Raquel J. Webster
Senior Counsel

December 23, 2014

BY HAND DELIVERY & ELECTRONIC MAIL

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

RE: National Grid's Proposed FY 2016 Electric Infrastructure, Safety, and Reliability Plan Docket No. _____

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or Plan) for fiscal year 2016.[2] National Grid has developed this proposed Electric ISR Plan, which is designed to enhance the safety and reliability of the Company's electric distribution system. As required by law, the Company submitted the proposed the Plan to the Rhode Island Division of Public Utilities and Carriers (Division) for review. In refining the proposed Plan, the Company received and responded to discovery requests from the Division and met with the Division's representatives regarding the proposed Plan.

The Electric ISR Plan is designed to protect and improve the electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, sustaining system viability through targeted investments that are driven primarily by condition, maintaining levels of inspection and maintenance, and operating a cost-effective vegetation management program. The Plan is intended to achieve these safety and reliability goals through a cost-effective, comprehensive work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island electric distribution infrastructure and directly benefit all Rhode Island electric customers.

The Plan separates the general categories of work into discretionary and non-discretionary work, and it includes a description of the categories of work the Company proposes to perform in fiscal year 2016 as well as the proposed targeted spending levels for each work category. In addition to the Plan, this filing includes the pre-filed direct testimony of several witnesses: In joint testimony, Mr. James Patterson and Mr. Ryan Moe introduce the Plan and describe the Plan's large program components; Ms. Amy S. Tabor sponsors the calculation of the Company's fiscal year

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).
[2] The Electric ISR Plan is submitted in compliance with the provisions of R.I. Gen. Laws § 39-1-27.7.1.

2016 revenue requirement under the Plan; and Ms. Jeanne Lloyd describes the calculation of the Electric ISR factors proposed in this filing and provides the customer bill impacts from the proposed rate changes. For the average residential customer using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $0.78, or 0.9%.

Please note that on December 19, 2014, the President of the United States signed into law the Tax Increase Prevention Act of 2014 (HR 5771), which temporarily extends over 50 expired incentives for individuals and businesses through 2014, including 50 percent bonus depreciation for certain qualified investments. As agreed to with the Division, the Company will supplement this filing for any impacts this newly signed federal legislation will have on the Company's ISR Plan cost of service as soon as the Company has had an opportunity to review and understand the implications of this newly enacted law.

The Plan that the Company is submitting to the PUC for review and approval presents an opportunity to facilitate and encourage investment in the Company's electric utility infrastructure and enhance its ability to provide safe, reliable, and efficient electric service to customers.

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

Very truly yours,

Raquel J. Webster

Enclosures

cc: Steve Scialabba, Division
Greg Booth, Division
Leo Wold, Esq.
James Lanni, Division
Al Contente, Division

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2121 ■ raquel.webster@nationalgrid.com ■ www.nationalgrid.com

National Grid

The Narragansett Electric Company

Electric Infrastructure, Safety, and Reliability Plan FY 2016 Proposal

December 23, 2014

Docket No. _____

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC DOCKET NO. _____
RE: FY 2016 ELECTRIC INFRASTRUCTURE,
SAFETY, AND RELIABILITY PLAN
WITNESSES: JAMES H. PATTERSON, JR. AND RYAN A. MOE

JOINT PRE-FILED DIRECT TESTIMONY

OF

JAMES H. PATTERSON, JR.

AND

RYAN A. MOE

December 23, 2014

Table of Contents

I. INTRODUCTION

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. No. However, I have represented the Company in negotiations with the Rhode Island Division of Public Utilities and Carriers regarding the Company's Fiscal Year (FY) 2016 Electric ISR Plan (Electric ISR Plan or Plan).

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

A. My name is Ryan A. Moe. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am employed by the Service Company as a Vegetation Strategist. I am responsible for supporting the design and long-term planning of vegetation strategies used on National Grid USA's distribution and transmission assets. I have also provided support for regulatory reporting in Rhode Island since starting in my current position.

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

A. I graduated from the University at Buffalo with a bachelor's degree in Environmental Design in 2006. I began working for National Grid's Real Estate department in September 2008. My responsibilities included mapping the Company's property records

along the transmission lines as well as analyzing vegetation management rights. In February 2012, I began working in my current position as a Vegetation Strategist.

Q. Have you previously testified before the PUC?

A. Yes. I previously testified before the PUC in Docket No. 4473 on the FY 2015 Electric ISR Plan supporting Vegetation Management issues. In addition, I have represented National Grid in negotiation sessions for the FY 2015 Electric ISR and the FY 2016 Electric ISR with the Division for forestry issues. I have also provided support for Electric ISR reporting since I began working for Vegetation Strategy.

II. PURPOSE OF JOINT TESTIMONY

Q. What is the purpose of this joint testimony?

A. The purpose of this joint testimony is to present the Electric ISR Plan, which the Company developed as part of a collaborative process with the Division[1]. As is described in the Plan, implementation of the Electric ISR Plan will allow the Company to meet its obligation to provide safe, reliable, and efficient, electric service for customers at reasonable cost. The proposed Electric ISR Plan document is Exhibit 1 to this testimony.

[1] The Electric ISR Plan presented in this filing is the fourth annual plan submitted to the PUC pursuant to the provisions of R.I. Gen. Laws § 39-1-27.7.1.

Q. Please summarize the categories of infrastructure, reliability and safety spending covered by the FY 2016 Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2016, or the twelve-month fiscal year ending March 31, 2016: capital spending on electric infrastructure projects; operation and maintenance (O&M expenses for vegetation management (VM); and O&M expenses for an inspection and maintenance (I&M) program.

Q. Please explain how the FY 2016 Electric ISR Plan is structured.

A. The FY 2016 Electric ISR Plan, which is provided as Exhibit 1 to this testimony, encompasses the electric infrastructure, safety, and reliability spending plan for FY 2016, as well as an annual rate reconciliation mechanism that would provide for recovery related to capital investments and other spending undertaken pursuant to the annual pre-approved budget for the Electric ISR Plan. The Electric ISR Plan itemizes the recommended work activities by general category and provides budgets for capital investment, as well as O&M expenses for a VM program and an I&M program. After the end of the fiscal year, the Company would true up the ISR Plan's projected capital and O&M expense levels used for establishing the revenue requirement to actual or allowed investment and expenditures on a cumulative basis and reconcile the revenue requirement associated with the actual investment and expenditures to the revenue billed from the rate adjustments implemented at the beginning of each fiscal year.

III. CAPITAL INVESTMENT PLAN

Q. How has the Company formulated the capital investment plan for review by the PUC?

A. The Company prepared the Electric ISR Plan, and submitted it to the Division for review. In formulating the capital investment plan, the Company received and responded to discovery requests from the Division and had meetings and discussions with the Division's consultants, Mr. Greg Booth and Ms. Linda Kushner of PowerServices, Inc., regarding this proposed Plan. In this filing, the Company has proposed a capital spending plan for FY 2016 in the amount of $73.3 million, which encompasses a range of project work that is needed to maintain safe and reliable service. The project work that is included in the FY 2016 Electric ISR Plan is specifically designed to meet system performance objectives and/or customer service requirements, which the Company must address as part of its public service obligation. In the Plan, attached as Exhibit 1, the Company has provided a detailed explanation of the categories of investment that it plans to undertake, the factors motivating the nature and amount of investment to be completed, and the specific projects that will be undertaken in Rhode Island.

Q. Please describe the categories of work activities that are included in the FY 2016 Electric ISR Plan to address service reliability.

A. The Company's overall objective in preparing the Electric ISR Plan is to arrive at a capital spending plan that is the optimal balance in terms of making the investments

necessary to improve the performance of discreet aspects of the system, thereby, resulting in maintaining the overall reliability of the system, while also ensuring a cost-effective use of available resources. Therefore, the Plan includes the capital investment needed to: (1) meet state and federal regulatory requirements applicable to the electric system; (2) repair failed or damaged equipment; (3) address load growth/migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by condition. These categories of investment constitute the core of work required for the Company to meet its public-service obligation in Rhode Island, and for this reason, the Company has included these categories in the proposed Plan.

Q. Please review the FY 2016 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2016 are associated with five key work categories: Statutory/Regulatory, Damage Failure, System Capacity and Performance, Asset Condition, and Non-infrastructure. The Chart below summarizes the proposed spending level for each of these key driver categories proposed for FY 2016, as follows:

Proposed FY 2016 Capital Investment by Key Driver Category

SPENDING RATIONALE	FY 2016 PROPOSED BUDGET	%
Statutory/Regulatory	$15,647,000	21%
Damage/Failure	$11,177,000	15%
Subtotal	*$36,824,000*	*37%*
Asset Condition	$24,053,000	33%
Non-Infrastructure	$275,000	1%
System Capacity and Performance	$22,148,000	30%
Subtotal	*$46,476,000*	*63%*
Grand Total	**$73,300,000**	**100%**

As shown in the above table, a significant portion of the investment for capital projects in FY 2016 are necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates (i.e. $15.7 million). These investments arise from the Company's regulatory, governmental, or contractual obligations, such as responding to new customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by the Rhode Island Department of Transportation (RIDOT). For the most part, the scope and timing of this work is defined by others external to the Company.

The need to repair failed and damaged equipment totals approximately $11.2 million, or 15 percent, of the Company's investment. These projects are required to restore the

electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes.

The Plan includes the investment necessary to comply with statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and "non-discretionary" in terms of scope and timing. Together, these items account for approximately $36.8 million, or 37 percent, of proposed capital investment in FY 2016. Since the investments associated with these categories of work are non-discretionary, both in terms of timing and scope and are driven by forces outside the control of the Company, these categories of spending are subject to necessary and unavoidable deviations. As such, mandatory, or non-discretionary, capital investments are recovered through a capital rate adjustment mechanism that reconciles the plant in service amounts associated with this projected spending to the lesser of actual plant in service or actual spending on a cumulative basis following the close of the fiscal year.

The system capacity, asset condition, and non-infrastructure projects that the Company will pursue in FY 2016 have been chosen to maintain the overall reliability of the system and collectively total approximately $46.5 million, or 63 percent of the Company's proposed FY 2016 capital investment. System capacity and performance projects are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers. Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the Company's system and capacity loading policy. These projects are designed to

reduce the degradation of equipment service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

In addition to accommodating existing load and load growth/migration, the investments in this category are used to install new equipment, such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with system events. This category also includes investment to improve the overall performance of the network that is realized by the reconfiguration of feeders and the installation of feeder ties. System capacity and performance projects account for approximately $22.1 million, or 30 percent, of the proposed capital investment in FY 2016.

Projects necessary due to the poor condition of infrastructure assets account for about $24.1 million, or 33 percent, of the proposed capital investment in FY 2016. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the prospect for reliability issues.

Finally, the non-infrastructure category of investment represents those capital expenditures that do not fit into one of the foregoing categories, such as general and telecommunications equipment, but which are necessary to run the electric system. In total, capital investment for non-infrastructure projects will account for about $275,000 or less than one percent of capital investment in FY 2016.

Q. Is the Company able to provide a list and detail of the specific projects that will be undertaken in each of the work categories of the FY 2016 Electric Plan?

A. Yes. In the FY 2016 Electric Plan, the Company has provided detail on the specific projects within each work category that would be undertaken in FY 2016 as part of the Electric ISR Plan. The Company and the Division have reviewed these planned projects, as well as overall spending levels, and have come to consensus as to the appropriate investment levels for FY 2016.

Q. Throughout the fiscal year, will the Company provides periodic updates regarding the various categories of capital work approved in the FY 2016 Electric ISR Plan?

A. Yes. The Company will provide quarterly reports to the Division and PUC on the progress of its Electric ISR Plan programs. Additionally, the Company will provide an annual report on the prior fiscal year's activities at the time it makes its reconciliation and rate adjustment filings. The Company and the Division are aware that in executing the approved Electric ISR Plan, the circumstances encountered during the year may require

reasonable deviations from the original plan. In such cases, the Company will include an explanation of any significant deviations in its quarterly reports and in its annual year-end report.

IV. VEGETATION MANAGEMENT PROGRAM

Q. Could you briefly review the FY 2016 spending levels for the Company's VM Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service to customers?

A. Yes. The VM Program that the Company has reviewed with the Division is carefully balanced to implement the program aspects to a degree and in a manner that will achieve the reliability benefits sought by the Company without unduly burdening customers. The Electric ISR Plan provides for approximately $8.9 million in VM spending for FY 2016.

V. INSPECTION AND MAINTENANCE PROGRAM

Q. Could you briefly review the FY 2016 spending levels for the Company's I&M Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service to customers?

A. The Electric ISR Plan incorporates the implementation of an inspection program for overhead and underground distribution infrastructure to achieve the objective of maintaining safe and reliable service to customers in the short and long term. The I&M Program is designed to provide the Company with comprehensive system-wide

information on the condition of overhead and underground system components. The I&M program includes a component for a Contact Voltage Program as ordered in Docket No. 4237. This category also includes a component for a long-range system capacity load study, as agreed to with the Division. The Company proposes a total I&M Program O&M expense budget of approximately $3.2 million for FY 2016.

VI. CONCLUSION

Q. In your opinion does the FY 2016 Electric ISR Plan fulfill the requirements established in relation to the safety and reliability of the Company's electric distribution system in Rhode Island?

A. Yes. The Electric ISR Plan for FY 2016 is designed to establish the capital investment, VM, and I&M activities in Rhode Island that are necessary to meet the needs of its customers and maintain the overall safety and reliability of the Company's electric distribution system, and the Company believes that the proposed Plan accomplishes these objectives. In the end, the PUC's approval of the proposed FY 2016 Electric ISR Plan is essential for the Company to continue maintaining a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

Section 1

Introduction and Summary

FY 2016 Electric ISR Plan

Introduction and Summary
FY 2016 Proposal

National Grid[1] has developed the following proposed fiscal year 2016 (FY 2016) electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or Plan) in compliance with Rhode Island's statute providing for an annual electric "infrastructure, safety, and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget."[2] The proposed FY 2016 Electric ISR Plan addresses the following categories of costs as specified in R.I. Gen. Laws § 39-1-27.7.1(d), An Act Relating to Public Utilities and Carriers–Revenue Decoupling (the Act): capital spending on electric infrastructure; operation and maintenance (O&M) expenses on vegetation management; O&M expenses on system inspection; and other costs related to maintaining safety and reliability of the electric distribution system, including a discussion of O&M inspection and maintenance (I&M) costs associated with the Company's Contact Voltage Detection and Repair Program (Contact Voltage Program), mandated by R.I. Gen. Laws § 39-2-25 and approved by the Rhode Island Public Utilities Commission (PUC) in Docket No. 4237.

The proposed Plan that the Company is submitting for its electric distribution operations is the product of a collaborative effort between the Company and the Rhode Island Division of Public Utilities and Carriers (Division). The Plan is designed to maintain and upgrade the

1 The Narragansett Electric Company d/b/a National Grid (National Grid or Company).
2 R.I. Gen. Laws § 39-1-27.7.1.

Company's electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, providing for asset viability through targeted investments driven primarily by condition, sustaining levels of I&M, and operating a cost-effective vegetation management program. The Company now submits this Plan to the PUC for final review and approval.[3]

This Introduction and Summary presents an overview of the proposed FY 2016 Plan for the above-referenced categories of costs, a description of how the Company proposes to calculate a revenue requirement, a description of how the Company will calculate new rates, and customer bill impacts.

The Electric ISR Plan provides a description of the Company's proposed electric distribution system safety and reliability activities along with its proposed investments and expenditures contained in the Plan for FY 2016. The proposed Plan itemizes the recommended work activities by general category and provides budgets for capital investment, as well as O&M expenses for a vegetation management program and an inspection and maintenance program.

Consistent with the Act, after the end of the fiscal year, the Company will true-up the Electric ISR Plan's projected capital and O&M levels used for establishing the revenue requirement to actual or allowed investment and expenditures and reconcile the revenue requirement to the revenue billed from the rate adjustments implemented at the beginning of the fiscal year.

[3] R.I. Gen. Laws § 39-1-27.7.1 (d) provides that the Company and the Division must work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which the Company must submit to the for PUC for its review and approval.

As approved in PUC Docket No. 4218, the Company will continue to file quarterly reports with the Division and PUC on the progress of its Electric ISR Plan programs. The Company will file the annual report on the prior fiscal year's activities when it makes its reconciliation and rate adjustment filing. In executing the Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original Electric ISR Plan. In such cases, the Company will include an explanation of any significant deviations in its quarterly reports and annual year-end report.

In Docket No. 4473, the PUC directed that the Company provide in the FY 2016 ISR filing, a proposal to report in the quarterly reports and annual reconciliation filing details on individual projects, where costs have differed from the annual budget by more than 10%, where the difference resulted from either an over- or under-spending, or where the differences were due to timing differences. To meet this requirement, the Company will identify the projects or groups[4] of related projects for which the current fiscal year-to-date spend and/or current fiscal year-end-forecasts exceed the 10% variance. For each of these projects, the Company will note whether the total project costs across all fiscal years have changed as a result of an over or under spend. The Company will also note whether the costs have remained approximate to the total sanctioned costs for the project(s) and whether any variance is due to a scheduled timing change. The Company will start providing this information in the second quarter Electric ISR report for FY 2015. The Company is also proposing that going forward, the fourth quarter report and

[4] Projects that are interdependent are sanctioned together. For example, line and substation portions are sanctioned together because the ultimate benefit from the projects requires both projects to be completed. Attachment 5 shows the current grouping of projects for the FY 2016 ISR.

annual reconciliation filing be combined into one report (as done in FY 2014) and provided by August 1 of each year. As the Company performs additional review and audits at the end of each fiscal year, extra time is required for the fourth quarter report, which is a subset of the annual reconciliation report. Therefore, combining and filing these two reports at the same time will result in a more efficient and streamlined process.

The FY 2016 levels of net capital investment, vegetation management (VM) O&M expense, and I&M program O&M expense contained in the Company's proposed Plan are $73.3 million[5], $8.9 million, and $3.2 million, respectively.

The details of the remaining sections of this proposed Plan are as follows: Section 2 contains the Company's proposed capital investment plan for FY 2016; Section 3 contains the Company's proposed VM program; Section 4 contains the Company's proposed I&M program. Section 5 includes a description of how the Company has calculated the FY 2016 Electric ISR Plan revenue requirement. Section 6 includes the calculation of the proposed rates based on the final revenue requirement consistent with the rate design described below; and Section 7 provides the bill impacts associated with the proposed rates.

Electric Capital Investment Plan

The Company's proposed electric capital investment plan included in Section 2 summarizes capital investments by key drivers, describes the development of the capital plan, and outlines the large programs and projects contained in the Plan. For purposes of the

[5] For ISR purposes, only the incremental amount of capital additions above the amounts included in rate base in Docket 4323 will be reflected in the revenue requirement calculation.

ratemaking treatment of capital spending, the Company proposes that capital investments used for establishing rates for FY 2016 be those investments in electric distribution infrastructure assets that the Company projects will place into service during the applicable fiscal year. The Company has used its capital budget to identify the relevant projects that would be part of the FY 2016 Electric ISR Plan and to provide the Company's rationale for the need for and benefit of performing that work to provide safe and reliable service to its customers.

Vegetation Management

Section 3 of this proposal contains the Company's VM O&M expense for FY 2016, a discussion of the nature of the work the Company expects to perform, and the expected benefits of such work. Under the Company's proposed Plan, the O&M expense associated with VM activities is the amount the Company expects to expend for FY 2016. This estimated amount is subject to true-up to actual VM O&M expense.

Inspection and Maintenance Program

The Company has also estimated the O&M expense associated with the I&M program for FY 2016. Section 4 of this proposal provides details of the proposed I&M Program for FY 2016. As with the other projected spending provided in this proposed Plan, this estimated amount will be subject to true-up to actual I&M O&M expense.

Electric Revenue Requirement

As noted above, Section 5 provides a description of how the Company proposes to calculate the revenue requirement based on the projected incremental net infrastructure investment and the total annual VM and I&M O&M. This section includes a description of the revenue requirement model that will be used to support the final revenue requirement. The calculation includes the pre-tax rate of return on rate base approved by the PUC in Docket No. 4323, the Company's last general rate case.

Rate Design

Once the revenue requirement is calculated, it will then be appropriately allocated to the Company's rate classes. The rate design in this proposal is consistent with the Amended Settlement Agreement in Docket No. 4323, which the PUC approved on December 20, 2012. The rate design and a summary of proposed rates are presented in Section 6. The following provisions will apply for purposes of rate design:

a. The adjusted revenue requirement associated with the incremental net capital investments will be allocated to rate classes based upon the allocation of rate base to each rate class as approved in the allocated cost of service in Docket No. 4323. For non-demand-based rate classes, the allocated adjusted revenue requirement will be divided by the applicable fiscal year forecasted kWh deliveries for each rate class, arriving in a per-kWh factor unique to each rate class. For demand-based rate classes, the allocated adjusted revenue requirement will be divided by

estimated billing demand based on a historical load factor applied to the applicable fiscal year forecasted kWh deliveries for each rate class, resulting at a per-kW factor unique to each rate class.

b. The revenue requirement associated with the VM and I&M programs will be allocated to rate classes based upon the allocation of operations and maintenance expenses contained in the approved allocated cost of service in Docket No. 4323. For all rate classes, except Rates B-62/G-62, the allocated revenue requirement will be divided by the applicable forecasted kWh deliveries for each rate class, arriving at a per-kWh factor unique to each rate class. For Rates B-62/G-62, the allocated revenue requirement will be divided by estimated billing demand based on a historical load factor applied to the applicable forecasted kWh deliveries for each rate class, resulting in a per-kW factor for the rate class.

Bill Impacts

Section 7 includes a description of the bill impacts associated with the proposed rates.

Section 2

Electric Capital Investment Plan

FY 2016 Electric ISR Plan

Electric Capital Investment Plan
FY 2016 Proposal

Background

The Company[6] developed its proposed Electric ISR Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs. The Plan includes capital investment needed to (1) meet state and federal regulatory requirements applicable to the electric system; (2) repair failed or damaged equipment; (3) address load growth/migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by condition.

As shown below in Chart 1, the Company met both its SAIFI and SAIDI performance metrics in Calendar Year (CY) 2013, with SAIFI of 0.72 against a target of 1.05 and SAIDI of 57.28 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are based on a calendar year and measured excluding major event days.[7] A comparison of reliability performance in CY 2013 relative to that of previous years demonstrates that the Company's performance has shown a downward (improving) trend over the past several years with major event days excluded. The Plan focuses on the underlying drivers of reliability during

[6] The Company delivers electricity to 486,465 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 Rhode Island cities and towns. To provide this service, the Company owns and maintains 5,225 miles of overhead and 1,103 miles of underground distribution and sub-transmission circuit in a network that includes 94 sub-transmission lines and 390 distribution feeders. The Company relies on 66 distribution substations that house 134 power transformers and 823 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 280,612 distribution poles, 4,252 manholes and 64,498 overhead (pole-mounted) and underground (pad-mounted or in vaults) transformers.

[7] A Major Event Day (MED) is defined as a day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a MED threshold value (5.74 minutes for 2013). 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.

the entire year, and including major event days can skew that analysis significantly for the small number of days a year that would be major event days. For example, including major event days would underestimate the day-to-day drivers of reliability due to substation or underground equipment, because, typically, overhead equipment is most impacted by major event days, which are usually driven by weather events. In CY 2013, there were three major event days. For informational purposes, Attachment 4 shows reliability performance from CY 2004 to CY 2013, including major event days.

Chart 1

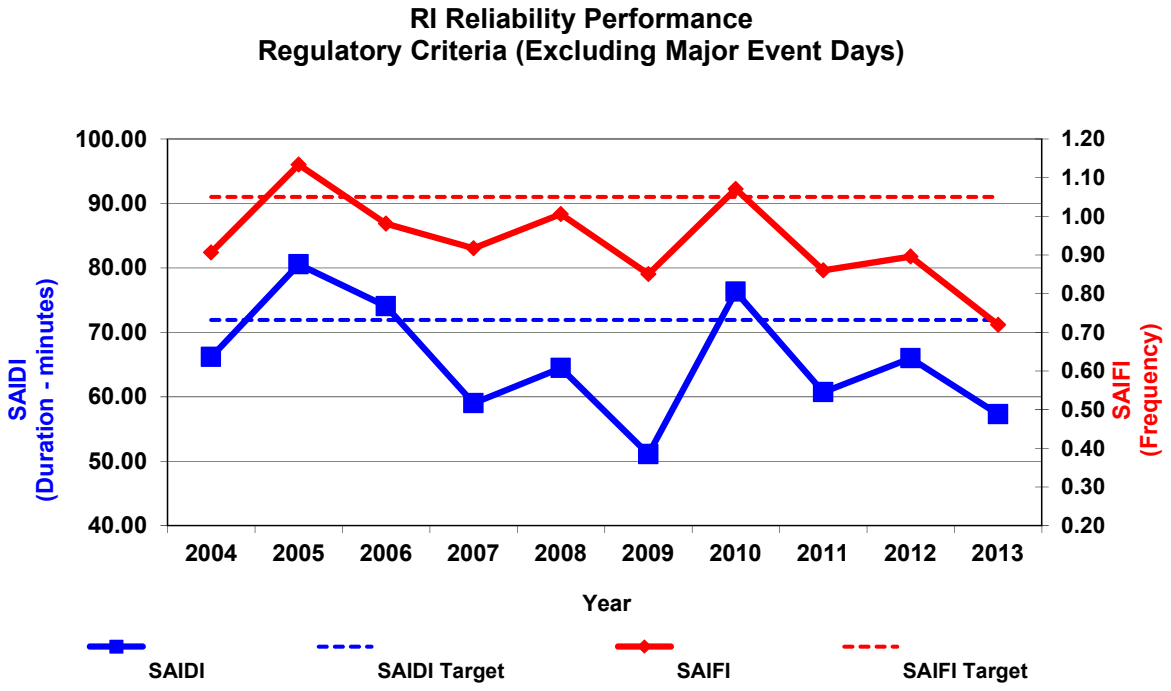


Chart 2 shows the customers interrupted by cause by CY from 2008 through 2013. Chart 3 shows the same information in tabular form.

