nationalgrid

Raquel J. Webster
Senior Counsel

August 3, 2015

BY HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4473 - Fiscal Year 2015 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing

Dear Ms. Massaro:

On behalf of National Grid,[1] relating to the Company's Fiscal Year (FY) 2015 Electric Infrastructure, Safety, and Reliability (ISR) Plan, I have enclosed ten copies of the Company's Electric ISR Reconciliation Filing. Pursuant to the approved ISR Plan and the ISR Provision, RIPUC No. 2188, after the end of the ISR Plan year, which runs from April 1 through March 31, the Company must file annually, by August 1 of each year, the proposed CapEx Reconciling Factors and O&M Reconciling Factor that will become effective for the twelve months beginning October 1. The CapEx Reconciling Factors recover or credit the difference between the reconciliation of actual billed revenue generated from the CapEx Factors and the actual Cumulative Revenue Requirement for the applicable plan year. Similarly, the annual O&M Reconciling Factor recovers or credits the difference between the reconciliation of actual billed revenue from the O&M Factor and actual Inspection and Maintenance (I&M) program expense and actual Vegetation Management (VM) program expense for the ISR Plan year. Additionally, on August 1, the Company must report on the prior fiscal year's ISR Plan activities and include descriptions of deviations from the original plans approved by the Rhode Island Public Utilities Commission (PUC).

This filing provides the actual discretionary and non-discretionary capital investment spending and the actual Vegetation Management (VM) and Inspection and Maintenance (I&M) expenses for the period April 1, 2014 to March 31, 2015. As explained in this filing, the actual capital plant-in-service is compared to the budgeted amounts for these categories, as approved by the PUC in Order No. 21559. The plant-in-service investment and Operation and Maintenance (O&M) expenses for VM and I&M are then used in the calculation of the revenue requirement for the annual reconciliation of investment and expenses for the fiscal year. This revenue requirement is then compared to actual revenue billed, and any difference forms the basis for the proposed

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

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Electric ISR Plan reconciliation factors for effect October 1, 2015. This filing also includes details on the Company's actual discretionary and non-discretionary capital investment spending by category during FY 2015. Finally, this filing includes a summary of the Company's Reliability Performance through December 31,2014.

The pre-filed direct testimonies of James H. Patterson, Amy Tabor, and Adam Crary are enclosed with this filing. Mr. Patterson presents the Company's FY 2015 Electric ISR Plan Reconciliation Filing related to the FY 2015 Electric ISR Plan approved by the PUC in this docket. Ms. Tabor's testimony describes the calculation of the revenue requirement based on the capital plant-in-service and the total annual actual VM and I&M expenses for the fiscal year. Ms. Tabor's testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As explained in Ms. Tabor's testimony, for the FY 2015 Electric ISR reconciliation, the Company has an updated revenue requirement of $16,084,391. Mr. Crary describes the reconciliation of the final actual FY 2015 revenue requirement against revenue billed in support of that revenue requirement, the proposed factors resulting from the reconciliation, and the bill impacts of those proposed factors. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is an increase of $0.51, or approximately 0.5%, from $99.02 to $99.53.

Thank you for your attention to this filing. If you have any questions, please contact me at (781) 907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4473 Service List
LeoWold, Esq.
Steve Scialabba, Division
James Lanni, Division
Al Contente, Division

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

Paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

___________________________________ August 3, 2015
Joanne M. Scanlon Date

Docket No. 4473 National Grid's FY 2015 Electric Infrastructure, Safety and Reliability Plan - Service List as of 10/30/14

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PRE-FILED DIRECT TESTIMONY

OF

JAMES H. PATTERSON, JR.

August 3, 2015

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I. INTRODUCTION AND QUALIFICATIONS

Q. Mr. Patterson, please state your name and business address.

A. My name is James H. Patterson, Jr. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Mr. Patterson, by whom are you employed and in what position?

A. I am employed by National Grid USA Service Company, Inc. (Service Company) as Director, Network Strategy, New England Electric. I am responsible for regulatory filings and regulatory compliance related to electric distribution operation of The Narragansett Electric Company d/b/a National Grid (the Company or National Grid). I am also responsible for those types of filings relative to National Grid USA's electric distribution operations in Massachusetts.

Q. Mr. Patterson, please describe your educational background and professional experience.

A. In 1999, I graduated from Worcester Polytechnic Institute in Worcester, Massachusetts, with a Bachelor's Degree in Electrical Engineering. In the same year, I was employed by Massachusetts Electric Company as an Associate Operations Engineer in the Operations Engineering department. I was promoted to Operations Engineer in 2001. In these two roles, I was responsible for the engineering and design of distribution line construction projects, as well as participating in system restoration efforts due to equipment failures and severe weather events. In 2002, I joined the Distribution Planning and Engineering department as an Engineer. In 2005, I was promoted to Senior Engineer. In these two roles, I was responsible for identifying asset, capacity, and reliability issues, justifying proposed solutions, and initiating selected projects for Operations and Substation engineering departments. I also reviewed and recommended solutions to serve customers requiring significant demand. In 2005, I was promoted to Supervisor of the Distribution Design department, which was formerly called Operations Engineering. In 2007, I was promoted to Manager of the Distribution Design departments. In these two roles, I was responsible for the quality and throughput of the design of distribution line construction projects, as well as directing staff in system restoration during equipment failures and severe weather events. In 2010, I joined the Operations Program Management department in the National Grid USA Service Company as manager for the New England and New York Distribution Line portfolios. In 2012, my roles and responsibilities were changed to only include Massachusetts and New Hampshire Gas and Distribution Line functions in the Resource Planning department, formerly known as the Program Management department. In 2013, my roles and responsibilities were changes to only include Massachusetts and Rhode Island Distribution Line portfolios. In these three positions, I was responsible for creating, monitoring, and execution of the work plans for the applicable portfolio of construction projects. I was promoted and assumed my current role on October 1, 2014.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. Yes. I have testified in support of the previous Electric Infrastructure, Safety and Reliability (ISR) Plan filings in Docket Nos. 4539.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present the Company's Fiscal Year 2015 (FY 2015) Annual Reconciliation filing related to the FY 2015 Electric ISR Plan approved by the PUC in this docket. This filing provides the actual plant-in-service for discretionary and non-discretionary capital investment and associated cost of removal (COR)[1], the actual Vegetation Management (VM) expenses, and the actual Inspection and Maintenance (I&M) expenses for the period April 1, 2014 to March 31, 2015. As described in her testimony in this filing, Ms. Amy Tabor uses this plant-in-service investment and the Operation and Maintenance (O&M) expenses for VM and I&M to calculate the FY 2015 Electric ISR Plan revenue requirement. As explained in Mr. Adam Crary's testimony in this filing, this revenue requirement is then reconciled against actual revenue billed during FY 2015. The specific FY 2015 Electric ISR Plan plant-in-service additions and

[1] Under the Electric ISR Plan, discretionary capital investment for a fiscal year must be reconciled to the lesser of the actual capital investment placed-in-service and the level of approved spending on a cumulative basis. Non-discretionary capital investment for a fiscal year must be reconciled to the actual capital investment placed-in-service. Docket No. 4218, Report and Order No. 20852 at 6 (December 12, 2011).

COR by categories, as well as actual spending, are included in Attachment JHP-1 attached to this testimony.

III. PLANT-IN-SERVICE OVERVIEW

Q. Please provide an overview of the plant-in-service for FY 2015.

A. As shown on Table 1 in Attachment JHP-1, the Company placed $76.7 million of plant-in-service. This amount is $7.7 million more than the forecasted amount of $68.9 million for plant-in-service for FY 2015. This amount of $7.7 million is primarily driven by a variance of $11.0 million above the forecasted amount in the Discretionary Sub-category. This $11.0 million is offset by a variance of $3.2 million below the forecasted amount in the Non-discretionary Sub-category. Details on these variances are included in Section I of Attachment JHP-1.

As explained in Ms. Amy Tabor's testimony, the plant-in-service amounts and the COR provided in Table 2 in Attachment JHP-1 are used to calculate the revenue requirement included in the ISR Plan reconciliation for FY 2015. These amounts are reflected in the Electric ISR Plan reconciliation factors. The capital spending amounts are not used in this calculation.

IV. ACTUAL CAPITAL SPENDING

Q. Please summarize the Company's actual capital spending for FY 2015 for the Electric ISR Plan.

A. As set forth in Table 3 in Attachment JHP-1, for FY 2015, the Company spent $73.1 million for capital investment under the Electric ISR Plan. This amount was $7.2 million above budget against an annual approved budget of $65.9 million. This above budget spending variance was primarily driven by capital spending in the Discretionary Sub-category, which was above budget by $10.7 million. This $10.7 million variance was partially due to $5.5 million over-budget spending in the Asset Condition category. This was primarily because of an over-budget variance of $1.3 million on the DxT Relay Replacement strategy due to the advancement of relay replacements; an over-budget variance of $1.0 million on the Eldred Substation project due to the original budget estimate being based on preliminary engineering; and a $1.1 million over-budget variance on the Governor Street Providence Ductline project due to productivity losses in FY 2014, which pushed construction into FY 2015.

Also contributing to the $10.7 million variance was an over-budget variance of $0.9 million in the Non-Infrastructure category. Of this total, $0.5 million of the over-budget variance was driven by the FY 2015 reclassification of a net credit of capital accounting adjustments from Non-Infrastructure to an allocated population of Damage/Failure construction work orders. The remaining $0.4 million over-budget variance was due to purchases of transformer testing devices and general equipment.

Finally, contributing to the $10.7 million variance was an over-budget variance of $4.2 million in the System Capacity and Performance category. This variance was primarily because of the following: an over-budget variance of $2.8 million on the New Highland Drive Substation project due to conceptual grade estimates being used to establish the FY 2015 budget; an over-budget variance of $0.8 million on the Volt/Var pilot program due to unforeseen costs for engineering, materials, and information system support; and an over-budget variance of $0.7 million on the Pawtucket #1 Load Relief project due to the need to address summer capacity constraints at the Pawtucket #1 substation.

Offsetting the over-budget variance in the Discretionary Sub-category was an under-budget variance of $3.5 million in the Non-Discretionary Sub-category. This $3.5 million variance was partially due to $3.2 million over-budget spending in the Asset Condition category. Of this total, $1.3 million of the over-budget variance was due to the following: a reclassification of charges on the Shun Pike Substation; an over-budget variance of $1.2 million on the I-95 Relocation projects for Contracts 14 and 15 due to the identification of undocumented third-party assets; an over-budget variance of $0.8 million on the Watch Hill Underground project due to construction occurring in FY 2015 despite a customer contribution being received in FY 2014; and an over-budget variance of $0.8 million on the Ocean State New Business Residential blanket because of a higher than expected demand in FY 2015.

An under-budget variance of $6.8 million in the Damage/Failure category also contributed to the under-budget variance of $3.5 million on the Non-Discretionary Sub-category. This variance was primarily due to the following: an under-budget variance of $10.2 million on the Ocean State Storm Capital Confirming project due to an adjustment in the Company's storm reconciliation filing and a credit for the 2012 Rhode Island Flood; an over-budget variance of $2.4 million on the Ocean State Damage/Failure blankets for distribution line and substations due to an increased identification of assets to be replaced; and an over-budget variance of $2.1 million on the Damage/Failure reserve due to equipment failures on the Sockanosett, Nasonville, Warwick Mall, and Franklin Square substations.

The key drivers and variances by spending rationale category are discussed in detail in Section III of Attachment JHP-1.

V. O&M SPENDING

Q. Please summarize the Company's actual O&M spending for the FY 2015 Electric ISR Plan.

A. As shown on Table 11 in Attachment JHP-1, the total VM spending for FY 2015 was $8.0 million compared to an approved budget of $7.7 million. In addition, as shown on Table 12, the overall I&M spending was approximately $2.0 million compared to an approved budget of $3.0 million. Detailed information regarding the VM and I&M variances and the work completed is discussed in Sections IV and V of Attachment JHP-1.

VI. <u>RELIABILITY</u>

Q. Please summarize the results of the Company's reliability performance for FY 2015.

A. Section VI of Attachment JHP-1 presents the Company's Reliability Performance for calendar year 2014 (CY 2014). As shown in Table 13, the Company met both its SAIFI and SAIDI performance metrics in CY 2014, with SAIFI of 0.78, against a target of 1.05, and SAIDI of 54.06 minutes, against a target of 71.9 minutes. Overall, the Company's performance has shown a downward (improving) trend over the past several years with major event days excluded. For CY 2014, the Company had zero days that were characterized as major event days. Table 14 provides the overall reliability performance measures including major event days.

Q. Does this conclude this testimony?

A. Yes, it does.

Attachment JHP-1

FY 2015 Electric Infrastructure, Safety and Reliability Plan Reconciliation Filing

Electric Infrastructure, Safety and Reliability Plan

Fiscal Year 2015 Reconciliation

EXECUTIVE SUMMARY

In accordance with tariff, RIPUC No. 2044, Sheets 1- 4, The Narragansett Electric Company d/b/a/ National Grid (the Company) submits this annual reconciliation filing for the fiscal year 2015 (FY 2015) Infrastructure, Safety and Reliability (ISR) Plan approved by the Rhode Island Utilities Commission (PUC) in this docket. This filing provides the actual discretionary and non-discretionary capital investment spending and the actual Vegetation Management (VM) and Inspection and Maintenance (I&M) expenses for the period April 1, 2014 to March 31, 2015. As explained in this filing, the actual capital plant-in-service is compared to the budgeted amounts for these categories, as approved by the PUC in Order No. 21559. The plant-in-service investment and Operation and Maintenance (O&M) expenses for VM and I&M are then used in the calculation of the revenue requirement for the annual reconciliation of investment and expenses for the fiscal year. This revenue requirement is then compared to actual revenue billed, and any difference forms the basis for the proposed Electric ISR Plan reconciliation factors for effect October 1, 2015. This filing also includes details on the Company's actual discretionary and non-discretionary capital investment spending by category during FY 2015. Finally, this filing includes a summary of the Company's Reliability Performance through December 31, 2014.

For FY 2015, the Company's Electric ISR Plan plant-in-service investment was $76.7 million, which was $7.7 million greater than the forecasted plant-in-service of $68.9 million. Also, the 7.0 million cost of removal was $1.4 million less than the Company's forecast of $8.4 million. These totals resulted in a net Electric ISR investment that was $6.3 million over what the Company forecasted. Section I below provides a summary of the actual plant placed-in-service in FY 2015 compared to the FY 2015 Electric ISR Plan budget approved in Docket No. 4473. This summary separates non-discretionary and discretionary capital investments. Section I also includes a similar summary for Cost of Removal (COR).

For FY 2015, the Company's capital Electric ISR spending was $73.1 million, which was $7.2 million over the annual approved budget of $65.9 million. Section II of this report provides a summary overview of the actual capital spending by category. Section III provides a detailed explanation of capital investment variances by each category to the budget approved in Docket No. 4473. Section IV provides a breakdown of VM expenses and an explanation of the variance for these expenses within the categories of the approved budget of $7.7 million. Section V provides a similar breakdown for I&M expenses and an explanation of the variance with the approved budget of $3.0 million. Finally, the Company's reliability performance metrics are addressed in Section VI.

This filing includes testimony from James H. Patterson, Amy Tabor, and Adam Crary. Mr. Patterson's testimony introduces the FY 2015 reconciliation. Ms. Amy Tabor's testimony describes the calculation of the revenue requirement based on the capital plant-in-service and the total annual actual VM and I&M expenses for the fiscal year. Ms. Tabor's testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As shown in Ms. Tabor's testimony, for the FY 2015 filing, the Company has an updated revenue requirement of $16,084,391.

Mr. Adam Crary's testimony provides a description of the reconciliation of the final actual FY 2015 revenue requirement against revenue billed in support of that revenue requirement, the proposed factors resulting from the reconciliation, and the bill impacts of those proposed factors. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is an increase of $0.51, or approximately 0.5%, from $99.02 to $99.53.

I. FY 2015 Capital for Plant Investment Placed in Service

In its reconciliation filing, the Company is required to submit the annual capital spending for Plant Additions that were placed in service during the fiscal year. As shown in Table 1 below, for FY 2015, $76.7 million was placed in service, which was $7.7 million above the annual ISR forecast of $68.9 million. The Non-Discretionary Sub-category was $3.2 million under the FY 2015 Electric ISR Plan planned amount, primarily due to storm reconciliation adjustments and insurance credits in the Damage Failure spending rationale category. The variance to the Customer and Public Requirements sub-category was driven by I-195 and Shun Pike plant additions. The Discretionary Sub-category was $11.0 million over the FY 2015 Electric ISR Plan planned amount. This variance was primarily due to Eldred substation being placed into service and a higher than expected amount of I&M work being placed into service under the Asset Condition spending rationale category. Also contributing to this variance was the New Highland Drive substation being placed into service under the System Capacity & Performance spending rationale category.

Table 1

	FY 2015 Total		
	Annual ISR Forecast	Actual in Service	Variance
Customer Request/Public Requirement	$14,574,000	$18,443,062	$3,869,062
Damage Failure	$10,921,000	$3,803,602	($7,117,398)
Subtotal Non-Discretionary	*$25,495,000*	*$22,246,664*	*($3,248,336)*
Asset Condition	$20,153,000	$28,094,392	$7,941,392
Non-Infrastructure	$277,000	$345,779	$69,779
System Capacity & Performance	$23,013,000	$25,970,206	$2,957,206
Subtotal Discretionary	*$43,443,000*	*$54,410,377*	*$10,967,377*
Total Capital Investment in Systems	**$68,938,000**	**$76,657,041**	**$7,719,041**

* ( ) denotes an underspend for the period

The variances referenced in Table 1 reflect the timing of when plant investment is placed into service. In general, once equipment is energized and placed into service to support electric load, capital costs are transferred from FERC Account 107 (Construction Work in Progress or CWIP) to FERC Account 106 (Plant-In-Service) at the time that the underlying capital work becomes used and useful in the service of customers. This can differ by the type of plant and facility. For example, electric distribution line equipment is normally placed in service closer to the time it is installed because it is typically energized at that time and begins to support electric load, and therefore, is used and useful in the service of customers. Because electric distribution line equipment is typically energized as it is installed, a relatively significant amount of plant is placed into service as work progresses. By contrast, substation construction typically involves multi-year projects. Therefore, the assets must pass testing, the work must be commissioned, and the assets must be energized before they can be placed in service. Because substation construction is typically completed in one or more phases as part of a multi-year process, these assets will only be placed in service to serve customers once all work in a particular phase is completed.

Table 2 provides the total Cost of Removal (COR) for FY 2015, which was $7.0 million, or $1.4 million below the Annual ISR forecast of $8.4 million. The Non-Discretionary Sub-category was $2.7 million over the FY 2015 Electric ISR Plan planned amount. This variance was primarily driven by an overall increase in spend on the blanket projects within the Damage Failure category. The Discretionary Sub-category was $4.1 million under the FY 2015 Electric ISR Plan planned amount. This variance was primarily driven by lower than expected removal within the I&M program under the Asset Condition category, account entry adjustments in the Non-Infrastructure category, and salvage credits applied to the System Capacity & Performance category.

