to recover through the transition surcharge of a period of five years

Q. Please provide an overview of the proposed Rate Year amortization expense at NYSEG Electric.

A. NYSEG Electric is projected to have a net regulatory asset balance of $242.8 million at the start of the Rate Year. As noted above, the Panel proposes that the vast majority of this balance be amortized over a five year period, which would result in a $29.0 million increase to O&M expenses. The largest components of this balance include storm, Pension, OPEB, and bonus depreciation non-cash return ("NCR") deferrals. A summary of the deferred balances at the start of the Rate Year, the amortization periods, and the amortization amounts in the Rate Year is provided below.

Table 42: Regulatory Amortizations – NYSEG Electric
Rate Year Amounts ($ thousands)

Amortization	Deferred Balance at the Start of Rate Year 1	Period (Years)	Rate Year Amortization Amount
Deferrals Amortized Over 5 Years			
Storm	$ 262,359		
Pension	76,568		
OPEB	(56,124)		
Bonus Depreciation NCR	(52,808)		
All Other	(26,705)		
Total - 5 Year Amortizations	$ 203,290	5	$ 40,659
PowerTax Regulatory Asset	$ 54,274	27	$ 2,010
Unfunded Future Income Taxes	$ (1,129)	27	$ (42)
PBA Deferral	$ (13,655)	1	$ (13,655)
Total NYSEG Electric	**$ 242,780**		**$ 28,972**

Q. Please provide an overview of the proposed Rate Year amortization expense at RG&E Electric.

A. RG&E Electric is projected to have a $66.3 million net regulatory liability balance at the start of the Rate Year. As noted above, the Panel proposes that the vast majority of this balance be amortized over a five year period, which would result in a $42.7 million offset to O&M expenses. As noted previously in this testimony, the Company has proposed to transfer approximately $32.4 million from one of the deferred regulatory liability accounts to the Beebee and Russell decommissioning reserves. Therefore, that amount is not part of the amortizations included in the table. The largest components of this balance include property tax, bonus depreciation NCR, OPEB, and DOE liability true-up deferrals. A summary of the deferred balances at the start of the Rate Year, the amortization periods, and the amortization amounts in the Rate Year is provided below.

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Table 43: Regulatory Amortizations – RG&E Electric
Rate Year Amounts ($ thousands)

Amortization	Deferred Balance at the Start of Rate Year 1	Period (Years)	Rate Year Amortization Amount
Deferrals Amortized Over 5 Years			
Property Tax	$ (63,108)		
Bonus Depreciation NCR	(44,782)		
OPEB	(13,618)		
DOE Liability True Up	(12,188)		
All Other	(63,354)		
Total - 5 Year Amortizations	$ (197,050)	5	$ (39,411)
PowerTax Regulatory Asset	$ 43,622	39	$ 1,119
Unfunded Future Income Taxes	$ 124,953	39	$ 3,204
PBA Deferral	$ (37,853)	5	$ (7,571)
Total RG&E Electric	**$ (66,329)**		**$ (42,659)**

Q. Please provide an overview of the proposed Rate Year amortization expense at NYSEG Gas.

A. NYSEG Gas is projected to have a net regulatory asset balance of approximately $60 million at the start of the Rate Year. As noted above, the Panel proposes the vast majority of this balance be amortized over a five-year period, which would result in a $3.3 million increase to O&M expenses. The largest components of this balance include OPEB and bonus depreciation NCR deferrals. A summary of the deferred balances at the start of the Rate Year, the amortization periods, and the amortization amounts in the Rate Year is provided below.

Table 44: Regulatory Amortizations – NYSEG Gas
Rate Year Amounts ($ thousands)

Amortization	Deferred Balance at the Start of Rate Year 1	Period (Years)	Rate Year Amortization Amount
Deferrals Amortized Over 5 Years			
OPEB	$ (12,044)		
Bonus Depreciation NCR	(11,865)		
All Other	(2,835)		
Total	$ (26,744)	5	$ (5,349)
Deferrals Recovered vs Transition Surcharge			
Pension	$ 27,235		
Property Tax	9,738		
Total	$ 36,973	5	$ 7,395
PowerTax Regulatory Asset	$ 22,325	39	$ 572
Unfunded Future Income Taxes	$ 27,426	39	$ 703
Total NYSEG Gas	**$ 59,980**		**$ 3,321**

Q. Please provide an overview of the proposed Rate Year amortization expense at RG&E Gas.

A. Unlike the other businesses outlined above, the majority of the RG&E Gas $16.8 million net regulatory asset balance is associated with the PowerTax $34.6 million asset and unfunded future income tax $12 million asset that the Panel proposes to be amortized over the average remaining service lives of the Companies' assets. The Panel proposes that the remainder, a net balance of $29.8 million of regulatory liabilities, be amortized over five years. This would result in a $4.6 million offset to O&M expenses. A summary of the deferred balances at the start of the Rate Year, the amortization periods, and the amortization amounts in the Rate Year is provided below.

Table 45: Regulatory Amortizations – RG&E Gas
Rate Year Amounts ($ thousands)

Amortization	Deferred Balance at the Start of Rate Year 1	Period (Years)	Rate Year Amortization Amount
Deferrals Amortized Over 5 Years			
Property Tax	$ (19,260)		
Bonus Depreciation NCR	(14,643)		
Pension	8,472		
All Other	(4,327)		
Total	$ (29,758)	5	$ (5,952)
PowerTax Regulatory Asset	$ 34,584	34	$ 1,017
Unfunded Future Income Taxes	$ 11,968	34	$ 352
Total RG&E Gas	**$ 16,794**		**$ (4,582)**

33. Use Taxes

Q. How are the Companies accounting for Use Taxes?

A. The Companies reflect Use Taxes incurred as part of the related Capital and/or O&M accounts that are the basis for the Use Tax. The Companies began expensing the O&M component of Use Tax to the O&M accounts that are the basis for the Use Tax in January 2015. This is a customary accounting procedure and in accordance with GAAP. The incurred Use Taxes related to O&M are reflected on the Materials and Supplies line of the O&M Expenses with General Inflator workpaper and, as required, within the forecast amounts of other items such as Incremental Maintenance and Vegetation Management. Additionally, Use Taxes associated with storm restoration costs will be reflected as part of the storm costs.

C. Depreciation

Q. Please discuss how the adjustment for Depreciation was developed.

A. As noted earlier in this testimony, the Depreciation expense starting in the Rate Year for each business is based on the application of the proposed service lives and net salvage rates testified to by Company Witness Spanos. Depreciation amounts depend on the level of capital plant-in-service at any point in time; the Panel's approach to determining the plant-in-service was described earlier in this testimony. A summary of the Test Year to Rate Year depreciation expense for each business is summarized in the table below.

Table 46: Depreciation Expense
Rate Year Depreciation ($ thousands)

			Rate Year Ending 3-31-17	
Company	**2014**	**2015**	**Current Deprec. Rates, Common Alloc.**	**Proposed Deprec. Rates, Common Alloc.**
NYSEG Electric	$ 99,895	$ 99,451	$ 118,878	$ 116,354
NYSEG Gas	22,935	23,580	30,256	30,607
RGE Electric	$ 40,364	$ 41,755	$ 52,098	$ 59,132
RGE Gas	20,474	21,426	24,438	24,354

D. Theoretical Excess Depreciation Reserve Balance

Q. Have the Companies been amortizing any theoretical excess depreciation reserve?

A. Yes, as part of the agreement reached in the 2010 JP, the Companies began amortizing a NYSEG Electric and RG&E Electric theoretical excess depreciation reserve balance. The NYSEG Electric excess reserve was identified as $303.9 million and is currently being amortized over a 20-year period at

$15.2 million annually beginning in September 2010. The RG&E Electric excess reserve was identified as $105 million and is being amortized over a 20-year period at $5.25 million annually beginning in September 2012.

Q. Have the Companies provided new depreciation studies in this filing?

A. Yes. In this rate filing, consistent with the requirements in its 2010 JP, the Companies are providing new depreciation studies for all four businesses. Based on the new depreciation studies, which have been performed by Company Witness Spanos, the Companies have re-estimated the theoretical excess / deficient depreciation reserve amounts. The new studies indicate a theoretical excess reserve exists only at NYSEG Electric, while a theoretical deficient reserve exists at NYSEG Gas. An excess or deficient reserve is considered to exist if the actual book depreciation reserve balance differs from the theoretical depreciation reserve balance by more than 10%. If the difference is within 10% then the depreciation reserve balance is not deemed to be in excess or deficient.