Chart 2

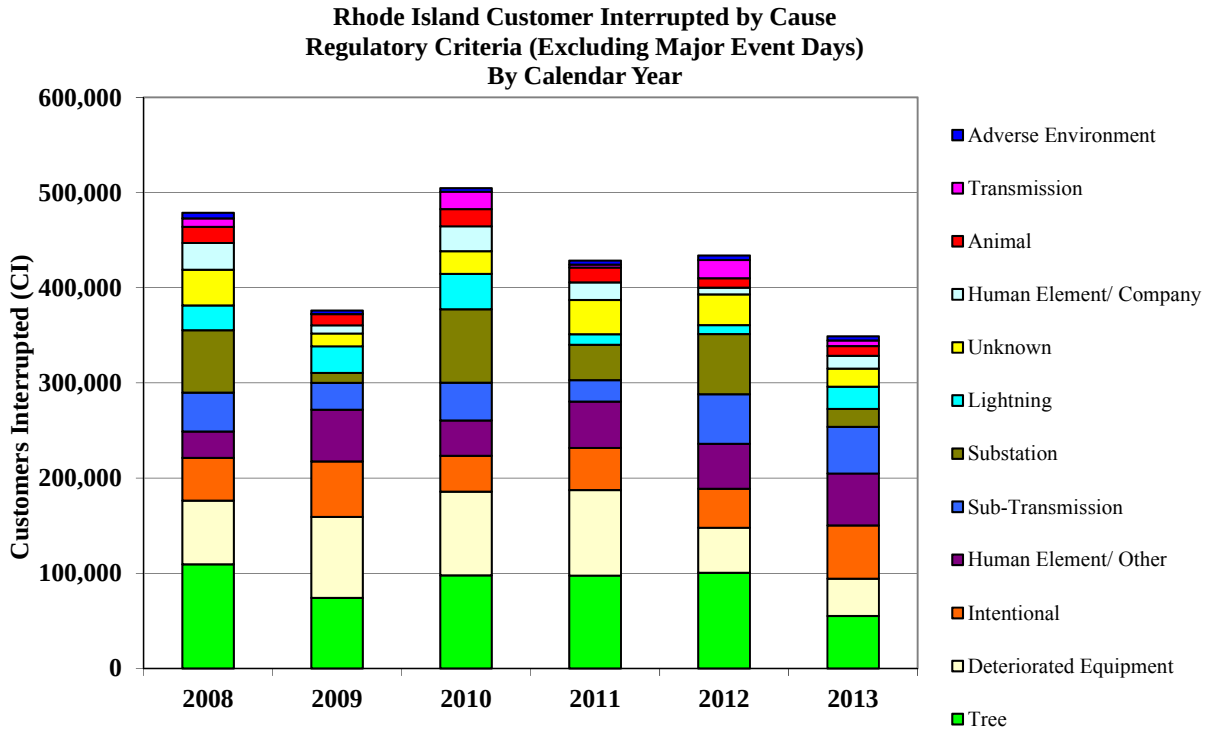


Chart 3

Customers Interrupted by Cause Group Major Event Days Excluded By Calendar Year						
Cause Group	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Adverse Environment	5,910	3,926	3,800	4,444	4,778	4,318
Animal	16,977	11,769	18,021	15,547	9,912	10,324
Deteriorated Eqmt	67,114	85,047	87,768	89,743	47,301	39,131
Human Element/Company	28,298	8,450	26,047	18,455	7,043	13,481
Human Element/Other	27,607	54,275	36,999	48,650	47,404	54,719
Intentional	44,887	58,356	37,743	44,526	40,927	55,927
Lightning	25,987	27,874	36,859	11,044	9,362	23,310
Substation	65,704	10,713	77,189	37,086	63,397	18,882
Sub-Transmission	40,845	28,046	40,034	22,524	51,972	48,902
Transmission	8,721	25	18,438	2,973	19,099	5,958
Tree	109,214	74,116	97,807	97,485	100,459	55,056
Unknown	37,501	13,545	23,962	36,065	32,176	19,008
Total	**478,765**	**376,142**	**504,667**	**428,542**	**433,830**	**349,016**

Although service quality for the Company is based on a calendar year, spending for the ISR is based on the Company's fiscal year (April 1 to March 31). Charts 4 and 5 below provide the reliability data as presented in Charts 2 and 3 by fiscal year through FY 14 (ending March 31, 2014).

Chart 4

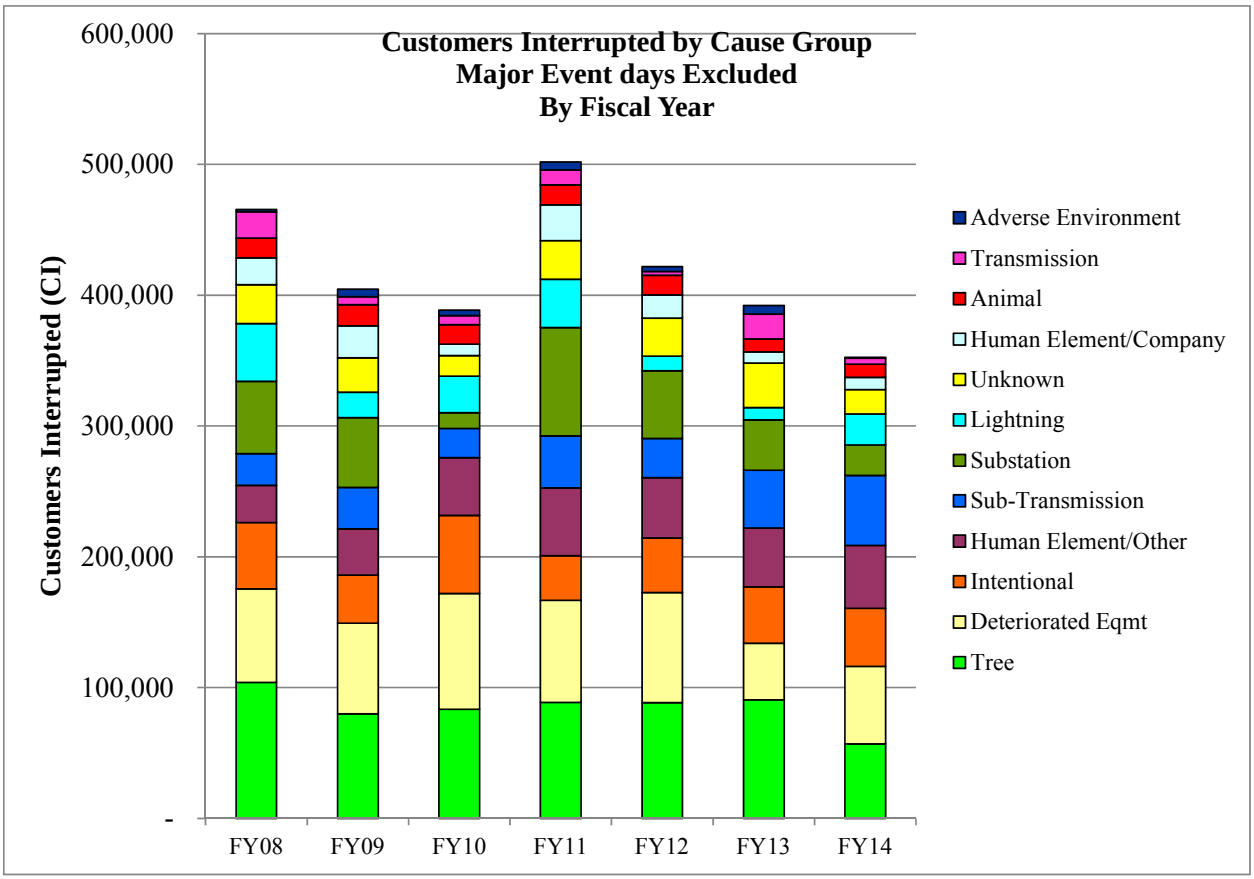

Customers Interrupted by Cause Group
Major Event days Excluded
By Fiscal Year
Customers Interrupted (CI)
600,000
500,000
400,000
300,000
200,000
100,000
-
FY08
FY09
FY10
FY11
FY12
FY13
FY14
Adverse Environment
Transmission
Animal
Human Element/Company
Unknown
Lightning
Substation
Sub-Transmission
Human Element/Other
Intentional
Deteriorated Eqmt
Tree

Chart 5

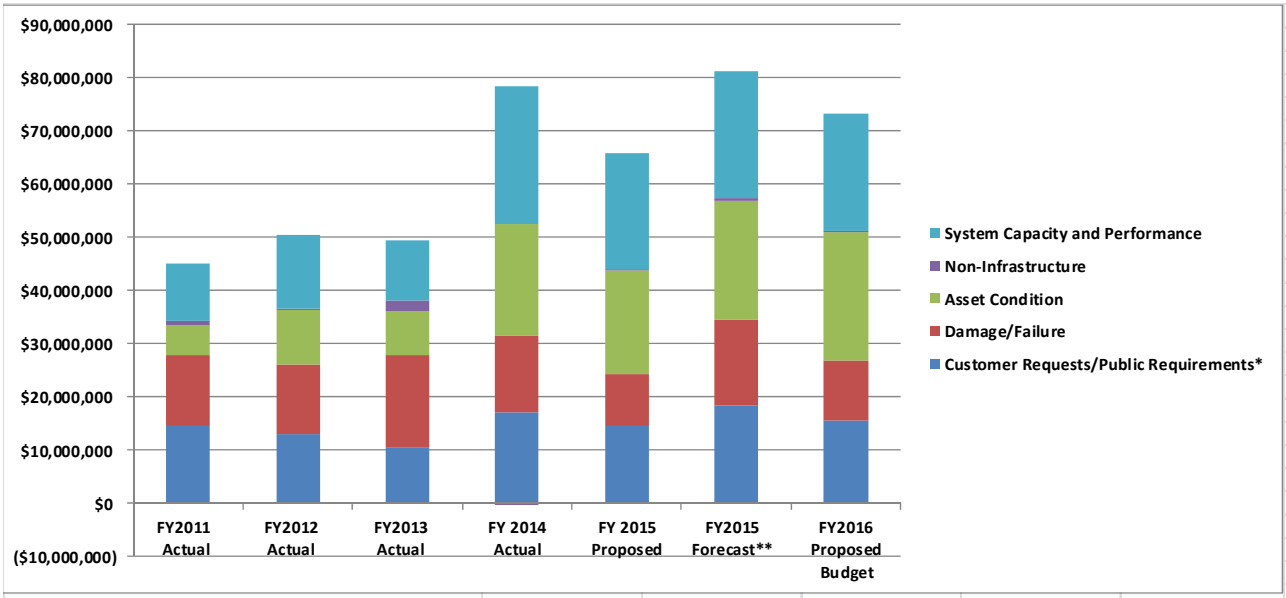
Customers Interrupted by Cause Group Major Event Days Excluded By Fiscal Year							
Cause Group	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Adverse Environment	1,673	5,651	4,018	5,992	3,674	6,584	811
Animal	15,103	16,303	14,751	15,335	15,008	9,864	10,098
Deteriorated Eqmt	71,336	69,296	88,655	78,009	84,052	43,196	59,239
Human Element/Company	20,633	24,393	8,846	27,305	17,722	8,500	9,304
Human Element/Other	28,547	35,531	44,248	51,837	46,171	45,152	48,008
Intentional	50,735	36,569	59,581	33,987	41,879	42,989	44,451
Lightning	44,176	19,577	27,874	36,883	11,098	9,362	23,882
Substation	55,282	53,391	12,120	82,926	51,866	38,492	23,243
Sub-Transmission	24,298	31,628	22,243	39,770	29,805	44,084	53,550
Transmission	20,176	6,000	7,093	11,370	2,973	19,099	4,568
Tree	104,023	79,977	83,311	88,714	88,474	90,726	56,964
Unknown	29,583	26,146	15,807	29,629	29,163	34,143	18,501
Grand Total	**465,565**	**404,462**	**388,547**	**501,757**	**421,885**	**392,191**	**352,619**

Although reliability in FY 2104 was better than any of the prior six fiscal years, trees and deteriorated equipment were the top two drivers affecting customers interrupted. It is, therefore, critical that the Company continue to invest in its infrastructure and VM and I&M programs to provide reliable electric delivery service to customers.

As shown in Chart 6, the Company plans to invest $73.3 million to maintain the safety and reliability of its electric delivery infrastructure in FY 2016, covering the period from April 2015 through March 2016. Chart 7 shows the same information in tabular form. This spending level is approximately 11% higher than the Company's budget of $65.9 million for capital improvements on the Rhode Island network during FY 2015. As discussed in more detail in section 2, the increase is primarily driven by the Asset Condition category.

Chart 6

Capital Spending by Category



* Previously called Statutory/Regulatory

** FY 2015 Second Quarter Report

Chart 7

Capital Spend by Category

SPENDING RATIONALE	FY2011 Actual	FY2012 Actual	FY2013 Actual	FY 2014 Actual	FY 2015 Proposed	FY2015 Forecast**	FY2016 Proposed Budget
Customer Requests/Public Requirements*	$14,631,341	$13,075,000	$10,410,223	$17,137,642	$14,537,000	$18,493,000	$15,647,000
Damage/Failure	$13,194,101	$12,993,000	$17,515,452	$14,373,392	$9,816,000	$16,109,000	$11,177,000
Asset Condition	$5,830,800	$10,320,000	$8,070,832	$20,904,838	$19,511,000	$22,271,000	$24,053,000
Non-Infrastructure	$705,603	$149,000	$2,269,065	($346,246)	$277,000	$399,000	$275,000
System Capacity and Performance	$10,758,714	$13,995,000	$11,249,212	$25,972,338	$21,759,000	$24,004,000	$22,148,000
Grand Total	**$45,120,559**	**$50,532,000**	**$49,514,784**	**$78,041,964**	**$65,900,000**	**$81,276,000**	**$73,300,000**

* Previously called Statutory/Regulatory

** FY 2015 Second Quarter Report

Because a portion of the proposed capital spending in FY 2016 is for projects (mainly substation projects) that will be completed over multiple years, the Company anticipates that

only part of that spending will be placed into service in FY 2016. Likewise, a portion of the capital to be placed in service in FY 2016 will also reflect the capital spending for similar multiyear projects that commenced in prior years. In Docket No. 4473, the PUC directed the Company to provide additional detail in support of the proposed investment for multi-year projects classified as major projects. On August 25, 2014, the Company met with the Division and its consultant regarding the Plan. During that meeting, the Company provided the Division with additional detailed information on major multi-year projects included in the FY 2016 Plan. A summary of information regarding these major multi-year projects is included in Attachment 5. This information varies from the information the Company presented at the August 25 meeting because, since that time, the Company had finalized its FY 2016 budget proposal and reduced the proposed investment in the Asset Condition and System Capacity and Performance categories.

Chart 8 below provides actual and forecasted Plant in Service from FY 2012, when the ISR was first implemented, through the proposed FY 2016 Plan. The Kilvert Street, Clarke, Kent County, Pontiac, and Hope substations will be placed in service under the proposed FY 2016 Plan.

Chart 8

SPENDING RATIONALE	FY2012 Actual Plant in Service	FY2013 Actual Plant in Service	FY 2014 Actual Plant in Service	FY2015 Proposed Plant in Service*	FY2015 Forecasted Plant in Service**	FY2016 Proposed Plant in Service
Customer Request/Public Requirements*	$15,144,000	$11,261,897	$13,844,844	$14,574,000	$17,537,000	$16,611,000
Damage/Failure	$13,628,000	$12,172,707	$16,928,183	$10,921,000	$15,462,000	$11,299,000
Asset Condition	$13,019,000	$6,638,163	$14,639,889	$20,153,000	$24,993,000	$25,354,000
Non-Infrastructure	$60,000	$112,879	$1,989,798	$277,000	$222,000	$277,000
System Capacity and Performance	$9,799,000	$14,145,495	$8,726,837	$23,013,000	$24,894,000	$23,934,000
Grand Total	**$51,650,000**	**$44,331,141**	**$56,129,551**	**$68,938,000**	**$83,108,000**	**$77,475,000**

* Previously called Statutory/Regulatory
** FY 2015 Second Quarter Report

A. Summary of Investment Plan by Key Driver

Chart 9 below summarizes the planned spending level for each of the key driver categories of the Electric ISR Plan proposed for FY 2016.

Chart 9

Proposed FY 2016 Capital Spending by Key Driver Category

SPENDING RATIONALE	FY 2016 PROPOSED BUDGET	%
Non-Discretionary		
Customer Request/Public Requirements*	$15,647,000	21%
Damage Failure	$11,177,000	15%
Subtotal	*$26,824,000*	37%
Discretionary		
Asset Condition	$24,053,000	33%
Non-Infrastructure	$275,000	1%
System Capacity and Performance	$22,148,000	30%
Subtotal	*$46,476,000*	63%
Total	**$73,300,000**	**100%**
* Previously called Stautory/Regulatory		

As shown in Chart 9, $15.7 million or 21% of the spending for capital projects in FY 2016 is necessary to meet customer requests and public requirements. Such investments arise from the Company's regulatory, governmental, or contractual obligations, such as responding to new customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested

by cities and towns as well as the Rhode Island Department of Transportation (RIDOT). For the most part, the scope and timing of this work is defined by others external to the Company.

The need to immediately repair failed and damaged equipment equates to approximately $11.2 million, or 15%, of the Company's investment. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes.

The Company considers the investment required to comply with customer requests and statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and "non-discretionary" in terms of scope and timing. Together, these items total approximately $26.8 million, or 36% of the proposed capital investment in FY 2016.

The Company also has minimal discretion to address load constraints caused by the existing and growing and/or shifting demands of customers. Investments to address these issues account for 87% of the investment dollars categorized as system capacity and performance, or 26% of the proposed capital budget in FY 2016. These investments are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers and to maintain the requisite power quality required by customers. Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the Company's system and capacity loading policy and are designed to reduce degradation of equipment service lives due to thermal stress. These types of projects are also designed to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

The Company has somewhat more discretion with regard to the timing of the other categories and closely monitors the risk associated with delaying such projects due to the potential impact of the consequences of the failure of equipment or systems. The reliability, asset condition, and non-infrastructure projects that the Company will pursue in FY 2016 have been chosen to minimize the likelihood of reliability issues and other problems due to under investment in the overall system.

Investments that are required to maintain reliable service to customers accounted for 13% of the system capacity and performance category, or 4% of the total FY 2016 capital budget. This category includes investment to improve the overall performance of the network. These reliability enhancements include the expansion of the Company's remote monitoring and control capability, and smaller localized enhancements identified by our field operations personnel. Together with load relief projects, these performance projects total approximately $22.1 million, or 30%, of network investment.

Projects necessary based on the condition of the infrastructure assets account for $24.1 million or 33%, of the proposed capital spending in FY 2016. The Company has identified these projects to reduce the risks and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the potential for reliability issues. Moreover, the large number of aged assets in the Company's service area requires the Company to develop strategies to replace assets if their condition

impairs reliable and safe service to customers. Based on the Company's experience with assets that have poor operating characteristics in the field, the Company has developed strategies to remove such equipment. The investments made in these assets are prioritized based on their likelihood of failure along with consequences of such an event.

The "non-infrastructure" category of investment is for those capital expenditures that do not fit into one of the above-mentioned categories but which are necessary to run the electric system, such as general and telecommunications equipment. In total, capital spending for non-infrastructure projects will account for $275,000 and less than 1% of capital spending in FY 2016.

B. Development of the Annual Capital Plan

Each year, the Company develops an Annual Work Plan, which is designed to achieve its overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. The Annual Work Plan represents a compilation of proposed spending for programs and individual capital projects, which are categorized by the following spending categories: Customer Requests/Public Requirements, Damage/Failure, System Capacity and Performance, and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects and initial estimates for newly-proposed projects.

Once the mandatory budget level has been established for the Customer Request/Public Requirements and Damage/Failure spending rationales, the Company reviews programs and

projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) for inclusion in the spending plan. A risk score is assigned to each project based upon the estimated probability and consequence of a particular system event occurring, including the impact on customers and the public. The project risk score takes into account key performance areas such as safety, reliability, and environmental, while also accounting for criticality. The decision regarding whether to include or exclude any given project from the Plan is based on several different factors, including, but not limited to: project new or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the Company analyzes the bundling of work and/or projects to optimize the total cost and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project. The Company makes historical and forward-looking checks y spending rationale to identify any deviations from expected or historical trends.

The portfolio is presented to the Company's senior executives, approved by the Jurisdictional President for Rhode Island, and ultimately goes to the Company's Board as part of the entire United States plan for review and approval. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible for managing the approved budget.

The capital plan for FY 2016 presented in this Plan represents the Company's best information regarding the investments it will need to make to sustain the safe, reliable, and efficient operation of the electric system. As described above, some of the projects are already in

progress or will soon be in progress. Estimates for those projects are quite refined. Other projects are at earlier stages in the project evolution process. The budgets for those projects are accordingly less refined and are more susceptible to change.[8] The capital plan is continuously reviewed during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, permitting/licensing/agency approvals, system operations, performance, safety, and customer-driven needs that arise. The capital plan is updated accordingly throughout the current year.

As stated above, the result of the budgeting process is the approval of a total dollar amount for capital spending in the budget year. In addition to this planning and budgeting process, specific approval must be obtained for any strategy, program, or project within the Annual Work Plan. Approval is obtained through a "Delegation of Authority" (DOA) requirement prior to proceeding with project work, including engineering and construction. Each project must receive the appropriate level of management authorization prior to the start of any work. Approval authority is administered in accordance with the Company's DOA governance policy, with projects over $1 million requiring a Project Sanction Paper (PSP). A PSP is written by the sponsor and details many aspects of the project including:

- Project background, description, and drivers
- Business issues and the analysis of alternative courses of action

[8] National Grid defines three levels of estimate grade accuracy – "Conceptual" = +50/-25%, "Preliminary" = +25/-25%, and "Project" = +10/-10%. Each project transitions through these estimate grades as engineering and design is refined.

- Cost analysis of the proposed project
- Project schedule, milestones, and implementation plan

Once an approved project (greater than $1 million) is completed, the project manager is responsible for preparing closure papers, which present information on a number of factors, including a discussion of whether and to what extent project deliverables were achieved and lessons learned as a result of project implementation.

Projects under $1 million are authorized online, and the project sponsor must provide relevant information regarding the cost and justification of the proposed project.

Capital projects are authorized for construction following preliminary engineering. Reauthorization is required if the project cost is expected to exceed the approved estimate plus an approved variance range identified in the project spending plan. Any reauthorization request must include original authorized amount, the variance amount, the reasons for the variance and the details and costs of the variance drivers, as well as the estimated impact on the current year's spending. Project spending is monitored monthly against authorized levels by the project management and program management groups. Exception reports covering actual or forecasted project spending greater than authorized amounts are reviewed monthly. The Company includes certain reserve line items in its spending plan, by budget category, to allocate funds for projects whose scope and timing have not yet been determined. In such cases, historical trends are used to develop the appropriate reserve levels. The majority of projects that are emergent are the result of in-year occurrences in mandatory, or "non-discretionary", project categories such as damaged or failed equipment, customer or generator requirements, or regulatory mandates. The

Company manages budgetary reserves and emergent projects within the overall budget as part of its investment planning and current year spending management processes.

C. Description of Large Programs and Projects

Attachment 1 to this section provides program and project detail on major projects that support the proposed level of capital spending by key driver shown on Chart 9. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available at the present time and the risk score associated with the project.

i. Customer Request/Public Requirements

As shown in Attachment 1, the Company has set a budget of $15.7 million to meet its Customer Request/Public requirements in FY 2016. This is approximately 8% higher than the FY 2015 budget of $14.5 million, but $1.5 million, or 9% percent less than the actual costs incurred by the Company in this category in FY 2014.