Table 2

	FY 2015 Total		
	Annual ISR COR Forecast	**FY 2015 Actual COR**	**Variance**
Customer Request/Public Requirement	$1,348,520	$1,752,357	$403,837
Damage Failure	$1,452,850	$3,763,847	$2,310,997
Subtotal Non-Discretionary	*$2,801,370*	*$5,516,204*	*$2,714,834*
Asset Condition	$3,996,410	$1,966,687	($2,029,723)
Non-Infrastructure	$0	($1,004,710)	($1,004,710)
System Capacity & Performance	$1,602,220	$510,217	($1,092,003)
Subtotal Discretionary	*$5,598,630*	*$1,472,194*	*($4,126,436)*
Total Cost of Removal	**$8,400,000**	**$6,988,398**	**($1,411,602)**

* ( ) denotes an underspend for the period

II. FY 2015 Actual Results

1. FY 2015 Capital Spending Overview

As set forth in Table 3 below, overall, for FY 2015, the Company spent $73.1 million for capital investment under the Electric ISR Plan. This amount was $7.2 million over the annual approved budget of $65.9 million. This above budget spending variance was primarily driven by capital spending in the Discretionary Sub-category, which was above budget by $10.7 million. This variance was primarily due to over-budget spending in the Asset Condition ($5.5 million over-budget), Non-Infrastructure ($0.9 million over-budget), and System Capacity & Performance ($4.2 million over-budget) categories. Spending in the Non-Discretionary Sub-category was under-budget by $3.5 million, which was comprised of an over spending of $3.2 million in the Customer Request/Public Requirements category and an under spend of $6.8 million in the Damage/Failure category. The key drivers and variances by category are discussed in detail in Section III below.

Table 3

	FY 2015 Total		
	Budget	**Actual**	**Variance**
Customer Request/Public Requirement	$14,537,000	$17,759,797	$3,222,797
Damage Failure	$9,816,000	$3,044,445	($6,771,555)
Subtotal Non-Discretionary	*$24,353,000*	*$20,804,242*	*($3,548,758)*
Asset Condition	$19,591,000	$25,140,871	$5,549,871
Non-Infrastructure	$277,000	$1,216,345	$939,345
System Capacity & Performance	$21,679,000	$25,889,850	$4,210,850
Subtotal Discretionary	*$41,547,000*	*$52,247,066*	*$10,700,066*
Total Capital Investment in Systems	**$65,900,000**	**$73,051,308**	**$7,151,308**

* ( ) denotes an underspend for the period.

III. Actual Spending by Category

1. FY 2015 Non- Discretionary Capital Expenditures Compared to Budget

The key drivers for the variances by major categories for non-discretionary capital spending compared to the budget for FY 2015 are listed below.

a. ***Customer Request/Public Requirement - $3.2 million over-budget for FY 2015***

Spending for FY 2015 in the Customer Request/Public Requirement category (previously called the Statutory/Regulatory category) was $3.2 million over-budget. This variance was driven primarily by the projects described below.

- Capital spending for FY 2015 on the new Shun Pike Substation project was approximately $1.3 million over-budget. Although this project was completed in FY 2014, charges were reclassified between an associated transmission project and two distribution projects during the closeout process in FY 2015.

- Capital spending for FY 2015 on the I-195 Relocation projects for Contracts 14 and 15 was approximately $1.2 million over-budget. This variance was due to the identification of undocumented third-party utility assets. This required a relocation of the manhole and duct system from the original designed layout. This work also resulted in the need for additional contaminated soil displacement. Additional construction labor hours were also required to meet changes to the State contractor's schedule.

- Capital spending for FY 2015 on phase two of the Watch Hill Underground project was $0.8 million over-budget. This variance was due to the fact that construction occurred in FY 2015 and the Company received the customer contribution in FY 2014.

- Capital spending for FY 2015 on the Ocean State New Business Residential blanket was $0.8 million over-budget due to higher than expected demand and costs to date.

Among the major projects in this category, the following under-budget projects offset these over-spending projects.

- Both the meter and transformer purchase blankets were $2.4 million under-budget due to the timing of scheduled deliveries and payments between FY 2015 and FY 2016.

Detailed budget and actual spending by budget classification for the Statutory/Regulatory category is shown in Table 4 below.

Table 4

		FY 2015 Total		
Spending Rationale	**Budget Classification**	**Budget**	**Actual**	**Variance**
Customer Request/Public Requirement	Third-party Attachments	$305,000	$271,810	($33,190)
	Land and Land Rights - Distribution	$179,000	$164,892	($14,108)
	Meters - Distribution	$1,824,000	$612,212	($1,211,788)
	New Business - Commercial	$3,924,000	$4,781,763	$857,763
	New Business - Residential	$2,870,000	$3,768,711	$898,711
	Outdoor Lighting - Capital	$533,000	$478,696	($54,304)
	Distributed Generation	$0	$981,410[2]	$981,410
	Regulatory Requirement	$0	$13,765	$13,765
	Public Requirements[1]	$1,268,000	$4,198,864	$2,930,864
	Transformers & Related Equipment	$3,634,000	$2,487,674	($1,146,326)
	Customer Request/Public Requirement Sub-Total	**$14,537,000**	**$17,759,797**	**$3,222,797**

* ( ) denotes an underspend for the period
[1] Removed $59k worth of capital charges from the Public Requirements budget classification category under funding number C057619. This funding number is now part of a streetlight metering pilot that has a separate recovery model in place to recover costs.
[2] The Distributed Generation budget classification category was over budget due to a project completed in FY15 with CIACs collected in prior years; and a prior year CIAC transferred to the New Business - Commercial budget classification category.

b. *Damage/Failure - $6.8 million under-budget for FY 2015*

Spending for FY 2015 in the Damage/Failure category was $6.8 million under-budget. This variance was primarily driven by the projects described below.

- The Ocean State Storm Capital Confirming project was approximately $10.2 million under-budget. During the third quarter of FY 2015, an adjustment associated with the Company's storm reconciliation filing, which was made to true-up storm-related capital costs to actual installed units, reclassified $6.2 million from Capital to O&M expense. In addition, the Company received a $2.6 million credit that was associated with an insurance claim for a 2012 Rhode Island Flood.

- There was an increased spend in the identification and replacement of assets by Operations in the Ocean State Damage/Failure blankets for line and substations. Spending for FY 2015 on these blankets was a combined $2.4 million over-budget.

- Projects for equipment failures at the Sockanosett, Nasonville, Warwick Mall, and Franklin Square substations contributed to $2.1 million in capital spend. This spend exceeded the funded Damage/Failure reserve of $1 million for a net spend of $1.1 million over-budget. Detailed budget and actual spending by budget classification for the Damage/Failure category is shown in Table 5 below.

Table 5

		FY 2015 Total		
Spending Rationale	**Budget Classification**	**Budget**	**Actual**	**Variance**
Damage/Failure	Damage/Failure	$8,816,000	$12,130,420	$3,314,420
	Major Storms - Distribution	$1,000,000	($9,239,977)	($10,239,977)
	Substation	$0	$154,003	$154,003
	Damage/Failure Sub-Total	**$9,816,000**	**$3,044,445**	**($6,771,555)**

* ( ) denotes an underspend for the period

2. FY 2015 Discretionary Capital Expenditures Compared to Budget

a. *Asset Condition - $5.5 million over-budget for FY 2015*

For FY 2015, capital spending for the Asset Condition category was $5.5 million over-budget. This variance was primarily driven by the projects described below.

- The Asset Replacement budget contained a year-end allowance of $4.6 million for schedule delays, which did not fully materialize. To account for this allowance, projects such as the Underground Residential Development (URD) Replacement ($0.8 million under-budget) and the Metal-Clad switchgear retirement ($1.7 million under-budget) were selected for deferral. However, the reductions required to offset the entire $4.6 million allowance were not fully realized.

- Capital spending for FY 2015 on the DxT Relay Replacement strategy was $1.3 million over-budget. The Company advanced the purchase of replacement equipment because the remaining obsolete electro-mechanical and solid state relays were no longer supported by the manufacturer and had limited availability of spare parts. This replacement alleviates prolonged outages that negatively impact transmission system stability and damage equipment.

- Capital spending for FY 2015 on the Eldred Substation project was $1.0 million over-budget. The original budget estimate for this project was based on a preliminary engineering estimate, which accounted for the installation of a single substation transformer. The project was ultimately designed for two transformers, which resulted in a cost increase when final engineering was completed.

- Capital spending for FY 2015 on the Governor Street Providence Ductline project was $1.1 million over-budget. In FY 2014, productivity loss associated with restricted working locations and schedules where the result of public concerns raised during construction in this high profile area, as well as a conflict with the City sewer project, resulted in the project being delayed from FY 2014 into FY

2015. Detailed budget and actual spending by budget classification for the Asset Condition category is shown in Table 6.

Table 6

		FY 2015 Total		
Spending Rationale	**Budget Classification**	**Budget**	**Actual**	**Variance**
Asset Condition	Asset Replacement	$11,887,000	$16,478,396	$4,591,396
	Asset Replacement - I&M (NE)	$7,040,000	$7,593,359	$553,359
	Safety	$514,000	$1,069,116	$555,116
	Other	$150,000	$0	($150,000)
	Asset Condition Sub-Total	**$19,591,000**	**$25,140,871**	**$5,549,871**

* ( ) denotes an underspend for the period

b. *Non-Infrastructure - $0.9 million over-budget for FY 2015*

For FY 2015, the Non-Infrastructure category capital spending was $0.9 million over-budget. Of this total, $0.5 million of the over-budget variance was driven by the FY 2015 reclassification of a net credit of capital accounting adjustments from Non-Infrastructure to an allocated population of Damage/Failure construction work orders. These net accounting adjustments had been temporarily accrued to Non-Infrastructure in FY 2014 and represented high level entries to correctly state capital, cost of removal and O&M labor on Damage/Failure work orders. The remaining $0.4 million over-budget variance was due to purchases of transformer testing devices and general equipment.

Detailed budget and actual spending by budget classification for the Non-Infrastructure category is shown in Table 7.

Table 7

		FY 2015 Total		
Spending Rationale	**Budget Classification**	**Budget**	**Actual**	**Variance**
Non-Infrastructure	Corporate/Administrative/General	$0	$446,538	$446,538
	General Equipment - Distribution	$102,000	$532,277	$430,277
	Information Technology	$0	($852)	($852)
	Meters - Distribution	$0	$164,592	$164,592
	Telecommunications	$175,000	$112,815	($62,185)
	Other	$0	($39,025)	($39,025)
	Non-Infrastructure Subtotal	**$277,000**	**$1,216,345**	**$939,345**

* ( ) denotes an underspend for the period

c. ***System Capacity and Performance - $4.2 million over-budget for FY 2015***

Overall, capital spending for FY 2015 for the System Capacity and Performance category was $4.2 million over-budget. This variance was primarily driven by the projects described below.

- The System Capacity and Performance category contained a fiscal year-end allowance of $5.2 million for schedule delays, which did not fully materialize. Several projects, such as the New London substation, were selected for deferral to account for the allowance. However, the reductions required to offset the entire $5.2 million allowance were not fully realized.

- Capital spending in FY 2015 for the New Highland Drive Substation project was $2.8 million over-budget. This variance was driven by use of conceptual estimates when the FY 2015 ISR budget was established. This forecast was updated as project grade estimates were developed when detailed engineering was completed and more accurate numbers were available.

- Capital spending in FY 2015 for the Volt/Var pilot program was $0.8 million over-budget. This project was over-budget due to the required funding for Information Systems support, which was not yet identified at the time the budget was created as well as higher than expected costs for engineering and materials.

- Capital spending in FY 2015 for the Pawtucket #1 Load Relief project was $0.7 million over-budget. This emergent project was identified to address summer capacity constraints at the Pawtucket #1 substation.

Among the major projects in this category, the following under-budget projects offset these over-spending projects:

- The scope of the Chase Hill project was reduced from installing eight distribution feeders to installing four distribution feeders due to greater than anticipated distribution line costs and right-of-way construction and maintenance challenges. Consequently, the Chase Hill project had a year-end variance of $5.6 million under-budget.

- Capital spending in FY 2015 for the Newport Substation project was $1.6 million under-budget. This variance was due to the fact that this project is still in the permitting and engineering phases, and construction is now expected to begin in FY 2017.

- Capital spending in FY 2015 for the New London Ave substation was $1.5 million under-budget. This project was selected for deferral to manage the overall discretionary portfolio to budget.

- Capital spending in FY 2015 for the projects associated with the Kilvert substation were $0.9 million under-budget. This project experienced delays due to the impact of the TF Green airport expansion project on the line construction scope.

Detailed budget and actual spending by budget classification for the System Capacity and Performance category is shown in Table 8.

Table 8

		FY 2015 Total		
Spending Rationale	**Budget Classification**	**Budget**	**Actual**	**Variance**
System Capacity and Performance	Load Relief	$19,052,000	$20,837,038	$1,785,038
	Reliability	$2,627,000	$5,052,812	$2,425,812
	System Capacity and Performance Sub-Total	**$21,679,000**	**$25,889,850**	**$4,210,850**

* ( ) denotes an underspend for the period
* A $290,612 credit in the Corporate/Administrative/General budget classification category was removed from this reconciliation filing. This amount was erroneously included in the Q4 report. However, it has no effect on the plant-in-service or COR numbers presented in Section I.

In Docket No. 4473, the PUC ordered the Company to include in the FY 2015 Electric ISR Plan filing a proposal to identify and report in annual reconciliation filings the projects that exceeded or were under the fiscal year-end budgets by ten percent (10%).[1] For the identified projects, the Company must note whether variances were due to the project being accelerated, delayed, or whether the variances were due to an increase or decrease in total project cost. The Company is submitting explanations for the portfolio of large projects[2] with variances exceeding $0.1 million. These projects represented approximately $22.5 million for the FY 2015 budget. Information regarding these projects is included in Table 9 below.

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1 Docket No. 4473 Order No. 21559.
2 Large projects are defined as high profile projects, usually exceeding $1.0 million in total project cost.

Table 9

		FY 2015 Total ($000's)			
Project Description	**Project Funding Numbers**	**Budget**	**Actuals**	**Variance**	**FY 2015 Variance Cause**
Eldred Substation Projects	CD00648, CD00659	$794	$1,804	$1,010	Increased spend on project
I-195 Contracts 14, 15 - Providence	CD00766, CD00135	$255	$1,463	$1,208	Increased spend on project
Clarke Street Substation Upgrades	C046831, C046832	$646	$934	$288	Project delays into FY 2016. Overall project costs increased in FY 2015
New Highland Drive Substation	CD00972, CD00978	$3,344	$6,096	$2,752	Increased spend on project
Volt/Var Pilot	C046352, C052708, C053111	$1,200	$2,015	$815	Increased spend on project
Pontiac Substation Flood Restoration	CD01242, CD01243	$1,275	$1,789	$514	Increased spend on project
Langworthy Substation	C036230, C036232	$97	$452	$355	Project Accelerated
South Street Substation Replacement	C051212, C051213	$200	$106	($94)	Project delayed into future years
Governor Street Providence Ductline	C023852	$50	$1,161	$1,111	Project delays from FY 2014 into FY 2015. Overall project spend increased in FY 2015
Kilvert Street #87 Upgrades	C036522, C036516	$2,308	$1,432	($876)	Project delayed into future years
New London Ave Substation	C028920, C028921	$2,300	$857	($1,443)	Project delayed into future years
Aquidneck Island	C015158, C028628, C024159, CD00649, CD00656, C054054, CD00651, CD00652	$2,140	$1,054	($1,086)	Project delayed into future years
Johnston Substation Expansion	C033535, C034002, C028884, C036072	$1,861	$2,641	$780	Project Accelerated
Chase Hill Substation	C024176, C024175	$6,056	$468	($5,588)	Project delayed into future years. Overall project cost decreased during FY 2015
	Totals:	**$22,526**	**$22,272**	**($218)**	

* ( ) denotes an underspend for the period

3. FY 2015 Work Plan Accomplishments

Table 10 below provides actual work plan accomplishments against the goals of the FY 2015 work plan.

Table 10

Program Type	FY 2015 Goals	FY 2015 Accomplishments	Comments
Distribution Transformer Upgrades	750	902	120% Completed
Network Protector Replacements	18	22	122% Completed
I&M program[1]	N/A	54,266 hours[2]	36 Feeders were 100% Completed
Substation Battery Replacement Program	3	3	100% Completed

[1] Starting in FY 2016, the I&M program will no longer be measured by hours, it will be measured by the number of structures inspected.
[2] In October 2015, all contracted work on the I&M program was stopped because the spend for the first half of FY 2015 was trending over-budget. In January 2015, all work, both internal and contracted, was suspended.

IV. FY 2015 Vegetation Management

As shown below in Table 11, overall, the total vegetation management spending for FY 2015 was $8.0 million with an approved budget of $7.7 million. The Company completed 100% of its annual distribution mileage cycle pruning goal of 1,168 miles. This represented an associated spending of 117% of the FY 2015 budget for the cycle pruning program.

As previously noted in earlier FY 2015 ISR Quarterly Reports, the costs for this program typically lag behind the work performed. The variance is driven by cycle pruning bids, which were significantly higher than previous years. Also, to maintain safe and reliable service and complete hourly pruning work, the Company re-prioritized some Sub-Transmission and Core Crew work. The Company's police detail costs were in line with what was expected for the year.

The Company remains in confidential discussions with Verizon Communications (Verizon) in efforts to resolve the vegetation management spending issues. On June 30, 2014, Verizon notified the Company that it was terminating Section 7 of IOP-J, effective July 31, 2014, and that absent a new agreement, each party would be responsible for its own tree trimming and clearing of facilities going forward.

Table 11

US Electricity Distribution - Rhode Island
O&M Vegetation Management Expenditures
FY 2015

	FY 2015 Total		
	Budget	Actual	Variance
Cycle Pruning (Base)	$4,475,000	$5,220,265	$745,265
Hazard Tree	$1,000,000	$800,769	($199,231)
Sub-T (on & off road)	$316,000	$234,291	($81,709)
Police/Flagman Details	$650,000	$645,770	($4,230)
Core Crew (all other activities)	$1,285,000	$1,128,000	($157,000)
Total Vegetation Management	**$7,726,000**	**$8,029,095**	**$303,095**

	FY 2015 Goal	FY 2015 Completed	Annual % Completed vs FY 2015 Goal
Distribution Mileage Trimming	1,168	1,168	**100%**

V. FY 2015 Inspection and Maintenance

As shown in Table 12 below, in FY 2015, the Company completed 100% of its annual structure inspection goal of 56,542. In FY 2015, 68% of the total I&M budget was spent with an associated spending of $2.0 million. Fewer O&M repairs were required than expected, resulting in an under spend on the capital related opex and repair categories. The Long Range Plan had a FY 2015 budget of $250k, with an associated spend of only $9k. This is due to National Grid progressing study work under its Preliminary Service and Investigation (PS&I) funding. Study efforts to summarize issues are generally considered O&M costs, while those study efforts to analyze alternatives and develop solutions are considered capital costs. Consequently, the O&M budget was reduced in FY 2016 to cover the expected issue identification efforts.