For NYSEG Electric, Company Witness Spanos has calculated an excess depreciation reserve of $227.5 million based on plant balances as of December 31, 2014. The Company is proposing to amortize the entire excess depreciation reserve over 20 years consistent with the 2010 JP, despite Company Witness Spanos's recommendation that only the amount over the 10% threshold be considered for amortization. The proposed annual amortization amount is $11.4 million and has been reflected as a reduction in electric revenue requirements. This amount is $3.8 million less than the $15.2 million currently being amortized.

At NYSEG Gas, Company Witness Spanos has calculated a reserve deficiency of $56.9 million. Consistent with the NYSEG Electric excess reserve treatment, the Company is proposing to amortize this gas depreciation reserve deficiency over 20 years. The annual amortization for NYSEG Gas is $2.84 million, which is reflected as in an increase in the gas revenue requirement.

Company Witness Spanos calculated theoretical versus book depreciation amounts for RG&E Electric and RG&E Gas. As these amounts did not exceed the 10% threshold described, no amortizations are being proposed for RG&E and the amortization currently in place for RG&E Electric would cease as of the start of the Rate Year.

E. <u>Operating Taxes</u>

Q. What are the property taxing jurisdictions in New York State?

A. Counties, cities, towns, villages and school districts.

Q. What is the difference between Real and Special Franchise Property?

A. Real Property is property that is on private property while Special Franchise Property is property that is on public property.

Q. Have the Companies been successful in managing their property tax expense?

A. Yes. The Companies efforts at managing their property tax expense have resulted in an estimated cumulative property tax savings of $39.8 million, $15.4 million, $12.0 million and $2.8 million for RG&E Electric, RG&E Gas, NYSEG Electric and NYSEG Gas, respectively, from 2010 to 2014, as compared to the estimated expense that the Companies would have otherwise incurred absent any mitigation efforts.

Q. How did the Companies achieve these savings?

A. The Companies requested, and were granted, economic obsolescence reductions for the assessed value of Special Franchise Property (Electric and Gas Infrastructure on Public Rights of Way), by the New York State Office of Real Property Tax Services ("ORPTS"), which is responsible for assigning value to Special Franchise Property.

Q. Are the savings associated with economic obsolescence limited to Special Franchise Property?

A. No. The economic obsolescence percentage reduction granted by ORPTS is applied to Real Property (Electric and Gas Infrastructure not on Public Rights of Way and not traditionally assessed by ORPTS), when, and if, assessing jurisdictions, such as cities, towns and counties, request advisory appraisals from ORPTS related to the Real Property owned by the Companies.

Q. How often are assessing jurisdictions required to request advisory appraisals?

A. There does not appear to be a New York State requirement for assessing jurisdictions to request advisory appraisals on certain intervals. In NYSEG's service territory, the experience is that assessing jurisdictions request advisory appraisals every four years on average. In RG&E's service territory, the experience is two years on average, except the City of Rochester which appears to be on a four-year cycle.

Q. Please describe the timing related to the application of the economic obsolescence reductions to assessed value for Special Franchise and Real Property.

A. The economic obsolescence reduction is applied to the assessed value of Special Franchise Property at the next available date that the tax roll is created. For example, if a reduction of 10% is granted in October of 2014, the reduction in the Special Franchise Property value is included in the total assessed value in the 2015 tax roll. The 2015 tax roll will be used to determine the assessed value for the School Tax assessment covering the period July 1, 2015 to June 30, 2016. The 2015 tax roll will also be used to determine the assessed value for the Town and County tax assessment covering the period January 1, 2016 to December 31, 2016.

Q. So there is a delay in the full effect of the economic obsolescence benefit being reflected in the tax assessment?

A. Yes. There is not only the delay in the savings associated with Special Franchise Property described above, but an additional delay, or perhaps no savings at all, associated with Real Property based on the timing of assessing jurisdictions requesting advisory appraisals.

Q. Please describe the additional delay regarding Real Property.

A. If an assessing jurisdiction requests an advisory appraisal in calendar year 2015, and the economic obsolescence reduction percentage remains at 10%, the 10% reduction will be applied to the Real Property value for that jurisdiction in the development of the 2016 tax roll. The 2016 tax roll will be used to determine the assessed value for the School tax assessment covering the period July 1, 2016 to

June 30, 2017. The 2016 tax roll will be used to determine the assessed value for the Town and County tax assessment covering the period January 1, 2017 to December 31, 2017. This 10% reduction will then remain in place until the assessing jurisdiction requests another advisory appraisal. At that time the economic obsolescence reduction percentage that is in place (it can be higher or lower than the 10%) would be applied to the Real Property value for the subsequent tax roll. If an assessing jurisdiction never requests an advisory appraisal during the time frame that an economic obsolescence reduction is in place, the assessed value of the Real Property in that jurisdiction will never reflect the economic obsolescence percentage reduction and the company will never experience any savings related to those values. Conversely, if an assessing jurisdiction requests an advisory appraisal in a year that an economic obsolescence reduction is in place and the economic obsolescence reduction is eliminated the next year, the value of the Real Property in that jurisdiction will continue to be reduced by the economic obsolescence reduction until such time that the assessing jurisdiction requests another advisory appraisal.

Q. Based on the description above it appears that the savings associated with the economic obsolescence reduction can change significantly from one year to the next. Is that correct?

A. Yes. As indicated above, the annual impact is driven by several factors. These factors include increases and decreases in the actual granted economic obsolescence reduction percentage, the timing of the application of the reduction to Special Franchise Property and the timing of the application, if any, of the reduction to Real Property for assessing jurisdictions that request advisory appraisals from ORPTS.

Q. Are there any difficulties in forecasting the Rate Year property taxes?

A. Yes. There are several difficulties. The economic obsolescence percentage reduction for a particular year is one of those difficulties. Others are estimating each tax jurisdiction's tax rate (even with the 2% cap) and the determination of the overall assessed value.

Q. Recognizing these difficulties, have you prepared an estimate for the Rate Year?

A. Yes. The estimated property tax for each business unit is provided in the table below.

Table 47: Property Tax
Rate Year Costs ($ thousands)

Company	Historical Test Year	Adjustment	Rate Year Ended 3/31/17
NYSEG Electric	$ 84,139	$ 15,872	$ 100,011
RG&E Electric	57,514	17,520	75,034
NYSEG Gas	19,789	793	20,582
RG&E Gas	20,984	5,019	26,003
Total Costs	**$182,426**	**$ 39,204**	**$ 221,630**

In determining the tax projection, the Companies used a five-year average escalation rate based on the estimated property tax expense for 2009 to 2014 without the impacts of the favorable economic obsolescence reductions granted by ORPTS. This escalation factor was applied against the estimated 2014 property tax expense, absent the estimated benefits of the economic obsolescence reductions, to arrive at the 2015 estimate. The escalator was applied to the 2015 estimate to arrive at the 2016 value and to the 2016 value to arrive at the 2017 value.

Q. Why are the estimated economic obsolescence reductions eliminated from the development of the escalation factor?

A. As described above, the property tax savings associated with the economic obsolescence reductions will vary over time based on several factors. The development of the escalation factor is intended to capture the impacts on property tax expense related to items such as increased investment, retirements, changes in the Reproduction Cost New Less Depreciation ("RCNLD") value of historical additions, which occur annually based on the application of the Handy Whitman Index to those historical additions, general economic conditions in the areas the Companies serve and town, county, and school budget increases. The economic obsolescence percentage reduction is not impacted by these factors. The economic obsolescence percentage reduction is intended to reflect the result of external forces on the earnings ability of the utility, and therefore the desirability of the utility's assets. The reduction is determined pursuant to the requirements of 20 NYCRR 8197-2.8. Due to this disconnect between what impacts the overall assessed value and tax assessment and the determination of the economic obsolescence reduction, the Companies believe the development of the escalator based on the most recent six years' gross tax assessment and applying that escalator to arrive at the gross tax assessment for the future Rate Year is appropriate.

Q. If the economic obsolescence savings are eliminated from the escalation factor and the escalation factor is applied to the gross tax assessment absent the economic obsolescence savings, how does the economic obsolescence benefit get reflected in the overall property tax expense projected for the Rate Year?