Approximately 49% of the Customer Request/Public Requirement budget is required to establish electric delivery service to new customers. The Company currently expects to spend approximately $7.7 million for this category work in FY 2016. Importantly, the actual and proposed spending in this category is net of contributions in aid of construction that are received from customers.

The Company expects that required spending for public projects will increase by 26%. This category includes such projects as:

- Relocating/adding company assets due to road or bridge-work
- Moving assets such as poles to accommodate a new driveway or other similar customer requests
- Construction as requested by the telephone company, public authorities, towns, municipalities, RIDOT, and other similar entities
- Required environmental expenditures

The budget for FY 2016 includes $1.6 million for public requirement projects. Since much of this construction work is variable and requested on short notice, the Company must set a budget based on previous experience since it does not yet have the project detail. Since the Company gets reimbursed for a portion of this spending (especially for work requested by the Rhode Island Department of Transportation), the budget placeholder represents the capital expected to be spent, net of reimbursements.

The Company expects that it will need to spend approximately $154,000 to facilitate third-party attachments. Spending to enable third-party attachments is highly variable year-to-year based on the timing of contributions from third parties and costs to complete construction. In addition, some costs required to address existing asset conditions are not reimbursed by the third-party customers and, therefore, may increase the balance spent within this category. When applicable, the Company will pursue reimbursements from existing attachments that are non-conforming to standards.

Also included in this spending rationale are distribution costs associated with connecting Block Island to the mainland through the Block Island Transmission System (BITS). The BITS requires changes at the Wakefield substation. The scope for the changes necessary at the Wakefield substation is currently under development. The Company has budgeted $600,000 for these upgrades in FY 2016.

ii. Damage/Failure

The Company is proposing an $11.2 million budget for FY 2016 for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. This is approximately 14% more than the $9.8 million budget for FY 2015, but $3.2 million, or approximately 28% less than the actual Damage/Failure costs incurred by the Company in FY 2014. Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historic trends. A portion of the damage/failure budget allows for larger project work that will arise within the current year as well as carryover projects from the prior fiscal year where the final restoration of the plant-in-service will not be complete until FY 2016 (e.g. failed substation transformer). As in FY 2015, the budget set for FY 2016 also includes capital spending to address issues that have been identified for immediate repair as part of the inspection and maintenance program as described in Section 4.

The damage/failure portion of the Company's capital plan has three major components:

- Damage/Failure Blanket Projects – These projects are for substation or line equipment failures whose size is unknown at the time of the failure,

but are expected to be less than $100,000. The budget for FY 2016 is built on the assumption of flat failure rates along with inflation assumptions.

- Damage/Failure Reserve for Specific Projects – A reserve to address larger failures that require capital expenditures in excess of $100,000. The reserve is built on recent historic trends of such items and allows the Company to complete unplanned work without having to halt work on projects that are planned to stay on target with the overall capital budget.

  Major Storms – Each year, the Company carries a budgeted project for major storm activity that affects the Company's assets. While the actual spend in this category may vary greatly, this reserve, based on average trends over the past several years, allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required.

iii. Asset Condition

The Company is proposing to spend $24.1 million in FY 2016 to replace assets that must be replaced to maintain reliability performance. This level is approximately 23% higher than the FY 2015 budget of $19.5 million. This increase is driven primarily by the South Street asset replacement project, a lower level of negative schedule reserves, and increased levels of blanket asset replacement projects (individual projects under $100,000.) Attachment 3 contain charts illustrating the current age profiles for distribution poles, distribution service transformers,

metalclad substations, substation batteries, substation power transformers, and substation breakers and reclosers. Age is not a perfect indicator of asset condition, and, in general, the Company makes asset replacement decisions factoring in asset condition, rather than asset age. Nonetheless, reviewing asset age is a method to demonstrate how current spending levels are improving or maintaining overall asset condition. Attachment 3 also includes charts indicating how current spending levels are expected to improve asset age for metalclad substations and batteries, as these two categories of assets use age as a primary driver for replacement. For metalclad substations, continuing with current spending levels for 10 years, the average age of this asset will move from 47 years to 25 years. For substation batteries, continuing with current spending levels for 10 years, the average age of this asset will move from 7 years to 5 years. The Company is currently developing the analysis for other asset categories.

The key asset condition budget categories are as follows:

URD Cable Strategy - This strategy applies to Underground Residential Development (URD) and Underground Commercial Development (UCD) cables that are sized #2 and 1/0, and does not apply to mainline or supply cables. It sets forth the approach for replacing or rehabilitating (through cable injection) these cables. This strategy supports the current method for handling cable failures by fixing immediately upon failure and offers options for managing cables that have sustained multiple failures. Although interruptions on #2 and 1/0 cables do not significantly influence Company-level service quality metrics, they can have significant localized impacts on affected neighborhoods.

For URDs with at least three cable failures within the last three years, two options are considered for addressing repeated failures: cable rehabilitation through insulation injection or cable replacement. Insulation injection is identified as the preferred solution for direct buried Cross Linked Polyethylene (XLPE) cables in a loop fed arrangement. The overall condition of the primary and neutral cables and installation specifics will determine whether insulation injection is a viable option. The Company proposes to spend the majority of the $2.5 million budget for the replacement of assets at Maplewood Drive and the Wionkhege Subdivision in the towns of Cumberland and Smithfield respectively.

Underground Cable Strategy - The goal of this strategy is to replace primary underground cable that is in poor condition or has a poor operating history. The Company's present underground cable replacement program is a mixture of reactive "fix on fail" replacement in the Damage/Failure spending rationale and proactive replacement in the Asset Condition spending rationale based on type of construction, asset condition, and failure history for a specific asset and similar assets. Reactive "fix on failure" replacement, which the Company considers mandatory spending, often evolves into proactive replacement of an entire circuit or a localized portion of a circuit, which is considered discretionary spending. Discretionary spending for proactive replacement can be further categorized by that work justified by the need to eliminate repeated in-service failures, work justified by anticipated end-of-life based on historic performance or

industry experience, and work made necessary by other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. Examples of distribution cables currently being planned for replacement include the 1109A, 1111, 79F1, 54K21, and portions of the network secondary cable system. The Company proposes to spend approximately $1.0 million to continue implementing this strategy in FY 2016 by managing the resources and schedules of the identified circuits and proceeding with engineering, design, and/or construction for those selected for FY 2016 expenditures.

Strategy to Replace Distribution Substation Batteries - The Company has more than 80 battery systems in its distribution substations, and these systems play a significant role in the safe and reliable operation of substations. The batteries and chargers in these systems provide DC power for protection, control, and communications within the substation and between substations and control centers. One goal of the Company's strategy is to replace batteries that are 20 years old or older. Another goal is to ensure that battery systems meet the current operating requirements and perform their designed function. The Company proposes to spend $200,000 in FY 2016 to implement this strategy.

The Substation Metalclad Switchgear Replacement Strategy and Program - This program is another important strategy to improve the reliability of substations. This strategy addresses metalclad switchgear that has known operating issues or are of the

same type and manufacturer as equipment that has failed at another location. Solutions typically include replacing the equipment. In some cases, system configurations allow load to be transferred from these stations in a cost-effective manner, allowing the metalclad equipment to be retired and removed. Presently, there are 45 metalclad switchgear units in Rhode Island operating between 4kV and 23kV. Of the 45 units, 24 units were installed prior to 1971. Several design factors with older vintage metalclad switchgear stations contribute to bus failures or component failures. These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the metalclad switchgear and buss failures. Gaskets and caulking of enclosures deteriorate over time allowing rain and melting snow to enter.
- Ventilation - Metalclad interiors can reach high temperatures in the summer even if ventilation systems are working correctly. High temperatures degrade the lubrication in breaker mechanisms and other moving parts and can cause failure of electronic controls and relays.
- Insulation - Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages, are apparent in earlier vintage switchgear.

The FY 2016 budget includes engineering and construction work on the Hyde Avenue, Daggett Avenue, Front Street, and Southeast projects and engineering-only on the Lee Street, Cottage Street, and Centre Street projects. The four construction projects

for FY 2016 are substation retirements, utilizing system configurations to convert load to higher voltages in a cost effective manner and remove the station. A portion of this work was deferred from FY 2015 due to increased cost estimates to perform the necessary distribution work. While these costs have increased, retiring these assets is still more cost effective than replacing them. This distribution strategy is funded at $1.17 million in FY 2016.

The Substation Circuit Breaker Strategy and Program - This program targets obsolete and unreliable breaker facilities. The Company has approximately 817 distribution substation circuit breakers and reclosers in substations that it maintains, refurbishes, and replaces as necessary. Units with obsolete technology, such as air magnetic interruption, have been specifically identified for replacement. Additionally, where cost-effective and where conditions warrant, the Company bundles work and replaces disconnects, control cable, and other equipment associated with these circuit breakers. The Company proposes to spend approximately $1.0 million to implement this strategy in FY 2016.

The Relay Replacement Strategy - This strategy intends to replace those relays, relay packages, communication packages, and control houses that have operational issues or are obsolete and no longer supported by the manufacturer. A certain percentage of the electro-mechanical and solid state relay population is currently demonstrating a trend of decreasing reliability. The attempt to keep these relays in working order is thwarted by a

lack of spare parts and knowledge base due to obsolescence. The primary intent of the strategy is to replace those relays that have a higher probability of failure. The protection afforded by relays is critical to safety and the stability of the electric system. The relays are designed to protect high-value system assets from effects of system faults and to quickly isolate system disturbances so that no additional damage can occur, while ensuring continued safe and reliable operation of the system. The strategy represents a six-year plan to replace transformer and under frequency relays that have been identified using the criteria mentioned above, and will be completed in FY 2016. The Company proposes to spend $940,000 to implement this strategy in FY 2016.

Substation Transformer Replacement Strategy – This strategy supports the substation transformer asset replacement program, which allows National Grid to rank its substation transformers in terms of health and risk and to identify those transformers that are most critical to the system so that the transformers are properly prioritized for asset replacement. The primary intent of this strategy is to proactively replace transformers that have a high likelihood of failure due to asset condition issues. The transformer replacement at Lafayette Substation #30 is in the FY 2016 plan, as well as engineering for the transformer replacement at West Cranston #21. The Company proposes to spend $795,000 on this strategy in FY 2016.

Southeast Substation - This project is required to address asset condition concerns at Pawtucket No. 1 substation. Pawtucket No. 1 station consists of a four-story brick

building constructed in 1907 with an indoor substation and an outdoor switchyard. The indoor substation includes breakers and relays with condition issues, structures with clearance issues, and the building has structural issues. Electrically, Pawtucket No. 1 station is located and serves half of its load on the west side of the Seekonk River. The other half of the Pawtucket No. 1 load is located on the east side of the river. While the asset conditions indicate the need for a station rebuild of Pawtucket No. 1, the Southeast station site, located on the east side of the river, creates an opportunity to split the load, improve overall capacity, and avoid the capacity and operational constraints created by the river.[9] This is a new significant multi-year project as shown in Attachment 5, and the Company proposes to spend approximately $50,000 in FY 2016.

South Street Substation - South Street Substation is a major 115/11 kV supply substation serving downtown Providence and surrounding area. The South Street Substation replacement is driven by asset condition concerns. The building layout is such that it precludes the implementation of modern installation standards in order to replace original equipment. Additionally, spare parts for the protection components are unavailable and will be irreplaceable in the event of a failure. Finally, maintenance work is time-consuming, and because of issues described above, results in custom site-specific repairs. Specific asset condition issues exist for the transformers, breakers, switches,

[9] The Southeast substation is currently a metal clad substation proposed for retirement (see Substation Metalclad Switchgear Replacement Strategy and Program). Upon completion of the Southeast metalclad retirement project, the Southeast site becomes an optimal location to address the Pawtucket No.1 substation issues.

feeder reactors, and the battery system. This a another new significant multi-year project as shown in Attachment 5 and the Company proposes to spend approximately $4.6 million in FY 2016.

Westerly Flood Restoration - To mitigate future flood damage risk at Westerly substation, a long-term plan was developed in 2010. The plan recommended abandoning the Westerly substation site and expanding the proposed Hopkinton substation that was being permitted in the Town of Hopkinton on Company-owned land west of route 3. The recommendation was to install a second power transformer and four additional feeders at Hopkinton substation. This investment would provide capacity to retire Westerly substation. The Company was not successful in permitting the original substation site and a new site was found. The new site resulted in greater than anticipated distribution line costs and right-of-way construction and maintenance challenges. Although the additional distribution distance was considered in the decision to move to the new site, further design reviews identified significant increased right-of-way construction costs. A more comprehensive review by operations also identified challenges with access, initial construction, and long-term maintenance of distribution circuits on the right-of-way. Due to the rising distribution line costs associated with the original recommended plan, the alternative analysis was reevaluated. The strategy to install 8-feeders at the Chase Hill substation site has been modified to only install 4-feeders and the Westerly

Substation will be rebuilt. The project proposes to spend approximately $650,000 in FY 2016.

Network Arc Flash Program - This program addresses the requirements of the National Electrical Safety Code's (NESC) Part 4: Work Rules for the Operation of Electric Supply and Communication Lines and Equipment. A 2012 revision to this part of the NESC requires an arc flash hazard analysis for work assignments on facilities operating under 1000 volts. The Company completed its analysis and identified issues concerning certain maintenance activities on its 480V spot network systems. This strategy will mitigate the calculated incident energy levels by installing engineering controls such as primary and secondary switches. The Company expects to address all of its 480V spot networks over a five-year horizon. The project proposes to spend approximately $600,000 in FY 2016.

Flood Mitigation Projects – As discussed in previous Electric ISR Plans, major flooding occurred on the Pawtuxet River, Pawcatuck River, Blackstone River, and Hunt River from March 30 through April 1, 2010, which resulted in substations located in those areas being de-energized because of excessive water levels. The impacted areas represented a significant health and safety risk to personnel, reliability impacts to customers, as well as significant damage to mechanical, electrical, control, and communications equipment in these substations and their control houses. On June 29, 2012, the Company filed its

Rhode Island Flood Mitigation Plan[10] with the PUC. The FY 2014 Electric ISR Plan identified certain changes to the June 2012 Flood Mitigation Plan regarding the Sockanossett and Warwick Mall substations. The flood mitigation work for the Sockanossett substation will remain deferred. A recently completed area capacity study recommends transmission expansion that would eliminate the need for the Sockanossett substation and associated flood mitigation work. A Warwick Mall flood mitigation project has been progressed based on last year's refined estimates to raise a portion of the station equipment. Work for FY 2016 includes continuation of substation engineering, procurement of equipment, permitting and licensing, and construction on several projects to address flood mitigation. The majority of these projects are multi-year projects.

Projects in the FY 2016 budget are shown in Chart 10 below.

Chart 10

Substation Flood Mitigation Projects in FY 2016 Plan

Substation with Flood Risk	Preferred Alternative Substation	FY 2016 Activities	Projected Capital Spending FY 2016 ($M)
Sockanosett	TBD	On Hold	$0.00
Pontiac	Pontiac	Construction	$1.09
Warwick Mall	Warwick Mall	Construction	$0.02
Hope	Hope	Construction	$0.61
TOTAL			**$1.72**

[10] Rhode Island Flood Mitigation Plan, Docket No. 4307.

The flood mitigation for Westerly substation has been previously discussed. The flood mitigation for the Hunt River substation will be addressed by the capacity project at Kent County, which is discussed in the System Capacity and Performance section. The flood mitigation work for the Riverside Substation has been completed. This work was performed under a blanket project, as it was estimated to be under $100,000.

Inspection & Maintenance Program - This program has both capital and O&M components. The proposed capital spending for FY 2016 is $6.7 million. Section 4 further discusses both the capital and O&M components of the I&M Program.

iv. System Capacity and Performance

The Company has set a budget of $22.2 million for system capacity and performance projects in FY 2016. This is a small increase from the $21.8 million that the Company budgeted in FY 2015. The System Capacity and Performance category is comprised of Load Relief and Reliability projects. The Load Relief projects account for $19.3 million or 87% of the proposed System Capacity and Performance spending in FY 2016.

These Load Relief projects were identified as part of the Company's annual capacity planning process, which is conducted each year to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur. The capacity planning process includes the following tasks:

- Review of historic loading on each sub-transmission line, substation transformer, and distribution feeder;
- Weather adjustment of recent actual peak loads;
- Econometric forecast of future peak demand growth;
- Analysis of forecasted peak loads vis-à-vis equipment ratings;
- Consideration of system flexibility in response to various contingency scenarios;
- Development of system enhancement project proposals.

The Company has developed a multi-step, top-down/bottom-up process to forecast the loading on these assets to identify the need for capacity expansion projects. First, the Company uses an econometric model to forecast summer and winter peak loads. The explanatory variables in this model include historical and forecasted economic conditions at the county level[11], historical peak load data, and a forecast of weather conditions based on historical data from several weather stations.

The Company uses this model to simulate the historical and forecasted peak demand for areas of the state under a normal and extreme weather scenario. The normal weather scenario assumes the same normal peak-producing weather for each year of the forecast. The extreme weather scenario assumes an upper bound peak demand under a given set of economic conditions. Based on the historical experience, there is a 5% probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

[11] This data and forecasts are provided by Moody's Economy.com.

The forecast of peak load incorporates the energy efficiency (EE) savings achieved through 2013 since these savings would be reflected in the historical data used by the model. The Company subtracts forecasted incremental EE savings beyond the amounts achieved through 2013 from the load forecast.

The growth rates are applied to each of the substations and feeders within the area. Distribution planners then adjust forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planners use the forecasted peak loads for each feeder/substation under the extreme weather scenario to perform planning studies and to determine if the thermal capacity of its facilities is adequate.

Individual project proposals are identified to address planning criteria violations. At a conceptual level, these project proposals are prioritized and submitted for inclusion in future capital work plans. Projects in the load relief program are typically new or upgraded substations and distribution feeder mainline circuits. Other projects in this program are designed to improve the switching flexibility of the network, improve voltage profile, or to release capacity via improved reactive power support.

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. The goal is to seek the combination of wires and non-wires alternatives that solves capacity deficiencies in a cost-effective manner that also considers the potential benefits and risks. As part of this process, the Company would conduct analysis at a level of detail commensurate with the scale of the problems and the cost of potential solutions.

In Docket No. 4296, the Company proposed a pilot non-wires alternative project to the PUC on February 1, 2012. The proposed pilot was designed to test the capabilities of targeted energy efficiency applications to defer distribution investment.[12]

Some of the most significant Load Relief Projects for FY 2016 include:

- **Proposed New London Ave Substation (formerly West Warwick Substation)** This will include construction of a new 115/12.47 kV substation in the City of Warwick to provide thermal relief to area distribution feeders, transformers, and supply lines and support projected growth in the area. A number of distribution circuits, transformers, and supply lines are projected above their normal and emergency ratings in the City of Warwick and Towns of West Warwick, Scituate, and West Greenwich. Land has been acquired to house this substation and engineering will be conducted for the new site. The Company proposes to spend $6.8 million on this project in FY 2016.

- **Proposed Chase Hill Substation (formerly Hopkinton Substation) –** This project will include construction of a new 115/12.47 kV substation in the Town of Hopkinton to provide thermal relief to area distribution feeders, transformers, and supply lines and support projected growth in the area. A number of distribution circuits, transformers, and supply lines are projected above their normal and

[12] On November 1, 2013, the Company provided the PUC with a detailed update in Docket No.4353 - The Narragansett Electric Company, d/b/a National Grid 2013 System Reliability Procurement Plan.

emergency ratings. This project will also support retirement of the Ashaway substation. Land has been acquired to house this substation and detailed engineering has begun. As described in the Asset Condition section, the Chase Hill Substation project alternative analysis has been re-evaluated and the scope has been reduced. The Chase Hill Substation budget for FY 2016 is $4.9 million. The Company has included the Westerly Flood Restoration project in the proposed budget in the asset condition category.

- **Proposed Newport Substation –** This project will include construction of a new 69/13.8 kV substation and all related distribution line work to develop five new 13.8 kV feeders to provide load relief to the City of Newport. The completion of this project will provide thermal relief to overloaded feeders and supply lines in the City of Newport and improve the overall reliability to Aquidneck Island. The installation of new 13.8 kV feeders and conversion of 4 kV load to the new station improves the reliability of the 23 kV supply and 13.8 kV distribution systems during contingencies. This Plan supports the retirement of Bailey Brook and Vernon substations to address reliability, asset condition and environmental concerns with the most economical solution. The Company proposes to spend $1.8 million on this project in FY 2016.

- **Kilvert St – Install Second Transformer and Two-New Feeders** – This project is required to mitigate load at risk in the cities of Cranston and Warwick for loss

of the Kilvert Street substation transformer and to provide thermal relief to area distribution feeders, transformers, and supply lines. Kilvert Street substation has a single 115/13.2kV, 33/44/55MVA transformer supplying four distribution feeders. Loss of the Kilvert Street transformer would result in an initial outage of 29MW of load. Approximately 14MW of load can be transferred to other area substations through feeder ties leaving 15MW of load un-served until a spare or mobile transformer is installed. This results in a load at-risk exposure of 400MWh. The Company proposes to spend $1.1 million on this project in FY 2016.

- **Kent County – Install Second Transformer and One-New Feeder:** This project is required to mitigate load at risk for loss of the Kent County substation transformer and to address flooding and environmental risks that currently exist at Hunt River substation. Kent County substation has a single transformer supplying four distribution feeders. It supplies approximately 9,400 customers with a peak load of 42MW. Upon contingency, approximately 27MW of load (or approximately 6,000 customers) would be un-served until a spare or mobile transformer is installed resulting in an exposure of 696MWh. To address flood issues at Hunt River substation, this project installs a new feeder at Kent County substation. Hunt River substation is located in the flood plain adjacent to the Hunt River and is located within a wellhead protection area that supplies drinking

water to the Towns of East Greenwich and North Kingstown and the City of Warwick. The additional feeder at Kent County provides capacity to retire Hunt River, addressing the flood issues in a cost effective manner when compared to station reconstruction. This Company proposes to spend $1.2 million on this project in FY 2016.

- **Highland Drive Substation** – This project includes the construction of a new 115/13.8 kV low profile substation, six 13.8kV distribution feeders, and all related distribution line work in Cumberland, RI. This project is designed to provide contingency relief at Riverside substation and Staples substation, relieving the Riverside 108W55 and Staples 112W43 and 112W41 feeders due to concentrated commercial development at the Highland Drive Industrial Park. The substation construction is complete and the station is in service. The remaining work is distribution line construction to complete the circuit reconfigurations. The Company proposes to spend $1.2 million on this project in FY 2016.

- **Clark Street Substation Feeder Upgrade** – This project is required to address reliability concerns in the town of Jamestown. There are normal loading concerns as well as asset condition issues associated with a modular transformer and breaker at this station. The equipment nearing the end of its useful life will be upgraded providing needed capacity to this area. The Company proposes to spend $250,000 on this project in FY 2016.

- **Quonset Substation Expansion** – Area load growth in the vicinity of the Quonset substation is expected to create normal loading issues and exacerbate contingency loading issues. The Quonset Point Area Study, completed in April 2014, recommends expansion of the existing Quonset Substation to provide the necessary capacity to resolve the projected overload and the load at risk. The comprehensive study identified a number of asset condition issues at the Quonset station, which the recommended plan will also address. The Company proposes to spend $480,000 on this project in FY 2016.

In addition to these projects, the Company also has a Distribution Line Transformer Strategy to mitigate unplanned outage/failure risks due to overloads and asset condition of distribution line transformers. There are approximately 64,000 distribution transformers on the Company's distribution system. The Company reviews transformer loading annually using reports generated by the Company's Geographical Information System (GIS). The Company investigates transformers with calculated demands exceeding load limits specified in the applicable construction standard and addresses overloaded installations by replacing them with larger units or load is relieved via installation of a second transformer. The physical condition of distribution line transformers is evaluated on a five-year cycle as part of the Inspection and Maintenance Strategy. Poor-condition units are replaced based on inspection results. The strategy is in addition to replacements that are performed during customer-service upgrades, public requirements projects, and system-improvement projects. The main benefit of this

strategy is the maximization of asset utilization and sustained reliability performance. The Distribution Line Transformer strategy is funded at $600,000 in FY 2016. The reduction in funding this year is a result of reprioritization of the overall project portfolio. The Company balances the benefits of programs such as this against the need for specific large capacity and asset condition projects.