Table 12

US Electricity Distribution - Rhode Island
I&M Program Expenditures
FY 2015

	FY 2015 Total			
	Budget	Actual	Variance	% Spent
Opex Related to Capex	$1,811,000	$1,220,554	($590,446)	67%
Repair & Inspections Related Costs	$934,000	$793,607	($140,393)	85%
Long Range Plan	$250,000	$8,582.46	($241,418)	3%
Total Operation & Maintenance Expense	**$2,995,000**	**$2,023,136**	**($972,257)**	**68%**

	FY 2015 Goal	FY 2015 Completed	Annual % Completed vs FY 2015 Goal
RI Distribution Overhead Structures Inspected	56,542	56,542	**100%**

The Company began performing inspections on its overhead distribution system in FY 2011, and, in FY 2012 began performing the repairs based on those inspections. The Company categorizes the deficiencies found as Level I, II, or III, and repairs Level I deficiencies either immediately or within approximately one week of the inspection. The Company bundles Level II and III work for planned replacement. At the conclusion of FY 2015, the Company had completed repairs reported for approximately 29% of the deficiencies found. Total deficiencies found and repairs made to date are shown in the table below.

Summary of Deficiencies and Repair Activities RI Distribution				
Year Inspection Performed	**Priority Level/Repair Expected**	**Deficiencies Found (Total)**	**Repaired as of 03/31/15**	**Not Repaired as of 03/31/15**
FY 2011	I	19	19	0
	II	13,147	12,589	558
	III	38	9	29
FY 2012	I	20	20	0
	II	15,870	14,634	1,236
	III	667	455	212
FY 2013	I	17	17	0
	II	26,885	5,570	21,315
	III	8,129	1,064	7,065
FY 2014	I	11	11	0
	II	23,196	980	22,216
	III	8,776	316	8,460
FY 2015	I	5	5	0
	II	21,554	4	21,550
	III	4,395	2	4,393
Total Since Program Inception	**I, II, III**	**122,729**	**35,695**	**87,034**

As shown in the table below, results of the Company's manual elevated voltage testing for FY 2015 did not indicated any instances of elevated voltages found through either overhead or underground manual elevated voltage inspections.

Manual Elevated Voltage Testing FY 2015					
	Total System Units Requiring Testing	**FY 2015 Units Completed thru 03-31-15**	**Percent Completed**	**Units with Voltage Found (>1.0v)**	**Percent of Units Tested with Voltage (>1.0v)**
Distribution Facilities	285,315	55,755	19.54%	0	0%
Underground Facilities	13,870	2,850	20.55%	0	0%
Street Lights	5,888	2,874	48.81%	0	0%

Mobile elevated voltage testing was completed in FY 2015, as detailed in the Company's Annual Contact Voltage Report filed with the PUC on June 30, 2015. The FY 2015 mobile elevated voltage testing and its associated manual testing revealed twenty one (21) instances of elevated voltage readings of one volt or more. Eleven (11) of these elevated voltage readings were on Company-owned street lights and ten (10) were on Customer-owned assets.

Repair costs and quality assurance manual testing costs for the FY 2014 mobile elevated voltage testing program were incurred in FY 2015 and are, therefore, included in this filing.

Overall, the Inspection and Maintenance program cost was $2.0 million, approximately $1.0 million lower than the original ISR budget of $3.0 million.

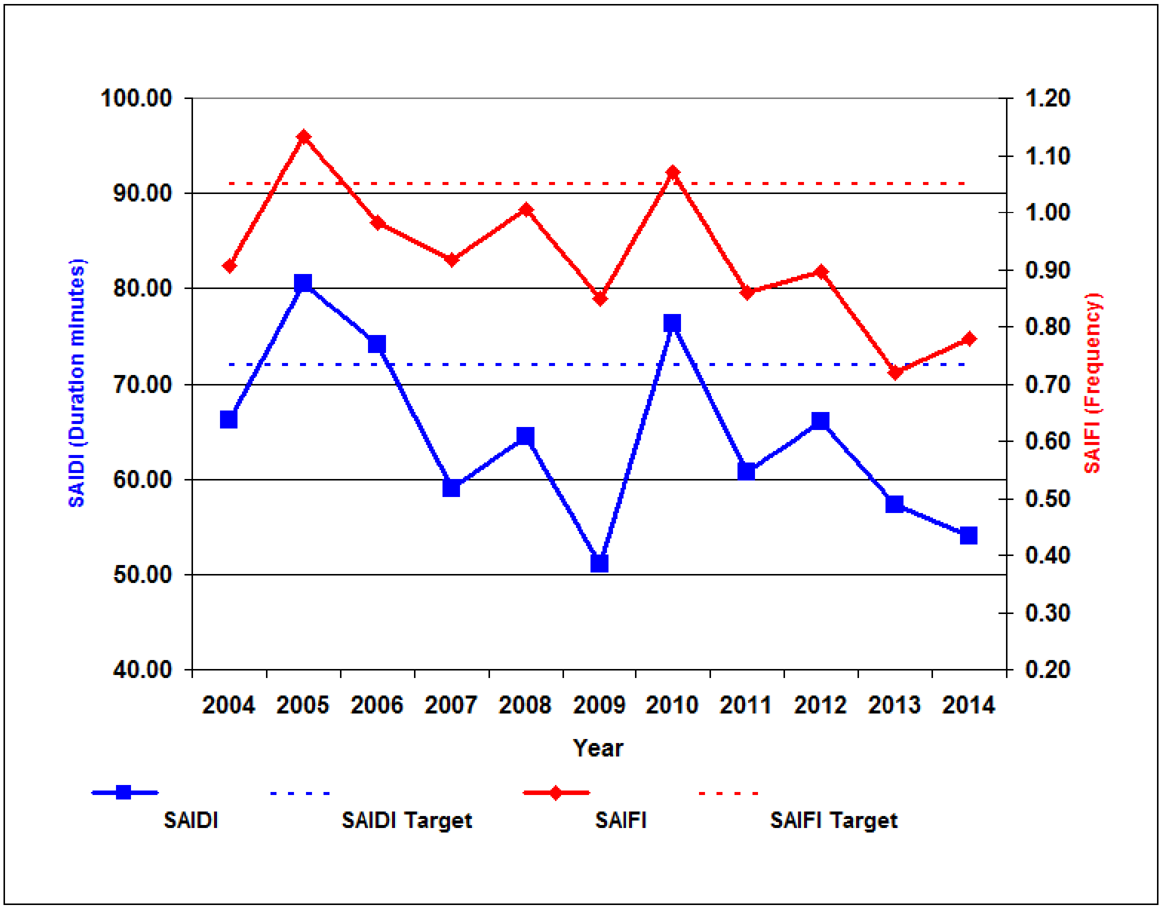
VI. Reliability Performance

The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in calendar year 2014 (CY 2014), with SAIFI of 0.78 against a target of 1.05, and SAIDI of 54.06 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[3] A comparison of reliability performance in CY 2014 relative to that of previous years is shown in Table 13. The Company's performance has shown a downward (improving) trend over the past several years with major event days excluded.

[3] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (5.64 minutes for CY 2014). For purposes of calculating daily system SAIDI any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.

Table 13

RI Reliability Performance
Regulatory Criteria (Excluding Major Event Days)

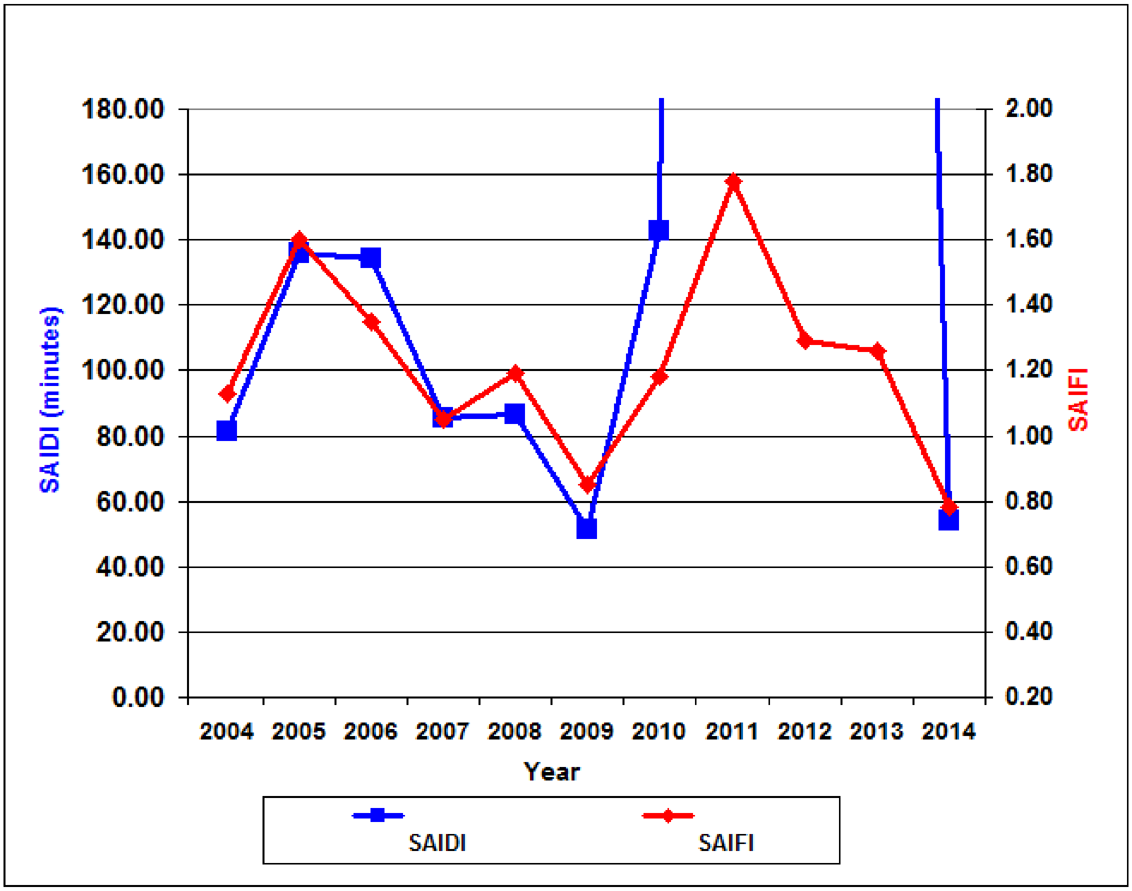


Calendar Year 2014 had zero days that were characterized as major event days.

Reliability performance, including major event days, is shown in Table 14 for 2004 through 2014. SAIDI for 2011, including major event days, exceeds the scale of the chart, at 1,947 minutes (32.5 hours). This was driven by Tropical Storm Irene. As shown in the graph in Table 14, Calendar Years 2011, 2012, and 2013 show the greatest differences between performance with and without major event days. In 2011, the Company experienced ten major events days from five events. Tropical Storm Irene and the October Snowstorm accounted for seven of these major event days. In 2012, the Company experienced four major event days from two events. Hurricane Sandy accounted for three of these major event days. As previously noted, 2013 performance, including major event days, was driven by the February 8 Nor'easter. In 2014, the Company did not experience any major event days.

Table 14

RI Reliability Performance
Regulatory Criteria (Including Major Event Days)



PRE-FILED DIRECT TESTIMONY

OF

AMY S. TABOR

August 3, 2015

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I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is Amy S. Tabor, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am a Senior Analyst of New England Revenue Requirements in the Regulation and Pricing department of National Grid USA Service Company, Inc. (Service Company). Service Company provides engineering, financial, administrative, and other technical support to subsidiary companies of National Grid USA (National Grid). My current duties include revenue requirements responsibilities for National Grid's electric and gas distribution activities in New England, including the electric operations of The Narragansett Electric Company d/b/a National Grid (Narragansett or the Company).

Q. Please describe your education and professional experience.

A. In 2000, I received a Bachelor of Science degree in Business Management from Salem State University. I worked at Oliver Wyman Company from 2000 to 2007 as an AP Coordinator, AP Supervisor, and Senior Accountant. From 2007 to 2013 I worked for Randstad as a Senior Accountant. In April of 2013 I joined National Grid as a Senior Analyst - the position I hold today.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. Yes. I have testified before the PUC in Docket No. 4539 in regards to the FY 2016 Electric Infrastructure, Safety and Reliability Plan.

Q. What is the purpose of your testimony?

A. In this docket, the PUC approved a new Electric Infrastructure, Safety and Reliability (ISR) factor, which went into effect on April 1, 2014. That factor was based on a projected fiscal year (FY) 2015 ISR revenue requirement of $12,250,308 for the estimated operation and maintenance (O&M) work associated with the Company's vegetation management (VM) and inspection and maintenance (I&M) programs for the Company's FY ended March 31, 2015, and on the estimated ISR plant additions during the Company's FY ended March 31, 2015, 2014, 2013, and 2012, and which were incremental to the levels reflected in rate base in the Company's last base rate case (Docket No. 4323). The purpose of my testimony is to present an updated FY 2015 ISR revenue requirement associated with actual FY 2015 O&M programs, the FY 2015, FY 2014, FY 2013, and FY 2012 incremental plant additions, and actual tax deductibility percentages for FY 2014 capital additions. Actual tax deductibility percentages for FY 2015 plant additions will not be known until the Company files its FY 2015 income tax return in December 2015. Consequently, the actual tax deductibility percentages for FY 2015 plant additions will be reflected in the Company's FY 2016 Electric ISR

Reconciliation filing next year and will generate a true up adjustment in that filing. The updated FY 2015 revenue requirement also includes an adjustment associated with the ISR property tax recovery formula that was approved in Docket No. 4323. The ISR property tax recovery adjustment became effective for periods subsequent to the rate year in Docket No. 4323, which ended on January 31, 2014. Consequently, the ISR recovery adjustment covers only the months of February and March of 2014 and the 12 months ended March 31, 2015. My testimony will also address the income tax Net Operating Loss (NOL) issue raised in the FY 2016 Electric ISR Proposal under Docket No 4539 and the resulting increase in the FY 2015 revenue requirement related to vintage FY 2012 through FY 2014 investment , as well as a one-time catch-up adjustment related to the increase in FY 2012 through FY 2014 revenue requirements on vintage FY 2012 through FY 2014 investment. Finally, this testimony addresses the correction of an error in the Company's FY 2014 Electric ISR reconciliation filing in Docket No 4382. This correction lowers the amount of the revenue requirement calculated in the FY 2014 reconciliation filing and relates to the calculation of average rate base on incremental FY 2014 ISR investment. As shown on Attachment AST-1, Page 1 at Line 14, the updated FY 2015 ISR revenue requirement collectible through the Company's ISR factor for the FY 2015 period, including the one-time catch up adjustment related to the NOL impact on prior fiscal years' revenue requirements, totals $16,084,391. This is an increase of $3,834,083 from the projected FY 2015 Electric ISR revenue requirement of $12,250,308 previously approved by the PUC and is primarily attributable to approximately $2.2 million of tax NOL adjustments as well as the property tax mechanism true-up of approximately $2.6 million that was not included in the projected revenue requirement. The tax NOL adjustment is the result of tax deductions reflected on National Grid's income tax returns that exceed the amount of taxable income the Company generated during FY 2012 through FY 2014. Guidance in recent years from the Internal Revenue Service and recent economic tax incentives made available through federal income tax legislation (namely, bonus tax depreciation) has provided National Grid with more tax deductions than taxable income with which to offset the deductions. National Grid's tax NOLs are unrealized tax deductions that can be used in the future to offset taxable income. As previously explained to the PUC during the course of the FY 2015 Electric ISR proceedings, the Company has submitted its Electric ISR Reconciliation filings for FY 2012 through FY 2014, and had also based its FY 2015 Electric ISR proposal on the incorrect assumption that the Company was able to utilize one hundred percent of all capital-related book/tax timing differences, primarily related to bonus and capital repairs tax deductions. However, for those years, the Company did not utilize all of those accelerated tax deductions. Instead, the Company incorrectly provided its customers with the full benefit of all of those tax deductions in the Electric ISR revenue requirements for each of those years. In other words, the Company inappropriately reduced its Electric ISR revenue requirement billed to customers for fiscal years 2012 through 2015 for presumed tax benefits that the Company was unable to secure. These benefits are not forfeited, however, and will be flowed through to customers in future years when the Company is able to utilize them on future federal income tax returns. Approximately $1.4 million of the $2.2 million tax NOL adjustment is a true up for the understated Electric ISR Reconciliation filings in FY 2012 to FY 2014, and the remaining $0.8 million is the FY 2015 revenue requirement effect of the NOLs related to vintage FY 2012 to FY 2014 investment. The tax NOL and property tax recover adjustments will be described in more detail further in my testimony.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following Attachment:

- Attachment AST-1: Electric Infrastructure, Safety, and Reliability Plan Revenue Requirement Reconciliation

II. <u>ISR PLAN FY 2015 REVENUE REQUIREMENT</u>

Q. Did the Company calculate the updated FY 2015 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the August 2014 ISR factor reconciliation?

A. With the exception of the previously mentioned tax NOL and property tax recovery adjustments, and the Company's correction to the related error, the updated FY 2015 ISR revenue requirement calculation is nearly identical to the ISR revenue requirement used to develop the approved ISR factors that were effective April 1, 2014, and which Mr. William R. Richer described in previous testimony in this proceeding. However, the updated calculation incorporates updated ISR investment amounts and known tax deductibility percentages. I will rely on Mr. Richer's previous testimony in this docket for a detailed description of the revenue requirement calculation, and will limit this testimony to summarizing the revenue requirement, describing the tax NOL and property tax recovery adjustments, the correction to the related error, and the update for the known tax deductibility percentages.

Q. Please explain the adjustments related to FY 2014, FY 2013, and FY 2012 NOLs. What are NOLs?

A. Tax NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. This does not mean that the Company is suffering losses in its financial statements; instead, the Company's tax NOLs are the result of the significant tax deductions that have been generated in recent years by the bonus depreciation deductions described above, as well as capital repairs tax deductions. In addition to first-year bonus tax depreciation discussed previously, the United States tax code allows the Company to classify certain costs as repairs expense for which the Company takes as an immediate deduction on its income tax return; however, these costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions have exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2014, with the exception FY 2011. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings when it applies these NOLs against taxable income in the future.

Q. Does National Grid generate NOLs frequently?

A. No, it does not. Prior to FY 2009, National Grid generated NOLs very infrequently. During 2009, the Internal Revenue Service (IRS) issued guidance regarding the capital repairs tax deduction. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in the FY 2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. The FY 2009 capital repairs tax deduction was particularly large in the first year in which the deduction was taken because the deduction included capital repairs amounts from FY2005 through FY 2009. Since that time, the Company has taken a capital repairs deduction on all subsequent FY tax returns. This has formed the basis for the capital repairs deduction assumed in the Company's revenue requirement. This tax deduction has the effect of increasing accumulated deferred taxes, which reduce rate base and consequently lower the revenue requirement that customers have paid under the ISR mechanism.

Q. Why are these tax NOLs causing a revision to the Electric ISR revenue requirements calculations as filed in the FY 2012, FY 2013, and FY 2014 reconciliation filings?