A. The Companies prepared an estimate for the property tax reduction related to economic obsolescence for the Rate Year by taking into consideration each of the variables related to the timing and application of the economic obsolescence reduction percentage described above, based on the best information that the Companies have available as of the date of these filings. For example, NYSEG reduced the School Tax savings related to the Special Franchise Property for the July 1, 2015 to June 30, 2016 period to reflect the reduction in the economic obsolescence reduction percentage granted by ORPTS from 14% to 1%. This same approach was applied to the Town and County savings related to Special Franchise Property for the period January 1, 2016 to December 31, 2016. For the Real Property component, NYSEG assumed that 25% of the assessing jurisdictions would request advisory appraisals in each of the 2015 to 2017 tax rolls (based upon the timing of past advisory requests) and reduced the tax savings for Real Property accordingly for the School and Town and County tax savings based on the date that the revised economic obsolescence reduction percentage would be applied. Furthermore, to ensure consistency with the application of the escalator in developing the projected gross tax expense, NYSEG applied the same escalator to the base results of the economic obsolescence savings on a year-by-year basis. For RG&E, the assumption was that the City of Rochester would file for an advisory request for the 2016 tax roll and that 50% of the remaining assessing jurisdictions would request advisory appraisals for the 2016 and 2017 tax rolls, respectively (based upon the timing of past advisory requests).

Q. What caused the NYSEG economic obsolescence percentage reduction to decrease from 14% to 1%?

A. The calculation is based on an average actual return, pursuant to 20 NYCRR 8197-2.8 utilizing the most recent five years. The average returns for the period 2009 to 2013 were greater than the average returns for the period 2008 to 2012.

Q. Is there anything else that the Companies considered in the development of the Property Tax expense?

A. Yes. In 2014, NYSEG filed an initial request for functional obsolescence for the NYSEG Gas property.

Q. What is functional obsolescence?

A. Functional obsolescence represents the difference between the current assessed value of property placed in service and the assessed value that would result if the property were replaced with the minimum size and capacity required to provide safe and reliable service for the actual current customer load and a reasonable load growth. For example, if a four inch pipe gas distribution system was installed to meet the natural gas needs of the City of Binghamton 30 years ago and, due to factors such as the use of alternative fuels, a depressed economy and lower population, safe and reliable service could be provided with the installation of a two inch pipe gas distribution system, the property tax law in New York would allow for a reduction in the assessed value of the gas distribution system to reflect the lower RCNLD that would result had the investment 30 years ago employed two inch pipe instead of four inch pipe.

Q. Did ORPTS grant a functional obsolescence reduction for NYSEG's gas business in 2014?

A. Yes. ORPTS granted a 15% functional obsolescence reduction, which will be applied against the value of all of NYSEG's gas mains.

Q. Did RG&E include a request for a functional obsolescence reduction for RG&E Gas in its April 30, 2015 ORPTS filing?

A. Yes. The Company filed a functional obsolescence reduction request for RG&E Gas, requesting a reduction of 30%.

Q. Does the functional obsolescence reduction work similarly to the economic obsolescence reduction, as far as the timing and impacts on Special Franchise and Real Property?

A. The application is similar with one major exception. Due to the cost and time that is required to prepare the engineering model, ORPTS recognizes that it is impractical to require companies to update the study annually. In addition, ORPTS recognizes that functional obsolescence occurs over time and therefore it is unlikely that a significant change in results would occur from one year to the next. As a result, the application of the 15% reduction for NYSEG Gas will remain in effect for five years.

Q. Did NYSEG reflect the tax savings associated with the 15% functional obsolescence in the determination of the NYSEG Gas property expense for the Rate Year?

A. Yes.

Q. Did RG&E reflect the tax savings associated with the filed functional obsolescence request of 30% in the determination of the RG&E Gas property tax expense for the Rate Year?

A. No. The Company did not reflect any impacts related to the April 30, 2015 economic obsolescence or functional obsolescence requests as the Companies cannot predict the final determination that will be made by ORPTS regarding these requests. In addition, ORPTS has never granted the full reductions requested by the Companies, but has instead granted reductions that were significantly lower. To the extent that the overall property tax in the Rate Year is impacted, favorably or unfavorably, by the actions of ORPTS related to the April 30 filings, any savings or increases will be reflected in the actual property tax expense and be reflected in the reconciliation mechanism discussed below.

Q. What did the Companies request in the April 30, 2015 filing?

A. The Companies requested economic obsolescence reductions of 14% for RG&E and 9% for NYSEG. The Companies requested functional obsolescence reductions of 30% for RG&E and 15% for NYSEG.

Q. Did the Companies have a property tax reconciliation mechanism in place in the 2010 JP?

A. Yes. Under the 2010 JP, if the level of actual property taxes, including any property tax refunds received, varied in any Rate Year from the projected level provided in rates, 90% of the variation was deferred for recovery or pass back to customers, subject to the following cap: each Company's 10% share of property tax expenses above or below the level in rates is capped at an annual amount equal to ten basis points on the common equity for each Rate Year. The Companies deferred on their books of account, for recovery from or credit to customers, 100% of the variation, above or below the level at which the cap takes effect.

Q. Do the Companies propose the continuation of the reconciliation mechanism for property taxes?

A. Yes. Given all of the variables that are subject to change that enter into the estimate of property taxes, the Companies propose to defer differences between actual property tax expense, including all related external costs for litigation and reduction efforts, and that included in revenue requirements in the Rate Year for all business units in a manner consistent with the reconciliation mechanism currently in place. The reconciliation mechanism provides the proper protection for both customers and the Companies by allowing for the proper reflection of property taxes in the rate setting process over time. As indicated above, the Companies' mitigation efforts resulted in estimated savings of $70 million from 2010 to 2014, as compared to the property tax that the Companies otherwise would have incurred. These savings have increased or held down the level of the property tax regulatory liability or asset that will be passed back or collected from customers in this and future rate proceedings. Absent the reconciliation mechanism, the savings likely would have been retained by the Companies at a value greater than the 10% allowed per the reconciliation mechanism. In addition, a reconciliation mechanism is consistent with the PSC's policy of encouraging cost containment for all operating costs.

F. Income Taxes

1. Power Tax Adjustment

Q. Please elaborate on the adjustment associated with the Income Tax - Power Tax Implementation.

A. The Companies have taken advantage of the tax benefit associated with Accelerated Depreciation over many years. The benefit is the ability to take a tax deduction for depreciation on new plant that is higher than book depreciation. This creates, in essence, a "loan" from the government in the amount of the tax savings attributable to the excess of the tax deduction taken over the book depreciation expense, which is paid back to the government over the life of the asset. For rate making purposes, the value of the "loan" is recorded as a deferred tax liability which is deducted from Rate Base in recognition that it is a zero cost source of funds for the Companies. The ability to take Accelerated Depreciation is a win-win situation. The Companies get the use of the funds at zero cost and the customers get the advantage of a lower Rate Base and thus lower rates. The funded accumulated deferred income tax liability balances associated with federal tax depreciation in excess of book depreciation were $440 million for NYSEG Electric, $169 million for NYSEG Gas, $258 million for RG&E Electric and $103 million for RG&E Gas at the end of the Test Year. As a Rate Base reduction, this saves NYSEG's customers approximately $66 million per year (assuming a weighted pre-tax cost of capital of 10.77%). RG&E customers save approximately $41 million per year (assuming a weighted pre-tax cost of capital of 11.34%).

Q. Are there any legislative conditions imposed regarding the Companies' ability to take advantage of Accelerated Depreciation?

A. Yes, there are. When Congress enacted the accelerated tax depreciation legislation, its intent was to stimulate investment by companies in new plant. In order to stimulate the investment by utilities it was necessary to ensure that the utility was not required to "flow through" the benefits of the lower federal tax to customers, but rather was required to "normalize" the tax benefits, thereby retaining the "loan" to support its investment.

The Internal Revenue Service ("IRS") has issued very strict Normalization Rules to ensure that there is not a flow through to customers of the tax benefits. Non-compliance with the Normalization Rules is a very serious matter that can have a draconian impact on both customers and the Companies. The penalty for violating the rules is the loss of the ability to take Accelerated Depreciation for federal tax purposes prospectively. Additionally, the deferred tax resulting from the previous use of accelerated tax depreciation would have to be paid back faster than it would have, had the violation not occurred.