The Company also has a Distribution Load Relief Blanket to provide the necessary funding for line work less than $100,000 in value. The blanket project provides local engineering, design, and operations personnel in each operating division with a controlled mechanism to initiate work that addresses capacity or power quality issues emerging from customer and municipal inquiries, recent or reoccurring outage events, and observations made during routine operations. Recommendations less than $100,000 from annual capacity reviews are also included in this blanket. Examples of line blanket work are short conductor upgrades and extensions; installation and upgrades of transformers, feeder voltage regulators, and capacitors; and recloser, switch, and fuse installations required for the reallocation of load on existing circuits. The amount of funding in the blanket project is reviewed and approved each year based on the results of the previous annual capacity planning review, historical trends in the volume of work required, as well as a forecasted impact of inflation on material and labor rates. The current year spending in the project is monitored on a monthly basis. The blanket project is budgeted at $381,000 in FY 2016.

In addition to the Load Relief Projects identified above, the Company is also proposing to spend approximately $3.3 million in FY 2016 on several programs designed to maintain system

reliability, which is an increase over the Company's spending level of $2.7 million for these programs from FY 2015. This increase in spending is driven by the following:

Distribution Reliability Blankets - In addition to specific projects (i.e. those $100,000 or greater), the Company also budgets for work less than $100,000 under two Distribution Reliability Blanket Projects for line and substation assets. These blanket projects provide local engineering, design, and operations personnel in each operating division with a controlled mechanism to initiate work that addresses reliability issues emerging from customer and municipal inquiries, recent or reoccurring outage events, and observations made during routine operations. Recommendations less than $100,000 from annual reliability reviews are also included in these blankets. Examples of line blanket work are short conductor upgrades and extensions; installation of reclosers, switches, and fuses to address reliability, operational, and coordination problems. The substation blanket is for simple substation equipment installations or replacements that have reliability or load relief benefits. The amount of funding in each divisional blanket project is reviewed and approved each year based on the results of the previous annual reliability review, historical trends in the volume of work required, as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. These blanket projects are budgeted at $760,000 in FY 2016.

Minor Storm Hardening Projects - The Company defines "Minor Storms" as occurring on days when the network experiences an exponentially greater number (between 1.5 and 2.5

Beta plus, three times the average number of events) of SAIDI minutes due to a weather event. A review of reliability on these Minor Storm days can identify areas of Customers Experiencing Multiple Interruptions (CEMI). These projects target areas and circuits with a CEMI greater than four. The Foster/Clayville Minor Storm Hardening project, including Anthony Road in Foster, is the current project in progress with engineering activities planned for FY 2016. Although the Company typically proposes an approximate $700,000 to $1,000,000 budget for these types of projects, the FY 2016 proposed budget is $25,000. The reduction in funding this year is a result of reprioritization of the overall project portfolio. The Company balances the benefits of programs such as this against the need for specific large capacity and asset condition projects.

Substation EMS/RTU (SCADA) Additions Program - The Company is proposing to expand the EMS/RTU program to improve reliability performance, increase operational effectiveness, and to provide data for asset expansion or operational studies. The Company proposes an approximately $ 1.1 million budget for this program in FY 2016. Targeted substations, subject to resource planning and other project constraints include: Natick #29, Hospital #146, Harrison #32, Warwick #52, Apponaug #3, Coventry #54, Knightsville #66, Hopkins Hill #63, Rochambeau Ave. #37, Davisville #84, Central Falls #104, Peacedale #59, Elmwood #7, Division St. #61, Lincoln Ave. #72, and Clarkson St. #32 substations.

Volt/Var Management Project - The Company has historically managed the voltage profile of its distribution feeders utilizing voltage regulators and capacitor banks with

independent local controls. In this fashion, the Company is generally able to keep the range of voltages provided to customers along the circuit within the required +/- 5% band. The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralized control of the regulating devices. The Company believes that this will benefit customers by reduced kWh usage. Projects completed by other utilities have shown energy savings of approximately 3%. Upon completion of the project, the Company will evaluate the enhanced benefits of centralized control schemes on its system.

To develop the scope of work for this project, a comprehensive study was conducted in two phases focusing on traditional Volt/Var management and an advanced Volt/Var management, which includes a two-way communication network and centralized control schemes. Through an RFP process, the Company requested proposals for Advanced Volt/Var management schemes, and Utilidata, a Rhode Island based company, was selected as the preferred vendor to provide the necessary integrated control system. The project is currently in the preliminary engineering stage and the Company proposes a $1.5 million budget to complete this program in FY 2016. This budget includes distribution substation, line communications and information systems necessary to complete the project based on the Company's best estimates at this time. The Company is currently in the process of obtaining bids for the required telecommunications and information systems work required for this project. In addition, the Volt/Var project will have ongoing O&M costs for maintaining network and telecommunications components, servers, hardware and software licensing. At this time, the Company does not have

a final cost estimate for this ongoing maintenance cost, but expects it to be approximately $300,000 annually. The Company has included a nominal cost of $100,000 in the I&M section of the ISR for this cost because the system will be implemented during FY 2016.

D. Recovery of Electric ISR Plan Capital Investment – Capital Placed In Service

In previous Electric ISR Plan filings, the Company calculated the revenue requirement based on the Company's projected capital amounts to be placed into service plus associated cost of removal. To develop its Capital Placed-In-Service figure for this filing, the Company has used estimated timing of in-service dates for capital spending being placed into service during FY 2016. Each year, as part of the Company's annual reconciliation, the revenue requirement related to discretionary in-service amounts is trued-up based on the lesser of allowed discretionary capital spending or actual capital investment placed into service on a cumulative basis since the inception of the Electric ISR Plan in April 2011. The discretionary categories include the Asset Condition, Non-Infrastructure, and System Capacity and Performance categories. Because of the multi-year nature of certain projects, current and prior year(s) capital spending was included in the plant in-service amount when a project is placed into service during the fiscal year. Similarly, the capital portion of a project included in a fiscal year's spending plan that will be placed into service in future fiscal periods was included in subsequent revenue requirement calculations during that project's in-service year.

Charts 11 below provides details regarding the total FY 2016 amounts for Capital Spending, Plant In-Service, and Cost of Removal that have been used in the development of the FY 2016 Electric ISR Plan revenue requirement.

Chart 11

Proposed FY 2016 Capital Spending, Plant-In-Service, and Cost of Removal (COR)

Spending Rationale	Proposed Capital Spending FY 2016	New Capital Placed-in-Service FY 2016	Estimated COR	New Capital in Service Plus COR
Non-Discretionary				
Customer Request/Public Requirement*	$15,647,000	$16,611,000	$1,825,000	$18,436,000
Damage Failure	$11,177,000	$11,299,000	$1,594,000	$12,893,000
Subtotal	*$26,824,000*	*$27,910,000*	*$3,419,000*	*$31,329,000*
Discretionary				
Asset Condition	$24,053,000	$25,354,000	$3,330,000	$28,684,000
Non-Infrastructure	$275,000	$277,000	$0	$277,000
System Capacity & Performance	$22,148,000	$23,934,000	$1,451,000	$25,385,000
Subtotal	*$46,476,000*	*$49,565,000*	*$4,781,000*	*$54,346,000*
Total	**$73,300,000**	**$77,475,000**	**$8,200,000**	**$85,675,000**

* Previously called Statutory/Regulatory

Attachment 1

Capital Spending by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASSIFICATION	FY11 Actual	FY12 Actual	FY13 Actual	FY14 Actual	FY15 Budget	FY15 Forecast	FY16 Proposed Budget
Customer Requests/Public Requirements	3rd Party Attachments	(910)	464	223	141	305		154
	Distributed Generation	-	-	(675)	195	-		645
	Land and Land Rights	281	185	128	94	179		167
	Meters - Dist	2,215	1,497	1,455	835	1,824		1,775
	New Business - Commercial	4,287	3,391	3,722	4,957	3,924		4,213
	New Business - Residential	3,530	2,833	2,886	3,593	2,870		3,500
	Outdoor Lighting - Capital	411	495	488	758	533		711
	Public Requirements	1,539	1,135	(1,231)	4,234	1,268		1,602
	Transformers & Related Equipment	3,278	3,075	3,415	2,331	3,634		2,880
Customer Requests/Public Requirements Total		**14,631**	**13,075**	**10,411**	**17,138**	**14,537**	**17,775**	**15,647**
Damage/Failure	Damage/Failure	8,331	9,574	7,795	11,228	8,816		10,177
	Major Storms - Dist	4,863	3,419	9,721	3,146	1,000		1,000
Damage/Failure Total		**13,194**	**12,993**	**17,516**	**14,374**	**9,816**	**11,421**	**11,177**
Non-Infrastructure	Corporate/Admin/General	645	118	890	(1,245)	-		
	General Equipment - Dist	61	149	191	395	102		100
	Telecommunications Capital - Dist	-	-	1,188	504	175		175
Non-Infrastructure Total		**706**	**267**	**2,269**	**(346)**	**277**	**277**	**275**
Asset Condition	Asset Replacement	5,604	9,767	6,984	14,011	11,957		16,748
	Asset Replacement - I&M (NE)	227	553	1,086	6,681	7,040		6,705
	Safety	-	-	-	213	514		600
Asset Condition Total		**5,831**	**10,320**	**8,070**	**20,905**	**19,511**	**22,110**	**24,053**
System Capacity & Performance	Load Relief	6,012	8,837	6,619	22,762	19,052		19,318
	Reliability	2,799	2,554	3,723	3,210	2,707		2,830
	Reliability - Feeder Hardening	1,984	2,564	907	-			
System Capacity & Performance Total		**10,795**	**13,955**	**11,249**	**25,972**	**21,759**	**21,280**	**22,148**
Grand Total		**45,157**	**50,610**	**49,515**	**78,043**	**65,900**	**72,863**	**73,300**

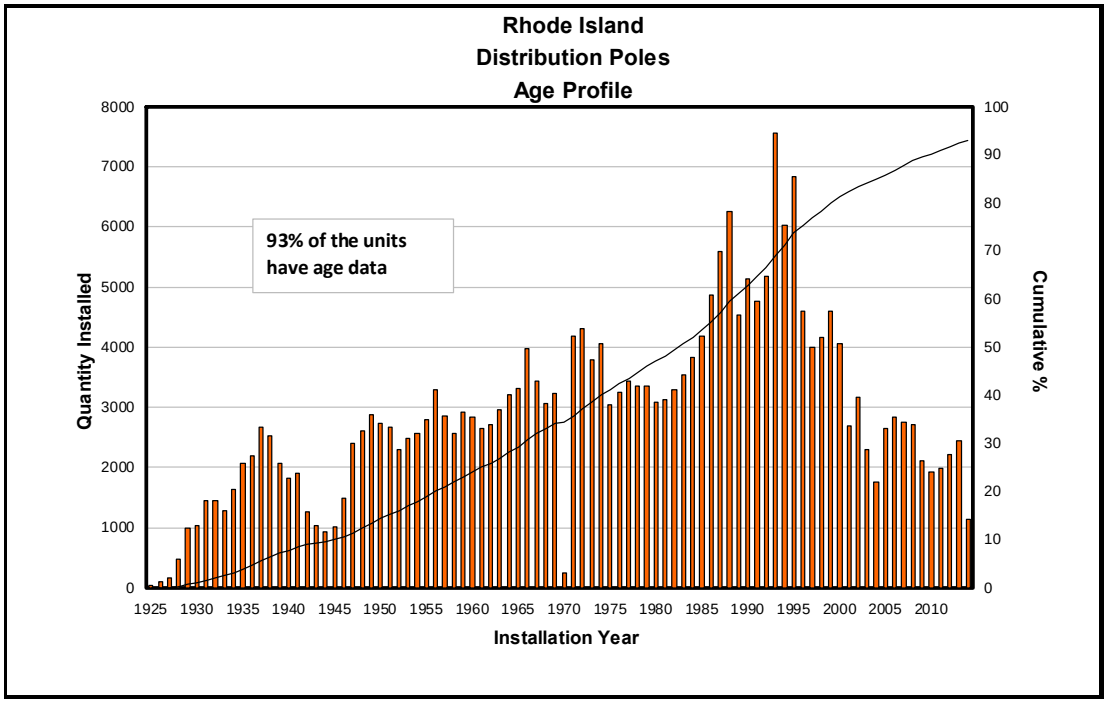
Attachment 2
Project Detail for Proposed FY 2016 Capital Spending

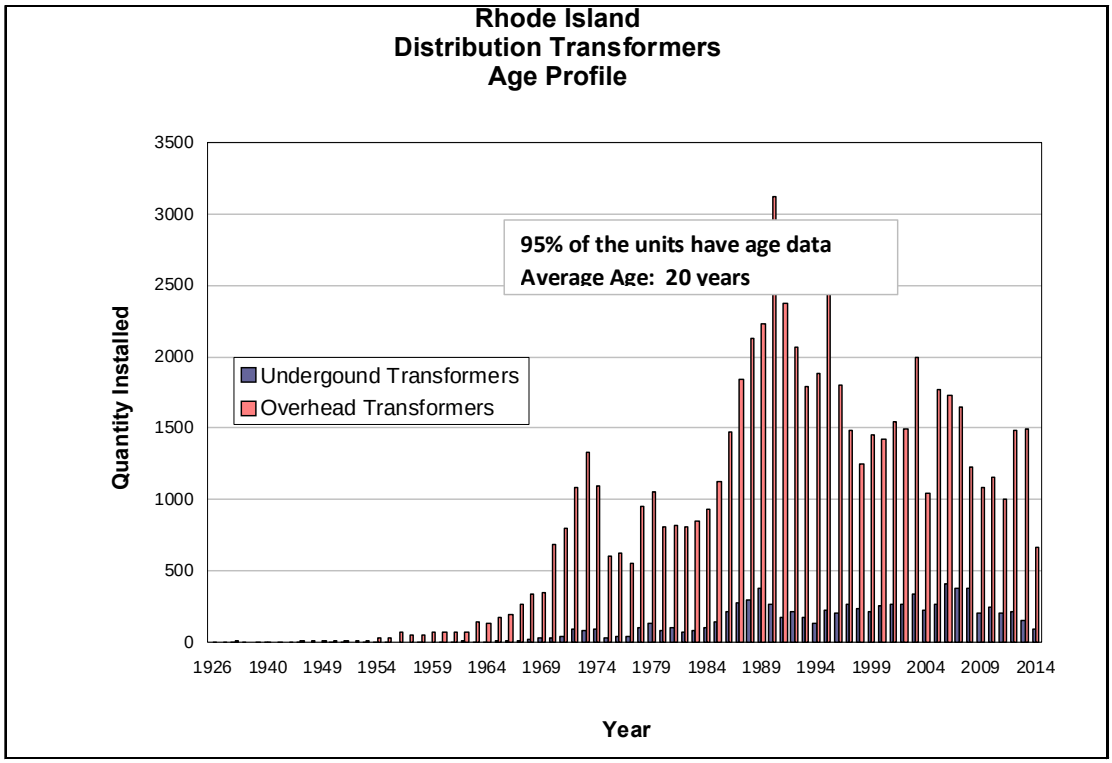
Customer Requests/Public Requirements	**3rd Party Attachments**	COS0022	Ocean St-Dist-3rd Party Attch Blnkt	154
	3rd Party Attachments Total			**154**
	Distributed Generation	C046386	BITS Wakefield Sub Upgrades (D-Sub)	595
		C051909	PS&I Dist Gen RI	50
	Distributed Generation Total			**645**
	Land and Land Rights	COS0009	Ocean St-Dist-Land/Rights Blanket	167
	Land and Land Rights Total			**167**
	Meters - Dist	CN04904	Narragansett Meter Purchases	1,180
		COS0004	Ocean St-Dist-Meter Blanket	595
	Meters - Dist Total			**1,775**
	New Business - Commercial	C046977	Reserve for New Business Commercial	400
		C049981	Nsnvlle 127W41 New Customer Load	553
		C051203	LNG Plant Svc Terminal Rd Prv DLine	30
		C051204	LNG Plant Svc Terminal Rd Prv DSub	30
		COS0011	Ocean St-Dist-New Bus-Comm Blanket	3,200
	New Business - Commercial Total			**4,213**
	New Business - Residential	C046978	Reserve for New Business Residentia	100
		COS0010	Ocean St-Dist-New Bus-Resid Blanket	3,400
	New Business - Residential Total			**3,500**
	Outdoor Lighting - Capital	COS0012	Ocean St-Dist-St Light Blanket	711
	Outdoor Lighting - Capital Total			**711**
	Public Requirements	C012179	DOTR-Repl Great Island Bridge No499	102
		C035087	DOTR-Apponaug Circulator Imprv Warw	616
		C045656	DOTR-Blackstone River Bikeway Seg8A	170
		C045684	Second Beach RI OH-UG conversion	89
		C046970	Reserve for Public Requirements Uni	(1,816)
		C047039	DOTR-East Main Rd, Portsmouth	170
		C047075	DOTR-Blackstone River Bikeway Seg8C	170
		C048717	DOTR-EMain/WMain Int Recon	85
		C050422	Admrl St 9J1 Line Relocation	85
		C050687	DOTR-Hi Haz Int/Ramps C2 Newport Co	170
		C050921	DOTR-Hi Haz IntersectionsBristol Co	170
		C051783	DOTR-E.Providence Bridges 471&472	170
		C052069	DOTR-Providence-Allens Av Arterial	85
		C054828	DOTR-Arterial Impr to Warwick Av	77
		CD00076	DOTR-Atwells Avenue Bridge No. 975,	64
		CD00373	Watch Hill UG Phase 2	173
		CD00567	DOTR-East Main Rd, Turnpike Av-Hedl	80
		CD00646	DOTR-Douglas Pike/Branch Pike Traff	80
		CD01066	DOTR-Union Village Railroad Bridge	34
		COS0013	Ocean St-Dist-Public Require Blankt	828
	Public Requirements Total			**1,602**
	Transformers & Related Equipment	CN04920	Narragansett Transformer Purchases	2,880
	Transformers & Related Equipment Total			**2,880**
Customer Requests/Public Requirements Total				**15,647**
Damage/Failure	**Damage/Failure**	C046986	Reserve for Damage/Failure Unidenti	500
		C051608	Reserve for Damage/Failure Substati	500
		C054323	Franklin Square Breaker Replacement	17
		COS0002	Ocean St-Dist-Subs Blanket	660
		COS0014	Ocean St-Dist-Damage&Failure Blankt	8,500
	Damage/Failure Total			**10,177**
	Major Storms - Dist	C022433	OSD Storm Cap Confirm Program Proj	1,000
	Major Storms - Dist Total			**1,000**
Damage/Failure Total				**11,177**

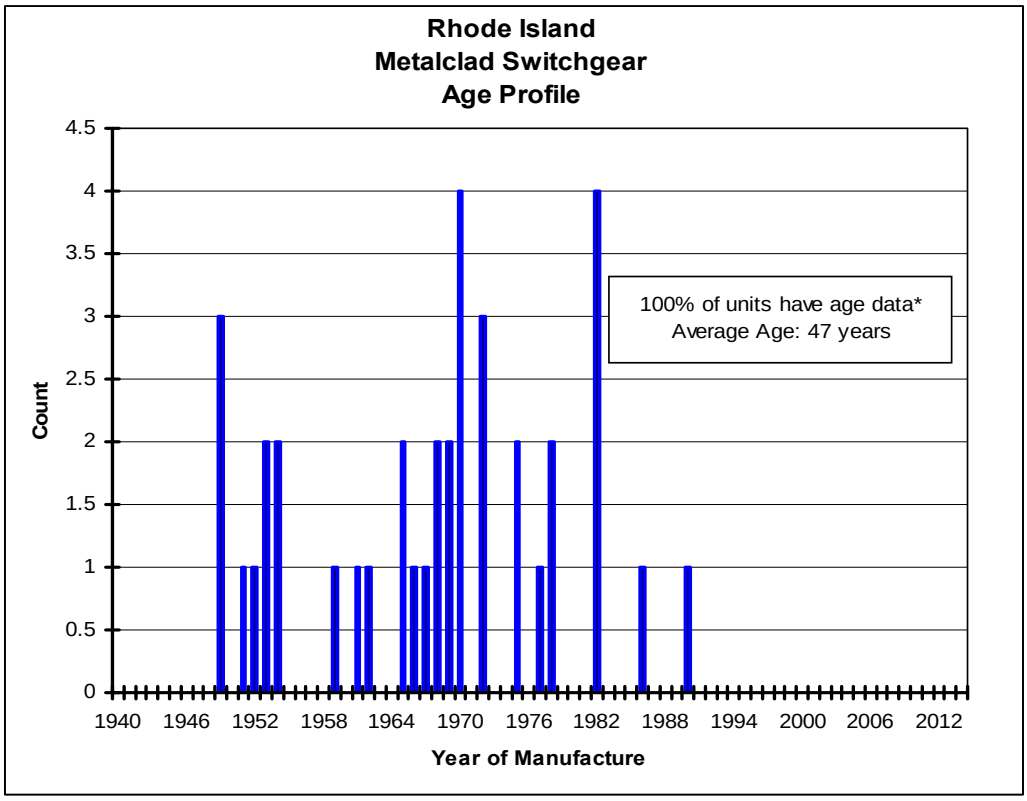
Non-Infrastructure	**General Equipment - Dist**	COS0006	Ocean St-Dist-Genl Equip Blanket	100
	General Equipment - Dist Total			**100**
	Telecommunications Capital - Dist	C040644	Telecom Small Capital Work - RI	175
	Telecommunications Capital - Dist Total			**175**
Non-Infrastructure Total				**275**
System Capacity & Performance	**Load Relief**	C005505	IE - OS Dist Transformer Upgrades	600
		C013967	PS&I Activity - Rhode Island	250
		C015158	Newport Substation (D-Sub)	300
		C024159	Newport 69kV Line 63 (D-Line)	50
		C024175	Chase Hill Sub (D_Line)	2,700
		C024176	Chase Hill Sub (D-Sub)	2,200
		C028628	NEWPORT Phase 2 (D-Line)	1,400
		C028920	New London Ave (D-Sub)	2,900
		C028921	New London Ave (D-Line)	3,900
		C036522	Kilvert St 87 - Install TB#2	1,100
		C046352	RI Volt/Var Mgmt Pilot Project	664
		C046726	East Bay Study (D-Sub)	84
		C046831	CLARKE 65J12 Feeder Upgrade (D-Sub)	200
		C046832	CLARKE St Feeder Upgrades (D-Line)	50
		C046975	Reserve for Load Relief Unidentifie	(700)
		C046987	Reserve for Load Relief Unidentifie	(964)
		C051385	Central Falls Sub Relief	298
		C053268	Pawtucket No 1 Bus Sect 73 Relief	425
		C053646	Quonset Sub Expansion (D-Sub)	400
		C053647	Quonset Sub Expansion (D-Line)	80
		C054054	Jepson 115kV Substation (D-Line)	50
		CD00557	Harrison Feeder Upgrades	300
		CD00649	Gate 2 Substation (D-Sub)	50
		CD00656	Jepson Substation	200
		CD00978	New Highland Drive Substation - DLi	1,200
		CD01101	Kent County 2nd Transformer (D-Sub)	1,100
		CD01104	Kent County 2nd Transformer (D-Line	100
		COS0016	Ocean St-Dist-Load Relief Blanket	381
	Load Relief Total			**19,318**
	Reliability	C005524	IE - OS Cutout Replacements	25
		C035726	EMS - Narragansett Elec	(500)
		C049679	Harrison #32 - EMS Expansion	147
		C049680	Rochambeau Ave - EMS Expansion	178
		C049681	Clarkson - EMS Expansion	92
		C049682	Warwick 52 - EMS Expansion	155
		C049699	Knightsville 66 - EMS Expansion	178
		C049700	Anthony 64-EMS Exp & Upgrades	145
		C049705	Apponaug- EMS Expansion	147
		C049799	Central Falls - EMS Expansion	147
		C049800	Coventry #54 - EMS Expansion	178
		C050698	Davisville #84 - EMS Expansion	155
		C050699	Hopkins Hill #63 - EMS Expansion	147
		C053111	VVO-IT/IS	800
		C054090	Reconductor Anthony Road, Foster RI	25
		CD00526	EMS Add-Peacedale 59 RI	5
		CD00528	EMS Expansion - Natick 29 Substatio	14
		CD00529	EMS Expansion - Hospital Sub 146	5
		CD00530	EMS Expansion - Elmwood Outdoor 7	10
		CD00531	EMS Expansion - Division Street 61	2
		CD00533	EMS Expansion - Lincoln Ave 72	5
		CD01102	Hunt River Substation Retirement	10
		COS0015	Ocean St-Dist-Reliability Blanket	660
		COS0025	OS-Dist-Substation LR/Rel Blnkt	100
	Reliability Total			**2,830**
System Capacity & Performance Total				**22,148**