A. The FY 2012 to FY 2014 reconciliation filings, and the FY 2015 Electric ISR revenue requirements calculation were prepared as if the Company had received and provided customers, with the full tax benefits associated with FY 2012 through FY 2014 ISR investment. During the preparation of the Electric ISR Plan FY 2016 Proposal, the Company consulted with its Tax Department for advice on the treatment of the December 2014 tax law legislation that extended bonus depreciation to calendar 2014 capital investment. The Tax Department indicated that deductibility resulting from the tax law legislation law would be limited to the extent that there was insufficient taxable income to absorb the full bonus depreciation tax deduction. Any bonus depreciation that could not be deducted because of excess tax deductions over taxable income would generate NOLs. This prompted the Company to consider whether NOLs were generated since the inception of the Electric ISR program in FY 2012, and the Tax Department confirmed that in FY 2012, FY 2013 and FY 2014, NOLs were also generated. As described above, prior to FY 2009, NOLs were generated infrequently. Although the Company was aware that NOLs were generated by the sizable capital repairs deduction covering FY 2005 through FY 2009 (when the Company first included a capital repairs deduction in its FY 2009 tax return), the Company did not recognize that NOLs had been generated after FY 2009. Therefore, the Company did not reflect those NOLs in the Electric ISR for fiscal years 2012 through 2015.

Q. How do these NOLs impact the revenue requirement calculations, and why should customers pay for this error?

A. Accumulated NOLs represent an offset to the company's accumulated deferred income taxes, which are included as a credit, or reduction in the calculation of rate base. Consequently, including accumulated NOLs in the revenue requirement calculations reduces the amount of accumulated deferred taxes in the derivation of ISR rate base. As described previously, deferred taxes are an offset, or reduction, to ISR rate base and are intended to represent the amount of cash benefit generated and associated with ISR investment related tax deductions that the Company has reflected in its income tax returns. Since the inception of the Electric ISR programs in FY 2012, the Company has assumed in its revenue requirement calculations that the Company received the full cash benefit of the significant ISR investment-related bonus depreciation and capital repairs tax deductions. However, the actual cash benefits from these deductions have been limited because the Company and the consolidated entity for which a consolidated tax return is prepared, reported a taxable loss. Therefore, all previously filed Electric ISR revenue requirement calculations since FY 2012 have provided customers with too much of a cash benefit associated with these tax deductions by not reducing ISR-related deferred taxes by the amount of ISR investment related NOLs.

Q. Why not spread the increase in the FY 2012 through FY 2015 revenue requirements over a period of years?

A. As explained earlier, the NOL issue impacts ISR rate base and represents the cumulative impact of NOLs for all years prior to and including FY 2015. Because of its cumulative rate base nature, this NOL issue also has an impact on ISR revenue requirements for fiscal years 2012 through 2014. Consequently, this FY 2015 cumulative revenue requirement impact of $0.8 million, as shown on page 15, Line 6, Column (d), is permanent until the Company can utilize the underlying cumulative tax losses that gave rise to this annual impact. In other words, the Company's current cumulative NOLs will produce a $0.8 million revenue requirement in the FY 2016 Electric ISR and for all future years until such time as the Company is able to utilize its cumulative NOLs. This is only further compounded by the fact that the Company did not include a deferred tax offset for NOLs in its vintage FY 2014, FY 2013 and FY 2012 rate base calculations, which results in an additional $1.4 million in excess benefit granted to customers, representing the cumulative revenue requirement impact for the FY 2012 through FY 2014 ISR reconciliation periods. Therefore, deferring an amount of the FY 2015 revenue requirement impact will only result in the need for increased recovery in future years and would result in incremental carrying charges on amounts deferred.

Q. Is the Company seeking to recover the revenue requirement impact for all ISR years affected by NOLs in the FY 2015 Electric ISR reconciliation?

A. Yes. By excluding NOLs in its FY 2012, FY 2013 and FY 2014 Electric ISR reconciliation filings, the Company has provided customers with assumed deferred tax cash benefits in excess of those actually realized by the Company on its tax returns for those years. To address those excess benefits, the FY 2015 Electric ISR reconciliation includes a one-time, prior period adjustment for the revenue requirement years FY 2012 through FY 2014 related to NOLs for tax years 2012 through 2014 on vintage FY 2012 through FY 2014 capital investment. As shown on page 1 at line 12, this totals $1.4 million. The FY 2015 Electric ISR reconciliation also includes the cumulative impact on the FY 2015 revenue requirement of NOLs for tax years 2012 through 2014 related to FY 2012 through FY 2014 investment. That amount totals $0.8 million, as shown on Page 15 at Line 6, Column (d), and is embedded in each vintage year's revenue requirement shown on Page 1 at Lines 5 through 9. Therefore, of the total $16.1 million revenue requirement requested for FY 2015, $2.2 million of that total is the result of applying NOL offsets against deferred tax liabilities in the calculation of rate base for vintage FY 2012 through FY 2014 capital investment.

Q. Why has the Company not included NOL in its vintage FY 2015 rate base calculation?

A. The tax depreciation calculation on vintage FY 2015 investment is an estimate until the Company files its FY 2015 tax return in December 2015. Until the FY 2015 tax return is filed, the Company assumes that it will be able to receive the full benefit of capital repairs and bonus depreciation deductions. If the Company generates additional NOLs based on its actual FY 2015 tax position, that adjustment will be reflected as a prior period adjustment to the FY 2015 revenue requirement in the FY 2016 Electric ISR reconciliation filing. Conversely, if the Company is able to utilize any of its currently accumulated NOLs, that benefit will be flowed through to customers in its FY 2016 Electric ISR Reconciliation filing.

Q. Please describe the ISR property tax recovery adjustment.

A. The method used to recover property tax expense under the ISR has been modified by the rate case settlement agreement. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company includes an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The ISR property tax recovery adjustment also includes the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative ISR net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery formula. This provision of the settlement agreement took effect for ISR property tax recovery periods subsequent to the end of the first rate year period, or January 31, 2014.

Q. Please explain the correction of the FY 2014 revenue requirement associated with calculation of average rate base on incremental FY 2014 ISR investment.

A. The Company incorrectly calculated the FY 2014 average rate base on FY 2014 investment in its FY 2014 Electric ISR reconciling filing. The average change in rate base is shown on Page 4 at Line 27. Average rate base in the ISR Plan revenue requirement is normally calculated as the average year-end cumulative change in rate base. This simple averaging method is how average year-end rate base was calculated on vintage FY 2014 investment in the FY 2014 Gas ISR Reconciliation revenue requirement. However, since a portion of FY 2014 non-growth capital investment was reflected in the Company's projected rate base through the January 31, 2014 end of rate year in Docket No. 4323, and the other portion is not, a separate calculation was necessary to apportion the incremental non-growth capital for the year for purposes of determining the weighted average rate base for incremental FY 2014 investment. This calculation is shown on Page 16 of Attachment AST-1. The portions of FY 2014 that fall outside of the rate year are the months of February and March of 2014. Therefore, it is assumed that one-twelfth of total FY 2014 non-growth capital investment was incurred in each of those months. For the remaining FY 2014 incremental non-growth capital investment (i.e. total incremental non-growth capital investment less the portion attributed to February and March of 2014), the Company assumes that such remaining investment will be incurred evenly during the months of April 2013 to January 2014. The incremental investment for each month is then weighted for the period that such investment was outstanding during the year, generating a weighted average plant investment ratio of 23.23 percent (i.e., the ratio of the weighted average plant investment for the year over total incremental ISR capital investment). Average rate base on Line 27 of Page 4 for FY 2014 on vintage FY 2014 capital investment equals the year-end rate base from Line 26 times the 23.23 percent from Page 16. This amount is multiplied by the pre-tax rate of return, as shown on Line 28, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 29.

Q. Are there any other changes to the FY 2014 revenue requirement that are being trued up in the FY 2015 Electric ISR Reconciliation?

A. The only other change is one that was anticipated during the preparation of the FY 2014 Electric ISR Reconciliation. The Company filed its FY 2014 Electric ISR Reconciliation on August 1, 2014. However, at that time, the Company had not filed its FY 2014 income tax return until later that year in the month of December. Consequently, the Company used an estimated capital repairs tax deduction. Therefore, the Company has revised its FY 2014 revenue requirement to reflect an actual capital repairs deduction rate of 34.46% percent, as shown on page 5, line 2 on Attachment AST-1. The ultimate true up to the FY 2014 revenue requirement on FY 2014 incremental capital investment resulting from the correction of the average rate base and the update to the capital repairs deduction percentage, exclusive of the impact of the NOL effect on the FY 2014 revenue requirement, is calculated on page 6 of Attachment AST-1, and the resulting reduction to the revenue requirement of $95,702 is carried forward to line 10 of page 1.

Q. Please summarize the updated FY 2015 ISR revenue requirement.

A. As shown on Page 1, of Attachment AST-1, the Company's FY 2015 Electric ISR Program revenue requirement includes two elements: (1) O&M expense associated with the Company's VM activities and system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's I&M Program, and (2) the Company's capital investment in electric utility infrastructure. The description of these elements and the related amounts are supported by the direct testimony and supporting attachments of Mr. James Patterson. Line 4 reflects the actual FY 2015 revenue requirement related to O&M expenses, of 9,888,482.

As shown on Page 1, at Line 12 of Attachment AST-1, the revenue requirement associated with the Company's actual FY 2015 capital investment totals $6,195,909. As previously noted, the total FY 2015 revenue requirement includes the full year revenue requirement on vintage FY 2015, FY 2014, FY 2013, and FY 2012 incremental ISR plant additions above or below the level of plant additions reflected in base distribution rates. In addition, the FY 2015 revenue requirement reflects a true-up for changes to previously estimated tax depreciation expense to align with tax depreciation rates used on the Company's FY 2014 tax return, which was filed in December 2014. The FY 2015 revenue requirement also reflects the correction of the average rate base on FY 2014 capital investment, the property tax recovery adjustment, and the true up related to the NOLs on FY 2014, FY 2013, and FY 2012, both of which were described earlier in my testimony. The total actual FY 2015 ISR Plan revenue requirement for both O&M expenses and capital investment of $16,084,391 is shown on Line 13.

Q. Please describe how the attachment to your testimony is structured.

A. Page 1 of Attachment AST-1 summarizes the individual components of the updated FY 2015 ISR revenue requirement. Lines 1 through 4 address the O&M components. Lines 5, 6, 7, and 8 represent the full year FY 2015 ISR revenue requirements for the incremental FY 2012, FY 2013, FY 2014, and FY 2015 ISR investments, or those investments not included in the Company's base rates, and as supported with detailed calculations on Pages 2, 4, 7, and 9, respectively. Line 10 reflects the reconciliation of the approved FY 2014 ISR revenue requirement for vintage FY 2014 plant additions with the actual vintage FY 2014 revenue requirement on those investments. As previously discussed, this reconciliation is necessary because the actual level of tax deductibility on FY 2014 investments was not known when the Company filed the FY 2014 and FY 2015 ISR Factor proposals and the average rate base correction. A detailed calculation of the updated FY 2014 revenue requirement is presented on page 4 of Attachment AST-1. Line 11 represents the results of the FY 2015 property tax recovery adjustment, which is supported by a detailed calculation on page 13 and is described below. Finally, line 12 shows the FY 2012, FY 2013, and FY 2014 revenue requirement impact of NOLs, which are shown in detail on Page 15 of the Attachment.

Q. Has the Company provided support for the actual level of FY 2015 ISR-eligible plant investments?

A. Yes. The description of the FY 2015 Electric ISR program and the amount of the incremental plant additions eligible for inclusion in the ISR Mechanism are supported by the direct testimony and supporting attachment of Company Witness, James Patterson. The ultimate revenue requirement on the ISR eligible plant additions equals the return on the investment (i.e. average rate base at the weighted average cost of capital), plus depreciation expense and property taxes associated with the investment. Incremental ISR eligible plant additions for this purpose is intended to represent the net change in rate base for electric infrastructure investments, since the establishment of the Company's ISR mechanism effective April 1, 2011, and is defined as capital additions plus cost of removal, less annual depreciation expense included in the Company's rates, net of depreciation expense attributable to general plant. As discussed in the testimony of Mr. Patterson, the actual ISR eligible plant additions for FY 2015 totals $76.7 million associated with the Company's FY 2015 ISR Plan (electric infrastructure investment net of general plant).

Q. Please explain the distinction between non-discretionary and discretionary capital spending as they relate to the revenue requirement calculation.

A. For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations; and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. The amount of discretionary investment the Company is allowed to include in the revenue requirement calculation is subject to certain limitations as shown on Page 12 of Attachment AST-1. The amount of discretionary capital investment the Company uses in the revenue requirement must be no greater than the cumulative amount of discretionary project spend as approved by the PUC in this proceeding. This means that the discretionary investment is limited to the lesser of actual cumulative discretionary capital additions or spending, or cumulative discretionary spending approved by the PUC in this docket. For purposes of the FY 2015 revenue requirement, the lesser of these items was actual discretionary capital additions of $54,410,377, as shown on Attachment AST-1, Page 12.

Q. What is the updated revenue requirement associated with actual plant additions?

A. The updated FY 2015 revenue requirement associated with the Company's actual FY 2012 through FY 2015 ISR eligible plant investments totals $6,195,909. This amount includes the updated FY 2015 revenue requirement on FY 2012, FY 2013, FY 2014, and FY 2015 investments, reconciliation of the approved FY 2014 and FY 2015 ISR revenue requirement for vintage FY 2015 investments with the actual vintage FY 2014 and FY

2015 revenue requirement on those investments, and the inclusion of the ISR property tax recovery formula adjustment.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment AST-1 Electric Infrastructure, Safety, and Reliability Plan Revenue Requirement Calculation

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
Summary

Line No.			Fiscal Year 2015
	Operation and Maintenance (O&M) Expenses:		
1	Current Year Vegetation Management (VM)	Attachment JHP-1, Page 15, Table 11	$8,029,095
2	Current Year Inspection & Maintenance (I&M)	Attachment JHP-1, Page 16, Table 12	$2,023,136
3	Electric Contact Voltage expenses included in R.I.P.U.C. Docket No. 4323 - FY 2015		($163,749)
4	**Total O&M Expense Component of Revenue Requirement**	Sum of Lines 1 through 3	**$9,888,482**
	Capital Investment:		
5	FY 2015 Revenue Requirement on FY 2015 Actual Incremental Capital Investment	Page 2 of 16, Line 31(a)	$2,173,410
6	FY 2015 Revenue Requirement on FY 2014 Actual Incremental Capital Investment	Page 4 of 16 Line 32(b)	$900,001
7	FY 2015 Revenue Requirement on FY 2013 Actual Incremental Capital Investment	Page 7 of 16, Line 31(c)	($1,133,816)
8	FY 2015 Revenue Requirement on FY 2012 Actual Incremental Capital Investment	Page 9 of 16, Line 29(d)	$350,820
9	Subtotal	Sum of Lines 5 through 8	$2,290,415
10	True Up for Bonus Depreciation and Capital Repairs Deduction, and to Weighted Average Rate Base of FY2014 Revenue Requirement Reconciliation R.I.P.U.C. Docket No. 4382	Page 6 of 16 Line 3	($95,702)
11	FY 2015 Property Tax Recovery Adjustment	Page 13 of 16 Line 48	$2,590,371
12	True Up for Net Operating Losses generated in FY 2012, FY 2013 and FY 2014	Page 15 of 16, Line 7(e)	$1,410,826
13	**Total Capital Investment Component of Revenue Requirement**	Sum of Lines 9 through 12	**$6,195,909**
14	**Total Fiscal Year Revenue Requirement**	Line 4 + Line 13	**$16,084,391**

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
FY 2015 Revenue Requirement on FY 2015 Actual Incremental Capital Investment

Line No.				Fiscal Year 2015 (a)
	Capital Investment Allowance			
1	*Non-Discretionary Capital*	Page 12 of 16, Line 1		$22,246,664
	Discretionary Capital			
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Page 12 of 16, Line 13		$54,410,377
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$76,657,041
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$76,657,041
5	Retirements		1/	$15,666,095
6	Net Depreciable Capital Included in Rate Base	Line 4 - Line 5		$60,990,946
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$76,657,041
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		43,031,774
9	Incremental Depreciable Amount	Line 7 - Line 8		$33,625,267
10	Cost of Removal	Attachment JHP-1, Page 4, Table 2	2/	$6,988,398
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$40,613,665**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%
13	Vintage Year Tax Depreciation:			
14	2015 Spend	Page 3 of 16, Line 20		$47,019,993
15	Cumulative Tax Depreciation	Current Year Line 14		$47,019,993
16	Book Depreciation	Line 6 * Line 12 * 50%		$1,036,846
17	Cumulative Book Depreciation	Current Year Line 16		$1,036,846
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$45,983,147
19	Effective Tax Rate			35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$16,094,101
21	Less: FY 2015 Federal NOL			$0
22	Net Deferred Tax Reserve	Line 20 + Line 21		$16,094,101
	Rate Base Calculation:			
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$40,613,665
24	Accumulated Depreciation	-Line 17		($1,036,846)
25	Deferred Tax Reserve	-Line 20		($16,094,101)
26	Year End Rate Base	Sum of Lines 23 through 25		$23,482,717
	Revenue Requirement Calculation:			
27	Average Rate Base	Current Year Line 26 ÷ 2		$11,741,359
28	Pre-Tax ROR		3/	9.68%
29	Return and Taxes	Line 27 * Line 28		$1,136,564
30	Book Depreciation	Line 16		$1,036,846
31	**Annual Revenue Requirement**	**Line 29 + Line 30**		**$2,173,410**

1/ Actual Retirements

2/ Actual Cost of Removal

3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2015 Incremental Capital Investments

Line No.				Fiscal Year 2015 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 of 16, Line 3		$76,657,041
2	Capital Repairs Deduction Rate	Per Tax Department	1/	21.05%
3	Capital Repairs Deduction	Line 1 * Line 2		$16,136,307
	Bonus Depreciation			
4	Plant Additions	Line 1		$76,657,041
5	Less Capital Repairs Deduction	Line 3		$16,136,307
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$60,520,734
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$59,915,527
9	Bonus Depreciation Rate (April 2014 - December 2014)	1 * 75% * 50%		37.50%
10	Bonus Depreciation Rate (January 2015 - March 2015)	1 * 25% * 50%		0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10		37.50%
12	Bonus Depreciation	Line 8 * Line 11		$22,468,323
	Remaining Tax Depreciation			
13	Plant Additions	Line 1		$76,657,041
14	Less Capital Repairs Deduction	Line 3		$16,136,307
15	Less Bonus Depreciation	Line 12		$22,468,323
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$38,052,411
17	20 YR MACRS Tax Depreciation Rates			3.750%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,426,965
19	Cost of Removal	Page 2 of 16, Line 10		$6,988,398
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18 and 19		$47,019,993

1/ Capital Repairs percentage is based on a three year average 2010, 2011, and 2012 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
FY 2015 Revenue Requirement on FY 2014 Actual Incremental Capital Investment

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*			$6,923,860	
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$6,400,406	
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$13,324,266	-
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$13,324,266	-
5	Retirements	Page 11 of 16, Line 9(c)	1/	($4,165,367)	
6	Net Depreciable Capital Included in Rate Base	Line 4 - Line 5		$17,489,633	17,489,633
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$13,324,266	-
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant	2/	7,173,397	$0
9	Incremental Depreciable Amount	Line 7 - Line 8		$6,150,869	$6,150,869
10	Total Cost of Removal	Page 11 of 16, Line 6(c)		($887,841)	(887,841)
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$5,263,028**	**$ 5,263,028**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%
13	Vintage Year Tax Depreciation:				
14	2014 Spend	Page 5 of 16, Line 20		$8,191,776	318,360
15	Cumulative Tax Depreciation	Current Year Line 14		$8,191,776	8,510,136
16	Book Depreciation	Line 6 * Line 12 * 50%		$297,324	594,648
17	Cumulative Book Depreciation	Current Year Line 16		$297,324	891,971
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$7,894,452	$ 7,618,165
19	Effective Tax Rate			35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$2,763,058	$ 2,666,358
21	Less: FY 2014 Federal NOL			($1,200,808)	($1,200,808)
22	Net Deferred Tax Reserve	Line 20 + Line 21		$1,562,250	$1,465,550
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$5,263,028	$ 5,263,028
24	Accumulated Depreciation	-Line 17		($297,324)	(891,971)
25	Deferred Tax Reserve	-Line 20		($1,562,250)	($1,465,550)
26	Year End Rate Base	Sum of Lines 23 through 25		$3,403,454	$ 2,905,507
	Revenue Requirement Calculation:				
27	Average Rate Base	Col (a) = Line 26 * Page 16 of 16, Line 16, Col (b) = (Prior Year Line 26 + Current Year Line 26)/2		$ 790,571	$ 3,154,481
28	Pre-Tax ROR		3/	9.68%	9.68%
29	Return and Taxes	Line 27 * Line 28		76,527	305,354
30	Book Depreciation	Line 16		297,324	594,648
31	Property Taxes				
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**		**$ 373,851**	**$ 900,001**

1/ Actual Retirements

2/ Depreciation Expense has been prorated for 2 months (February - March 2014)

3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2014 Incremental Capital Investments

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 4 of 16, Line 3		$13,324,266	
2	Capital Repairs Deduction Rate	Per Tax Department	1/	34.46%	
3	Capital Repairs Deduction	Line 1 * Line 2		$4,591,542	
	Bonus Depreciation				
4	Plant Additions	Line 1		$13,324,266	
5	Less Capital Repairs Deduction	Line 3		$4,591,542	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$8,732,724	
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$8,645,397	
9	Bonus Depreciation Rate (April 2013 - December 2013)	1 * 75% * 50%		37.50%	
10	Bonus Depreciation Rate (January 2014 - March 2014)	1 * 25% * 50%		12.50%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%	
12	Bonus Depreciation	Line 8 * Line 11		$4,322,699	
	Remaining Tax Depreciation				
13	Plant Additions	Line 1		$13,324,266	
14	Less Capital Repairs Deduction	Line 3		$4,591,542	
15	Less Bonus Depreciation	Line 12		$4,322,699	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$4,410,025	4,410,025
17	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 * Line 17		$165,376	$ 318,360
19	Cost of Removal	Page 4 of 16, Line 10		($887,841)	
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18 and 19		$8,191,776	$ 318,360

1/ Capital Repairs percentage is based on the FY 2014 tax return.