Q. How did the Companies track the differences between tax depreciation and book depreciation?

A. Prior to the implementation of the PowerTax software in 2012, the Companies used a combination of Excel spreadsheets and other software (the legacy systems) to track these differences. While book depreciation is tracked by asset class, the book asset classes need to be grouped and rolled up into approximately a half dozen tax asset classes. Since the Companies did not have an automated manner in which to accumulate the book depreciation for each tax asset class, assumptions had to be made to arrive at the composite book life of the assets grouped and rolled up into each tax asset class. This composite book life was entered into the legacy systems at the tax asset class level and compared to the tax depreciation for each tax asset class to arrive at the tax versus book depreciation temporary difference.

Q. What is the PowerTax software?

A. The PowerTax software is software developed specifically for capital intensive industries, such as utilities, to calculate and track federal and state tax depreciation, federal and state tax basis in assets and federal and state tax versus book temporary differences associated with plant investment.

Q. In what way does the use of PowerTax differ from the use of the legacy systems?

A. The PowerTax software links up to the fixed asset system used to record book depreciation based on the proper depreciation rates agreed to for regulatory purposes and captures the information at the book asset class level. In addition, the software calculates the tax depreciation at the book asset class level. The combination of these two features allows for the proper comparison of tax depreciation to the book depreciation used for regulatory purposes in the development of the temporary difference subject to normalization in accordance with the Normalization Rules of the IRS.

Q. Did the Companies change the way they calculated the difference between tax depreciation and book depreciation?

A. Yes. With the implementation of PowerTax, the deferred tax calculation for the 2011 tax year yielded a much higher required deferred income tax expense related to the Companies' property when compared to the deferred tax expense generated under the legacy system. The reason for the difference was that the composite book lives that had been loaded into the legacy system were shorter than the actual book depreciation lives that should have been used. As a result of the error, when rates were set in 2010, they incorporated a "flow through" of the tax benefits that, under the tax law, should have been normalized. The result was that a portion of the government "loan" that the Normalization Rules required be retained by the Companies was flowed through to customers each year. This flow through created an inadvertent inconsistency with the Normalization Rules.

Q. What did the Companies do after discovering the inadvertent flow through to customers of tax benefits that should have been normalized?

A. Given the penalties associated with a violation, the Companies reviewed prior guidance provided by the IRS in Private Letter Rulings ("PLRs") to other utilities that also found themselves inadvertently in a position inconsistent with the Normalization Rules.

A PLR is a legal guidance from the IRS to a taxpayer. While not legally binding precedent in the sense of making law, a PLR is an interpretation of the law by the IRS's subject matter experts that are charged with enforcing the rules that are the subject of the interpretations. There have been 16 PLRs issued dealing with inadvertent normalization inconsistencies. In each of the rulings, one of the main factors that the IRS considered in determining whether a violation had occurred was whether the taxpayer and the regulator remedied the situation that was causing the inadvertent inconsistency as soon as it was discovered.

Once the Companies identified this inconsistency, it was clear that the problem needed to be remedied as soon as possible. The issue the Companies faced was what to do in the interim before the next rate case with regard to the amounts being impermissibly flowed through in current rates.

Based on the PLRs they reviewed and the severity of the consequences of a Normalization Violation, the Companies took immediate steps to ensure that their risk of losing the right to continue to take advantage of accelerated tax depreciation was minimized. The Companies immediately recorded a deferred tax obligation in the amount of the tax benefits that were erroneously flowed through and established a regulatory asset in that amount. The Companies now seek recovery of these amounts over the estimated composite remaining book life of the assets for each business unit. The composite remaining book life represents the Companies' estimate of the time period that this regulatory asset would have otherwise been collected from customers if it had continued to be recorded in the unfunded future income tax regulatory asset. The action taken by the

Companies to immediately correct the inadvertent inconsistency and associated recovery period places customers in the exact same position they would have been in absent the corrective action from both a Rate Base and revenue requirement perspective.

Q. If the Companies did not believe that the continued inadvertent flow through of tax benefits associated with federal tax depreciation versus book depreciation used to set rates was a Normalization Violation, would the total balances the Companies are now requesting recovery of been different?

A. No. Using RG&E Electric as an example and assuming a 40% tax rate, the accounting to isolate the PowerTax impact (the value is provided in a table later in the testimony) and record the associated Regulatory Asset was:

PowerTax Regulatory Asset	$43.6 million	
Deferred Tax Expense – Depr	$26.2 million	
Deferred Tax Expense – PowerTax Reg Asset	$17.4 million	
Revenues	$43.6 million	
Accumulated Deferred Income Tax – Depr		$26.2 million
Accumulated Deferred Income Tax – Reg Asset		$17.4 million

If the inadvertent flow through was allowed to continue, the $43.6 million increase in deferred tax expense would not be recorded and income tax expense would have been $43.6 million lower. Subsequently, in accordance with the requirement of SFAS-109, the accumulated deferred income tax shortfall associated with the tax depreciation versus book depreciation actual timing difference would have revealed a $26.2 million shortfall in the accumulated deferred income tax balance. This would have required the following journal entry to reflect the collection of the future income tax expense the Company would incur:

Unfunded Future Income Tax Regulatory Asset	$43.6 million	
Accumulated Deferred Income Tax – Depr		$26.2 million
Accumulated Deferred Income Tax – Reg Asset		$17.4 million

In both instances, the Regulatory Assets and Accumulated Deferred Income Taxes are identical. The only difference is that with the accounting employed to isolate the PowerTax impact and, in the Companies' opinion, aligning themselves with the Normalization Rules, the offset to the Regulatory Asset and Accumulated Deferred Income Tax balances impact Revenues and deferred tax expense instead of being balance sheet only entries.

Q. Has the same issue occurred at the Companies' affiliate Central Maine Power Company ("CMP")?

A. Yes it has. CMP recorded a Regulatory Asset for the difference between the deferred income tax expense that was embedded in the income tax component of revenue requirement, which was based on the calculation produced by the Companies' legacy system and the deferred tax expense reproduced by the new PowerTax software.

Q. Has CMP taken any further steps regarding the issue?

A. Yes. As a part of a settlement of its most recent rate case, CMP agreed to file for a PLR with the IRS confirming that its position was correct. A copy of the PLR is provided as a workpaper, RRP-2-WP-29 PLR. The Companies expect that the

IRS will issue a ruling during calendar year 2015, which the Companies will provide to the Commission.

2. Full Normalization

Q. How do the Companies calculate federal income taxes for financial accounting and regulatory purposes?

A. The Companies currently account for the timing differences between when the tax is booked and when it is paid in two ways. The Companies normalize certain tax timing differences between book taxes and taxes actually paid and, for certain other items, flow through to customers the income tax benefits based on actual taxes paid. For taxes that are normalized, a deferred tax liability is established, with an offset to income tax expense and the accumulated deferred income tax balance is deducted from Rate Base, recognizing that the customers have funded this future cash tax obligation. For tax benefits that are flowed through to customers, a deferred tax liability is recorded, but instead of a debit to income tax expense, the offset is recorded to a regulatory asset, recognizing that customers will be required to fund the future tax when the Companies have to pay the tax.

Q. What are some examples of the tax timing differences that are currently treated as flow through?

A. The most significant flow through items are tax versus book depreciation on pre-1980 vintage year additions, cost of removal (both the removal cost component of book depreciation and the tax deduction associated with the cash outlay), and early retirement of assets.

Q. What were the impacts of these flow-through items on tax expense in the normalized historical Test Year?

A. These flow through items resulted in an increase in tax expense of $4.7 million for NYSEG Electric, a decrease of $0.8 million for NYSEG Gas, an increase of $2.1 million for RG&E Electric and an increase of $3.6 million for RG&E Gas, as shown in the table below (values adjusted to exclude the permanent items and CNY Depreciation Flow Through).