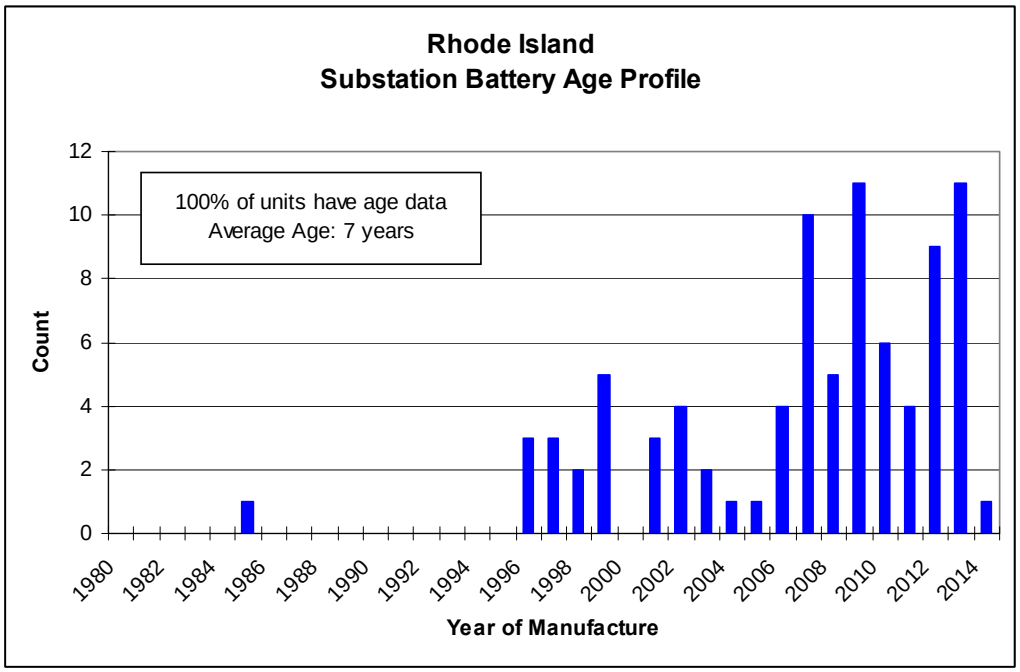
Asset Condition	**Asset Replacement**	C006644	IE - OS Targeted Pole Replace	25
		C025815	OS ARP Insul, SensDev, Surge Arrest	250
		C032019	Batts/Chargers NE South OS RI	200
		C032258	ACNW Vlt47 Structural Repairs Prov	514
		C032278	OS ARP Breakers & Reclosers	1,000
		C032583	OS ARP Metal Clad	(370)
		C035586	Relay Replacement Strategy Co 49DxT	600
		C036527	Westerly Substation Retire	540
		C041726	Replace HMIs - NEC	174
		C046397	Fdr 1109A - Install Cable Dorrance	298
		C046398	Memorial Blvd Easton's Beach inst d	730
		C046400	Capital Ctr Fdrs - Elim T-body join	43
		C046697	Hope Substation Flood Restoration	612
		C046982	Reserve for Asset Replacement Unide	(2,500)
		C046984	Reserve for Asset Replacement Unide	(100)
		C047398	IRURD Wionkheige	600
		C047422	IRURD Maplewood	1,700
		C048969	RI RAPR ARP	180
		C049354	NEC Relay Replacement Co.49- SG157	340
		C049910	Southeast Sub Retirement (D-Line)	254
		C050006	Hyde Ave Retirement (D-Line)	468
		C050017	Daggett Ave Sub Retirement (D-Line)	500
		C050070	IRURD Placeholder RI	200
		C050758	Lee St Retirement (D-Line)	20
		C050760	Cottage St Retirement (D-Line)	25
		C050778	Front St Substation Retirement (Dline)	236
		C051118	Lee St Retirement (D-Sub)	10
		C051126	Cottage St Retirement (D-Sub)	10
		C051198	Abandoned Equipment Removal	25
		C051200	Hyde Ave Metalclad	142
		C051205	Dyer St replace indoor subst D-SUB	100
		C051211	Dyer St replace indoor subst D-LINE	79
		C051212	South St repl indoor subst D-SUB	4,130
		C051213	South St repl indoor subst D-LINE	410
		C051273	Front St Metalclad-Sub Retirement (Dsub)	10
		C051274	Daggett Ave Metalclad - Sub Retirem	190
		C051824	Lafayette Sub Transformer Replaceme	475
		C052686	Prov RI Survey/Repl UG sec. cables	85
		C053657	Southeast Substation (D-Sub)	25
		C053658	Southeast Substation (D-Line)	25
		C055215	Westerly Flood Restoration (D-Line)	110
		C055343	RI UG Cable Placeholder FY19-24	(1,700)
		C055357	RI UG Cable Repl Program - Fdr 1111	750
		C055359	RI UG Cable Repl Program - Fdr 79F1	250
		C055367	RI UG Cable Repl Program Fdr 54K21	500
		C055392	Network Secondary Cable Replacement	900
		C055623	South St Sub 11kV Removal	20
		C055683	Pawtucket No 1 (D-Sub)	5
		C055844	W Cranston Transformer #2 Replaceme	320
		C056391	Centre St Retirement (Dsub)	10
		C056411	Centre St Retirement (DLine)	10
		C056570	Hospital Sub - Metalclad Replacemen	25
		CD01097	Warwick Mall Substation Flood Resto	24
		CD01242	Pontiac Substation Flood Restoratio	952
		CD01243	Pontiac Substation Flood Restoratio	138
		COS0017	Ocean St-Dist-Asset Replace Blanket	1,929
		COS0026	OS-Dist-Substation Asset Repl Blnk	250
	Asset Replacement Total			**16,748**
	Asset Replacement - I&M (NE)	C014326	I&M - OS D-Line UG Work From Insp	105
		C026281	I&M - OS D-Line OH Work From Insp	6,600
	Asset Replacement - I&M (NE) Total			**6,705**
	Safety	CD01257	Distribution Secondary Network Arc	600
	Safety Total			**600**
Asset Condition Total				**24,053**
Grand Total				**73,300**

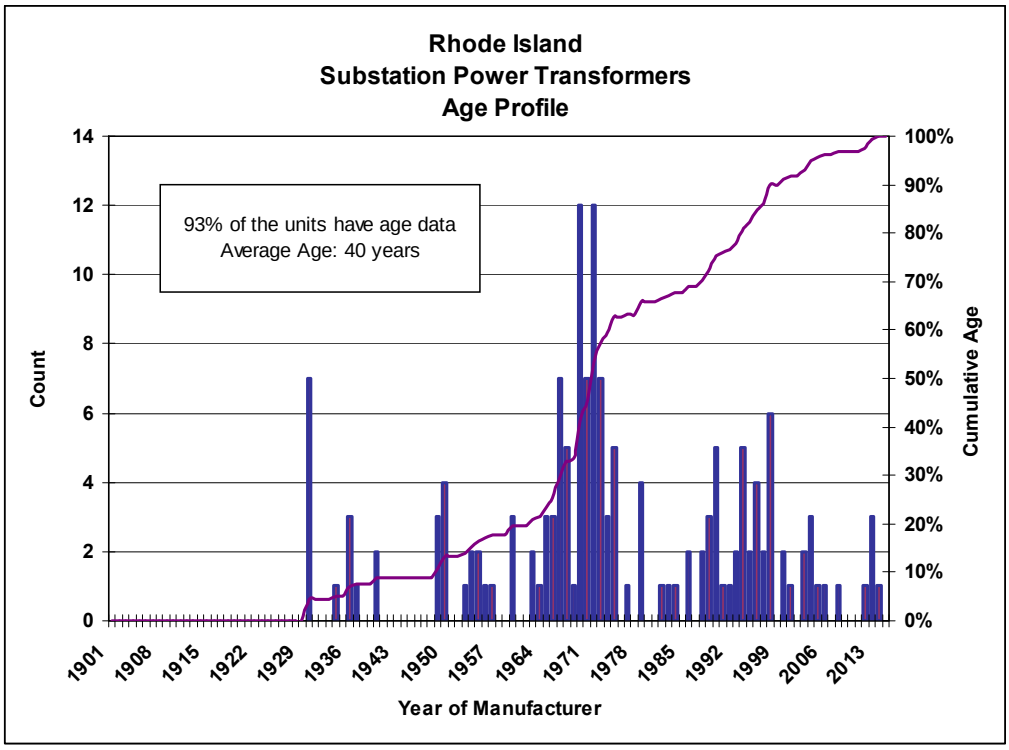
Attachment 3
Asset Age Profile Charts
Current Age Profiles

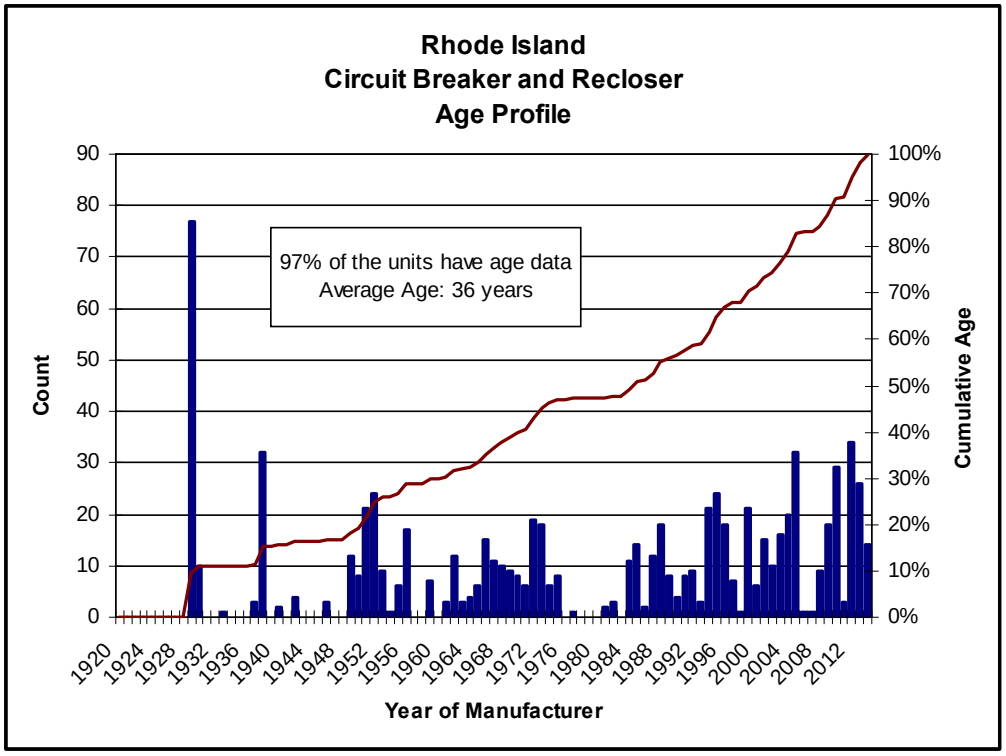



Rhode Island
Distribution Transformers
Age Profile
95% of the units have age data
Average Age: 20 years
Undergound Transformers
Overhead Transformers
Quantity Installed
Year
0
500
1000
1500
2000
2500
3000
3500
1926
1940
1949
1954
1959
1964
1969
1974
1979
1984
1989
1994
1999
2004
2009
2014

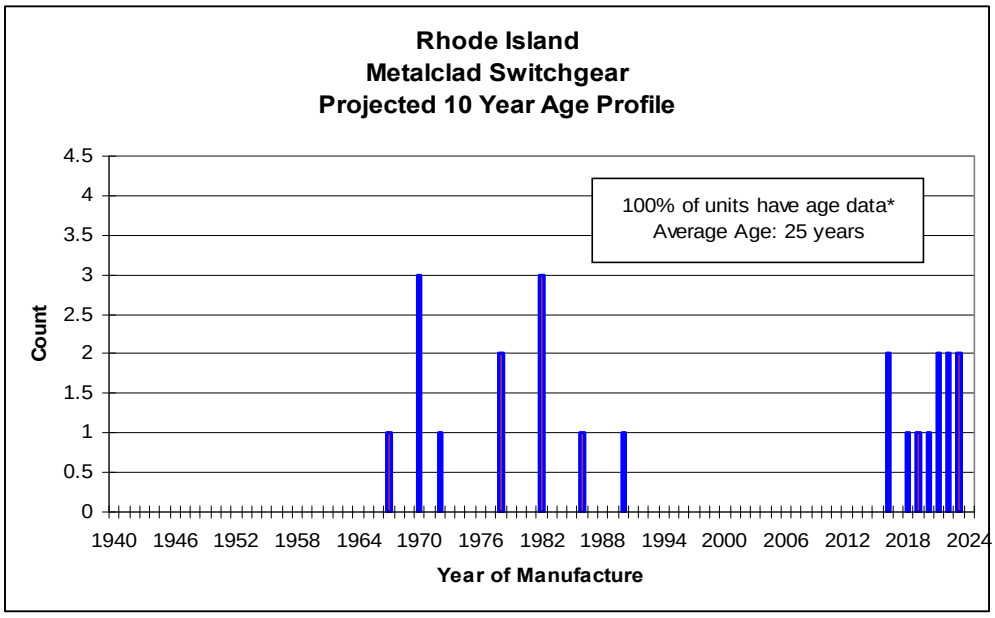

Rhode Island
Metalclad Switchgear
Age Profile
Count
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
1940
1946
1952
1958
1964
1970
1976
1982
1988
1994
2000
2006
2012
Year of Manufacture
100% of units have age data*
Average Age: 47 years

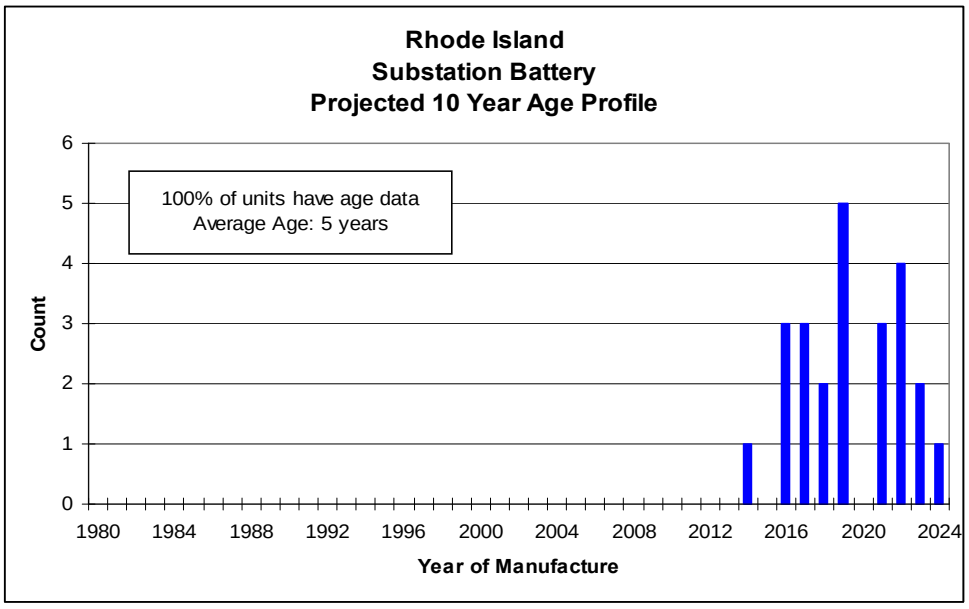

Rhode Island
Substation Battery Age Profile
100% of units have age data
Average Age: 7 years
Count
0
2
4
6
8
10
12
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
Year of Manufacture


Rhode Island
Substation Power Transformers
Age Profile
93% of the units have age data
Average Age: 40 years
Count
Cumulative Age
Year of Manufacturer
0
2
4
6
8
10
12
14
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1901
1908
1915
1922
1929
1936
1943
1950
1957
1964
1971
1978
1985
1992
1999
2006
2013


Rhode Island
Circuit Breaker and Recloser
Age Profile
97% of the units have age data
Average Age: 36 years
Count
Cumulative Age
Year of Manufacturer
0
10
20
30
40
50
60
70
80
90
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1920
1924
1928
1932
1936
1940
1944
1948
1952
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
2000
2004
2008
2012

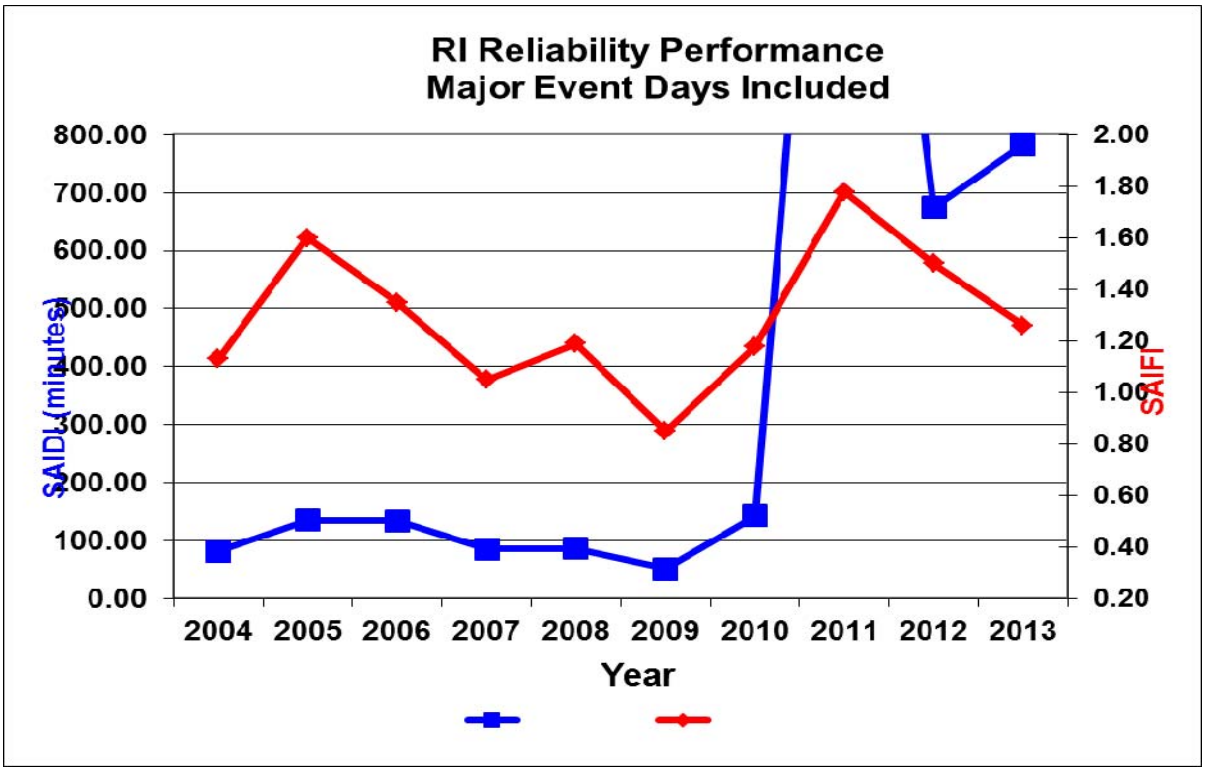
Projected Age Profiles with Current Level Spending**





* Within 10 years of level spending, metalclad substation average age improves form 47 to 25 years.
** Within 10 years of level spending, substation battery average age improves from 7 to 5 years.

Attachment 4



Attachment 5

Rhode Island Distribution Electric Capital Plan FY2016-20

SPENDING RATIONALE	BUDGET CLASSIFICATION	PY BUDGET FY15	FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
Customer Requests/Public Requirements	3rd Party Attachments	305	154	158	162	166	170
	Distributed Generation		645	455	50	50	50
	Land and Land Rights	179	167	170	173	176	179
	Meters - Dist	1,824	1,775	1,836	1,891	1,947	2,003
	New Business - Commercial	3,924	4,213	5,328	7,914	5,002	4,792
	New Business - Residential	2,870	3,500	3,801	3,898	3,998	4,100
	Outdoor Lighting - Capital	533	711	722	733	744	755
	Public Requirements	1,268	1,602	1,250	1,178	1,200	1,223
	Transformers & Related Equipment	3,634	2,880	2,970	3,060	3,150	3,240
Customer Requests/Public Requirements Total		**14,537**	**15,647**	**16,690**	**19,059**	**16,433**	**16,512**
Damage/Failure	Damage/Failure	8,816	10,177	10,298	10,437	10,578	10,721
	Major Storms - Dist	1,000	1,000	1,050	1,100	1,150	1,200
Damage/Failure Total		**9,816**	**11,177**	**11,348**	**11,537**	**11,728**	**11,921**
Non-Infrastructure	Corporate/Admin/General		-	-	-	-	-
	General Equipment - Dist	102	100	105	110	115	120
	Information Technology		-	-	-	-	-
	Other			-	-	-	-
	Telecommunications Capital - Dist	175	175	175	175	175	175
Non-Infrastructure Total		**277**	**275**	**280**	**285**	**290**	**295**
System Capacity & Performance	Load Relief	19,052	19,318	17,499	18,225	23,628	14,515
	Reliability	2,707	2,830	3,049	3,130	3,140	3,150
System Capacity & Performance Total		**21,759**	**22,148**	**20,548**	**21,355**	**26,768**	**17,665**
Asset Condition	Asset Replacement	11,957	16,748	27,710	30,399	32,461	31,057
	Asset Replacement - I&M (NE)	7,040	6,705	6,910	7,115	7,320	7,550
	Safety	514	600	514	250	-	-
Asset Condition Total		**19,511**	**24,053**	**35,134**	**37,764**	**39,781**	**38,607**
Grand Total		**65,900**	**73,300**	**84,000**	**90,000**	**95,000**	**85,000**

Spending Rationale as defined in ISR Document

Project Grouping/Strategy/ Program

For Project Grouping, is this the final sanction estimate (Project Grade)?

From the **most recent** Sanction document, this is the estimate for the total project grouping Or Listed is the FY15 Capital Budget for Other Programs/line items.

From the FIRST Sanction document, what was the estimate for the total project grouping. NOTE: SIGNIFICANT scope or cost changes may occur from this initial estimate as the project is refined through its life cycle (e.g. Chase Hill & Newport).

Construction Start Date from Primavera P6 for the major substation portion of the project (where applicable). Followed by letter "A" if actual construction has started.