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
True-up for Capital Repairs and Bonus Depreciation Deduction and Correction to Weighted Average Rate Base on FY 2014 Capital Investments

Line No.			
	Update Capital Repairs Rate and Bonus Depreciation and Correct Weighted Average Rate Base in FY 2014 Revenue Requirement on FY 2014 Capital Investment		
1	FY 2014 Revenue Requirement using estimated capital repairs deduction rate of 18.60% and estimated bonus depreciation rate of 37.50% and no NOL .	Docket No. 4382 FY14 Reconciliation, Attachment WRR-1-Revised, Page 2 of 14, Line 30	$442,553
2	FY 2014 Revenue Requirement using weighted average rate base, actual capital repairs deduction rate of 34.46%, actual bonus depreciation rate of 50.00% and NOL of $1,200,808	Page 4 of 16, Line 32(a)	$373,851
3	Change in revenue requirement	Line 2 - Line 1	($68,702)
4	Less: NOL impact	Page 15 of 16, Line 5	($27,000)
5	True up Amount	Line 3 + Line 4	($95,702)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
FY 2015 Revenue Requirement on FY 2013 Actual Incremental Capital Investment

Line No.				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)
			1/			
	Capital Additions Allowance					
	Non-Discretionary Capital					
1	Non-Discretionary Additions			($5,184,396)	$0	$0
	Discretionary Capital					
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending			($1,850,463)	$0	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 2		($7,034,859)	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		($7,034,859)	$0	$0
5	Retirements			$5,838,935	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b), (c), & (d) = Prior Year Line 6		($12,873,794)	($12,873,794)	($12,873,794)
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		($7,034,859)	$0	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$0	$0	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Columns (b), (c) & (d) = Prior Year Line 9		($7,034,859)	($7,034,859)	($7,034,859)
10	Total Cost of Removal			($1,895,059)	($1,895,059)	($1,895,059)
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**($8,929,918)**	**($8,929,918)**	**($8,929,918)**
	Deferred Tax Calculation:			($10,824,977)	($8,929,918)	
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%	3.40%
13	Tax Depreciation	Page 7 Line 20		($5,970,630)	($221,954)	($205,290)
14	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		($5,970,630)	($6,192,584)	($6,397,874)
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Columns (b), (c) & (d) = Line 6 * Line 12		($218,854)	($437,709)	($437,709)
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		($218,854)	($656,563)	($1,094,272)
17	Cumulative Book / Tax Timer	Line 14 - Line 16		($5,751,776)	($5,536,021)	($5,303,602)
18	Effective Tax Rate			35.00%	35.00%	35.000%
19	Deferred Tax Reserve	Line 17 * Line 18		($2,013,121)	($1,937,607)	($1,856,261)
20	Less: FY 2013 Federal NOL			($2,342,381)	($2,342,381)	($2,342,381)
21	Net Deferred Tax Reserve	Line 19 + Line 20		($4,355,503)	($4,279,989)	($4,198,642)
	Rate Base Calculation:					
22	Cumulative Incremental Capital Included in Rate Base	Line 11		($8,929,918)	($8,929,918)	($8,929,918)
23	Accumulated Depreciation	- Line 16		$218,854	$656,563	$1,094,272
24	Deferred Tax Reserve	- Line 19		$4,355,503	$4,279,989	$4,198,642
25	Year End Rate Base	Sum of Lines 20 through 22		($4,355,561)	($3,993,366)	($3,637,003)
	Revenue Requirement Calculation:					
26	Average Rate Base	(Prior Year Line 23 + Current Year Line 23) ÷2		($2,177,780)	($4,174,463)	($3,815,185)
27	Pre-Tax ROR		2/			9.68%
28	Return and Taxes	Line 24 * Line 25				($369,310)
29	Book Depreciation	Line 15				($437,709)
30	Property Taxes		3/			($326,798)
31	**Annual Revenue Requirement**	**Sum of Lines 26 through 28**		**N/A**	**N/A**	**($1,133,816)**

1/ Column (a) - FY 2013 Electric ISR Reconciliation Filing R.I.P.U.C. Docket No. 4307

2/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.17%	2.51%	9.68%

3/ FY 2015 effective property tax rate of 3.95% per Page 13 of 16, Line 22(h)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2013 Incremental Capital Investments

			Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)
	Capital Repairs Deduction				
1	Plant Additions	Page 6 Line 3	($7,034,859)		
2	Capital Repairs Deduction Rate	1/	12.59%		
3	Capital Repairs Deduction	Line 2 * Line 3	($885,689)		
	Bonus Depreciation				
4	Plant Additions	Line 1	($7,034,859)		
5	Less Capital Repairs Deduction	Line 3	($885,689)		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	($6,149,170)		
7	Percent of Plant Eligible for Bonus Depreciation		100.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	($6,149,170)		
9	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%	37.50%		
10	Bonus Depreciation Rate (January 2013 - March 2013)	1 * 25% * 50%	12.50%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10	50.00%		
12	Bonus Depreciation	Line 8 * Line 11	($3,074,585)		
	Remaining Tax Depreciation				
13	Plant Additions	Line 1	($7,034,859)		
14	Less Capital Repairs Deduction	Line 3	($885,689)		
15	Less Bonus Depreciation	Line 12	($3,074,585)		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	($3,074,585)	($3,074,585)	($3,074,585)
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 * Line 17	($115,297)	($221,954)	($205,290)
19	Cost of Removal	Page 6 Line 10	($1,895,059)		
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	($5,970,630)	($221,954)	($205,290)

1/ Capital Repairs percentage is based on the FY 2013 tax reurn.

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
FY 2015 Revenue Requirement on FY 2012 Actual Incremental Capital Investment

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)
	Capital Additions Allowance		1/				
	Non-Discretionary Capital						
1	Non-Discretionary			($4,019,686)	$0	$0	$0
	Discretionary Capital						
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending			$4,163,942	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$144,256	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$144,256	$0	$0	$0
5	Retirements			$19,938	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b), (c), (d) & (e) = Prior Year Line 6		$124,318	$124,318	$124,318	$124,318
	Change in Net Capital Included in Rate Base						
7	Incremental Depreciable Amount	Column (a) = Line 4, Columns (b), (c), (d) & (e) = Prior Year Line 7		$144,256	$144,256	$144,256	$144,256
8	Cost of Removal			($771,131)	($771,131)	($771,131)	($771,131)
9	**Total Net Plant in Service**	**Line 7 + Line 8**		**($626,875)**	**($626,875)**	**($626,875)**	**($626,875)**
	Deferred Tax Calculation:						
10	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%	3.40%	3.40%
				($626,875)	$0		
11	Tax Depreciation	Page 9 Line 20		($654,965)	$2,107	$1,949	$1,803
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11		($654,965)	($652,858)	($650,909)	($649,107)
13	Book Depreciation	Column (a) = -Line 6 * Line 10 * 50%; Columns (b), (c), (d) & (e)= Line 6 * Line 10		($2,113)	($4,227)	($4,227)	($4,227)
14	Cumulative Book Depreciation	Prior Year Line 14 + Current Year Line 13		($2,113)	($6,340)	($10,567)	($14,794)
15	Cumulative Book / Tax Timer	Line 12 - Line 14		($652,852)	($646,518)	($640,342)	($634,313)
16	Effective Tax Rate			35.00%	35.00%	35.000%	35.000%
17	Deferred Tax Reserve	Line 15 * Line 16		($228,498)	($226,281)	($224,120)	($222,009)
18	Less: FY 2013 Federal NOL			($4,310,461)	($4,310,461)	($4,310,461)	($4,310,461)
19	Net Deferred Tax Reserve	Line 17 + Line 18		($4,538,959)	($4,536,742)	($4,534,581)	($4,532,470)
	Rate Base Calculation:						
20	Cumulative Incremental Capital Included in Rate Base	Line 9		($626,875)	($626,875)	($626,875)	($626,875)
21	Accumulated Depreciation	Line * Line 20		$2,113	$6,340	$10,567	$14,794
22	Deferred Tax Reserve	- Line 17		$4,538,959	$4,536,742	$4,534,581	$4,532,470
23	Year End Rate Base	Sum of Lines 18 through 20		$3,914,197	$3,916,207	$3,918,273	$3,920,389
	Revenue Requirement Calculation:						
24	Average Rate Base	(Prior Year Line 21 + Current Year Line 21) ÷2					$3,919,331
25	Pre-Tax ROR		2/				9.68%
26	Return and Taxes	Line 22 * Line 23					$379,391
27	Book Depreciation	Line 19					($4,227)
28	Property Taxes		3/				($24,344)
29	**Annual Revenue Requirement**	**Sum of Lines 24 through 26**		**N/A**	**N/A**	**N/A**	**$350,820**

1/ Column (a) - FY 2012 Electric ISR Reconciliation Filing R.I.P.U.C. Docket No. 4218.
2/ Weighted Average Cost of Capital per Settlement Agreement R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.17%	2.51%	9.68%

3/ FY 2015 effective property tax rate of 3.95% per Page 13 of 16, Line 22(h)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Incremental Capital Investments

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)
	Capital Repairs Deduction						
1	Plant Additions	Page 3 Line 3		$144,256			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	21.05%			
3	Capital Repairs Deduction	Line 2 * Line 3		$30,366			
	Bonus Depreciation						
4	Plant Additions	Line 1		$144,256			
5	Less Capital Repairs Deduction	Line 3		$30,366			
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$113,890			
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	2/	85.00%			
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$96,807			
9	Bonus Depreciation Rate (April 2011 - December 2011)	1 * 75% * 100%		75.00%			
10	Bonus Depreciation Rate (January 2012 - March 2012)	1 * 25% * 50%		12.50%			
11	Total Bonus Depreciation Rate	Line 9 + Line 10		87.50%			
12	Bonus Depreciation	Line 8 * Line 11		$84,706			
	Remaining Tax Depreciation						
13	Plant Additions	Line 1		$144,256			
14	Less Capital Repairs Deduction	Line 3		$30,366			
15	Less Bonus Depreciation	Line 12		$84,706			
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$29,184	$29,184	$29,184	$29,184
17	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%	6.677%	6.177%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,094	$2,107	$1,949	$1,803
							6.177%
19	Cost of Removal	Page 3 Line 8		($771,131)			
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19		($654,965)	$2,107	$1,949	$1,803

1/ Per Docket 4307 FY 2013 Electric ISR Reconciliation Filing at Attachment WRR-1, Page 8, Line 2

2/ Since not all property additions qualify for bonus depreciation and because a project must be started after the beginning of the bonus period, January 1, 2008, an estimate of 85% is used rather than 100%.

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
FY 2012 - 2014 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Actual Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Investment				
1	ISR - Eligible Capital Investment	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218, Att. WRR-1, Page 3 of 4, Line 20(b); Col (b) = FY 2013 ISR Reconciliation Filing Docket No. 4307, Att WRR-1, Page 7 of 12, Line 31 (b); Col (c) = Page 9 of 14, Line 22(b)	$48,946,456	$44,331,141	$56,129,551
2	ISR - Eligible Capital Additions included in Rate Base per R.I.P.U.C. Docket No. 4323	Schedule MDL-3-ELEC Page 53, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Col (c)= Line Note 3(e)	$48,802,200	$51,366,341	$42,805,284
3	Incremental ISR Capital Investment	Line 1 - Line 2	$144,256	($7,035,200)	$13,324,267
	Cost of Removal				
4	ISR - Eligible Cost of Removal	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b)= FY 2013 Reconciliation Filing Docket No. 4307; Col (c) = Attachement JLG-1, Page 6 of 24, Table 2	$5,807,869	5,179,941	$5,007,992
5	ISR - Eligible Cost of Removal in Rate Base per R.I.P.U.C. Docket No. 4323	Workpaper MDL-19-ELEC Page 2, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Line Note 3(e)	$6,579,000	$7,075,000	$5,895,833
6	Incremental Cost of Removal	Line 4 - Line 5	($771,131)	($1,895,059)	($887,841)
	Retirements				
7	ISR - Eligible Retirements/Actual	Col (a)= FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) = FY 2013 ISR Reconciliation Filing Docket No. 4307; Col (c) = Per Company Books	$7,740,446	14,255,714	$ 3,299,874
8	ISR - Eligible Retirements/Estimated	Col (a)= FY 2012 ISR Proposal Filing Docket No. 4218; Col (b)= FY 2013 ISR Proposal Filing Docket No. 4307; Col (c) = Line 2 (c) * 17.44% Retirement rate per Docket 4323 (Workpaper MDL-19-ELEC Page 3)	$7,720,508	$8,416,779	$7,465,242
9	Incremental Retirements	Line 7 - Line 8	$19,938	$5,838,935	($4,165,367)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
FY 2015 Capital Investment

Line No.			Actuals (a)
	Non-Discretionary Capital		
1	**Total Allowed Non-Discretionary Capital Included in Rate Base Current Year**	Attachment JHP-1, Page 3, Table 1	**$22,246,664**
	Discretionary Capital		
2	Cumulative FY 2012 - FY 2014 Discretionary Capital **ADDITIONS**	Docket No. 4382 FY14 Reconciliation Sch. WRR-1 Page 7 of 11, Line 4; Col (b) = Att. JLG-1, Page 4 of 24, Table 1	$69,131,503
3	FY 2015 Discretionary Capital **ADDITIONS**	Attachment JHP-1, Page 3, Table 1	$54,410,377
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$123,541,880
5	Cumulative FY 2012 - FY 2014 Discretionary Capital **SPENDING**	Docket No. 4382 FY14 Reconciliation Att. JLG-1, Page 7 of 24, Table 3	$92,544,086
6	FY 2015 Discretionary Capital **SPENDING**	Attachment JHP-1, Page 5, Table 3	$51,956,455
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$144,500,541
			As Approved in Docket No. 4473
8	Cumulative FY 2012 - FY 2014 Approved Discretionary Capital **SPENDIN**	Docket No. 4382 FY14 Proposal Sch. WRR-1, Page 7 of 11, Line 5	$86,189,150
9	FY 2015 Approved Discretionary Capital **SPENDING**	Attachment JHP-1, Page 5, Table 3	$41,547,000
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$127,736,150
			Total Allowed
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$123,541,880
12	Prior Year Cumulative Allowed Disretionary Capital Included in Rate Base	Docket No. 4307 FY13 Reconciliation Filing Att. WRR-1, Page 7, Line 27	$69,131,503
13	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 11 - Line 12	**$54,410,377**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$76,657,041**

The Narragansett Electric Company
d/b/a National Grid
FY 2015 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		RY End	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2014
1	Plant In Service	$1,358,470	$9,335	$1,885	$11,220		$550		$1,370,240
2									
3	Accumulated Depr	$611,570				$7,498	$550	($835)	$618,783
4									
5	Net Plant	$746,900							$751,457
6									
7	Property Tax Expense	$29,743							$27,502
8									
9	Effective Prop tax Rate	3.98%							3.66%
10									
11									
12	**Effective tax Rate Calculation**	End of FY 2014	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2015
13									
14	Plant In Service	$1,370,240	$76,657	$5,801	$82,458		($15,666)		$1,437,032
15									
16	Accumulated Depr	$618,783				$46,522	($15,666)	($6,988)	$642,650
17									
18	Net Plant	$751,457							$794,382
19									
20	Property Tax Expense	$27,502							$32,549
21									
22	Effective Prop tax Rate	3.66%							4.10%
23									
24									

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)
25		(a)	(b)	(c)	(d)	(e)	(f)	(g)
26	**Property Tax Recovery Calculation**							
27		Cumulative Increm. ISR Prop. Tax for FY14				Cumulative Increm. ISR Prop. Tax for FY15		
28			2 mos					
29	ISR Additions		$9,335				$76,657	
30	Book Depreciation: base allowance on ISR eligible plant		($7,173)				($43,032)	
31	Book Depreciation: current year ISR additions		($324)				($1,037)	
32	COR		$835				$6,988	
33								
34	Net Plant Additions		$2,672				$39,577	
35								
36	RY Effective Tax Rate		3.98%				3.98%	
37	ISR Property Tax Recovery on FY 2014 vintage investment			$106				$105
38	ISR Property Tax Recovery on FY 2015 vintage investment							$1,576
39								
40	ISR Year Effective Tax Rate	3.66%				4.10%		
41	RY Effective Tax Rate	3.98%	-0.32%			3.98%	0.12%	
42	RY Effective Tax Rate 2 mos for FY 2014		-0.05%					
43	RY Net Plant times 2 mo rate	$746,900	-0.05%	($401)		$746,900	* 0.12%	$861
44	FY 2014 Net Adds times ISR Year Effective Tax rate	$2,672	-0.32%	($9)		$2,632	* 0.12%	$3
45	FY 2015 Net Adds times ISR Year Effective Tax rate					$39,577	* 0.12%	$46
46				($410)				$910
47								
48	Total ISR Property Tax Recovery			($304)				$2,590