Table 48: Income Tax Flow Through Impacts
($ thousands)

Company	Historical Test Year	Out of Period Adjustments	Income Tax Flow Through Impacts
NYSEG Electric	$ (2,030)	$ 6,689	$ 4,659
RG&E Electric	(428)	2,565	2,137
NYSEG Gas	(6,837)	6,020	(817)
RG&E Gas	2,533	1,049	3,582
Totals	**$ (6,762)**	**$ 16,323**	**$ 9,561**

Notes:
1) Historical Test Year amounts exclude permanent tax impacts and normalizing adjustments

Q. What are the Companies proposing in this case?

A. The Companies are proposing to normalize all tax versus book temporary differences.

Q. Please describe what is meant by full normalization.

A. Full normalization means that income tax expense for rate purposes is determined by providing for deferred tax expense on all originating and reversing book versus tax temporary differences.

Q. Why is this change from flow through to full normalization being proposed at this time?

A. This move to full normalization is being proposed for several reasons. First, it will eliminate the inconsistency between the flow through benefits that are provided to customers on an estimated basis in the rate setting process and that are incurred by the Companies. Second, it eliminates the intergenerational charge for income taxes that occurs when current customers are provided tax benefits at the expense of future customers that will be required to fund the tax when the Companies are required to pay the taxing authority. Third, as the Companies are also proposing audit protection, the use of full normalization will limit the audit protection required for temporary differences to the interest associated with a lost deduction due to the fact that the disallowance of the deduction will not impact total tax expense, but rather will shift the tax expense from a deferred tax expense to a current tax expense. Fourth, the move to full normalization also provides for the proper remedy to eliminate any future inadvertent Normalization Violations such as occurred with PowerTax. Fifth, with the continuous updating of book service lives via the depreciation studies, and the related determination of the Theoretical Reserve balance and amortization, this move to full normalization eliminates the need to isolate the impacts of these two concepts on the components of book depreciation that require normalization versus the components that require flow through treatment. All changes associated with temporary differences can be tax-affected using the statutory tax rate to determine revenue requirement. This also eliminates the potential for an inadvertent flow through and the true-up mechanism that has been used in the past associated with the book depreciation and theoretical reserve estimated flow through impacts. Sixth, the IRS recently issued Tangible Property Regulations that went into effect on January 1, 2014. These regulations contain several new requirements that companies must adhere to in order to continue to take certain accelerated tax deductions, which may not be cost-effective for the Companies. In addition, if the Companies do choose to continue to accelerate certain tax deductions, such as tax basis repairs, the tax treatment of certain flow through items would be impacted, including cost of removal and early retirement of assets. Due to these complexities, the IRS is providing utilities additional time to conform to the Tangible Property Regulations. The move to full normalization eliminates the need to attempt to include estimates for these items in the development of the income tax expense included in cost of service and also eliminates the audit exposure, as discussed above and further explained later in the Panel's testimony. Lastly, while the Companies recommend the collection of the regulatory asset on a straight line basis, the move to full normalization allows the Companies and the PSC to shape the recovery to reach settlement on overall revenue requirement, as opposed to the recovery being dictated by the timing of the reversing timing difference.

Q. What is the estimated balance related to the PowerTax and Unfunded Future Income Tax Components at the beginning of the Rate Year in this proceeding?

A. The balances as of March 31, 2016 are estimated at:

Table 49: Unfunded Future Income Tax
Estimated at Beginning of Rate Year ($ thousands)

Company	PowerTax Reg. Asset	Unfunded Future Income Taxes	Totals
NYSEG Electric	$ 54,274	$ (1,129)	$ 53,145
RG&E Electric	43,622	124,953	$ 168,575
NYSEG Gas	22,325	27,426	$ 49,751
RG&E Gas	34,584	11,968	$ 46,552
Totals	**$ 154,805**	**$ 163,218**	**$ 318,023**

Q. Do the Companies adhere to SFAS-109?

A. Yes. While SFAS-109 is now referred to as ASC-740, the Companies will use the term SFAS-109 throughout this testimony.

Q. Does SFAS-109 require that a deferred tax asset or deferred tax liability be established for all tax versus book temporary differences?

A. Yes.

Q. How do the Companies both adhere to SFAS-109 and not record a deferred tax expense associated with the temporary differences that are treated as flow through?

A. Paragraph 29 of SFAS-109 provides that regulated enterprises offset the establishment of a deferred tax asset or deferred tax liability with a regulatory liability or regulatory asset due to the fact that regulated companies are required to be made whole for tax expense associated with regulated activities.

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Q. Can you explain the journal entry that would be made using a $2 million flow through tax benefit as an example?

A. Yes. The purpose of this journal entry would be to establish a deferred tax liability of $2.0 million. Since the Company would be entitled to collect the $2 million in future rates, this value is grossed up to reflect the proper revenue requirement impact, given the fact that the Company cannot take a tax deduction for income tax expense. As a result a regulatory asset of $3.3 million is recorded. A deferred tax liability of $1.3 million is established to reflect the tax expense that will occur in the future when the $3.3 million is collected.

Q. How is the $3.3 million collected from customers?

A. In a subsequent rate proceeding, the reversal of the flow through temporary difference will result in an increase of $2 million to the level of income tax expense included in cost of service. The inclusion of the $2 million in the income tax expense component of cost of service results in an increase to revenue requirement of $3.3 million.

Q. Does the table above provide the combined total unfunded future income tax balance as of March 31, 2016?

A. Yes.

Q. Please explain what happens to these balances if the Commission approves full normalization of all originating and reversing temporary differences, using RG&E Electric as an example?

A. As discussed previously, the $43.6 million associated with the PowerTax implementation has already been recorded gross as a credit to revenues and a charge to income tax expense. As for the $125 million Unfunded Future Income Tax balance, a day one entry would be recorded to reverse the cumulative unfunded future income tax accounting recorded through the date of implementation of full normalization. The required ADIT and associated regulatory asset would in turn be recorded gross in a manner similar to how the PowerTax Regulatory Asset was recorded. Using a 40% tax rate, the entries would be:

<u>Entry 1</u> (To reverse the cumulative unfunded future income tax accounting.)

ADIT Previously Flowed Through Tax Benefits	$75.0 million	
ADIT Unfunded Future Income Tax Reg Asset	$50.0 million	
Unfunded Future Income Tax Reg Asset		$125.0 million

<u>Entry 2</u> (To establish the appropriate ADIT balance with the offset to deferred income tax expense.)

Deferred Income Tax Expense	$75.0 million	
ADIT Previously Flowed Through Tax Benefits		$75.0 million

<u>Entry 3</u> (To establish the future revenue requirement required to collect the future income tax payable associated with tax benefits that were previously provided to customers.)

Unfunded Future Income Tax Reg Asset	$125.0 million	
Revenues		$125.0 million

Entry 4 (To establish the deferred taxes associated with the established regulatory asset.)

Deferred Income Tax Expense	$50.0 million
ADIT Unfunded Future Income Tax Reg Asset	$50.0 million

The combination of the PowerTax and Unfunded Future Income Tax regulatory assets as of the date of the implementation of full normalization would be amortized and collected straight line over a period of 39 years.

Q. Why do the Companies treat both the PowerTax Regulatory Asset and the Unfunded Future Income Tax Regulatory Asset similarly in this full normalization proposal?

A. Both the PowerTax Regulatory Asset and the Unfunded Future Income Tax Regulatory Asset relate to tax benefits associated with timing differences that were provided to customers via the income tax component of cost of service in previous rate cases. The future cash tax liability that will arise as these timing differences reverse has not been funded for either of these balances. As has been described previously regarding the PowerTax Regulatory Asset, the PowerTax Regulatory Asset has been isolated due to the Companies' interpretation of the Normalization Rules whereby the continued flow through of federal tax depreciation versus book depreciation used to set rates after the discovery of the inadvertent flow through by the Companies would have resulted in a Normalization Violation and put at risk the continued utilization of accelerated tax depreciation for tax purposes.

Q. Absent the implementation of PowerTax and the shift to full normalization as described above, what would the impact on overall revenue requirement be in the future as these timing differences reverse?

A. The overall impact on revenue requirement related to these balances would be identical to the Companies' proposal. The only difference is that the amount is collected straight line rather than increasing and decreasing on an annual basis based on the value of the reversing flow through temporary differences.

Q. How is the customer made whole for the time value of money associated with the acceleration of this collection or pay for the time value of money if the collection is decelerated?

A. Both the regulatory asset and ADIT will be included in Rate Base, ensuring the neutrality to the time value of money concern.