Estimated Construction End Date form Primavera P6 (the latest one if different phases or breakouts)

Estimated Financial Closure Date (all invoices paid - final testing, etc done) from Primavera P6 (the latest one)

Not applicable for programs/ blanket projects where budget/sanction is single year

Not applicable for programs/ blanket projects where budget/sanction is single year

Prior ISR Plan

From Narragansett Electric working files for building the 5-year plan

ISR Spending Rationale	ISR Category	Is the Current Estimate Project Grade? (yes/no)	Current Estimate	Initial Estimate at time of First Sanction	Construction Start	Estimated Construction End	Estimated Financial Closure	Pre-FY14 Actual Capital Spend	FY2014 Actual Capital Spend	FY2015 Actuals 3-mtd	Total-to-Date Actual Capital spend	Prior Plan FY15 Capital Budget	REVISED FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
System Capacity & Performance	Johnston Sub	Yes	6,515	4,594	Oct-2013 A	Dec-2014	Apr-2015	530	4,120	550	5,200	1,861	-	-	-	-	-
	Kilvert St - DLine	Yes	3,140	2,820	Oct-2013 A	Jun-2015	Nov-2015	15	1,182	431	1,628	1,600	-	-	-	-	-
	Kilvert St - DSub	No	3,017	2,260	Mar-2015	Aug-2015	Dec-2015	40	959	70	1,069	708	1,100	200	-	-	-
	Chase Hill (Hopkinton) & Related	No	17,121	2,850	Jan-2015	Mar-2016	Jul-2016	1,032	3,143	(244)	3,931	6,056	4,900	5,800	320	-	-
	New London Ave (West Warwick) & Related	No	13,341	2,900	Oct-2015	Jan-2017	Jun-2017	199	232	76	507	2,300	6,800	5,400	-	-	-
	Newport & Related	No	28,620	10,800	Feb-2017	Jun-2018	Oct-2018	333	185	171	689	2,140	1,800	3,870	7,620	7,950	1,920
	Clarke St	No	1,360	1,340	Dec-2014	Feb-2015	Jun-2015	19	159	74	252	646	250	-	-	-	-
	Highland Drive	Yes	16,436	6,124	Sep-2013 A	Jul-2014	Dec-2014	79	8,674	3,418	12,171	3,344	1,200	-	-	-	-
	Kent County	No	2,238	3,630	Jun-2015	Oct-2015	Feb-2016	-	116	67	183	347	1,210	536	-	-	-
	Quonset Substation	No	4,520	4,520	Mar-2016	Aug-2016	Dec-2016	-	-	-	-	-	480	2,175	1,500	-	-
	Providence LT Study	N/A	-								-	-	-	484	942	3,316	-
	East Bay Study	N/A	-								-	-	84	236	3,831	2,488	-
	Jepson Substation (Newport Area)	N/A	-								-	-	250	600	6,500	6,500	4,650
Subtotal - Major System Capactiy & Performance Projects												**19,002**	**18,074**	**19,301**	**20,713**	**20,254**	**6,570**
	Volt/Var	No	3,523	3,523	Aug-2014	Apr-2016	Sep-2016	-	23	248	271	1,200	1,464	-	-	-	-
	Storm Hardening	(a)	-						417	533		1,024	25	1,025	1,000	1,000	1,000
	EMS	(b)	1,665						1,106	298		1,705	1,065	1,074	1,350	1,350	1,350
	OH Line Transformer Replacement Program	(b)	1,950						1,420	373		1,900	600	625	650	725	750
	Blanket Project(s)	N/A	1,141						1,054	318		1,087	1,141	1,157	1,173	1,189	1,205
	Other Load Relief	N/A	1,273						1,947	82		846	1,273	460	373	280	290
	Other Reliability	N/A	170						453	10		145	170	105	-	-	-
	Reserves	N/A	tbd									(5,150)	(1,664)	(3,199)	(3,904)	1,970	6,500
System Capacity & Performance Total												**21,759**	**22,148**	**20,548**	**21,355**	**26,768**	**17,665**
Asset Condition	Eldred Sub	Yes	3,765	2,857	Jan-2014 A	Dec-2014	Apr-2015	160	1,445	564	2,169	794	-	-	-	-	-
	Flood - Langworthy Sub	Yes	1,690	2,095	Nov-2013 A	Sep-2014	Jan-2015	77	1,270	209	1,556	97	-	-	-	-	-
	Flood - Pontiac	No	3,118	1,710	Oct-2014	Jul-2015	Oct-2015	41	425	96	562	1,275	1,090	-	-	-	-
	Flood - Warwick Mall Sub	(a)	775	(a)	Dec-2015	May-2016	Aug-2016	4	8	31	43	438	24				
	Flood - Hope Substation	(a)	350	(a)	Jun-2015	Jul-2015	Nov-2015	-	12	19	31	494	612	-	-	-	-
	Flood - Westerly	No	9,160	9,160	Feb-2018	Mar-2019	Jun-2019	2	-	0	2	-	650	4,050	3,600	840	-
	Flood - Sockanosset	Not Yet Sanctioned	-		tbd	tbd	tbd	-	-	-	-	20	-	-	-	-	-
	Pawtucket #1	Not Yet Sanctioned	-		Jan-2016	Apr-2016	Jul-2016	-	-	-	-	-	5	5	10	10	-
	Southeast Sub	Not Yet Sanctioned	-		Jul-2016	Dec-2016	Apr-2017	-	-	-	-	-	50	3,800	6,200	3,950	-
	South Street	No	18,240	18,240	Aug-2015	Apr-2019	Jul-2019	-	-	-	-	200	4,560	7,260	5,990	-	-
	Asset Replacement - I&M (NE)	(b)	8,605						6,682	2,573		7,040	6,705	6,910	7,115	7,320	7,550
	Battery Replacement	(b)	200						266	24		250	200	200	200	200	200
	Indoor Sub Replacement	(b)	179						-	-		150	179	871	2,496	1,004	143
	Metalclad Replacement	(b)	3,716						551	131		2,680	1,540	2,085	3,675	2,735	2,660
	Substation Transformers	(b)	2,150						153	15		750	795	2,900	2,970	2,100	2,100
	Substation Breakers & Reclosers	(b)	1,000						1,939	288		924	1,000	1,000	1,100	1,100	1,200
	Network Arc Flash	(b)	600						213	8		514	600	514	250	-	-
	RAPR	(b)	180						91	13		175	180	185	190	195	200
	T-Body	(b)	43						509	198		560	43	-	-	-	-
	UG Cable	(b)	2,698						820	237		985	998	3,370	5,800	8,110	7,740
	URD	(b)	4,496						1,220	287		3,344	2,500	3,250	3,500	3,600	3,750
	Blanket Project(s)	N/A	2,179						2,076	714		1,316	2,179	2,208	2,237	2,267	2,297
	Other Asset Replacement	N/A	2,807						3,044	885		2,064	2,743	806	269	250	250
	Reserves	N/A	tbd						-	-		(4,559)	(2,600)	(4,280)	(7,838)	6,100	10,517
Asset Condition Total												**19,511**	**24,053**	**35,134**	**37,764**	**39,781**	**38,607**

(a) - Since total expected project cost is below $1M, this item was sanctioned in full on-line in our PowerPlant system (no sanction paper required).
Reauthorization will occur if the initial estimate changes above the 10% variance threshold.

(b) - Project is an ANNUAL program where the dollars are reset and resanctioned each fiscal year. Therefore, the "Current Estimate" shown is the FY2015 capital budget amount

Non-Discretionary	Cust & Public Req	**14,537**	**15,647**	**16,690**	**19,059**	**16,433**	**16,512**
Non-Discretionary	D/F	**9,816**	**11,177**	**11,348**	**11,537**	**11,728**	**11,921**
Non-Discretionary	Non-Inf	**277**	**275**	**280**	**285**	**290**	**295**
TOTAL PROPOSED BUDGET		**65,900**	**73,300**	**84,000**	**90,000**	**95,000**	**85,000**

				Values									
Spending Rationale	ISR/MEGA FILE Category	Project #	Project Description	Approved amount	PRE FY14 Spend	FY14 Spend	3-MTD FY15 Spend	FY15 Capital Forecast (4+8)	PRIOR YEAR BUDGET	FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
System Capacity & Performance	Johnston Sub	C028884	Install Johnston 18F10 Feeder	970	206	626	20	20	71	-	-	-	-	-
		C033535	Johnston Sub 12.47 kV Expansion	4,250	63	1,914	339	992	1,635	-	-	-	-	-
		C034002	Johnston Sub 12kV Expansion Getaway	270	20	51	41	123	112	-	-	-	-	-
		C036072	Johnston #18 Substation Expansion	1,855	241	1,529	149	159	43	-	-	-	-	-
	Johnston Sub Total			**7,345**	**530**	**4,120**	**550**	**1,294**	**1,861**	**-**	**-**	**-**	**-**	**-**
	Kilvert St - DLine	C036516	Kilvert St 87 - New Fdr (DLine)	3,831	15	1,182	431	1,876	1,600	-	-	-	-	-
	Kilvert St - DLine Total			**3,831**	**15**	**1,182**	**431**	**1,876**	**1,600**	**-**	**-**	**-**	**-**	**-**
	Kilvert St - DSub	C036522	Kilvert St 87 - Install TB#2	1,520	40	959	70	682	708	1,100	200	-	-	-
	Kilvert St - DSub Total			**1,520**	**40**	**959**	**70**	**682**	**708**	**1,100**	**200**	**-**	**-**	**-**
	Chase Hill (Hopkinton) & Related	C024175	Chase Hill Sub (D_Line)	760	330	100	38	912	2,600	2,700	3,000	-	-	-
		C024176	Chase Hill Sub (D-Sub)	4,000	702	3,043	(282)	411	3,456	2,200	2,800	-	-	-
		C034102	Retire Ashaway 43 Substation	0	-	-	-	-	0	-	-	10	-	-
		C036233	Hope Valley (D_Sub)	0	-	-	-	-	0	-	-	10	-	-
		C036234	Hope Valley (D_Line)	0	-	-	-	-	0	-	-	300	-	-
	Chase Hill (Hopkinton) & Related Total			**4,760**	**1,032**	**3,143**	**(244)**	**1,323**	**6,056**	**4,900**	**5,800**	**320**	**-**	**-**
	New London Ave (West Warwick) & Relate	C028920	New London Ave (D-Sub)	2,543	190	208	41	519	2,000	2,900	2,800	-	-	-
		C028921	New London Ave (D-Line)	8,613	7	3	22	884	300	3,900	2,600	-	-	-
		C032002	New London Ave (DxT)	3,746	2	21	13	(10)	0	-	-	-	-	-
	New London Ave (West Warwick) & Related Total			**14,902**	**199**	**232**	**76**	**1,394**	**2,300**	**6,800**	**5,400**	**-**	**-**	**-**
	Newport & Related	C015158	Newport Substation (D-Sub)	1,100	153	144	108	164	2,000	300	1,000	3,000	3,000	700
		C024159	Newport 69kV Line 63 (D-Line)	400	67	32	5	47	30	50	100	100	450	20
		C028628	NEWPORT Phase 2 (D-Line)	1,400	105	9	42	173	100	1,400	2,600	4,000	4,000	900
		CD00649	Gate 2 Substation (D-Sub)	400	5	-	14	132	10	50	150	500	500	300
		CD00651	Bailey Brook Retirement (D-Sub)	50	-	-	-	-	0	-	10	10	-	-
		CD00652	Vernon Retirement (D-Sub)	30	-	-	-	-	0	-	10	10	-	-
	Newport & Related Total			**3,380**	**330**	**185**	**170**	**516**	**2,140**	**1,800**	**3,870**	**7,620**	**7,950**	**1,920**
	Clarke St	C046831	CLARKE 65J12 Feeder Upgrade (D-Sub)	900	18	139	63	1,107	510	200	-	-	-	-
		C046832	CLARKE St Feeder Upgrades (D-Line)	100	1	20	10	343	136	50	-	-	-	-
	Clarke St Total			**1,000**	**19**	**159**	**74**	**1,451**	**646**	**250**	**-**	**-**	**-**	**-**
	Highland Drive	CD00972	New Highland Drive Substation - DSu	8,580	69	6,978	3,005	4,586	2,904	-	-	-	-	-
		CD00978	New Highland Drive Substation - DLi	1,380	10	1,696	413	505	440	1,200	-	-	-	-
	Highland Drive Total			**9,960**	**79**	**8,674**	**3,418**	**5,091**	**3,344**	**1,200**	**-**	**-**	**-**	**-**
	Kent County	CD01101	Kent County 2nd Transformer (D-Sub)	530	-	79	60	350	340	1,100	400	-	-	-
		CD01102	Hunt River Substation Retirement	30	-	26	3	15	0	10	75	-	-	-
		CD01104	Kent County 2nd Transformer (D-Line	20	-	11	4	8	7	100	61	-	-	-
	Kent County Total			**580**	**-**	**116**	**67**	**372**	**347**	**1,210**	**536**	**-**	**-**	**-**
	Quonset Sub	C053646	Quonset Sub Expansion (D-Sub)	600	-	-	-	150	0	400	1,500	1,500	-	-
		C053647	Quonset Sub Expansion (D-Line)	300	-	-	-	7	0	80	675	-	-	-
	Quonset Sub Total			**900**	**-**	**-**	**-**	**157**	**0**	**480**	**2,175**	**1,500**	**-**	**-**
	Providence LT Study	C046415	Providence Long Term Study: D-SUB		-	-	-	-	0	-	233	465	1,860	-
		C046421	Providence Long Term Study: D-LINE		-	-	-	-	0	-	251	477	1,456	-
		C051586	Providence Study Engineering		-	-	-	-	0	-	-	-	-	-
	Providence LT Study Total				**-**	**-**	**-**	**-**	**0**	**-**	**484**	**942**	**3,316**	**-**
	East Bay	C046726	East Bay Study (D-Sub)		-	-	-	-	0	84	186	2,325	2,488	-
		C046727	East Bay Study (D-Line)		-	-	-	-	0	-	50	1,506	-	-
	East Bay Total				**-**	**-**	**-**	**-**	**0**	**84**	**236**	**3,831**	**2,488**	**-**
	Jepson Sub (Newport area)	C054054	Jepson 115kV Substation (D-Line)		-	-	-	-	0	50	100	2,500	2,500	1,350
		CD00656	Jepson Substation	50	3	-	1	2	0	200	500	4,000	4,000	3,300
	Jepson Sub (Newport area) Total			**50**	**3**	**-**	**1**	**2**	**0**	**250**	**600**	**6,500**	**6,500**	**4,650**
	Volt/Var	C046352	RI Volt/Var Mgmt Pilot Project	760	-	19	217	1,527	1,200	664				
		C052708	Volt Var-Substation	20	-	4	31	116	0	-	-	-	-	-
		C053111	VVO-IT/IS	520	-	34	1	25	0	800	-	-	-	-
		C053488	VVO-Substation		-	-	-	-	0	-	-	-	-	-
	Volt/Var Total			**1,300**	**-**	**57**	**249**	**1,668**	**1,200**	**1,464**	**-**	**-**	**-**	**-**
	Storm Hardening	C046383	Storm Hardening for Rhode Island		-	-	-	-	700	-	250	1,000	1,000	1,000
		C046384	Storm Hardening - Hope 15F2 Feeder		-	-	-	-	0	-	-	-	-	-
		C046506	Tunk Hill Road, Scituate RI, Storm	1,850	-	417	533	670	324	-	-	-	-	-
		C054090	Reconductor Anthony Road, Foster RI	1,165	-	-	-	-	0	25	775	-	-	-
	Storm Hardening Total			**3,015**	**-**	**417**	**533**	**670**	**1,024**	**25**	**1,025**	**1,000**	**1,000**	**1,000**
	EMS	C035726	EMS - Narragansett Elec	696	19	(21)	(4)	75	100	(500)	850	1,350	1,350	1,350
		C046678	EMS Expansion - Hopkins Hill 63	0	-	-	-	39	47	-	-	-	-	-

				Values										
Spending Rationale	ISR/MEGA FILE Category	Project #	Project Description	Approved amount	PRE FY14 Spend	FY14 Spend	3-MTD FY15 Spend	FY15 Capital Forecast (4+8)	PRIOR YEAR BUDGET	FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
	EMS	C049679	Harrison #32 - EMS Expansion	20	-	15	2	13	80	147	27	-	-	-
		C049680	Rochambeau Ave - EMS Expansion	20	-	13	3	7	150	178	44	-	-	-
		C049681	Clarkson - EMS Expansion	20	-	15	4	114	97	92	-	-	-	-
		C049682	Warwick 52 - EMS Expansion	20	-	13	3	58	55	155	10	-	-	-
		C049683	Drumrock - EMS Expansion		-	-	-	-	0	-	-	-	-	-
		C049699	Knightsville 66 - EMS Expansion	20	-	13	2	13	160	178	45	-	-	-
		C049705	Apponaug- EMS Expansion	20	-	10	6	18	85	147	27	-	-	-
		C049798	Lakewood #57 - EMS Expansion	20	-	-	-	-	0	-	-	-	-	-
		C049799	Central Falls - EMS Expansion	20	-	14	1	14	0	147	-	-	-	-
		C049800	Coventry #54 - EMS Expansion	20	-	8	4	14	75	178	44	-	-	-
		C050698	Davisville #84 - EMS Expansion	20	-	11	3	59	80	155	-	-	-	-
		C050699	Hopkins Hill #63 - EMS Expansion	20	-	12	4	123	0	147	27	-	-	-
		CD00526	EMS Add-Peacedale 59 RI	367	40	131	33	208	0	5	-	-	-	-
		CD00528	EMS Expansion - Natick 29 Substatio	100	3	48	12	127	388	14	-	-	-	-
		CD00529	EMS Expansion - Hospital Sub 146	100	2	106	21	131	388	5	-	-	-	-
		CD00530	EMS Expansion - Elmwood Outdoor 7	287	40	22	13	155	0	10	-	-	-	-
		CD00531	EMS Expansion - Division Street 61	367	122	63	64	257	0	2	-	-	-	-
		CD00533	EMS Expansion - Lincoln Ave 72	461	206	154	36	142	0	5	-	-	-	-
		CD00534	EMS Expansion - Old Baptist 46	485	79	302	88	83	0	-	-	-	-	-
		CD00916	Wood River - EMS Expansion	321	16	177	4	4	0	-	-	-	-	-
	EMS Total			**3,405**	**527**	**1,106**	**298**	**1,655**	**1,705**	**1,065**	**1,074**	**1,350**	**1,350**	**1,350**
	OH Line Tranformer Replacement Program	C005505	IE - OS Dist Transformer Upgrades	2,299	1,727	1,420	373	1,262	1,900	600	625	650	725	750
	OH Line Tranformer Replacement Program Total			**2,299**	**1,727**	**1,420**	**373**	**1,262**	**1,900**	**600**	**625**	**650**	**725**	**750**
	Blankets Projects	COS0015	Ocean St-Dist-Reliability Blanket	956	571	659	106	425	683	660	670	680	690	700
		COS0016	Ocean St-Dist-Load Relief Blanket	312	266	395	213	432	254	381	387	393	399	405
		COS0025	OS-Dist-Substation LR/Rel Blnkt	156	-	-	-	-	150	100	100	100	100	100
	Blankets Projects Total			**1,425**	**837**	**1,054**	**318**	**857**	**1,087**	**1,141**	**1,157**	**1,173**	**1,189**	**1,205**
	Other Load Relief	C013967	PS&I Activity - Rhode Island	510	(58)	1,070	(106)	(90)	206	250	260	270	280	290
		C024179	Coventry MITS (Dist Sub)	2,970	1,612	333	53	85	0	-	-	-	-	-
		C024180	Coventry MITS (Dist Line)	775	680	(1)	0	0	0	-	-	-	-	-
		C024221	Load Relief to 9J3 - Brown Street	833	435	(4)	-	-	0	-	-	-	-	-
		C027222	West Farnum - Rem. Dist. Equipment	550	26	(1)	2	4	6	-	-	-	-	-
		C027245	Relocate 23kV 2227 & 22230	1,667	2,690	(307)	-		0	-	-	-	-	-
		C028627	WAMPANOAG 48F3 Load Relief	300	184	-	9	9	0	-	-	-	-	-
		C028851	Recon. 38F5 and 2227 Greenville Ave	886	512	54	-	-	0	-	-	-	-	-
		C028932	Recon. 0.5 Miles Segment of 2232	746	3	218	42	42	0	-	-	-	-	-
		C036167	Manton 69F3 - Upgrade getaway, etc		-	-	-	-	0	-	-	103	-	-
		C036397	Clarkson - new 13F10 feeder (line)	367	7	94	20	345	0	-	-	-	-	-
		C036450	83F2 Load Relief - New Fdr (Dline)	495	-	12	0	290	428	-	-	-	-	-
		C046662	Kents Corner47- Feeder 47J3	179	-	133	(1)	(1)	0	-	-	-	-	-
		C051385	Central Falls Sub Relief	295	-	1	0	4	0	298	-	-	-	-
		C053268	Pawtucket No 1 Bus Sect 73 Relief	485	-	1	50	298	0	425	-	-	-	-
		CD00092	Fdr 1131 Mars Plastics - Olneyville	586	326	54	-	-	0	-	-	-	-	-
		CD00410	38K23 Line Upgrade	374	145	117	-	-	0	-	200	-	-	-
		CD00557	Harrison Feeder Upgrades	432	-	1	0	0	150	300	-	-	-	-
		CD00808	68F3 - Kings Factory Rd stepdown co	221	135	13	-	-	0	-	-	-	-	-
		CD00932	Worden Pond Rd Conversion So. Kings	9	10	36	0	0	0	-	-	-	-	-
		CD01025	Converting Customers to 127W41 fro	72	11	2	(7)	57	0	-	-	-	-	-
		CD01087	Wakefield 17F1 Feeder Upgrades	126	4	104	-	-	0	-	-	-	-	-
		CD01092	Warwick Sub 52F3 Feeder Upgrade	314	-	-	(0)	(0)	0	-	-	-	-	-
		CD01093	KENTS CORNER transformer contingenc	590	-	17	21	342	56	-	-	-	-	-
	Other Load Relief Total			**13,780**	**6,722**	**1,947**	**82**	**1,386**	**846**	**1,273**	**460**	**373**	**280**	**290**
	Other Reliability	C005485	IE - OS Recloser Installations	291	4,535	(34)	-	-	0	-	-	-	-	-
		C005524	IE - OS Cutout Replacements	2,136	1,201	355	5	5	0	25	-	-	-	-
		C016122	IE - OS ERR	74	412	1	0	0	0	-	-	-	-	-
		C029494	Work for NERC-CIP Cyber Security	94	23	-	0	0	0	-	-	-	-	-
		C032575	Pockets of Poor Performance - OS	589	107	(8)	-	-	0	-	-	-	-	-
		C033762	Ocean State _Electric Fence FY10	174	323	5	0	0	0	-	-	-	-	-
		C042692	Wood River - Differential Scheme	603	482	12	(0)	(0)	0	-	-	-	-	-
		C049700	Anthony 64-EMS Exp & Upgrades	20	-	-	-	(0)	65	145	105	-	-	-
		C051199	Mobile Battery Trailer	88	-	-	2	81	80	-	-	-	-	-
		C053927	1 ph Cutout Mounted Reclosers		-	-	-	-	0	-	-	-	-	-
		C053946	45J4 45J6 Fdr Tie Carr Ln Jamestown	320	-	-	3	138	0	-	-	-	-	-
		CD00018	Targeted Reliability Improvements 2	373	215	1	0	0	0	-	-	-	-	-
		CD00859	Tiverton - Install metering on 33F1	28	2	4	-	-	0	-	-	-	-	-
		CD01213	OS Voltage Regulator Spare	28	3	54	-	-	0	-	-	-	-	-
	Other Reliability Total			**4,818**	**7,303**	**390**	**10**	**225**	**145**	**170**	**105**	**-**	**-**	**-**
	Reserves	C046971	Reserve for Reliability Unidentifie		-	-	-	-	(500)		-	-	-	-
		C046972	Reserve for Reliability Unidentifie		-	-	-	-	(500)		-	-	-	-
		C046975	Reserve for Load Relief Unidentifie		-	-	-	-	(2,318)	(700)	(2,399)	(2,904)	1,220	5,000
		C046987	Reserve for Load Relief Unidentifie		-	-	-	-	(1,832)	(964)	(800)	(1,000)	750	1,500
	Reserves Total				**-**	**-**	**-**	**-**	**(5,150)**	**(1,664)**	**(3,199)**	**(3,904)**	**1,970**	**6,500**
System Capacity & Performance Total				[redacted]	**19,363**	**25,161**	**6,475**	**21,881**	**21,759**	**22,148**	**20,548**	**21,355**	**26,768**	**17,665**