Line Notes	
1(a)-9(a)	Per Rate Year cost of service
1(b)-(d),(f)	
	Per FY 2014 Electric ISR Reconciliation Filing R.I.P.U.C. Docket No. 4382
3(a)	Per Rate Year cost of service
3(e)	
	Base Rate depreciation expense allowance $44,986 * 2/12+ Line 1(b) * Composite Depreciation rate 3.40% * 50% * 2/12
3(f),(g)	
	Per FY 2014 Electric ISR Reconciliation R.I.P.U.C. Docket No. 4382
3(h)	Line 3 cols (a) +(e)+(f)+(g)
5(h)	Line 1(h) - Line 3(h)
7(h)	FY 2014 property tax expense per Company books
9(h)	Line 7(h) / Line 5(h)
14(b)	Page 4, Line 3
14(c)	FY 2015 forecasted in service amount
14(f)	Page 4, Line 5
16(e)	
	Rate Year depn allowance of $44,986 + (Line 1(d)+1(f)* composite depreciation rate of 3.40%) + (Line 14(d)+14(f)* composite depreciation rate of 3.40% * 50%)
16(g)	Page 4, Line 10
18(h)	Line 14(h) - Line 16(h)
20(h)	FY 2015 forecasted property tax expense
22(h)	Line 20(h) / Line 18(h)
29(a) - 48(c)	per FY 2014 Electric ISR Reconciliation R.I.P.U.C. Docket No. 4382

Line Notes	
29(f)	Line 16(b)
30(f)	Per , Line
31(f)	Per , Line
32(f)	- Line 16(g)
34(f)	Sum of lines through
36(f)	Line 9(a)
37(g)	((Lines 29(b) + 30(b) + 32(b)) - ((Line 29(b)+ Line 1(f)) * 3.4% composite depn rate * 50% * 2/12) - ((Line 39(b)+Line 1(f)) * 3.4%) * Line 36(f)
38(g)	Line 34(f) * Line 36(f)
40(e)	Line 22(h)
41(e)	Line 9(a)
41(f)	Line 40(e) - Line 41(e)
43(e)	Line 5(a)
44(e)	
	Line 29(e) -((Line 29(e) +Line 1(f)) *3.4%*50%*2/12) + Line 30(b)+Line 32(b)-((Line 29(e)+Line 1(f)*3.4%)
45(e)	Line 34(f)
43(f)-45(f)	Line 41(f)
43(g)	Line 43(e) * Line 43(f)
44(g)	Line 44(e) * Line 44(f)
45(g)	Line 45(e) * Line 45(f)
46(g)	Sum of Lines 43(g) through 45(g)
48(g)	Line 37(g) + Line 38(g) + Line 46(g)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
							CY 2011	CY 2012	Jan-2013	Feb 13 - Jan 14	
1	Total Base Rate Plant DIT Provision						$15,856,458	$ 5,546,827	$ 521,151	$(1,967,911)	
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
2	Total Base Rate Plant DIT Provision						$13,279,050	$ 4,353,286	$(1,639,926)	$ -	$ -
3	Incremental FY 12	$ (228,498)	$ (226,281)	$ (224,120)	$ (222,009)	$ (219,947)	$ (228,498)	$ 2,217	$ 2,161	$ 2,110	$ 2,063
4	Incremental FY 13		$(2,013,121)	$(1,937,607)	$(1,856,261)	$(1,769,533)		$(2,013,121)	$ 75,514	$ 81,347	$ 86,727
5	Incremental FY 14			$ 2,763,058	$ 2,770,421	$ 2,769,418			$ 2,763,058	$ 7,363	$ (1,003)
6	FY 2015				$15,226,743	$15,464,460				$15,226,743	$ 237,717
7	FY 2016					$ 9,377,550					$ 9,377,550
8	TOTAL Plant DIT Provision	$ (228,498)	$(2,239,403)	$ 601,331	$15,918,894	$25,621,948	$13,050,552	$ 2,342,381	$ 1,200,808	$15,317,563	$ 9,703,054
9	NOL						$ 4,310,461	$11,442,811	$19,452,677	TBD	TBD
10	Lesser of NOL or DIT Provision						$ 4,310,461	$ 2,342,381	$ 1,200,808	TBD	TBD

1(f) Per Dkt 4323 Compliance filing Attachment 1, Page 64 of 71, Line 19(e) less Line 19(a)
1(g)-1(i) Per Dkt 4323 Compliance filing Attachment 1, Page 70 of 71, Lines 32, 42, and 48
3(a)-7(e) ADIT per vintage year ISR revenue requirement calculations
3(f) -7(j) Year over year change in ADIT shown in Cols (a) through (e)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
True-Up for FY 2012, FY 2013 and FY 2014 Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)
		Revenue Requirement Year				
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
1	Return on Rate Base	9.30%	9.84%	9.68%	9.68%	9.68%
		Vintage Capital Investment Year				
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2106
2	Lesser of NOL or DIT Provision	$ 4,310,461	$ 2,342,381	$ 1,200,808	TBD	TBD

<u>Revenue Requirement Increase due to NOL</u>

				Revenue Requirement Year		
	Vintage Capital Investment Year	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
3	FY 2012	$ 200,436	$ 424,149	$ 417,253	$ 417,253	$ 417,253
4	FY 2013	$ -	$ 115,245	$ 226,743	$ 226,743	$ 226,743
5	FY 2014	$ -	$ -	$ 27,000	$ 116,238	$ 116,238
6	TOTAL	**$ 200,436**	**$ 539,395**	**$ 670,996**	**$ 760,233**	**$ 760,233**
7	**Total FY 2012 through FY 2014 revenue requirement impact**					**$ 1,410,826**

1(a) Per Docket No. 4065
1(b)-(c) Per vintage year revenue requirement calculations at Page 7 of 16, and Page 4 of 16, respectively
2 Per Page 14 of 16, Line 10
3 Line 2(a) * Line 1(a) * 50%; Line 2(a) * Line 1(b); Line 2(a) * Line 1(c); Line 2(a) * Line 1(d); Line 2(a) * Line 1(e)
4 Line 2(b) * Line 1(b) * 50%; Line 2(b) * Line 1(c); Line 2(b) * Line 1(d); Line 2(b) * Line 1(e)
5 Line 2(c) * Line 1(c) * Page 16, Line 16 (f); Line 2(c) * Line 1(d); Line 2(c) * Line 1(e)
6 Sum of Lines 3 through 5
7 Line 6(a) + Line 6(b) + Line 6(c)

The Narragansett Electric Company
d/b/a National Grid
FY 2015 Electric ISR Revenue Requirement Reconciliation
ISR Additions February and March 2014

Line No.	Month No.	Month	FY 2014 Plant Additions	In Rates	Not In Rates	Weight	Weighted Average
			(a)	(b)	(c) = (a) - (b)	(d)	(f) = (d) * (c)
1							
2	1	Apr-13	4,677,463	4,280,528	396,934	0.958	380,395
3	2	May-13	4,677,463	4,280,528	396,934	0.875	347,317
4	3	Jun-13	4,677,463	4,280,528	396,934	0.792	314,240
5	4	Jul-13	4,677,463	4,280,528	396,934	0.708	281,162
6	5	Aug-13	4,677,463	4,280,528	396,934	0.625	248,084
7	6	Sep-13	4,677,463	4,280,528	396,934	0.542	215,006
8	7	Oct-13	4,677,463	4,280,528	396,934	0.458	181,928
9	8	Nov-13	4,677,463	4,280,528	396,934	0.375	148,850
10	9	Dec-13	4,677,463	4,280,528	396,934	0.292	115,772
11	10	Jan-14	4,677,463	4,280,528	396,934	0.208	82,695
12	11	Feb-14	4,677,463	-	4,677,463	0.125	584,683
13	12	Mar-14	4,677,463	-	4,677,463	0.042	194,894
14		Total	$56,129,551	$42,805,284	$13,324,267		$3,095,026
15	**Total February & March 2014**				**$ 9,354,925**		
16	**FY2014 Weighted Average Incremental Rate Base Percentage**						**23.23%**

Column (a)Page 11 of 16, Line 1(c)
Column(b) Page 11 of 16, Line 2(c)
Line 15 = Line 12(c) + Line 13(c)
Line 16 = Line 14(f)/Line 14(c)

PRE-FILED DIRECT TESTIMONY

OF

ADAM S. CRARY

August 3, 2015

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Adam S. Crary, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am a Senior Analyst for Electric Pricing, New England in the Regulation and Pricing Department of National Grid USA Service Company, Inc. This department provides rate-related support to The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Q. Please describe your educational background and training.

A. In 1995, I graduated from Berklee College of Music in Boston, MA with a Bachelor of Music degree.

Q. Please describe your professional experience?

A For approximately eight years between 2000 and 2014, I was employed by Computer Sciences Corporation as a Pricing Analyst for their Managed Hosting and Cloud Computing business divisions, respectively. I began my employment as a Senior Pricing Analyst with National Grid in June 2014.

Q. Have you previously testified before Rhode Island Public Utilities Commission ("PUC")?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the Fiscal Year 2015 (FY 2015) Electric ISR Plan and presents the following:

- the results of the annual reconciliation of the actual FY 2015 capital investment revenue requirement and the Operations and Maintenance (O&M) expense to the actual revenue billed;
- the status of the Fiscal Year 2013 (FY 2013) CapEx and O&M reconciliations;
- the status of the Fiscal Year 2014 (FY 2014) CapEx and O&M reconciliations;
- the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2015; and
- the typical bill impacts related to the proposed reconciling factors.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section III presents the Summary of FY 2015 CapEx and O&M Reconciliations;

- Section IV presents the results of the FY 2015 CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation, the calculation of the proposed CapEx Reconciling Factors, and the status of the refunds of the FY 2013 and FY 2014 CapEx reconciliation balances;
- Section V presents the results of the FY 2015 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the status of the recovery of the FY 2013 O&M under-recovered balance, and the refund of the FY 2014 O&M over-recovered balance; and
- Section VI presents the rate class bill impact analysis.

III. SUMMARY OF FY 2015 CAPEX AND O&M RECONCILIATIONS

Q. Please summarize the results of the FY 2015 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2015 CapEx and O&M reconciliations is presented in Attachment ASC-1. The annual reconciliations pursuant to the ISR Provision require the comparison of the actual revenue billed during the plan year through the approved CapEx and O&M Factors to the actual CapEx and O&M revenue requirement. The calculation of the actual revenue requirement is presented in the testimony of Company Witness, Amy S. Tabor. Attachment ASC-1 indicates that the result of the CapEx reconciliation is an under-recovery of approximately $4.6 million, and the result of the O&M reconciliation is an over-recovery of approximately $0.4 million.

Q. Please briefly summarize the operation of the tariff provision that provides the Company the opportunity to recover certain costs through the ISR Plan.

A. In accordance with the ISR Provision, the Company is allowed to recover the revenue requirement related to capital investments through CapEx Factors and to recover the revenue requirement related to certain expenditures for Inspection and Maintenance (I&M) and Vegetation Management (VM) activities through O&M Factors.

In the ISR Plan filing for the upcoming plan year, the Company determines the CapEx Factors, which are designed to recover the revenue requirement on the forecasted capital investment for the ISR Plan's investment year, plus the cumulative revenue requirement associated with prior years' capital investments, and the O&M Factors which are designed to recover the forecasted plan year O&M expense. Afterward, on an annual basis, the Company is required to reconcile the actual cumulative CapEx revenue requirement and the actual O&M expense to actual billed revenue generated from the CapEx Factors and the O&M Factors. The over or under-recovered balances resulting from the CapEx and O&M reconciliations are either refunded to or recovered from customers through the CapEx Reconciling Factors and the O&M Reconciling Factor, respectively.

IV. <u>CAPEX RECONCILIATION & PROPOSED CAPEX RECONCILING FACTORS</u>

Q. What is the result of the CapEx reconciliation for FY 2015?

A. The FY 2015 CapEx reconciliation by rate class is presented in Attachment ASC-2, page 1, Lines 4 through 6. Line 5 shows the CapEx Revenue billed during the period April 1, 2014 through March 31, 2015. Line 4 shows the actual CapEx Revenue Requirement amount of approximately $6.2 million. Line 6 shows the under-recovered balance of approximately $4.6 million, representing an under-recovery of this revenue requirement.

Q. Why has the Company prepared the CapEx Factor reconciliation by rate class?

A. The ISR Provision requires that the CapEx Reconciling Factors be calculated as class-specific per-kWh factors designed to recover or refund the under or over-recovery of the actual Cumulative Revenue Requirement, as allocated to each rate class by the Rate Base Allocator, for the prior fiscal year. The Rate Base Allocator is the percentage of total rate base allocated to each rate class determined in the most recently-approved allocated cost of service study. Page 1, Line 4 of Attachment ASC-2 shows the allocation of the actual CapEx revenue requirement to each rate class based upon the Rate Base Allocator approved in the Company's 2012 general rate case in Docket No. 4323.

Q. Please describe the results of the rate class reconciliation.

A. As shown on Attachment ASC-2, page 1, the allocated actual FY 2015 revenue requirement on capital investment, as shown on Line 4, is subtracted from the CapEx Factor revenue billed for each rate class, as shown on Line 5, resulting in an under-recovery from each rate class, as shown on Line 6, which totals approximately $4.6

million. The detail of each rate class' CapEx revenue billed is presented on Attachment ASC-2, page 2.

Q. Please describe the amount included on Line 7.

A. The amounts presented on Line 7 reflect the final balance related to the refund of the FY 2013 over-recovery reconciliation balance. The refund of the FY 2013 CapEx reconciliation balance is presented on page 3. Of the $505,592 over-recovery for FY 2013 approved by the PUC for refund, the Company refunded $467,377 from October 1, 2013 through September 30, 2014. As described in Docket No. 4382, the Company is including each rate class' residual balance with the FY 2015 CapEx Reconciliation Factors.

Q. How is the Company proposing to recover the FY 2015 CapEx under-recovery?

A. The Company is proposing to implement a CapEx Reconciling Credit Factor for each rate class that is consistent with the results of the rate class reconciliation. The calculation of the proposed CapEx Reconciling Factors is presented in Attachment ASC-2, page 1. The under-recoveries on Line 8 are divided by each class' forecasted kWh deliveries for the period October 1, 2015 through September 30, 2016 on Line 9. The class-specific CapEx Reconciling Factors, as shown on Line 10, are as follows:

Rate Class	Charge/(Credit) per kWh
A-16 & A-60	0.076¢
C-06	0.075¢
G-02	0.052¢
G-32 & B-32	0.021¢
G-62 & B-62	0.023¢
Streetlights	0.367¢
X-01	0.062¢

Q. Is the Company providing the status of the over-recovery balance from the FY 2014 CapEx reconciliation?

A. Yes. The status of the refund of the FY 2014 CapEx reconciliation over-recovery balance is presented in Attachment ASC-2, page 4. As of June 30, 2015, the balance reflects a remaining over-recovery of $484,118, which the Company continues to credit to customers. The Company will continue to refund this balance through September 30, 2015.

Q. How will the Company propose to refund or recover any residual balances as of September 30, 2015?

A. Pursuant to the ISR Provision, the amount approved for recovery or refund through the CapEx Reconciling Factors is subject to reconciliation. Therefore, the Company will present the final reconciliation of balances from the FY 2014 reconciliation in the FY 2016 ISR Plan Reconciliation Filing and include each rate class' residual balance from the FY 2014 CapEx reconciliation with the FY 2016 CapEx Reconciliation Factors.

V. O&M RECONCILIATION & PROPOSED O&M RECONCILING FACTOR

Q. What is the result of the O&M reconciliation for FY 2015?

A. The O&M reconciliation for FY 2015 is presented in Attachment ASC-3, page 1. Line 2 shows O&M Revenue billed through the O&M Factors from April 1, 2014 through March 31, 2015 of approximately $10.3 million. Line 1 shows the actual O&M expense for FY 2015 of approximately $9.9 million, which is supported in the testimony of Company Witnesses, Mr. James H. Patterson and Ms. Tabor. Line 3 shows the difference of $391,720 representing an over-recovery.

Q. Please describe the amount included on Line 4.

A. The amount presented on Line 4 reflects the final balance related to the recovery of the FY 2013 O&M reconciliation under-recovered balance. The recovery of the FY 2013 O&M reconciliation balance is presented on page 3. Of the $346,982 over-recovery for FY 2013 approved by the PUC for recovery, the Company refunded $303,818 from October 1, 2013 through September 30, 2014. As described in Docket No. 4382, the Company is including the residual balance with the FY 2015 O&M Reconciliation Factor.

Q. Is the Company providing the O&M Factor Revenue?

A. Yes. Attachment ASC-3, page 2 presents the O&M Factor Revenue billed by month.

Q. What is the proposed O&M Reconciling Factor?

A. The proposed O&M Reconciling Factor is calculated on Attachment ASC-3, page 1. The over-recovery of $434,885 on Line 5 is divided by the forecasted kWhs during the recovery period, October 1, 2015 through September 30, 2016, on Line 6, resulting in a credit of (0.005¢) per kWh on Line 7.

Q. Why is the Company proposing a uniform per kWh O&M Reconciling Factor?

A. Pursuant to the ISR Provision, the O&M Reconciling Factor is a uniform per-kWh factor designed to recover or refund the under- or over-billing of actual I&M and VM expense for the prior fiscal year, based on forecasted kWhs during the recovery or refund period beginning October 1.

Q. Is the Company providing the status of the refund of the over-recovery of the FY 2014 O&M reconciliation?

A. Yes. The status of the balance from the FY 2013 O&M reconciliation is presented in Attachment ASC-3, page 4. As of June 30, 2015, there is a remaining over-recovery balance of $144,188, which the Company will continue to refund through September 30, 2015.

Q. How does the Company propose to refund or recover the residual balance at September 30, 2015?

A. Pursuant to the ISR Provision, the amount approved for recovery or refund through the O&M Reconciling Factor is subject to reconciliation. Therefore, the Company will present the final reconciliation of the balances from the FY 2014 O&M reconciliation in the FY 2016 ISR Reconciliation Filing and include the residual balance of the FY 2014 O&M reconciliation with the FY 2016 O&M Reconciliation Factor.

VI. <u>TYPICAL BILL ANALYSIS</u>

Q. Is the Company providing a typical bill analysis to illustrate the impact of the proposed rates on each of the Company's rate classes?

A. Yes. The typical bill analysis illustrating the monthly bill impact of the proposed rate changes for each rate class is provided in Attachment ASC-4. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is an increase of $0.51, or approximately 0.5%, from $99.02 to $99.53.

Q. Is the Company providing a proposed Summary of Retail Delivery Rates, Tariff No. 2095, reflecting the reconciling factors proposed in this filing?