Q. Have the Companies calculated their forecasted ADIT consistent with the IRS proration requirements?

A. Yes, the Companies have computed ADIT to reflect the proration method.

G. <u>Reflecting Results of Tax Audits</u>

Q. Please describe your proposal regarding deferral of federal, state and local tax audits.

A. The Companies propose to defer the revenue requirement impact of all tax expense and associated interest recorded as a result of tax audits.

Q. Why is this deferral being requested?

A. Tax authorities continue to be very aggressive and the Companies believe they should be protected from any impacts that arise from aggressive tax positions that they take to benefit customers.

Q. Is there any other reason for this protection?

A. Yes. Section 189 of the PSL requires that all tax refunds be reported to the PSC and that the Companies pass those refunds back to customers, unless there is a justification as to why the refunds should not go back to customers. This protection for audit exposure balances this requirement by ensuring that the Companies are not harmed by unfavorable audit results, while at the same time allowing customers to benefit from favorable audit results. The elimination of this inconsistency is in line with the PSC's position that utilities take prudent actions to minimize all operating costs, including income taxes, property taxes, and sales and use taxes.

Q. Is there anything further related to taxes that the Panel would like to mention?

A. The Companies are aware of a tax planning strategy in New York State that may provide tax savings for customers. The Companies are still evaluating the tax law related to this opportunity and may file a refund claim, or take a position on a future tax return, during this rate proceeding based on this opportunity. The resolution of the filing position with New York State may, or may not, occur during the Rate Year covered under this proceeding.

Consistent with the PSC's position that utilities take prudent actions to minimize operating costs, the Companies propose a sharing of any sustained refunds or tax reductions, net of all fees incurred similar, but not identical, to the sharing related to property tax expense currently in place. The Companies propose to provide 90% of any sustained tax savings, net of fees to customers.

H. Rate Base

Q. How was the Rate Base shown on Exhibit __ (RRP-4) developed?

A. The Rate Base for the forecast Rate Year was derived consistently with other components of Revenue Requirement and is based on the actual historical Test Year Rate Base which was filed with the Companies' 2014 Annual Financial Compliance Filing on March 24, 2015. Forecast balances for Utility Plant and Depreciation Reserve were derived from calculations contained within the Plant Model, Exhibit __ (RRP-5). For NYSEG Electric, the Depreciation Study supports a modification to the amortization of the Electric Excess Depreciation Reserve from $15.2 million per year to a revised annual amount of $11.9 million. Also, the Panel has reflected the removal of certain distribution property from Rate Base in anticipation of the divestiture of those assets. Additionally, the results of the Depreciation Study found that NYSEG Gas has a reserve deficiency. Therefore, RG&E Gas has reflected the impacts of the proposed Deficiency Amortization of $2.8 million per year on the reserve balance. For RG&E Electric, the Depreciation Study supports the discontinuation of the previous amortization of $5.2 million of excess reserves, which is reflected in the reserve balances.

Q. How were the other working capital components of Rate Base adjusted?

A. As described earlier in this testimony, Materials & Supplies and Prepayments, excluding the Temporary Assessment ("TSAS"), were forecast based on the Test

Year using a General Inflator of 4.02%. Additionally, the Companies O&M Working Capital forecast represents the application of the Commission's long-standing practice of applying a one-eighth formula to the Rate Year O&M expense (less Uncollectibles, TSAS, and Regulatory Amortizations).

Q. How were the Deferred Debits and Credits forecasts developed?

A. The forecast balance of Deferred Debits and Credits reflects the roll-in of all Regulatory Assets and Liabilities that have been deferred, with interest, during the Companies' current rate plan, except for two items – Environmental and Economic Development – which are both liabilities. The Companies propose to utilize these liabilities to help pay for future related Environmental and Economic Development costs. It is also the Companies' proposal that these balances will continue to accrue carrying charges. As described earlier, most of the other Regulatory balances are proposed to be amortized in rates over five years and are summarized in Exhibit __ (RRP-2), Schedule H. Exceptions to the five-year amortization relate to the PowerTax Regulatory Deferral and the Unfunded Future Income Tax items, which are forecast to be amortized over the estimated remaining life of the underlying assets. Also, as discussed earlier in this testimony, the Pension and Property Tax Regulatory deferral balances for NYSEG Gas are being amortized over five years, but with recovery proposed to occur through that Company's existing Transition Surcharge. NYSEG Electric's PBA balance of $13.7 million is being fully amortized over the Rate Year. Lastly, it is proposed that remaining costs associated with the decommissioning of RG&E's Russell and Beebee sites be funded through partial utilization of that

Company's Post Term Amortization Liability. This calculation is presented within the Regulatory Assets & Liability workpaper RC-RRP-4-WP-02. Aside from Regulatory Assets and Liabilities, the only other items being adjusted are the Pension Asset and OPEB Reserve, which utilize the forecasts provided by the Companies' actuary and are included in the Pension and OPEB workpapers.

Q. How have the Companies adjusted ADIT and ITCs?

A. Deferred Taxes associated with the Regulatory Assets, Liabilities, and Pension / OPEB forecasts track at the combined Federal and State statutory rate of 39.225%. Plant related deferred taxes are derived from calculations contained within the Plant model, Exhibit __ (RRP-5), and reflect full normalization. Of note, the Rate Base forecast reflects inclusion of the unamortized ADIT balances associated with the Bonus Depreciation and Mixed Use 263(a) tax benefits, which have been accruing NCR in accordance with the terms of the existing rate agreement. These deferred tax liabilities, along with the inclusion of the associated Regulatory NCR liabilities, have the impact of significantly lowering Rate Base as compared to historic Test Year levels. With respect to ITCs, the Companies' forecast continues amortization rates at the historic Test Year level. Noteworthy is that both RG&E Electric and Gas ITC balances were fully amortized just prior to the end of the Test Year and are therefore zero in the Rate Year.

Q. How have the Companies forecast the EBCAP adjustment?

A. The forecast level of EBCAP was based upon an analysis that utilizes a four-year average of actual historic amounts. Rounded to the nearest million, this has resulted in forecast levels of ($9 million) for NYSEG Electric, ($4 million) for RG&E Electric, ($3 million) for NYSEG Gas, and ($2 million) for RG&E Gas.

Q. Where is the primary support included for the Companies' Rate Base calculation?

A. Schedules A through G of Exhibit __ (RRP-4) G provide the primary support for most of the Rate Base line items. The Plant Models, Exhibit __ (RRP-5), provide the primary support for the Plant and Depreciation Reserve forecasts. Exhibit __ (RRP-3), Schedule A provides a description of all the adjustments to Rate Base. Additionally, the Companies have prepared separate RRP-4 workpapers detailing the historic Test Year Rate Base; the forecast Rate Year beginning balance of Regulatory Assets and Liabilities and; the four-year average EBCAP calculation.

XIV. <u>RESERVES AND RECONCILIATIONS</u>

Q. Please summarize the proposed reconciliation and reserve accounting items at each Company.

A. The Companies are proposing only minor modifications to the list of reconciliation and reserve accounting items approved in the 2010 JP. The table below provides a summary of the current and proposed treatment.

Table 50: Reconciliation and Reserve Accounting Items
Rate Year Costs ($ thousands)

Reconciliation / Reserve	Current Treatment	Proposed Treatment
Pensions	Symmetrical[1]	Symmetrical[1]
OPEBs	Symmetrical[1]	Symmetrical[1]
Property Taxes	Symmetrical w/ Sharing[2]	Symmetrical w/ Sharing[2]
Electric Distribution Veg Mgmt	Downward Only	Symmetrical
Gas Veg Mgmt	Downward Only	Downward Only
Variable Rate Debt	Symmetrical	Symmetrical
Gas R&D	Symmetrical	Symmetrical
Pipeline Integrity Costs	Downward Only	Downward w/ Carryover
Incremental Maintenance	Downward Only	Downward w/ Carryover
Environmental Costs	Symmetrical[3]	Symmetrical[3]
Major Storm	Symmetrical	Symmetrical[4]
Legis, Actg, Regulatory, Tax & Rel Actns	Symmetrical[5]	Symmetrical[5]
Economic Development	Symmetrical w/ Carryover	Symmetrical w/ Carryover
Low Income Program	Symmetrical[6]	Symmetrical[6]

1) Excludes non-qualified plan costs
2) 90% of the variation above or below the target will be deferred. The Companies' 10% share of property tax expenses above or below the target will be limited to 10 basis points on the amount of common equity supporting Rate Base. 100% of additional variances are deferred.
3) The Companies propose to continue using reserve accounting for Environmental Costs.
4) The Companies to begin using reserve accounting for Major Storm Costs.
5) Subject to annual thresholds of $1 million for the electric businesses and $0.5 million for the gas businesses.
6) The Companies propose to continue the limitations established in Appendix I of the 2010 JP.