				Values										
Spending Rationale	ISR/MEGA FILE Category	Project #	Project Description	Approved amount	PRE FY14 Spend	FY14 Spend	3-MTD FY15 Spend	FY15 Capital Forecast (4+8)	PRIOR YEAR BUDGET	FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
Asset Condition	**Eldred Sub**	CD00648	Eldred Sub Asset Replacement (D-Sub	3,688	141	1,431	466	1,324	646	-	-	-	-	-
		CD00659	Eldred Sub Asset Replacement (D-Lin	186	19	14	97	210	148	-	-	-	-	-
	Eldred Sub Total			**3,874**	**160**	**1,445**	**564**	**1,534**	**794**	**-**	**-**	**-**	**-**	**-**
	Flood - Langworthy Sub	C036230	Langworthy Substation (D-Sub)	1,667	69	1,162	179	253	97	-	-	-	-	-
		C036232	Langworthy Substation (D-Line)	138	8	108	30	52	0	-	-	-	-	-
	Flood - Langworthy Sub Total			**1,805**	**77**	**1,270**	**209**	**305**	**97**	**-**	**-**	**-**	**-**	**-**
	Flood - Pontiac	CD01242	Pontiac Substation Flood Restoratio	730	40	413	81	1,140	1,200	952	-	-	-	-
		CD01243	Pontiac Substation Flood Restoratio	30	1	12	14	109	75	138	-	-	-	-
	Flood - Pontiac Total			**760**	**41**	**425**	**96**	**1,249**	**1,275**	**1,090**	**-**	**-**	**-**	**-**
	Flood - Warwick Mal Sub	CD01097	Warwick Mall Substation Flood Resto	850	4	8	31	384	438	24				
	Flood - Warwick Mal Sub Total			**850**	**4**	**8**	**31**	**384**	**438**	**24**				
	Flood - Hope Substation	C046697	Hope Substation Flood Restoration	410	-	12	19	340	494	612	-	-	-	-
	Flood - Hope Substation Total			**410**	**-**	**12**	**19**	**340**	**494**	**612**	**-**	**-**	**-**	**-**
	Flood - Westerly	C036527	Westerly Substation Retire	10	2	-	0	0	0	540	3,550	3,000	500	-
		C055215	Westerly Flood Restoration (D-Line)		-	-	-		0	110	500	600	340	-
	Flood - Westerly Total			**10**	**2**	**-**	**0**	**0**	**0**	**650**	**4,050**	**3,600**	**840**	**-**
	Flood - Sockanosset	C046877	Sockanosset Substation - RI Flood R		-	-	-	-	20	-	-	-	-	-
	Flood - Sockanosset Total				**-**	**-**	**-**	**-**	**20**	**-**	**-**	**-**	**-**	**-**
	Pawtucket #1	C055683	Pawtucket No 1 (D-Sub)		-	-	-	-	0	5	5	10	10	-
	Pawtucket #1 Total				**-**	**-**	**-**	**-**	**0**	**5**	**5**	**10**	**10**	**-**
	Southeast Sub	C053657	Southeast Substation (D-Sub)		-	-	-	-	0	25	2,000	4,000	3,250	-
		C053658	Southeast Substation (D-Line)		-	-	-	-	0	25	1,800	2,200	700	-
	Southeast Sub Total				**-**	**-**	**-**	**-**	**0**	**50**	**3,800**	**6,200**	**3,950**	**-**
	South Street	C051212	South St repl indoor subst D-SUB	6,140	-	-	-	331	100	4,130	6,600	5,450	-	-
		C051213	South St repl indoor subst D-LINE	200	-	-	-	30	100	410	650	540	-	-
		C055623	South St Sub 11kV Removal	300	-	-	-	-	0	20	10			
	South Street Total			**6,640**	**-**	**-**	**-**	**361**	**200**	**4,560**	**7,260**	**5,990**	**-**	**-**
	Asset Replacement - I&M (NE)	C014326	I&M - OS D-Line UG Work From Insp	113	776	(11)	0	0	104	105	110	115	120	125
		C026281	I&M - OS D-Line OH Work From Insp	11,448	1,743	6,693	2,573	7,674	6,936	6,600	6,800	7,000	7,200	7,425
		C045588	Narragansett Electric SubT I&M		-	-	-	-	0					
	Asset Replacement - I&M (NE) Total			**11,561**	**2,519**	**6,682**	**2,573**	**7,674**	**7,040**	**6,705**	**6,910**	**7,115**	**7,320**	**7,550**
	Battery Replacement	C032019	Batts/Chargers NE South OS RI	263	849	159	22	139	250	200	200	200	200	200
		C033843	BatteryRplStrategyCo49DxT	1,019	571	107	2	5	0	-	-	-	-	-
	Battery Replacement Total			**1,282**	**1,420**	**266**	**24**	**143**	**250**	**200**	**200**	**200**	**200**	**200**
	Indoor Sub Replacement	C051205	Dyer St replace indoor subst D-SUB		-	-	-	10	100	100	713	2,180	855	143
		C051211	Dyer St replace indoor subst D-LINE		-	-	-	8	50	79	158	316	149	-
	Indoor Sub Replacement Total				**-**	**-**	**-**	**17**	**150**	**179**	**871**	**2,496**	**1,004**	**143**
	Metalclad Replacement	C032583	OS ARP Metal Clad		-	-	-	-	0	(370)	-	350	1,650	2,300
		C046735	Harrison Replace Metalclad Gear		-	-	-	-	0	-	-	-	-	-
		C046736	Washington 261 - Replace Metalclad		-	-	-	-	0	-	-	-	-	-
		C049910	Southeast Sub Retirement (D-Line)	708	-	21	16	268	500	254	-	-	-	-
		C050006	Hyde Ave Retirement (D-Line)	710	-	4	20	616	650	468	-	-	-	-
		C050017	Daggett Ave Sub Retirement (D-Line)	830	-	5	13	27	600	500	-	-	-	-
		C050758	Lee St Retirement (D-Line)	490	-	9	2	68	70	20	600	-	-	-
		C050760	Cottage St Retirement (D-Line)	490	-	12	2	58	90	25	800	-	-	-
		C050778	Front St Substation Retirement (Dline)	240	-	73	39	50	140	236	-	-	-	-
		C051118	Lee St Retirement (D-Sub)	10	-	3	2	3	0	10	-	-	-	-
		C051126	Cottage St Retirement (D-Sub)	10	-	3	2	2	0	10	-	-	-	-
		C051200	Hyde Ave Metalclad		-	-	-	-	0	142	-	-	-	-
		C051271	Hyde Ave Metalclad - Sub Retirement	150	-	-	-	-	150	-	-	-	-	-
		C051272	Southeast 60 Metaclad - Sub Retirem	150	-	-	-	-	150	-	-	-	-	-
		C051273	Front St Metalclad-Sub Retirement (Dsub)	100	-	-	-	-	100	10	-	-	-	-
		C051274	Daggett Ave Metalclad - Sub Retirem	150	-	-	-	-	150	190	-	-	-	-
		C055589	Centredale Sub Retirement (D-Sub)		-	-	-	-	0	-	-	-	-	-
		C055590	Centredale Sub Retirement (D-Line)		-	-	-	-	0	-	-	-	-	-
		C056391	Centre St Retirement (Dsub)		-	-	-		0	10	10	10	-	-
		C056392	Crossman- Retirement (Dsub)		-	-	-		0	-	-	10	-	-
		C056411	Centre St Retirement (DLine)		-	-	-		0	10	190	900	-	-
		C056507	Crossman- Retirement (DLine)		-	-	-		0	-	110	590	-	-
		C056570	Hospital Sub - Metalclad Replacemen		-	-	-			25	200	1,300	725	-
		C056571	Kingston 131 - Metalclad Replacemen		-	-	-			-	175	515	360	360
		CD00641	Retire Pawtuxet Substation (D-Line)	619	30	421	34	62	80	-	-	-	-	-
	Metalclad Replacement Total			**4,657**	**30**	**551**	**131**	**1,153**	**2,680**	**1,540**	**2,085**	**3,675**	**2,735**	**2,660**

				Values										
Spending Rationale	ISR/MEGA FILE Category	Project #	Project Description	Approved amount	PRE FY14 Spend	FY14 Spend	3-MTD FY15 Spend	FY15 Capital Forecast (4+8)	PRIOR YEAR BUDGET	FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
	Substation Transformers	C025803	OS ARP Transformers	10	-	-	-	143	150	-	-	1,000	1,300	1,500
		C026058	OS ARP Spare Substation Transformer	1,100	-	-	-	-	600	-	600	600	600	600
		C051824	Lafayette Sub Transformer Replaceme	311	-	153	15	40	0	475	850	-	-	-
		C055421	Warwick 52 - Replace TRFs		-	-	-	-	0	-	450	650	200	-
		C055844	W Cranston Transformer #2 Replaceme		-	-	-		0	320	1,000	720		
	Substation Transformers Total			**1,421**	**-**	**153**	**15**	**182**	**750**	**795**	**2,900**	**2,970**	**2,100**	**2,100**
	Substation Breakers & Reclosers	C032278	OS ARP Breakers & Reclosers	1,080	3,448	1,939	288	1,150	924	1,000	1,000	1,100	1,100	1,200
	Substation Breakers & Reclosers Total			**1,080**	**3,448**	**1,939**	**288**	**1,150**	**924**	**1,000**	**1,000**	**1,100**	**1,100**	**1,200**
	Network Arc Flash	CD01257	Distribution Secondary Network Arc	24	-	213	8	427	514	600	514	250	-	-
	Network Arc Flash Total			**24**	**-**	**213**	**8**	**427**	**514**	**600**	**514**	**250**	**-**	**-**
	RAPR	C048969	RI RAPR ARP	175	-	91	13	109	175	180	185	190	195	200
	RAPR Total			**175**	**-**	**91**	**13**	**109**	**175**	**180**	**185**	**190**	**195**	**200**
	T-Body	C046400	Capital Ctr Fdrs - Elim T-body join	700	-	496	198	291	160	43	-	-	-	-
		C051202	13F1 Elim T-Body Joints Prov	400	-	13	0	95	400	-	-	-	-	-
	T-Body Total			**1,100**	**-**	**509**	**198**	**386**	**560**	**43**	**-**	**-**	**-**	**-**
	UG Cable	C031777	OS UG Cable ReplProgram budget only	356	-	-	-	-	0	-	-	-	-	-
		C046397	Fdr 1109A - Install Cable Dorrance	470	-	-	3	44	200	298	-	-	-	-
		C046399	Fdr 1103 Inst Cable So Main St Prov	430	-	381	33	36	345	-	-	-	-	-
		C046405	Fdr 1113 Inst Cable Fountain St Pro	30	-	15	113	175	80	-	-	-	-	-
		C046406	Fdr 1109B Inst Cable Pine St & west	450	-	321	35	35	360	-	-	-	-	-
		C055343	RI UG Cable Placeholder FY19-24		-	-	-		0	(1,700)	-	-	5,000	5,000
		C055357	RI UG Cable Repl Program - Fdr 1111		-	-	-		0	750	-	-	-	-
		C055359	RI UG Cable Repl Program - Fdr 79F1		-	-	-		0	250	1,110	-	-	-
		C055360	RI UG Cable Repl Program - Fdr 2J8		-	-	-		0	-	390	420	-	-
		C055361	RI UG Cable Repl Program - Fdr 1107		-	-	-		0	-	-	420	-	-
		C055362	RI UG Cable Repl Program - Fdr 1105		-	-	-		0	-	-	520	-	-
		C055363	RI UG Cable Repl Program - Fdr 1127		-	-	-		0	-	-	300	-	-
		C055364	RI UG Cable Repl Program - Fdr 13F1		-	-	-		0	-	-	220	-	-
		C055365	RI UG Cable Repl Program - Fdr 1113		-	-	-		0	-	-	620	90	-
		C055367	RI UG Cable Repl Program Fdr 54K21		-	-	-		0	500	120	-	-	-
		C055369	RI UG Cable Repl Program Fdr 54K23		-	-	-		0	-	380	240	-	-
		C055370	RI UG Cable Repl Program Fdr 1144		-	-	-		0	-	-	520	-	-
		C055371	RI UG Cable Repl Program Fdr 1142		-	-	-		0	-	-	240	280	-
		C055392	Network Secondary Cable Replacement		-	-	-		0	900	1,370	2,300	2,740	2,740
		CD00396	Fdr 1135 Inst Cable - Eddy St., Pro	649	389	-	-	-	0	-	-	-	-	-
		CD00397	Fdr 1127 Inst Cable - Dyer/Dorrance	326	250	-	-	-	0	-	-	-	-	-
		CD00902	Fdr 1107 Inst Cable - Chapel St & w	395	222	85	50	50	0	-	-	-	-	-
		CD00926	Fdr 37K22 Inst Cable - Merton sub t	420	230	1	-	-	0	-	-	-	-	-
		CD01079	1107 - Inst Cable - Mathewson St &	355	128	17	5	5	0	-	-	-	-	-
	UG Cable Total			**3,882**	**1,219**	**820**	**237**	**344**	**985**	**998**	**3,370**	**5,800**	**8,110**	**7,740**
	URD	C047322	IRURD Saddle Rock Road	150	-	117	-	-	0	-	-	-	-	-
		C047375	IRURD Mystery Farms Estates	620	-	-	2	57	43	-	730	-	-	-
		C047377	IRURD Wethersfield Commons	600	-	17	3	22	1,020	-	650	-	-	-
		C047378	IRURD Willowbrook	80	-	1	0	43	43	-	-	-	-	-
		C047379	IRURD Wood Estate	350	-	12	3	8	510	-	-	-	-	-
		C047386	IRURD Terre Mar	135	2	88	-	-	0	-	-	-	-	-
		C047389	IRURD Stone Ridge Acres	120	1	97	3	42	0	-	-	-	-	-
		C047394	IRURD Tanglewood	650	-	14	5	8	43	-	34	-	-	-
		C047396	IRURD Silver Maple Drive	160	-	3	4	50	0	-	150	-	-	-
		C047397	IRURD Cedarhurst	200	-	109	5	38	153	-	135	-	-	-
		C047398	IRURD Wionkheige	700	-	-	7	19	85	600	-	-	-	-
		C047422	IRURD Maplewood	400	-	11	2	2	850	1,700	-	-	-	-
		C047828	IRURD Westwood Estates	310	-	84	1	1	43	-	40	-	-	-
		C047829	IRURD High Hawk	600	-	-	3	41	43	-	274	-	-	-
		C049237	IRURD Phase 2 Wethersfield Comm.	400	-	-	-	22	0	-	240	-	-	-
		C049291	IRURD Wood Estates Phase 2	700	-	-	-	16	0	-	-	-	-	-
		C049356	IRURD Silver Maple Phase 2	400	-	-	-	37	43	-	40	-	-	-
		C049462	IRURD Stone Ridge Acres Phase 2	900	-	-	3	42	43	-	40	-	-	-
		C050070	IRURD Placeholder RI		-	-	-	-	0	200	300	3,500	3,600	3,750
		C050299	IRURD Eastward Look	900	-	-	-	38	0	-	319	-	-	-
		C052964	IRURD Rollingwood	800	-	-	5	35	0	-	298	-	-	-
		CD00686	IRURD Carriage Drive	706	153	52	5	73	0	-	-	-	-	-
		CD00826	IRURD Stonegate Repl N.Kingsto	218	6	136	14	14	0	-	-	-	-	-
		CD00827	IRURD South Rd Est So. Kingstown	234	176	28	1	162	0	-	-	-	-	-
		CD00937	IRURD Village Green Rehab	853	-	451	222	658	425	-	-	-	-	-
	URD Total			**11,186**	**338**	**1,220**	**287**	**1,427**	**3,344**	**2,500**	**3,250**	**3,500**	**3,600**	**3,750**
	Blankets Projects	COS0017	Ocean St-Dist-Asset Replace Blanket	1,691	1,229	2,060	612	1,477	1,166	1,929	1,958	1,987	2,017	2,047
		COS0026	OS-Dist-Substation Asset Repl Blnk	156	-	16	101	139	150	250	250	250	250	250
	Blankets Projects Total			**1,847**	**1,229**	**2,076**	**714**	**1,616**	**1,316**	**2,179**	**2,208**	**2,237**	**2,267**	**2,297**
	Other Asset Replacement	C002251	RECONSTRUCTION OF VAULT #72	344	6	-	(6)	(6)	0	-	-	-	-	-
		C003693	Woonsocket Sub New 115/13 kV Sub	5,100	5,117	2	10	24	0	-	-	-	-	-

				Values										
Spending Rationale	ISR/MEGA FILE Category	Project #	Project Description	Approved amount	PRE FY14 Spend	FY14 Spend	3-MTD FY15 Spend	FY15 Capital Forecast (4+8)	PRIOR YEAR BUDGET	FY16 Capital Budget	FY17 Capital Budget	FY18 Capital Budget	FY19 Capital Budget	FY20 Capital Budget
	Other Asset Replacement	C006140	RTU Rplcmnt Program - NECo	244	1,249	(9)	-	-	150	-	-	-	-	-
		C006644	IE - OS Targeted Pole Replace	180	51	78	9	29	0	25				
		C020297	Sac AB Repl Prog Phase 7 NEC DxT	1,127	428	190	68	261	81	-	-	-	-	-
		C023852	Inst Ductline Governor St. Prov.	1,653	101	212	166	568	50	-	-	-	-	-
		C024279	Woonsocket Sub New 13 kV S/gear	3,200	2,743	2	-	0	0	-	-	-	-	-
		C025322	OS Station Retirement	50	3	-	(3)	(3)	0	-	-	-	-	-
		C025815	OS ARP Insul, SensDev, Surge Arrest	263	962	116	7	137	250	250	250	250	250	250
		C025979	NE South - OS_Fdr Patrol Work	575	245	7	0	0	0	-	-	-	-	-
		C027911	Replace open wire secondary-NE OS	307	913	27	-	16	0	-	-	-	-	-
		C032028	Regulator Repl-NE South OS RI	530	400	-	-	-	83	-	-	-	-	-
		C032258	ACNW Vlt47 Structural Repairs Prov	970	17	23	73	149	570	514	-	-	-	-
		C035124	NES Co49 TxD Remote Racking Devices	24	22	-	-	-	0	-	-	-	-	-
		C035586	Relay Replacement Strategy Co 49DxT	1,250	107	605	268	862	400	600	-	-	-	-
		C036093	Elmwood#7Replace 23KV Groun Bank	540	143	175	15	173	200	-	-	-	-	-
		C038604	Battery Eyewash StationRplProgram	0	-	-	-	-	0	-	-	-	-	-
		C041726	Replace HMIs - NEC	20	-	2	-	159	254	174	71	19	-	-
		C046398	Memorial Blvd Easton's Beach inst d	600	-	6	19	31	25	730	400	-	-	-
		C048596	Kents Corner - Replace VRs	244	-	234	-	-	0	-	-	-	-	-
		C049140	Randall St Bridge Ductline. Prov.	375	-	286	72	72	0	-	-	-	-	-
		C049354	NEC Relay Replacement Co.49- SG157	320	-	-	5	106	0	340	75	-	-	-
		C049726	UG Fdrs 1141-1143 Hurr Barrier Prov	210	-	10	36	187	0	-	-	-	-	-
		C051198	Abandoned Equipment Removal	251	-	-	-	1	1	25	10	-	-	-
		C052283	RI Convention Center - Replace Swgr	127	-	5	1	120	0	-	-	-	-	-
		C052686	Prov RI Survey/Repl UG sec. cables	525	-	12	17	128	0	85	-	-	-	-
		C053149	NW Vlt 89 Federal Courthouse, Prov.	195	-	108	125	94	0	-	-	-	-	-
		C053266	NW Vlt 122 Kinsley Bldg, Prov.	30	-	1	0	0	0	-	-	-	-	-
		C053723	Arctic Substation Retirement	250	-	-	-	-	0	-	-	-	-	-
		C054365	63 Line Improvements	85	-	-	9	10	0	-	-	-	-	-
		CD00442	Pawtucket #1 Emergency Roof Replace	300	6	3	(1)	(1)	0	-	-	-	-	-
		CD00601	Retire Pawtuxet Substation (D-Sub)	106	-	-	3	17	0	-	-	-	-	-
		CD00909	Replace UG switch - MH2784 Smith St	125	116	-	-	-	0	-	-	-	-	-
		CD01109	Wakefield - GE Butyl Rubber PT Repl	53	1	35	1	1	0	-	-	-	-	-
		CD01194	Repl Padmt Swgr mult locns 79F1-13F	785	33	581	-	-	0	-	-	-	-	-
	Other Asset Replacement Total			**20,959**	**12,663**	**2,711**	**894**	**3,135**	**2,064**	**2,743**	**806**	**269**	**250**	**250**
	Reserves	C046982	Reserve for Asset Replacement Unide		-	-	-	-	(2,896)	(2,500)	(3,380)	(6,088)	5,100	9,017
		C046984	Reserve for Asset Replacement Unide		-	-	-	-	(1,663)	(100)	(900)	(1,750)	1,000	1,500
	Reserves Total				**-**	**-**	**-**	**-**	**(4,559)**	**(2,600)**	**(4,280)**	**(7,838)**	**6,100**	**10,517**
Asset Condition Total				[redacted]	**23,150**	**20,391**	**6,300**	**21,938**	**19,511**	**24,053**	**35,134**	**37,764**	**39,781**	**38,607**

PROJECT DETAIL FOR PROPOSED FY2016 CAPITAL SPENDING

SPENDING RATIONALE	BUDGET CLASSIFICATION	PROJECT #	PROJECT DESCRIPTION	
Customer Requests/Public Requirements	**3rd Party Attachments**	COS0022	Ocean St-Dist-3rd Party Attch Blnkt	154
	3rd Party Attachments Total			**154**
	Distributed Generation	C046386	BITS Wakefield Sub Upgrades (D-Sub)	595
		C051909	PS&I Dist Gen RI	50
	Distributed Generation Total			**645**
	Land and Land Rights	COS0009	Ocean St-Dist-Land/Rights Blanket	167
	Land and Land Rights Total			**167**
	Meters - Dist	CN04904	Narragansett Meter Purchases	1,180
		COS0004	Ocean St-Dist-Meter Blanket	595
	Meters - Dist Total			**1,775**
	New Business - Commercial	C046977	Reserve for New Business Commercial	400
		C049981	Nsnvlle 127W41 New Customer Load	553
		C051203	LNG Plant Svc Terminal Rd Prv DLine	30
		C051204	LNG Plant Svc Terminal Rd Prv DSub	30
		COS0011	Ocean St-Dist-New Bus-Comm Blanket	3,200
	New Business - Commercial Total			**4,213**
	New Business - Residential	C046978	Reserve for New Business Residentia	100
		COS0010	Ocean St-Dist-New Bus-Resid Blanket	3,400
	New Business - Residential Total			**3,500**
	Outdoor Lighting - Capital	COS0012	Ocean St-Dist-St Light Blanket	711
	Outdoor Lighting - Capital Total			**711**
	Public Requirements	C012179	DOTR-Repl Great Island Bridge No499	102
		C035087	DOTR-Apponaug Circulator Imprv Warw	616
		C045656	DOTR-Blackstone River Bikeway Seg8A	170
		C045684	Second Beach RI OH-UG conversion	89
		C046970	Reserve for Public Requirements Uni	(1,816)
		C047039	DOTR-East Main Rd, Portsmouth	170
		C047075	DOTR-Blackstone River Bikeway Seg8C	170
		C048717	DOTR-EMain/WMain Int Recon	85
		C050422	Admrl St 9J1 Line Relocation	85
		C050687	DOTR-Hi Haz Int/Ramps C2 Newport Co	170
		C050921	DOTR-Hi Haz IntersectionsBristol Co	170
		C051783	DOTR-E.Providence Bridges 471&472	170
		C052069	DOTR-Providence-Allens Av Arterial	85
		C054828	DOTR-Arterial Impr to Warwick Av	77
		CD00076	DOTR-Atwells Avenue Bridge No. 975,	64
		CD00373	Watch Hill UG Phase 2	173
		CD00567	DOTR-East Main Rd, Turnpike Av-Hedl	80
		CD00646	DOTR-Douglas Pike/Branch Pike Traff	80
		CD01066	DOTR-Union Village Railroad Bridge	34
		COS0013	Ocean St-Dist-Public Require Blankt	828
	Public Requirements Total			**1,602**
	Transformers & Related Equipment	CN04920	Narragansett Transformer Purchases	2,880
	Transformers & Related Equipment Total			**2,880**
Customer Requests/Public Requirements Total				**15,647**
Damage/Failure	**Damage/Failure**	C046986	Reserve for Damage/Failure Unidenti	500
		C051608	Reserve for Damage/Failure Substati	500
		C054323	Franklin Square Breaker Replacement	17
		COS0002	Ocean St-Dist-Subs Blanket	660
		COS0014	Ocean St-Dist-Damage&Failure Blankt	8,500
	Damage/Failure Total			**10,177**
	Major Storms - Dist	C022433	OSD Storm Cap Confirm Program Proj	1,000
	Major Storms - Dist Total			**1,000**
Damage/Failure Total				**11,177**
Non-Infrastructure	**General Equipment - Dist**	COS0006	Ocean St-Dist-Genl Equip Blanket	100
	General Equipment - Dist Total			**100**
	Telecommunications Capital - Dist	C040644	Telecom Small Capital Work - RI	175
	Telecommunications Capital - Dist Total			**175**
Non-Infrastructure Total				**275**
System Capacity & Performance	**Load Relief**	C005505	IE - OS Dist Transformer Upgrades	600
		C013967	PS&I Activity - Rhode Island	250
		C015158	Newport Substation (D-Sub)	300
		C024159	Newport 69kV Line 63 (D-Line)	50
		C024175	Chase Hill Sub (D_Line)	2,700
		C024176	Chase Hill Sub (D-Sub)	2,200
		C028628	NEWPORT Phase 2 (D-Line)	1,400
		C028920	New London Ave (D-Sub)	2,900
		C028921	New London Ave (D-Line)	3,900
		C036522	Kilvert St 87 - Install TB#2	1,100
		C046352	RI Volt/Var Mgmt Pilot Project	664
		C046726	East Bay Study (D-Sub)	84
		C046831	CLARKE 65J12 Feeder Upgrade (D-Sub)	200
		C046832	CLARKE St Feeder Upgrades (D-Line)	50
		C046975	Reserve for Load Relief Unidentifie	(700)