A. Not at this time. The Company anticipates submitting a Pension and other post-employment benefits (OPEB)Adjustment Factor (PAF) filing, and will be proposing a PAF for effect on October 1, 2015. The Company will file a Summary of Retail Delivery Rates reflecting all rate changes proposed for October 1, 2015 in compliance with the PUC's orders in this proceeding and the PAF proceeding.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

Attachment ASC-1	FY2015 ISR Plan Annual Reconciliation Summary
Attachment ASC-2	CapEx Reconciliations and Proposed CapEx Reconciling Factors
Attachment ASC-3	O&M Reconciliations and Proposed O&M Reconciling Factor
Attachment ASC-4	Typical Bill Analysis

Attachment ASC-1

FY2015 ISR Plan Annual Reconciliation Summary

FY 2015 ISR Plan Annual Reconciliation Summary

Line No.		CapEx (a)	O&M (b)	Total (c)
(1)	Actual Revenue Requirement	$6,195,909	$9,888,482	$16,084,391
(2)	Revenue Billed	$1,611,692	$10,280,202	$11,891,895
(3)	Total Over/Under Recovery	($4,584,217)	$391,720	($4,192,496)

Line Notes:
(1) Column (a) per Attachment AST-1, Page 1, Line (13)
Column (b) per Attachment AST-1, page 1, Line (4)
Column (c) per Attachment AST-1, page 1, Line (14)
(2) Column (a) per Attachment ASC-2, page 1, Line (5), Column (b) per Attachment ASC-3, page 2, Column (c)
(3) Line (2) - Line (1)

Attachment ASC-2

CapEx Reconciliations and Proposed CapEx Reconciling Factors

Proposed CapEx Reconciling Factors
For Fiscal Year 2015 ISR Plan
For the Recovery (Refund) Period October 1, 2015 through September 30, 2016

Line No.		Total (a)	Residential A-16 / A-60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	3000 kW Demand B-62 / G-62 (f)	Lighting S-10 / S-14 (g)	Propulsion X-01 (h)
(1)	Actual FY2015 Capital Investment Revenue Requirement	$6,195,909							
(2)	Total Rate Base ($000s)	$561,738	$296,490	$54,542	$82,460	$77,651	$19,545	$29,286	$1,764
(3)	Rate Base as Percentage of Total	100.00%	52.78%	9.71%	14.68%	13.82%	3.48%	5.21%	0.31%
(4)	Allocated Actual FY2015 Capital Investment Revenue Requirement	$6,195,909	$3,270,249	$601,593	$909,525	$856,484	$215,580	$323,025	$19,452
(5)	CapEx Revenue Billed	$1,611,692	$822,688	$158,405	$249,605	$250,076	$45,180	$81,023	$4,715
(6)	Total Over (Under) Recovery for FY 2015	($4,584,217)	($2,447,561)	($443,188)	($659,920)	($606,408)	($170,400)	($242,002)	($14,738)
(7)	Remaining Over (Under) For FY 2013	$38,215	$24,287	($1,553)	$5,567	$1,936	$7,251	$561	$167
(8)	Total Over (Under) Recovery	($4,546,001)	($2,423,274)	($444,741)	($654,353)	($604,472)	($163,149)	($241,441)	($14,571)
(9)	Forecasted kWhs - October 1, 2015 through September 30, 2016	7,620,692,416	3,155,355,251	591,368,123	1,243,289,737	2,024,407,907	517,349,195	65,623,914	23,298,288
(10)	Proposed Class-specific CapEx Reconciling Factor (Charge) per kWh		$0.00076	$0.00075	$0.00052	$0.00021	$0.00023	$0.00367	$0.00062

Line Notes:
(1) Column (a) per Attachment AST-1, Page 1, Line (13)
(2) per R.I.P.U.C. 4323, Compliance Attachment 3A, (Schedule HSG-1), page 2, Line (10)
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per page 2
(6) Line (5) - Line (4)
(7) per page 3
(8) Line (6) + Line (7)
(9) per Company forecasts
(10) -1 x [Line (8) ÷ Line (9)], truncated to 5 decimal places

Fiscal Year 2015 Operations & Maintenance Reconciliation
For the Period April 1, 2014 through March 31, 2015
For the Recovery/Refund Period October 1, 2015 through September 30, 2016

CapEx Revenue By Rate Class:

Line No.		Residential A-16 / A-60			Small C&I C-06			General C&I G-02			200 kW Demand B-32 / G-32		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-14	$13,031	($9,150)	$22,182	$2,988	($1,410)	$4,397	$5,116	($2,157)	$7,273	$5,548	($2,094)	$7,642
	May-14	$38,260	($19,495)	$57,755	$8,880	($3,156)	$12,037	$15,036	($5,172)	$20,208	$13,786	($5,001)	$18,787
	Jun-14	$37,263	($18,622)	$55,886	$8,817	($3,105)	$11,922	$15,786	($5,061)	$20,848	$14,880	($4,855)	$19,735
	Jul-14	$50,546	($25,284)	$75,830	$10,283	($3,618)	$13,901	$16,645	($5,833)	$22,477	$15,672	($5,154)	$20,826
	Aug-14	$54,967	($27,478)	$82,446	$11,121	($3,879)	$15,000	$16,191	($6,122)	$22,313	$17,377	($5,887)	$23,263
	Sep-14	$50,052	($25,020)	$75,073	$10,572	($3,710)	$14,282	$17,152	($5,963)	$23,115	$16,738	($5,386)	$22,124
	Oct-14	$30,245	($30,138)	$60,383	$6,824	($5,675)	$12,499	$13,070	($9,513)	$22,583	$12,281	($9,149)	$21,430
	Nov-14	$13,170	($44,712)	$57,882	$2,600	($8,874)	$11,473	$4,885	($15,757)	$20,642	$6,030	($14,498)	$20,528
	Dec-14	$15,513	($54,334)	$69,847	$2,854	($10,039)	$12,893	$3,741	($16,113)	$19,853	$4,610	($14,946)	$19,556
	Jan-15	$17,497	($61,249)	$78,746	$3,103	($10,864)	$13,967	$3,880	($16,008)	$19,888	$4,389	($14,732)	$19,122
	Feb-15	$17,797	($62,264)	$80,061	$3,310	($11,536)	$14,847	$3,768	($16,152)	$19,921	$4,291	($15,449)	$19,740
	Mar-15	$16,183	($56,590)	$72,773	$3,181	($11,163)	$14,344	$3,944	($15,903)	$19,847	$5,178	($14,658)	$19,836
(2)	Apr-15	$ 7,516.50	$ (26,307.75)	$33,824	$ 1,520.71	$ (5,322.48)	$6,843	$ 2,347.56	$ (8,289.78)	$10,637	$ 9,715.54	$ (7,771.12)	$17,487
	Total	$362,042	($460,646)	$822,688	$76,053	($82,352)	$158,405	$121,561	($128,044)	$249,605	$130,496	($119,580)	$250,076

Line No.		3000 kW Demand B-62 / G-62			Lighting S-10 / S-14			Propulsion X-01		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-14	$275	($661)	$936	$4,458	($191)	$4,650	($80)	($80)	$0
	May-14	$2,652	($1,455)	$4,107	$5,528	($421)	$5,949	$266	($181)	$447
	Jun-14	$2,505	($1,295)	$3,800	$4,258	($325)	$4,582	$301	($194)	$495
	Jul-14	$2,835	($1,380)	$4,215	$4,634	($354)	$4,987	$262	($168)	$430
	Aug-14	($6,252)	$980	($7,232)	$4,945	($377)	$5,322	$285	($183)	$469
	Sep-14	$7,917	($1,661)	$9,578	$6,260	($477)	$6,737	$262	($168)	$430
	Oct-14	$4,700	($4,992)	$9,692	$2,604	($2,711)	$5,315	$294	$294	$0
	Nov-14	$1,003	($4,064)	$5,067	$1,447	($6,218)	$7,664	$129	($336)	$465
	Dec-14	$116	($3,407)	$3,523	$1,677	($7,216)	$8,893	$129	($365)	$494
	Jan-15	$23	($2,911)	$2,934	$1,785	($7,667)	$9,452	$115	($327)	$442
	Feb-15	($134)	($3,626)	$3,492	$1,418	($6,087)	$7,505	$109	($309)	$418
	Mar-15	($77)	($3,486)	$3,409	$1,267	($5,437)	$6,704	$105	($298)	$403
(2)	Apr-15	$ (37.09)	$ (1,696.52)	$1,659	$ 616.67	$ (2,646.54)	$3,263	$ 58.28	$ (165.11)	$223
	Total	$15,526	($29,654)	$45,180	$40,896	($40,128)	$81,023	$2,235	($2,479)	$4,715

Line Notes:
(1) Reflects revenue associated with consumption on and after April 1
(2) Reflects revenue associated with consumption prior to April 1

Column Notes:
(a) from monthly revenue reports
(b) per page 3 and page 4
(c) Column (a) - Column (b)

Fiscal Year 2013 CapEx Reconciliation of Over Recovery
For the Period April 1, 2012 through March 31, 2013
For the Recovery Period October 1, 2013 through September 30, 2014

Line No.		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery	$505,592		$301,683		$39,592		$70,113		$62,660
(2)	CapEx Reconciling Factors			($0.00009)		($0.00007)		($0.00005)		($0.00003)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-13	($14,475)	89,426,267	($8,048)	18,172,491	($1,272)	42,557,296	($2,128)	69,180,839	($2,075)
	Nov-13	($33,513)	211,219,303	($19,010)	40,348,085	($2,824)	98,176,139	($4,909)	153,385,786	($4,602)
	Dec-13	($39,902)	269,792,281	($24,281)	48,512,343	($3,396)	102,889,615	($5,144)	164,580,919	($4,937)
	Jan-14	($45,297)	314,659,652	($28,319)	54,844,919	($3,839)	114,335,036	($5,717)	178,237,603	($5,347)
	Feb-14	($41,448)	278,468,067	($25,062)	52,412,974	($3,669)	107,171,540	($5,359)	164,708,297	($4,941)
	Mar-14	($40,011)	271,422,299	($24,428)	51,805,939	($3,626)	102,896,022	($5,145)	160,211,645	($4,806)
	Apr-14	($36,018)	232,598,207	($20,934)	46,077,430	($3,225)	98,705,038	($4,935)	159,699,323	($4,791)
	May-14	($34,881)	216,615,942	($19,495)	45,091,382	($3,156)	103,435,782	($5,172)	166,687,293	($5,001)
	Jun-14	($33,456)	206,916,220	($18,622)	44,351,895	($3,105)	101,229,153	($5,061)	161,823,775	($4,855)
	Jul-14	($41,791)	280,936,258	($25,284)	51,684,939	($3,618)	116,656,860	($5,833)	171,812,526	($5,154)
	Aug-14	($42,946)	305,315,613	($27,478)	55,419,679	($3,879)	122,432,650	($6,122)	196,218,744	($5,887)
	Sep-14	($42,385)	278,004,530	($25,020)	53,000,764	($3,710)	119,259,882	($5,963)	179,522,892	($5,386)
(4)	Oct-14	($19,237)	126,796,152	($11,412)	26,068,459	($1,825)	61,178,666	($3,059)	98,065,043	($2,942)
(5)	Total	($467,377)	2,992,744,524	($277,395)		($41,145)		($64,546)		($60,724)
(6)	Ending Over(Under) Recovery	$38,215		$24,287		($1,553)		$5,567		$1,936

		3000 kW Demand B-62 / G-62		Lighting S-10 / S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery		$22,937		$6,332		$2,275
(2)	CapEx Reconciling Factors		($0.00003)		($0.00009)		($0.00009)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-13	22,164,215	($665)	2,369,522	($213)	816,341	($73)
	Nov-13	48,536,327	($1,456)	6,064,161	($546)	1,846,398	($166)
	Dec-13	44,672,551	($1,340)	7,039,472	($634)	1,881,226	($169)
	Jan-14	41,426,522	($1,243)	7,048,986	($634)	2,195,741	($198)
	Feb-14	56,308,347	($1,689)	6,382,132	($574)	1,701,483	($153)
	Mar-14	45,511,176	($1,365)	5,322,165	($479)	1,786,214	($161)
	Apr-14	50,414,209	($1,512)	4,859,305	($437)	2,027,668	($182)
	May-14	48,501,849	($1,455)	4,679,271	($421)	2,009,991	($181)
	Jun-14	43,165,460	($1,295)	3,605,805	($325)	2,150,872	($194)
	Jul-14	45,987,939	($1,380)	3,928,051	($354)	1,868,046	($168)
	Aug-14	(32,670,404)	$980	4,190,348	($377)	2,037,981	($183)
	Sep-14	55,354,534	($1,661)	5,304,104	($477)	1,869,332	($168)
(4)	Oct-14	53,508,407	($1,605)	3,329,142	($300)	1,232,519	($111)
(5)	Total		($15,686)		($5,771)		($2,108)
(6)	Ending Over(Under) Recovery		$7,251		$561		$167

Line Notes:
(1) per R.I.P.U.C. Docket No. 4307, Attachment NR-4, page 1, line (6)
(2) per R.I.P.U.C. Docket No. 4307, Attachment NR-4, page 1, line (8)
(3) prorated for usage on and after October 1st
(4) prorated for usage prior to October 1st
(5) sum of kWhs & revenue
(6) Line (1) + Line (5)

Column Notes:
(a) sum of Column (b) from each rate
(b) from Company revenue report
(c) Column (b) x CapEx Reconciling Factor

Fiscal Year 2014 CapEx Reconciliation of Over Recovery
For the Period April 1, 2013 through March 31, 2014
For the Recovery Period October 1, 2014 through September 30, 2015

Line No.		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery	$1,343,559		$705,228		$129,527		$195,785		$193,300
(2)	CapEx Reconciling Factors			($0.00021)		($0.00021)		($0.00015)		($0.00009)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-14	($41,183)	89,174,129	($18,727)	18,333,618	($3,850)	43,026,182	($6,454)	68,967,904	($6,207)
	Nov-14	($94,458)	212,914,730	($44,712)	42,256,130	($8,874)	105,046,828	($15,757)	161,088,205	($14,498)
	Dec-14	($106,421)	258,735,389	($54,334)	47,804,902	($10,039)	107,417,420	($16,113)	166,069,386	($14,946)
	Jan-15	($113,759)	291,662,816	($61,249)	51,734,569	($10,864)	106,722,023	($16,008)	163,691,448	($14,732)
	Feb-15	($115,424)	296,494,019	($62,264)	54,934,751	($11,536)	107,682,866	($16,152)	171,658,577	($15,449)
	Mar-15	($107,535)	269,475,029	($56,590)	53,157,201	($11,163)	106,023,306	($15,903)	162,869,749	($14,658)
	Apr-15	($98,541)	236,491,062	($49,663)	47,845,897	($10,048)	104,328,236	($15,649)	163,001,410	($14,670)
	May-15	($86,988)	197,106,718	($41,392)	42,260,625	($8,875)	96,525,702	($14,479)	158,062,439	($14,226)
	Jun-15	($95,132)	219,470,754	($46,089)	45,994,759	($9,659)	109,235,977	($16,385)	173,482,075	($15,613)
	Jul-15	$0	-	$0	-	$0	-	$0	-	$0
	Aug-15	$0	-	$0	-	$0	-	$0	-	$0
	Sep-15	$0	-	$0	-	$0	-	$0	-	$0
(4)	Oct-15	$0	-	$0	-	$0	-	$0	-	$0
(5)	Total	($859,441)		($435,020)		($84,908)		($132,901)		($125,000)
(6)	Ending Over(Under) Recovery	$484,118		$270,208		$44,619		$62,884		$68,300

		3000 kW Demand B-62 / G-62		Lighting S-10 / S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery		$44,400		$71,348		$3,971
(2)	CapEx Reconciling Factors		($0.00009)		($0.00103)		($0.00017)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-14	37,631,785	($3,387)	2,341,343	($2,412)	866,815	($147)
	Nov-14	45,152,379	($4,064)	6,036,531	($6,218)	1,974,718	($336)
	Dec-14	37,859,725	($3,407)	7,005,971	($7,216)	2,145,782	($365)
	Jan-15	32,344,546	($2,911)	7,443,788	($7,667)	1,922,981	($327)
	Feb-15	40,289,862	($3,626)	5,909,752	($6,087)	1,816,228	($309)
	Mar-15	38,729,815	($3,486)	5,278,690	($5,437)	1,752,188	($298)
	Apr-15	35,585,017	($3,203)	4,850,547	($4,996)	1,833,529	($312)
	May-15	33,452,922	($3,011)	4,525,372	($4,661)	2,026,489	($345)
	Jun-15	35,177,423	($3,166)	3,752,332	($3,865)	2,088,454	($355)
	Jul-15	-	$0	-	$0	-	$0
	Aug-15	-	$0	-	$0	-	$0
	Sep-15	-	$0	-	$0	-	$0
(4)	Oct-15	-	$0	-	$0	-	$0
(5)	Total	336,223,474	($30,260)	47,144,326	($48,559)	16,427,184	($2,793)
(6)	Ending Over(Under) Recovery		$14,140		$22,789		$1,178

Line Notes:
(1) per R.I.P.U.C. Docket No. 4382, Attachment SMM-2-Revised, page 1, line (8)
(2) per R.I.P.U.C. Docket No. 4382, Attachment SMM-2-Revised, page 1, line (10)
(3) prorated for usage on and after October 1st
(4) prorated for usage prior to October 1st
(5) sum of kWhs & revenue
(6) Line (1) + Line (5)

Column Notes:
(a) sum of Column (b) from each rate
(b) from Company revenue report
(c) Column (b) x CapEx Reconciling Factor

Attachment ASC-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2014 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2015 ISR Plan
For the Recovery (Refund) Period October 1, 2015 through September 30, 2016

Line No.		
(1)	Actual FY 2015 O&M Revenue Requirement	$9,888,482
(2)	O&M Revenue Billed	$10,280,202
(3)	Total Over (Under) Recovery for FY 2015	$391,720
(4)	Remaining Over (Under) For FY 2013	$43,164
(5)	Total Over (Under) Recovery	$434,885
(6)	Forecasted kWhs - October 1, 2015 through September 30, 2016	7,620,692,416
(7)	Proposed O&M Reconciling Factor (Credit) per kWh	($0.00005)

Line Notes:
(1) per Attachment AST-1, page 1, Line (4)
(2) per Page 2
(3) Line (2) - Line (1)
(4) per page 3 Line (4)
(5) Line (3) + Line (4)
(6) per Company forecast
(7) -1 x [Line (5) ÷ Line (6)], truncated to 5 decimal places

Fiscal Year 2014 Operations & Maintenance Reconciliation
For the Period April 1, 2014 through March 31, 2015
For the Recovery/Refund Period October 1, 2015 through September 30, 2016

O&M Factor Revenue:

Line No.	Month	O&M Revenue (a)	Prior Period Reconciliation Factor Revenue (b)	Base O&M Revenue (c)
(1)	Apr-14	$372,348	($37,158)	$409,506
	May-14	$747,447	($23,481)	$770,928
	Jun-14	$708,766	($22,530)	$731,296
	Jul-14	$867,052	($26,915)	$893,967
	Aug-14	$865,776	($26,118)	$891,893
	Sep-14	$904,021	($27,693)	$931,714
	Oct-14	$801,776	($27,824)	$829,600
	Nov-14	$738,545	($28,723)	$767,269
	Dec-14	$838,886	($31,352)	$870,238
	Jan-15	$893,568	($32,776)	$926,344
	Feb-15	$899,636	($33,939)	$933,575
	Mar-15	$839,225	($31,864)	$871,090
(2)	Apr-15	$437,043	($15,739)	$452,783
	Total	$9,914,090	($366,113)	$10,280,202