A. Debt Cost Deferral

Q. Are the Companies proposing to continue to defer variable rate debt?

A. Yes, consistent with the current rate plans, the Companies propose to defer differences in variable rate debt. The Companies have accrued regulatory liabilities (amounts owed to customers) of $14.1 million at NYSEG (electric and gas) and $0.3 million at RG&E (electric and gas).

Q. Are the Companies also proposing to add deferral accounting for differences in the cost of new fixed rate debt?

A. No.

XV. RATE ADJUSTMENT MECHANISM / TRANSITION SURCHARGE

Q. What is the Companies' proposal for a Rate Adjustment Mechanism ("RAM") / Transition Surcharge?

A. The Companies propose to implement a RAM to return or collect deferred costs, reserve balances and service and reliability revenue adjustments with minimal regulatory lag. In addition, the Companies recommend the continued use of a Gas Transition Surcharge to recover deferred / uncontrollable costs.

Q. How do the Companies propose that a RAM operate?

A. The Companies propose that a RAM be instituted to manage the buildup of large regulatory assets or liabilities. The Companies propose to measure the deferred regulatory asset and liability balances each December 31 to determine if a RAM is necessary. The Companies proposes two measurements, one for major storms and the other for all other regulatory assets and liabilities. The major storm reserve trigger will be $20 million at NYSEG Electric and $10 million at RG&E

Electric. The trigger for all other regulatory assets and liabilities trigger will be: 1) $20 million at NYSEG Electric; 2) $10 million at RG&E Electric; and 3) $5 million at both NYSEG Gas and RG&E Gas. If the storm reserve balance exceeds the applicable trigger threshold and / or the other regulatory assets / liabilities exceed the applicable trigger threshold then the applicable business will implement a RAM to return or collect the deferred costs. The Companies propose that the RAM be identified in their ACFs submitted on March 31 of each year and be implemented in rates on July 1 of each year. The Companies propose that the RAM impact be limited to 10% of Delivery revenues (or approximately 5% of overall bill). The RAM would collect the amount of the excess over the trigger level subject to the rate limitation. Any remaining balance would continue to be deferred and roll forward to the next year's calculation.

Q. Why is the creation of a RAM necessary?

A. A RAM would help avoid the build-up of deferred costs or credits. Cash flow is a critical measure in determining the Companies' credit ratings and allowing for a RAM would assist in keeping cash outlays or receipts consistent with revenue collection or return. The mechanism would operate whether a charge or credit.

Q. Does the creation of a Rate Adjustment Mechanism limit Staff's right to audit the deferred cost?

A. No. The implementation of the RAM will not limit Staff's right to audit the deferred costs.

XVI. CREDIT METRICS ANALYSIS

Q. Please describe the credit metrics analysis the Panel performed.

A. The Panel used financial information from the Companies' projected regulatory income statements, balance sheets and cash flow entries for the Rate Year to calculate the key financial ratios employed by both S&P and Moody's when assessing credit quality and assigning credit ratings. Taken as a whole, these measures focus on the Companies' ability to pay their debt service, finance their operations, and attract capital.

Q. What metrics does S&P employ in assessing the financial health of a company?

A. S&P uses two core credit ratios: 1) funds from operations ("FFO") to debt and 2) debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA"). These ratios assess a company's ability to cover its debt service and its financial leverage. S&P employs five additional supplemental ratios to develop a more complete understanding of a company's risk profile. S&P's ratios are listed in the following table:

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Table 51: S&P Core and Supplemental Ratios

Ratio	Description
Core 1. FFO to Debt	Funds from Operations as a % of Debt Outstanding
Core 2. Debt to EBITDA	Debt divided by Earnings before Interest, Taxes, Depreciation and Amortization
Sup. 1. CFO to Debt	Cash Flow from Operations as a % of Debt
Sup. 2. FOCF to Debt	Free Operating Cash Flow as a % of Debt
Sup. 3. DCF to Debt	Discretionary Cash Flow as a % of Debt
Sup. 4. FFO to Interest	Funds from Operations plus interest divided by interest
Sup. 5. EBITDA to Interest	Earnings before Interest, Taxes, Depreciation and Amortization divided by Interest

Q. S&P's ratios employ a variety of cash flow measures. What is the difference between FFO, Cash Flow from Operations ("CFO"), Free Operating Cash Flow ("FOCF") and Discretionary Cash Flow ("DCF")?

A. FFO measures cash generated by the operation of a company before changes in working capital and before capital expenditures or dividends. CFO adjusts FFO for changes in working capital. FOCF adjusts CFO for capital expenditures and DCF adjusts FOCF for dividends paid. FFO is the least restrictive of the cash flow measures because it is not adjusted to reflect working capital changes and the elimination of other items, while DCF is the most restrictive because it measures cash flow after most mandatory and discretionary obligations have been met.

Q. What metrics does Moody's employ in assessing the credit quality of a company?

A. Moody's uses four ratios to measure financial health: 1) CFO before changes in working capital plus interest to interest; 2) CFO before changes in working capital to debt; 3) CFO before changes in working capital less dividends to debt; and 4) debt to total capital (including deferred taxes).

Q. Have S&P and Moody's provided any indications regarding how the results of these calculations are factored into their respective credit quality assessments for the Companies?

A. Yes, each credit rating agency has issued a document that links the results for each metric to a particular letter grade ratings category.[4]

Q. Has the Panel computed the credit metric results for each of the Companies?

A. Yes, the electric and gas financial results for each Company were combined to develop a single set of metrics for NYSEG and for RG&E. FFO was calculated using the following components available in Exhibit __ (RRP-2):

1) Funds available from Common (net income);
2) Depreciation;
3) Deferred Taxes related to Plant;
4) Amortization of regulatory asset and liabilities; and
5) Deferred taxes related to amortizations.

Moreover, since this is a forward looking exercise, no change to working capital was assumed from period to period. As a result, FFO and CFO were presumed to be equal. We also used the Companies' proposed capital expenditures, and calculated dividends as the amount required each year to

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[4] See Rating Methodology, Regulated Electric and Gas Utilities, Moody's Investors Service (Dec. 23, 2013) and Ratings Direct, Corporate Methodology, Standard & Poors Ratings Services (Nov. 19, 2013).

maintain a 50/50 capital structure. Finally, we used interest expense from the Companies' income statement as well as the long-term debt, equity and deferred taxes outstanding from schedules A through G in Exhibit __ (RRP-2).

Q. Please describe the results of this analysis for NYSEG.

A. Exhibit __ (RRP-8) shows the calculation of the ratios for the Rate Year for both Moody's and S&P. The Moody's ratios justify an 'A' rating. Both of S&P's core ratios equate to an 'A-/BBB+' rating, while three of the five supplemental ratios support a 'A-/BBB+' rating. The other two S&P supplemental ratios – FOFC to debt and DCF to debt support a BB and BB+ ratings respectively. These are non-investment grade ratings.

Q. Please describe the results of the FOCF to debt and the DCF to debt computations in more detail.

A. These metrics assess the ability of a company to maintain its financial health while financing capital expenditures and paying dividends. To accomplish this, the cash flow measure in the numerator of both ratios is reduced by capital expenditures. NYSEG's capital expenditure program is large relative to cash generated by operations. Thus, the levels of these two ratios are troubling because they are consistent with non-investment grade ratings from S&P.

Q. What is the significance of a non-investment grade rating?

A. Interest rates on non-investment grade debt are likely to be over 100 basis points greater than rates on 'BBB/Baa' debt and the terms and conditions of such debt may restrict certain utility activities. Thus, it is not in the public interest for New York utilities to have non-investment grade ratings.

Q. Please describe the results of this analysis for RG&E.

A. Exhibit __ (RRP-8) shows the calculation of the ratios for the Rate Year for both Moody's and S&P. Three of Moody's ratios justify an 'A' rating while the other equates to a 'Baa' rating. Both of S&P's core ratios equate to an 'A- / BBB+' rating. Additionally, three of the five supplemental ratios are between 'BBB' and 'A- / BBB+'.