Line Notes:
(1) Reflects kWhs consumed on and after April 1
(2) Reflects kWhs consumed prior to April 1

Column Notes:
(a) from monthly revenue reports
(b) per page 3 and page 4
(c) Column (a) - Column (b)

Fiscal Year 2013 O&M Reconciliation of Under Recovery
For the Period April 1, 2013 through March 31, 2014
For the Recovery Period October 1, 2013 through September 30, 2014

Line No.		Total
(1)	Over (Under) Recovery	$346,982
(2)	O&M Reconciling Factor	($0.00004)

		Total kWhs (a)	Total Revenue (b)
	Oct-13	244,686,971	($9,787)
	Nov-13	559,576,199	($22,383)
	Dec-13	639,368,407	($25,575)
	Jan-14	712,748,459	($28,510)
	Feb-14	667,152,840	($26,686)
	Mar-14	638,955,460	($25,558)
	Apr-14	594,381,180	($23,775)
	May-14	587,021,510	($23,481)
	Jun-14	563,243,180	($22,530)
	Jul-14	672,874,619	($26,915)
	Aug-14	652,944,611	($26,118)
	Sep-14	692,316,038	($27,693)
	Oct-14	370,178,388	($14,807)
(3)	Total	7,595,447,862	($303,818)
(4)	Over (Under) Recovery		$43,164

Line Descriptions:
(1) per R.I.P.U.C. Docket No. 4307, Attachment NR-5-Revised, page 1, line (3)
(2) per R.I.P.U.C. Docket No. 4307, Attachment NR-5-Revised, page 1, line (5)
(3) sum of kWhs & revenue
(4) Line (1) + Line (3)

Column Descriptions:
(a) per Company Records
(b) Line (2) x Column (a)

Fiscal Year 2014 O&M Reconciliation of Over Recovery
For the Period April 1, 2013 through March 31, 2014
For the Recovery Period October 1, 2014 through September 30, 2015

Line No.		Total	
(1)	Over (Under) Recovery	$401,715	
(2)	O&M Reconciling Factor	($0.00005)	
		Total kWhs	Total Revenue
		(a)	(b)
	Oct-14	260,341,776	($13,017)
	Nov-14	574,469,521	($28,723)
	Dec-14	627,038,575	($31,352)
	Jan-15	655,522,171	($32,776)
	Feb-15	678,786,055	($33,939)
	Mar-15	637,285,978	($31,864)
	Apr-15	593,935,698	($29,697)
	May-15	533,960,267	($26,698)
	Jun-15	589,201,774	($29,460)
	Jul-15	-	$0
	Aug-15	-	$0
	Sep-15	-	$0
	Oct-15	-	$0
(3)	Total	5,150,541,815	($257,527)
(4)	Over (Under) Recovery		$144,188

Line Descriptions:
(1) per R.I.P.U.C. Docket No. 4382, Attachment SMM-3, page 1, line (5)
(2) per R.I.P.U.C. Docket No. 4382, Attachment SMM-3, page 1, line (7)
(3) sum of kWhs & revenue
(4) Line (1) + Line (3)

Column Descriptions:
(a) per Company Records
(b) Line (2) x Column (a)

Attachment ASC-4

Typical Bill Analysis

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$34.01	$16.26	$17.75	$34.17	$16.26	$17.91	$0.16	0.5%	13.7%
300	$61.88	$32.52	$29.36	$62.18	$32.52	$29.66	$0.30	0.5%	17.5%
400	$80.44	$43.35	$37.09	$80.85	$43.35	$37.50	$0.41	0.5%	11.8%
500	$99.02	$54.19	$44.83	$99.53	$54.19	$45.34	$0.51	0.5%	10.8%
600	$117.59	$65.03	$52.56	$118.20	$65.03	$53.17	$0.61	0.5%	9.4%
700	$136.17	$75.87	$60.30	$136.88	$75.87	$61.01	$0.71	0.5%	7.7%
1,200	$229.04	$130.06	$98.98	$230.26	$130.06	$100.20	$1.22	0.5%	15.0%
2,000	$377.65	$216.77	$160.88	$379.67	$216.77	$162.90	$2.02	0.5%	14.1%

<u>Present Rates</u>

Customer Charge		$5.00
RE Growth Factor		$0.17
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02348
Distribution Energy Charge (1)	kWh x	$0.04065
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.10405

<u>Proposed Rates</u>

Customer Charge		$5.00
RE Growth Factor		$0.17
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02348
Distribution Energy Charge (2)	kWh x	$0.04162
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.10405

Note (1): includes the current CapEx Reconciliation Factor of -0.021¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.076¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$26.70	$16.26	$10.44	$26.85	$16.26	$10.59	$0.15	0.6%	10.7%
300	$52.46	$32.52	$19.94	$52.76	$32.52	$20.24	$0.30	0.6%	23.2%
400	$69.62	$43.35	$26.27	$70.03	$43.35	$26.68	$0.41	0.6%	14.9%
500	$86.79	$54.19	$32.60	$87.30	$54.19	$33.11	$0.51	0.6%	12.2%
600	$103.97	$65.03	$38.94	$104.58	$65.03	$39.55	$0.61	0.6%	9.6%
700	$121.14	$75.87	$45.27	$121.85	$75.87	$45.98	$0.71	0.6%	7.3%
1,200	$207.00	$130.06	$76.94	$208.21	$130.06	$78.15	$1.21	0.6%	12.3%
2,000	$344.37	$216.77	$127.60	$346.40	$216.77	$129.63	$2.03	0.6%	9.8%

<u>Present Rates</u>

Customer Charge		$0.00
RE Growth Factor		$0.17
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02348
Distribution Energy Charge (1)	kWh x	$0.02718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.10405

<u>Proposed Rates</u>

Customer Charge		$0.00
RE Growth Factor		$0.17
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02348
Distribution Energy Charge (2)	kWh x	$0.02815
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.10405

Note (1): includes the current CapEx Reconciliation Factor of -0.021¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.076¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
250	$52.44	$23.40	$29.04	$52.69	$23.40	$29.29	$0.25	0.5%	35.2%
500	$93.43	$46.80	$46.63	$93.92	$46.80	$47.12	$0.49	0.5%	17.0%
1,000	$175.39	$93.59	$81.80	$176.39	$93.59	$82.80	$1.00	0.6%	19.0%
1,500	$257.37	$140.39	$116.98	$258.87	$140.39	$118.48	$1.50	0.6%	9.8%
2,000	$339.35	$187.19	$152.16	$341.35	$187.19	$154.16	$2.00	0.6%	19.1%

<u>Present Rates</u>

Customer Charge		$10.00
RE Growth Factor		$0.26
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02072
Distribution Energy Charge (1)	kWh x	$0.03668
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

<u>Proposed Rates</u>

Customer Charge		$10.00
RE Growth Factor		$0.26
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02072
Distribution Energy Charge (2)	kWh x	$0.03764
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): includes the current CapEx Reconciliation Factor of -0.021¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.075¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$743.85	$374.38	$369.47	$746.64	$374.38	$372.26	$2.79	0.4%
50	10,000	$1,725.41	$935.94	$789.47	$1,732.39	$935.94	$796.45	$6.98	0.4%
100	20,000	$3,361.35	$1,871.88	$1,489.47	$3,375.30	$1,871.88	$1,503.42	$13.95	0.4%
150	30,000	$4,997.28	$2,807.81	$2,189.47	$5,018.21	$2,807.81	$2,210.40	$20.93	0.4%

<u>Present Rates</u>

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (1)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

<u>Proposed Rates</u>

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (2)	kWh x	$0.00754
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): includes the current CapEx Reconciliation Factor of -0.015¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.052¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$985.09	$561.56	$423.53	$989.28	$561.56	$427.72	$4.19	0.4%
50	15,000	$2,328.54	$1,403.91	$924.63	$2,339.00	$1,403.91	$935.09	$10.46	0.4%
100	30,000	$4,567.59	$2,807.81	$1,759.78	$4,588.53	$2,807.81	$1,780.72	$20.94	0.5%
150	45,000	$6,806.66	$4,211.72	$2,594.94	$6,838.06	$4,211.72	$2,626.34	$31.40	0.5%

Present Rates

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (1)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (2)	kWh x	$0.00754
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): includes the current CapEx Reconciliation Factor of -0.015¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.052¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$1,226.34	$748.75	$477.59	$1,231.92	$748.75	$483.17	$5.58	0.5%
50	20,000	$2,931.66	$1,871.88	$1,059.78	$2,945.62	$1,871.88	$1,073.74	$13.96	0.5%
100	40,000	$5,773.84	$3,743.75	$2,030.09	$5,801.76	$3,743.75	$2,058.01	$27.92	0.5%
150	60,000	$8,616.04	$5,615.63	$3,000.41	$8,657.91	$5,615.63	$3,042.28	$41.87	0.5%

Present Rates

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (1)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (2)	kWh x	$0.00754
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): includes the current CapEx Reconciliation Factor of -0.015¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.052¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,467.60	$935.94	$531.66	$1,474.57	$935.94	$538.63	$6.97	0.5%
50	25,000	$3,534.78	$2,339.84	$1,194.94	$3,552.22	$2,339.84	$1,212.38	$17.44	0.5%
100	50,000	$6,980.10	$4,679.69	$2,300.41	$7,014.99	$4,679.69	$2,335.30	$34.89	0.5%
150	75,000	$10,425.41	$7,019.53	$3,405.88	$10,477.75	$7,019.53	$3,458.22	$52.34	0.5%

Present Rates			Proposed Rates		
Customer Charge		$135.00	Customer Charge		$135.00
RE Growth Factor		$2.46	RE Growth Factor		$2.46
LIHEAP Charge		$0.73	LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02	Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894	Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23	Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (1)	kWh x	$0.00687	Distribution Energy Charge (2)	kWh x	$0.00754
Transition Energy Charge	kWh x	($0.00201)	Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983	Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232	Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985	Standard Offer Charge	kWh x	$0.08985

Note (1): includes the current CapEx Reconciliation Factor of -0.015¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.052¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,708.85	$1,123.13	$585.72	$1,717.22	$1,123.13	$594.09	$8.37	0.5%
50	30,000	$4,137.90	$2,807.81	$1,330.09	$4,158.84	$2,807.81	$1,351.03	$20.94	0.5%
100	60,000	$8,186.35	$5,615.63	$2,570.72	$8,228.22	$5,615.63	$2,612.59	$41.87	0.5%
150	90,000	$12,234.78	$8,423.44	$3,811.34	$12,297.59	$8,423.44	$3,874.15	$62.81	0.5%

Present Rates

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (1)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Customer Charge		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW	kW x	$5.23
Distribution Energy Charge (2)	kWh x	$0.00754
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): includes the current CapEx Reconciliation Factor of -0.015¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.052¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,382.83	$2,686.67	$2,696.16	$5,395.33	$2,686.67	$2,708.66	$12.50	0.2%
750	150,000	$20,118.24	$10,075.00	$10,043.24	$20,165.11	$10,075.00	$10,090.11	$46.87	0.2%
1,000	200,000	$26,816.15	$13,433.33	$13,382.82	$26,878.65	$13,433.33	$13,445.32	$62.50	0.2%
1,500	300,000	$40,211.99	$20,150.00	$20,061.99	$40,305.74	$20,150.00	$20,155.74	$93.75	0.2%
2,500	500,000	$67,003.65	$33,583.33	$33,420.32	$67,159.90	$33,583.33	$33,576.57	$156.25	0.2%

Present Rates

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (1)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (2)	kWh x	$0.00748
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.021¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$7,280.74	$4,030.00	$3,250.74	$7,299.49	$4,030.00	$3,269.49	$18.75	0.3%
750	225,000	$27,235.43	$15,112.50	$12,122.93	$27,305.74	$15,112.50	$12,193.24	$70.31	0.3%
1,000	300,000	$36,305.74	$20,150.00	$16,155.74	$36,399.49	$20,150.00	$16,249.49	$93.75	0.3%
1,500	450,000	$54,446.36	$30,225.00	$24,221.36	$54,586.99	$30,225.00	$24,361.99	$140.63	0.3%
2,500	750,000	$90,727.61	$50,375.00	$40,352.61	$90,961.99	$50,375.00	$40,586.99	$234.38	0.3%

Present Rates

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (1)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (2)	kWh x	$0.00748
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.021¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$9,178.65	$5,373.33	$3,805.32	$9,203.65	$5,373.33	$3,830.32	$25.00	0.3%
750	300,000	$34,352.61	$20,150.00	$14,202.61	$34,446.36	$20,150.00	$14,296.36	$93.75	0.3%
1,000	400,000	$45,795.33	$26,866.67	$18,928.66	$45,920.33	$26,866.67	$19,053.66	$125.00	0.3%
1,500	600,000	$68,680.74	$40,300.00	$28,380.74	$68,868.24	$40,300.00	$28,568.24	$187.50	0.3%
2,500	1,000,000	$114,451.58	$67,166.67	$47,284.91	$114,764.08	$67,166.67	$47,597.41	$312.50	0.3%

Present Rates

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (1)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (2)	kWh x	$0.00748
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.021¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$11,076.58	$6,716.67	$4,359.91	$11,107.83	$6,716.67	$4,391.16	$31.25	0.3%
750	375,000	$41,469.80	$25,187.50	$16,282.30	$41,586.99	$25,187.50	$16,399.49	$117.19	0.3%
1,000	500,000	$55,284.90	$33,583.33	$21,701.57	$55,441.15	$33,583.33	$21,857.82	$156.25	0.3%
1,500	750,000	$82,915.11	$50,375.00	$32,540.11	$83,149.49	$50,375.00	$32,774.49	$234.38	0.3%
2,500	1,250,000	$138,175.53	$83,958.33	$54,217.20	$138,566.15	$83,958.33	$54,607.82	$390.62	0.3%

<u>Present Rates</u>

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (1)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (2)	kWh x	$0.00748
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.021¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$12,974.49	$8,060.00	$4,914.49	$13,011.99	$8,060.00	$4,951.99	$37.50	0.3%
750	450,000	$48,586.99	$30,225.00	$18,361.99	$48,727.61	$30,225.00	$18,502.61	$140.62	0.3%
1,000	600,000	$64,774.49	$40,300.00	$24,474.49	$64,961.99	$40,300.00	$24,661.99	$187.50	0.3%
1,500	900,000	$97,149.49	$60,450.00	$36,699.49	$97,430.74	$60,450.00	$36,980.74	$281.25	0.3%
2,500	1,500,000	$161,899.49	$100,750.00	$61,149.49	$162,368.24	$100,750.00	$61,618.24	$468.75	0.3%

<u>Present Rates</u>

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (1)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW	kW x	$4.10
Distribution Energy Charge (2)	kWh x	$0.00748
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.021¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	600,000	$94,108.13	$40,300.00	$53,808.13	$94,308.12	$40,300.00	$54,008.12	$199.99	0.2%
5,000	1,000,000	$144,799.80	$67,166.67	$77,633.13	$145,133.13	$67,166.67	$77,966.46	$333.33	0.2%
7,500	1,500,000	$208,164.38	$100,750.00	$107,414.38	$208,664.37	$100,750.00	$107,914.37	$499.99	0.2%
10,000	2,000,000	$271,528.96	$134,333.33	$137,195.63	$272,195.62	$134,333.33	$137,862.29	$666.66	0.2%
20,000	4,000,000	$524,987.30	$268,666.67	$256,320.63	$526,320.63	$268,666.67	$257,653.96	$1,333.33	0.3%

<u>Present Rates</u>

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (1)	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (2)	kWh x	$0.00109
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.023¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	900,000	$121,564.38	$60,450.00	$61,114.38	$121,864.37	$60,450.00	$61,414.37	$299.99	0.2%
5,000	1,500,000	$190,560.21	$100,750.00	$89,810.21	$191,060.21	$100,750.00	$90,310.21	$500.00	0.3%
7,500	2,250,000	$276,805.00	$151,125.00	$125,680.00	$277,555.00	$151,125.00	$126,430.00	$750.00	0.3%
10,000	3,000,000	$363,049.79	$201,500.00	$161,549.79	$364,049.79	$201,500.00	$162,549.79	$1,000.00	0.3%
20,000	6,000,000	$708,028.96	$403,000.00	$305,028.96	$710,028.96	$403,000.00	$307,028.96	$2,000.00	0.3%

Present Rates

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (1)	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (2)	kWh x	$0.00109
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.023¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,200,000	$149,020.63	$80,600.00	$68,420.63	$149,420.62	$80,600.00	$68,820.62	$399.99	0.3%
5,000	2,000,000	$236,320.62	$134,333.33	$101,987.29	$236,987.29	$134,333.33	$102,653.96	$666.67	0.3%
7,500	3,000,000	$345,445.63	$201,500.00	$143,945.63	$346,445.62	$201,500.00	$144,945.62	$999.99	0.3%
10,000	4,000,000	$454,570.63	$268,666.67	$185,903.96	$455,903.96	$268,666.67	$187,237.29	$1,333.33	0.3%
20,000	8,000,000	$891,070.62	$537,333.33	$353,737.29	$893,737.29	$537,333.33	$356,403.96	$2,666.67	0.3%

Present Rates

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (1)	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (2)	kWh x	$0.00109
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.023¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,500,000	$176,476.88	$100,750.00	$75,726.88	$176,976.87	$100,750.00	$76,226.87	$499.99	0.3%
5,000	2,500,000	$282,081.05	$167,916.67	$114,164.38	$282,914.38	$167,916.67	$114,997.71	$833.33	0.3%
7,500	3,750,000	$414,086.25	$251,875.00	$162,211.25	$415,336.25	$251,875.00	$163,461.25	$1,250.00	0.3%
10,000	5,000,000	$546,091.46	$335,833.33	$210,258.13	$547,758.12	$335,833.33	$211,924.79	$1,666.66	0.3%
20,000	10,000,000	$1,074,112.30	$671,666.67	$402,445.63	$1,077,445.63	$671,666.67	$405,778.96	$3,333.33	0.3%

<u>Present Rates</u>

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (1)	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (2)	kWh x	$0.00109
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.023¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,800,000	$203,933.13	$120,900.00	$83,033.13	$204,533.12	$120,900.00	$83,633.12	$599.99	0.3%
5,000	3,000,000	$327,841.46	$201,500.00	$126,341.46	$328,841.46	$201,500.00	$127,341.46	$1,000.00	0.3%
7,500	4,500,000	$482,726.88	$302,250.00	$180,476.88	$484,226.87	$302,250.00	$181,976.87	$1,499.99	0.3%
10,000	6,000,000	$637,612.29	$403,000.00	$234,612.29	$639,612.29	$403,000.00	$236,612.29	$2,000.00	0.3%
20,000	12,000,000	$1,257,153.96	$806,000.00	$451,153.96	$1,261,153.96	$806,000.00	$455,153.96	$4,000.00	0.3%

<u>Present Rates</u>

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (1)	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge	kW x	$3.54
Distribution Energy Charge (2)	kWh x	$0.00109
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.06448

Note (1): includes the current CapEx Reconciliation Factor of -0.009¢/kWh and the current O&M Reconciliation Factor of -0.005¢/kWh

Note (2): includes the proposed CapEx Reconciliation Factor of 0.023¢/kWh and the proposed O&M Reconciliation Factor of (0.005¢)/kWh