Q. What about the final two S&P supplemental ratios, FOCF to debt and DCF/Debt?

A. As with NYSEG, RG&E's capital expenditures are large relative to cash generated by operations. As a result, the levels of these two ratios are troubling because they are consistent with non-investment grade ratings from S&P.

Q. What conclusions can you draw from these results?

A. The main ratios employed by both Moody's and S&P to assess the Companies' credit quality would suggest a 'BBB' to 'A-' credit rating for both NYSEG and RG&E. Moreover, the size of the Companies' construction program contributes to suboptimal results for two of S&P's supplemental credit metrics. Finally, it is important to note that the Companies' financial strength is below the single 'A' level that is the target for the State's utilities and their current credit ratings are lower than those of their New York gas and electric utility peers. Any reductions to the Companies' cash flows (e.g., lower return on equity or equity ratio, lower depreciation expense, or more aggressive amortization of regulatory liabilities) compared with their filed levels would weaken the Companies' financial health and create more distance between them and their peers, which all have credit ratings in the targeted 'A' rating range.

XVII. CHANGES IN ACCOUNTING AND CAPITALIZATION POLICIES

Q. What changes in Accounting and Capitalization Policies are being proposed by the Companies?

A. The Companies are proposing several changes in Accounting and Capitalization policies. These changes range from some very specific items to more global policy changes. Each will be described in the testimony that follows.

Q. To the extent that any or all of these proposed changes are not accepted by the Commission, what is the impact on proposed revenue requirements for each of the Companies' businesses?

A. The Companies' filing presumes that the Commission will accept each of these proposed changes in Accounting and Capitalization policies. To the extent that a proposed change is not accepted, the amount that is currently presumed to be capitalized, deferred or charged to supply will need to be added into the O&M expenses currently reflected in this rate filing and an increase in the revenue requirements for the relevant business(es) will need to occur.

Q. Why are the Companies proposing to remove $275,000 of O&M expense for the purchase of station heater fuel from base rates and to begin including it in gas supply cost, as discussed in the Electric Supply and Natural Gas Supply and Expansion Panel?

A. This cost is clearly a gas supply cost because it is fuel used at the purchase station in order to deliver all customers' gas supply.

Q. What changes are the Companies proposing to their Capitalization policies relating to certain gas mains and services?

A. The Companies are proposing to capitalize, with the cost of new mains, the associated costs to tie existing services to new mains. The Companies are also proposing to capitalize, with the cost of new services, the reconnection of customer house lines when services are replaced or relocated.

Q. Why are the Companies proposing to change the policy of expensing the associated costs to tie services to mains and when mains are replaced or relocated from O&M to Capital?

A. Current accounting practices at the Companies reflect the charging to O&M for the entire cost of such service connections in the year incurred rather than amortizing or depreciating these costs over the expected life of the asset being installed. All costs associated with these main replacements should be capitalized since they are associated with the replacement of the main. Absent the actual interconnect between the main and service, there is no used and useful asset. Therefore, the cost to perform the connection is a required component of the main capital. The Companies incurred approximately $334,000 of O&M costs during the Test Year for these types of service tie-ins ($223,000 at NYSEG Gas and $111,000 at RG&E Gas). These amounts would clearly vary based on the actual number of mains replaced year over year. This volatility also supports capitalization of the service tie-ins.

Q. Why are the Companies proposing to change the policy of expensing the reconnection of customer house lines when services are replaced or relocated from O&M to Capital?

A. Current accounting practices at the Companies reflect the charging to O&M for the entire cost of such customer house line reconnections in the year incurred rather than amortizing or depreciating these costs over the expected life of the asset being installed. All costs associated with these customer house line reconnections should be capitalized since they are associated with the replacement of the service. Absent the actual interconnect between the customer house line and the service, there is no used and usable asset. Therefore, the cost to perform the reconnection is a required component of the service capital. The Companies incurred $1.1 million of O&M costs during the Test Year for these types of customer house line reconnections ($770,000 at NYSEG Gas and $308,000 at RG&E Gas). These amounts would clearly vary based on the actual number of services replaced or relocated year over year. This volatility also supports capitalization of the house line reconnections.

Q. Are the Companies also proposing to capitalize and amortize / depreciate payments made to other entities (e.g., Electric Transmission Companies such as National Grid or New York State entities like the New York Power Authority) for the installation / upgrade of equipment at facilities (such as Substations) owned by these other entities when those installations / upgrades are required to support the completion of major capital projects of either NYSEG or RG&E?

A. Yes. For many good reasons, including security of their facilities, these entities want to maintain ownership of all equipment at their facilities, even though the upgrades are not benefiting the customers of those other entities. When NYSEG or RG&E make payments to these entities, they treat those payments as a contribution in aid of construction and essentially include the new or upgraded property on their books at $0 in plant value. Under current FERC accounting guidance, the utility making the payment to those entities would need to charge that payment to O&M, unless the State regulatory body agrees to an alternate accounting approach.

Q. Why does an alternate accounting approach make sense in these circumstances?

A. The matching principle in accounting would suggest that the costs associated with an asset be recovered from customers over the period that an asset is beneficial to customers. The current accounting rules would have customers be responsible for paying significant O&M amounts in the year that a payment is made to a third-party entity, while the asset being installed by NYSEG or RG&E will last for many decades. This creates intergenerational inequities, particularly in a time frame such as the one the Companies are entering, when NYSEG and RG&E are engaging in large transmission projects that result in the need to pay other entities for upgrades to their facilities.

Q. What are examples of specific projects for which the Companies expect payments will need to be made to third-party entities and for which, at this point in time, no O&M amounts have been included in the revenue requirements?

A. There are several projects where this situation is expected to arise. Three examples are: 1) RG&E's Rochester Area Reliability Project, for which RG&E is expected to need to make payments of more than $7 million to various third parties; 2) NYSEG's Columbia County Transmission project, where NYSEG is expecting to make nearly $0.2 million in payments to third parties; and 3) NYSEG's Auburn Transmission project, where NYSEG is expecting to make payments of nearly $7 million to third parties. As noted earlier, none of these anticipated payments have been included in the O&M costs reflected in proposed revenue requirements. If the Commission does not authorize NYSEG and RG&E to capitalize these types of payments, the O&M included in revenue requirements will need to be increased with a corresponding increase in customer Delivery rates in the Rate Year.

Q. What is the specific NYSEG and RG&E request of the Commission at this time?

A. The specific request is that the Commission authorize the Companies to charge the capital project being benefitted by payments to third parties with the cost of those payments to third parties, when the project payment would be in excess of $50,000, instead of charging O&M. The Companies would, therefore, depreciate the amount of those payments over the lives of the capital assets being installed as part of each affected project.

XVIII. INVESTMENT/RETIREMENT UNITS

Q. What is the Companies' proposal with respect to the listings and definitions of certain Investment / Retirement units?

A. Currently, NYSEG and RG&E have slightly different listings and definitions for units of property. This is the result of many years of historical practices followed by the separate companies. These varying listings and definitions result in differences in what each Company capitalizes based on its investment / retirement units. The goal of the Companies is to align the units of property between the Companies as much as possible. The Panel proposes to make the definitions for a number of units of property consistent between the Companies. The proposed changes affect the level of O&M for NYSEG Electric. The Companies propose that NYSEG adopt the RG&E definition of units of property for Cross Arms, Guy Wires, Anchors, and Cutouts. RG&E currently considers each of these items as separate units of property and, therefore, capitalizes their replacements or additions. NYSEG currently does not treat these items as separate units of property and, therefore, expenses their replacement or addition.

Q. What are the benefits for making the definitions of Investment / Retirement units consistent between the Companies?

A. Consistent definitions will result in better, and more consistent, tracking of property and costs.

Q. What is the annual incremental O&M impact associated with the proposal for NYSEG to adopt the RG&E definition of Investment / Retirement units for Cross Arms, Guy Wires, Anchors and Cutouts?

A. Based on the amounts included in O&M during the Test Year for these items (Cross arms, Anchors, Guy Wires, and Cutouts), NYSEG has estimated a $1.65 million reduction in O&M from the Test Year to the Rate Year through the adoption of this proposed change.

Q. Does this complete your testimony at this time?

A. Yes, it does.