PROJECT DETAIL FOR PROPOSED FY2016 CAPITAL SPENDING

SPENDING RATIONALE	BUDGET CLASSIFICATION	PROJECT #	PROJECT DESCRIPTION	
System Capacity & Performance	**Load Relief**	C046987	Reserve for Load Relief Unidentifie	(964)
		C051385	Central Falls Sub Relief	298
		C053268	Pawtucket No 1 Bus Sect 73 Relief	425
		C053646	Quonset Sub Expansion (D-Sub)	400
		C053647	Quonset Sub Expansion (D-Line)	80
		C054054	Jepson 115kV Substation (D-Line)	50
		CD00557	Harrison Feeder Upgrades	300
		CD00649	Gate 2 Substation (D-Sub)	50
		CD00656	Jepson Substation	200
		CD00978	New Highland Drive Substation - DLi	1,200
		CD01101	Kent County 2nd Transformer (D-Sub)	1,100
		CD01104	Kent County 2nd Transformer (D-Line	100
		COS0016	Ocean St-Dist-Load Relief Blanket	381
	Load Relief Total			**19,318**
	Reliability	C005524	IE - OS Cutout Replacements	25
		C035726	EMS - Narragansett Elec	(500)
		C049679	Harrison #32 - EMS Expansion	147
		C049680	Rochambeau Ave - EMS Expansion	178
		C049681	Clarkson - EMS Expansion	92
		C049682	Warwick 52 - EMS Expansion	155
		C049699	Knightsville 66 - EMS Expansion	178
		C049700	Anthony 64-EMS Exp & Upgrades	145
		C049705	Apponaug- EMS Expansion	147
		C049799	Central Falls - EMS Expansion	147
		C049800	Coventry #54 - EMS Expansion	178
		C050698	Davisville #84 - EMS Expansion	155
		C050699	Hopkins Hill #63 - EMS Expansion	147
		C053111	VVO-IT/IS	800
		C054090	Reconductor Anthony Road, Foster RI	25
		CD00526	EMS Add-Peacedale 59 RI	5
		CD00528	EMS Expansion - Natick 29 Substatio	14
		CD00529	EMS Expansion - Hospital Sub 146	5
		CD00530	EMS Expansion - Elmwood Outdoor 7	10
		CD00531	EMS Expansion - Division Street 61	2
		CD00533	EMS Expansion - Lincoln Ave 72	5
		CD01102	Hunt River Substation Retirement	10
		COS0015	Ocean St-Dist-Reliability Blanket	660
		COS0025	OS-Dist-Substation LR/Rel Blnkt	100
	Reliability Total			**2,830**
System Capacity & Performance Total				**22,148**
Asset Condition	**Asset Replacement**	C006644	IE - OS Targeted Pole Replace	25
		C025815	OS ARP Insul, SensDev, Surge Arrest	250
		C032019	Batts/Chargers NE South OS RI	200
		C032258	ACNW Vlt47 Structural Repairs Prov	514
		C032278	OS ARP Breakers & Reclosers	1,000
		C032583	OS ARP Metal Clad	(370)
		C035586	Relay Replacement Strategy Co 49DxT	600
		C036527	Westerly Substation Retire	540
		C041726	Replace HMIs - NEC	174
		C046397	Fdr 1109A - Install Cable Dorrance	298
		C046398	Memorial Blvd Easton's Beach inst d	730
		C046400	Capital Ctr Fdrs - Elim T-body join	43
		C046697	Hope Substation Flood Restoration	612
		C046982	Reserve for Asset Replacement Unide	(2,500)
		C046984	Reserve for Asset Replacement Unide	(100)
		C047398	IRURD Wionkheige	600
		C047422	IRURD Maplewood	1,700
		C048969	RI RAPR ARP	180
		C049354	NEC Relay Replacement Co.49- SG157	340
		C049910	Southeast Sub Retirement (D-Line)	254
		C050006	Hyde Ave Retirement (D-Line)	468
		C050017	Daggett Ave Sub Retirement (D-Line)	500
		C050070	IRURD Placeholder RI	200
		C050758	Lee St Retirement (D-Line)	20
		C050760	Cottage St Retirement (D-Line)	25
		C050778	Front St Substation Retirement (Dline)	236
		C051118	Lee St Retirement (D-Sub)	10
		C051126	Cottage St Retirement (D-Sub)	10
		C051198	Abandoned Equipment Removal	25
		C051200	Hyde Ave Metalclad	142
		C051205	Dyer St replace indoor subst D-SUB	100
		C051211	Dyer St replace indoor subst D-LINE	79
		C051212	South St repl indoor subst D-SUB	4,130
		C051213	South St repl indoor subst D-LINE	410

PROJECT DETAIL FOR PROPOSED FY2016 CAPITAL SPENDING

SPENDING RATIONALE	BUDGET CLASSIFICATION	PROJECT #	PROJECT DESCRIPTION	
Asset Condition	**Asset Replacement**	C051273	Front St Metalclad-Sub Retirement (Dsub)	10
		C051274	Daggett Ave Metalclad - Sub Retirem	190
		C051824	Lafayette Sub Transformer Replaceme	475
		C052686	Prov RI Survey/Repl UG sec. cables	85
		C053657	Southeast Substation (D-Sub)	25
		C053658	Southeast Substation (D-Line)	25
		C055215	Westerly Flood Restoration (D-Line)	110
		C055343	RI UG Cable Placeholder FY19-24	(1,700)
		C055357	RI UG Cable Repl Program - Fdr 1111	750
		C055359	RI UG Cable Repl Program - Fdr 79F1	250
		C055367	RI UG Cable Repl Program Fdr 54K21	500
		C055392	Network Secondary Cable Replacement	900
		C055623	South St Sub 11kV Removal	20
		C055683	Pawtucket No 1 (D-Sub)	5
		C055844	W Cranston Transformer #2 Replaceme	320
		C056391	Centre St Retirement (Dsub)	10
		C056411	Centre St Retirement (DLine)	10
		C056570	Hospital Sub - Metalclad Replacemen	25
		CD01097	Warwick Mall Substation Flood Resto	24
		CD01242	Pontiac Substation Flood Restoratio	952
		CD01243	Pontiac Substation Flood Restoratio	138
		COS0017	Ocean St-Dist-Asset Replace Blanket	1,929
		COS0026	OS-Dist-Substation Asset Repl Blnk	250
	Asset Replacement Total			**16,748**
	Asset Replacement - I&M (NE)	C014326	I&M - OS D-Line UG Work From Insp	105
		C026281	I&M - OS D-Line OH Work From Insp	6,600
	Asset Replacement - I&M (NE) Total			**6,705**
	Safety	CD01257	Distribution Secondary Network Arc	600
	Safety Total			**600**
Asset Condition Total				**24,053**
Grand Total				**73,300**

Section 3

Vegetation Management Program

FY 2016 Electric ISR Plan

Vegetation Management Program
FY 2016 Proposal

The Company's Vegetation Management Program is an essential component of the Company's plan to maintain the safety and the reliability of its electric distribution network. Trees are an important concern for several reasons. Tree contact with the electric distribution system increases the risk of electric shock to the public, slows the restoration of critical infrastructure, and may increase the risk of fire. Trees can also be a significant deterrent to reliability since tree contact with the distribution system during windy/stormy conditions may cause a phase-to-phase fault, which will trip either a line fuse, pole recloser or a station breaker and cause a service interruption.

As shown in Section 2, Chart 5 above, trees were responsible for approximately 57,000 customer interruptions in FY 2014, which represented approximately 17% of the total interruptions in FY 2014. Although the number of customer interruptions was down from the prior year, tree related interruptions were the second leading cause of interruptions after deteriorated equipment.

The Company has developed a strong VM program, which provides a measure of safety for the public/workforce, favorable operational efficiency, and minimizes the number of customer interruptions due to trees. The Company's VM program includes several different activities, each addressing a different aspect of utility vegetation management.

Cycle Pruning - The cycle pruning program is designed to ensure that the vegetation growth along the overhead portion of the Company's distribution network does not interfere with

the safe and reliable performance of the electric network. Cycle Pruning includes the scheduling of every distribution circuit for pruning on a fixed timeframe or rotation. The pruning work performed is based on a dimension clearance specification. Cycle Pruning is designed to maintain an acceptable clearance between overhead conductors and vegetation to minimize the safety risk to the public and utility workforce. A stable, consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a best utility practice.

Consistent circuit pruning also helps maintain service reliability and supports efficient management of the overhead network. Managing the vegetation along the network helps to avoid interruptions caused by phase-to-phase tree contact and makes the network more accessible to line crews so they can restore power quickly following an interruption. Cycle Pruning also provides crews the clearance necessary to accurately inspect circuits and to more efficiently perform any required maintenance which also helps avoid interruptions. As shown in the Vegetation Management Cost Benefit Report[13] filed on August 29, a review of the cycle pruning program shows, on average, a 28% improvement in customer interruptions (CI) per circuit in the first year after pruning. With the circuit pruning work in FY 2014, National Grid completed a full four-year cycle on all overhead distribution circuits for the first time due to consistent funding through the ISR process.

[13] Attachment 2, page 12.

The Company continues to recommend a four-year interval as the optimum pruning cycle for the Rhode Island overhead distribution assets based on tree growth rates and the acceptable clearance dimensions obtained at the time of pruning. The total overhead distribution mileage in Rhode Island is approximately 4,932 miles. To maintain a four-year pruning cycle, 1,233 miles need to be pruned each year. It is important to remain on cycle. Industry studies have shown a 25% increase in pruning costs when they are delayed by one year. The Company has also seen a 25% improvement in customer interruptions during the first year after pruning, so any delay could have significant reliability impacts as well. After detailed field analysis of the current circuits due at this time, the FY 2016 plan will require the pruning of 1,230 miles of distribution. The estimated cost for distribution cycle pruning in FY 2016 is $5.576 million, or approximately $4,532 per mile. This cost per mile figure is based on actual costs in FY 2015 with a 3% inflation factor. Costs have increased over the last few years primarily due to the Company's effort to improve contractor safety.

Enhanced Hazard Tree Mitigation ("EHTM") - Hazard tree removal, as part of a complete utility vegetation management program, has also become a best industry practice. Full tree and large limb failures have been shown to account for a significant portion of customer interruptions, not only in Rhode Island but also in other states. Using three years of tree-related interruption data for Rhode Island indicates that fallen trees account for 39% of tree-related customer interruptions.

To address this issue, in 2008, the EHTM program was implemented to identify and remove dying or structurally weakened trees and overhanging leads along the three phase sections of distribution circuits. The three-phase portion of the circuit is the most susceptible to tree caused faults and also serves the highest number of customers per exposed mile. Thus, hazard tree removal on three-phase sections of the distribution circuit intuitively provides the highest benefit per hazard tree removal dollar. EHTM uses an industry leading tree risk assessment protocol to identify hazard trees. To improve customer satisfaction and reliability, the Company has expanded its program to look beyond three phase sections on circuits experiencing multiple interruptions.

The purpose of the EHTM program is primarily to provide a reliability benefit. The hazard tree mitigation program targets the mainline portion of the Company's worst performing circuits where tree caused phase-to-phase faults will interrupt the entire population of customers on that circuit. To demonstrate these benefits and to meet the requirements of the FY 2012 Rhode Island Electric ISR Plan, the Company performed a study of the Company's EHTM program.[14] The results of this study reflect an average improvement in tree-related Customers Interrupted (CI) by circuit of 75% for the first year following project completion, thus demonstrating a significant improvement in customer service reliability on targeted circuits.[15] Since the Company has only performed EHTM on 15% of the circuits in Rhode Island, it is critical that this program continues to be sufficiently funded.

[14] Electric ISR Plan Vegetation Management Cost Benefit Report, filed September 5, 2012.
[15] Electric ISR Plan Vegetation Management Cost Benefit Report, filed August 29, 2014, Attachment 1, page 1.

Due to the spread of the Emerald Ash Borer throughout Massachusetts, the Company anticipates it becoming a serious threat throughout Rhode Island. Although this program is not funded in the FY 2016 Electric ISR Plan, implementation and funding of the program should be a topic of annual discussion.

Sub-Transmission - This category includes VM activities for the sub-transmission (Sub-T) right-of-way (ROW) network. Much like distribution cycle pruning, the Sub-T circuits are treated on a four-year cycle, but because of the smaller population, these circuits are not as easily balanced year to year. The FY 2016 schedule includes the off-road ROW edge or sideline pruning and hazard tree removal work on eleven circuits. The total cost for the required FY 2016 sub-transmission VM work is $220,000. The sideline pruning and hazard tree work is the most expensive type of work and is based on a price of approximately $20,000 per mile for off-road work and $4,500 per mile for on road work. Floor treatment cost is approximately $650 per acre. Because some of the Company's sub-transmission lines are classified as transmission assets, not all of the work being performed this fiscal year is included in the Plan. Overall, the Company expects to perform 82.16 miles of sideline work this fiscal year. However, only 42.31 miles are classified as distribution assets and are included in the FY 2016 ISR. There is no floor work scheduled for distribution lines this fiscal year. Instead, all of these circuits are classified as transmission lines.

Chart 1

Sub-Transmission Vegetation Management Miles/Acres

(includes both Distribution and Transmission Assets)

Sideline Pruning and Hazard Tree Removal (Miles)				
FY 2012	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**
12.1	28.51	59.52	34.09	82.16
Floor Treatment (Acres)				
FY 2012	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**
88.67	100.68	222.05	214.97	89.28

Police Detail/Flagman – To safely perform the Cycle Pruning and EHTM, the Company is required to hire police details and flagman. Police detail and flagger costs have recently been a major focus in recent Electric and Gas ISR proceedings in light of the increase in these costs over the past three years. For FY 2016, police detail costs are estimated to be $750,000. The Company considers several factors when estimating the police detail budget, including but not limited to, prior years, costs per mile and percent of total budget, as well as the general police detail policies of the specific towns and municipalities where work is to be performed during the fiscal year. Importantly, despite the year-over-year increase in police detail and flagger costs in Rhode Island, as a percentage of the overall tree trimming budget, these costs remain well below similar police detail costs in Massachusetts, which also requires the use of police details. Specifically, in FY 2012, police detail costs in Massachusetts represented 14.6% of the total tree trimming budget for the state. Massachusetts police detail costs increased to 16.1% of the budget in FY 2013, and 17.5% of the budget in FY 2014. By contrast, in Rhode Island, police detail costs represented 5.6% of the tree trimming budget in FY 2012, and 9.3% in FY 2013, and

9.0% in FY 2014, respectively, actually slightly decreasing as a percentage of the budget in FY 2014 in light of the Company's efforts to control costs referenced above.

It is also important to recognize that police detail and flagger costs are driven primarily by a number of factors outside of the Company's control, including a myriad of municipal requirements, work locations, and the hourly rates set by the municipalities. For example, the number and levels or required details vary by town and by traffic and road conditions. Also, certain towns mandate the use of police officers on a detail and limit or restrict the use of less expensive third-party flaggers. Depending on the town, different factors such as municipal ordinances, requirements in police union contracts, or specific safety municipal requirements can play of role in the ability of the Company to manage its total police detail costs budget.

Notwithstanding these factors, the Company has adopted a number of processes changes to attempt to minimize police detail and flagger costs where possible. This includes removing police detail costs from the Company's Cycle Pruning program vendor bidding process and placing these costs into an separate police detail and flagger budget account. This permits the Company to separately track detail costs and provides a more accurate historical basis for discussions with municipalities designed to mitigate police and detail costs, where possible. In addition, the Company now coordinates its police protection processes between vegetation management with the Company's electric and gas construction, and working through the Company's community relations department discusses police detail requirements with communities and municipalities in advance of performing the work.

Additionally, since much of the Company's tree trimming work is performed by contractors, the Company has added police detail costs to the system used to evaluate overall contractor performance for a fiscal year, thus creating an incentive for contractors to actively focus on police details. To assist in this effort, the Company has also revised its contracting strategies by placing only a single contractor in each municipality during a given year. This allows each contractor to develop a better relationship with each town, and to better address communications with public safety officials.

The PUC has recognized the complexity of addressing police detail costs. At the FY 2015 Electric ISR proceeding in Docket No. 4473, the PUC raised the issue of whether there could be a uniform statewide police detail rate in Rhode Island to better add certainty and control costs.[16] In its written order in Docket No. 4473, the PUC noted that it will begin gathering additional data in efforts to initiate a forum with the Police Chiefs Association regarding police detail costs. The PUC will also seek input from the Rhode Island League of Cities and Towns regarding the proper balance between police detail costs, town requirements, and public safety.[17] The Company looks forward to actively participating in any future PUC action on this matter.

Core Activities – The Company performs several other essential VM activities to efficiently maintain the safety and reliability of the network and to address customer needs. In contrast to Cycle Pruning or EHTM, the Company has very little discretion over the timing of

[16] Docket No. 4473,TR 1 at pages 172-173.
[17] Order No. 21559 in Docket No. 4473 at 24 (Written Order dated August 12, 2014).

these activities. This work includes responding to customer requests for vegetation-related work due to safety and reliability concerns. It also includes response to requests for interim or spot trimming by circuit patrols in locations where vegetation growth has exceeded normal conditions or where the patrols have identified other vegetation-related reliability concerns. Responding to sporadic emergency calls to remove trees or limbs from wires and to perform vegetation work necessary to restore power to customers is another important core activity performed by forestry crews. Spending for each core activity varies from year-to-year depending on the customer calls, weather, and system requirements. Each core activity separately consumes a small and variable proportion of the overall budget. Notably, the Company has recently identified an increase in vine-related interruptions in the last two years. To address these vine-related issues, the Company has added an additional $200,000 to perform additional work for vine control so as to mitigate and to prevent increased customer interruptions. Overall, for FY 2016, the Company expects to spend $1.5 million for the core activities.

Fiscal Year 2016 Vegetation Management Budget

As detailed in Chart 2 below, the FY 2016 Electric ISR Plan proposes to spend approximately $8.9 million for VM in FY 2016. This represents a 13% increase from the amount requested and approved for FY 2015.

Chart 2

Vegetation Management Spending
($000)

	FY 2012	FY 2013	FY 2014	FY 2015	FY 2015	FY 2016
				Approved	Projected	Proposed
Cycle Prune (Base)	$5,451	$4,764	$5,110	$4,475	$5,000	$5,414
Hazard Tree – EHTM	$806	$1,198	$700	1,000	$1,000	$1,000
Sub-T (off & on road)	$392	$243	$639	$316	$392	$220
Police/Flagman Detail	$461	$766	$769	$650	$650	$750
All Other Activities (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$1,066	$1,276	$1,312	$1,285	$1,285	$1,500
Total	**$8,176**	**$8,247**	**$8,530**	**$7,726**	**$8,327**	**$8,884**

Finally, with respect to the previous tree trimming issues with Verizon Communications (Verizon), on April 17, 2014, Verizon notified the Company that Verizon was declining to participate in the Company's pruning and hazard tree work plan for Rhode Island in fiscal year 2015, which the Company had previously provided to Verizon. Also, on June 30, 2014, Verizon notified the Company that Verizon was terminating section J of the Intercompany Operating Procedures (IOP) related to joint tree trimming. Consequently, there is currently no contractual arrangement between Verizon and the Company that governs joint tree trimming. At this time, the Company continues to discuss hazard tree removals and other issues with Verizon in efforts to resolve the tree trimming and other issues that have existed between the parties. On August 14, 2014, the Company and Verizon met to review hazard tree removals on the

49_56_63F6 circuit line. National Grid and Verizon have met a number of times during 2014 and continue to negotiate on a global solution to all VM and other issues between the companies.

Section 4

Inspection and Maintenance Plan

FY 2016 Electric ISR Plan

Inspection and Maintenance Program
FY 2016 Proposal

Consistent with the Company's condition-based asset management approach, the Company has implemented an Inspections and Maintenance program (I&M Program). To date, the Company has inspected 83% of its overhead distribution system feeders. From the inspection results, the Company has designed work for 34% of its feeders, and completed repair work on 12% of its feeders.

The goal of the I&M Program is to achieve a ten-year cycle in which all feeders are inspected and repairs are completed. The proposed spending for FY 2016 represents a 5% decrease in capital spending over last year. The Plan for FY 2016 represents a continued execution of the programs first cycle so that items identified as deteriorated are replaced within a ten-year period. Adjustments to the cycle length should be a topic of annual discussion based on execution and reliability results. The Company has successfully piloted and will continue to package all repair work by feeder so as to efficiently use its construction resources.

In addition to continuing overhead distribution system inspections, the FY 2016 I&M Program plans to ramp up inspections of its sub-transmission system as well as continuing inspections of its manhole-based underground assets. The goal for sub-transmission assets is to be on a ten-year inspection cycle. To date, the Company has inspected three sub-transmission feeders, with these inspections finding very limited issues for repair. The initial step for underground inspections is to formally document on-going working inspections. For FY 2016, the Company has proposed mobile elevated voltage testing of 100% of the "Designated Contact Voltage Risk Areas" designated in Docket No. 4237-A. At this time, FY 2015 mobile elevated

voltage testing has not been completed, and the proposed plan for FY 2016 testing will depend on results of the FY 2015 testing. The Company will adjust these costs, if necessary, based on any changes in that proceeding.

The primary driver of the I&M program is to address deteriorated assets to ensure the distribution and sub-transmission system is safe, reliable and environmentally sound. Asset replacement prior to failure provides incremental safety benefits for both the public and our employees. Implementation of this program should minimize potential safety issues related to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. This program also provides for the avoidance of potential environmental problems such as insulating fluid leaks/spills from assets such as transformers and capacitor banks. The program is intended to satisfy section 214 of the National Electric Safety Code (NESC), which outlines inspection of equipment guidelines for electric utilities.

In addition to addressing deteriorated assets, the data collected during the inspections enhances the Company's Asset Management reviews and the development of projects and programs to maintain reliability performance and customer satisfaction. As shown in Section 2, Chart 5, animals, lightning, and deteriorated equipment, caused over 93,000 customer interruptions in FY 2014, accounting for approximately 26% of all customer interruptions in FY 2014. Although the I&M program is not a reliability-based program, the Company believes that the I&M Program is essential to fulfilling its obligation to provide safe, reliable, and cost effective electric delivery service to customers in Rhode Island and the Company has agreed with the Division to assess the costs and benefits of the I&M Program on an ongoing basis.

The Company's proposal for each of the program components are as follows:

- The Company expects that by the end of FY 2015, distribution overhead I&M repairs will reach approximately 20% of all OH distribution feeders. The proposed Plan is designed to fund repair work necessary to reach a ten-year repair cycle.

- Sub-transmission overhead I&M in FY 2016 with inspections, engineering, and limited repairs.

- Underground I&M inspections will continue to be performed as part of normal working inspections.

- Overhead Manual Contact Voltage testing will be performed as part of the cycle inspections.

- Underground Manual Contact Voltage testing will continue on the five-year cycle.

- Street Light Manual Contact Voltage testing will continue on a three-year cycle.

- Mobile Contact Voltage Testing for the FY 2016 ISR will test 100% of the designated contact voltage risk areas.

- In addition, the Volt/Var project will have ongoing O&M costs for maintaining network and telecommunications components, servers, hardware and software licensing. At this time, the Company does not have a final cost estimate for this ongoing maintenance cost, but expects it to be approximately $300,000 annually. The Company has included a nominal cost of $100,000 in O&M in the ISR for this cost as the system will be implemented during FY 2016.

Fiscal Year 2016 Inspection and Maintenance Budget

As shown in Chart 2 below, the Company proposes a total I&M Program budget of approximately $11 million for FY 2016. The associated capital costs for this program are $6.7 million, and included in the capital budgets provided in Section 2 of this Electric ISR Plan. The O&M components of the I&M program total approximately $3.33 million. The I&M program

includes a component for a Contact Voltage Program as ordered in Docket No. 4237. In addition, $25,000 is included for the continuation of a long range plan study in FY 2016 for issue identification.

Chart 2
Inspection and Maintenance Program Costs

	Total
Capital Costs (see note 1)	**$6,705,000**
Opex Related to Capex	*$1,885,000*
Inspections and Repair Related Costs	*$1,423,000*
Long Range Plan Study	*$25,000*
Total Operations and Maintenance Expenses	**$3,333,000**
Removal Costs	**$939,000**
Total Program Costs	**$10,977,000**

Note 1: Capital costs are included in the total capital cost of $73.3 million as discussed in Section 2.

Section 5

Revenue Requirement

FY 2016 Electric ISR Plan

Revenue Requirement
FY 2016 Proposal

The attached proposed revenue requirement calculation reflects the revenue requirement related to the Company's proposed investment in its Electric ISR Plan for the fiscal year ended March 31, 2016.

As shown on Page 1, Column (b) of Attachment 1 to this Section, the Company's FY 2016 Electric ISR Plan revenue requirement totals $21,106,176 and consists of the following elements: (1) O&M expense associated with the Company's VM activities and the Company's I&M Program, and (2) the Company's capital investment in electric utility infrastructure. Lines 1 and 2 of that column reflect the forecasted FY 2016 revenue requirement related to O&M expenses for VM and I&M of $8,884,000 and $3,333,000, respectively. As described in Sections 1 and 4 of this Plan, the Electric ISR Plan includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program (Contact Voltage Program), mandated by R.I. Gen. Laws §39-2-25 and approved by the PUC in Docket No. 4237[18]. Contact Voltage Program costs are included in the $3,333,000 of I&M expenses referred to above. Line 3 includes a reduction of $163,749 which represents the portion of Contact Voltage Program costs that are being recovered in base rates from Docket No. 4323 and therefore should not be included in the Electric ISR revenue requirement.

The FY 2016 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $9,052,925 is shown on Line 11, and consists of the

[18] R.I. Gen. Laws § 39-2-25(6)(c).

$2,789,692 revenue requirement on FY 2016 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 2, plus the FY 2015, FY 2014, FY 2013, and FY 2012 revenue requirements on incremental ISR capital investment of $4,087,395, $497,128, $(1,312,107), and $(66,298) from Pages 4, 6, 8 and 10, respectively, and the Property Tax Recovery Adjustment of $3,057,115 from Page 13. Importantly, the incremental capital investment for the FY 2016 Electric ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4323 for fiscal years2012, 2013 and 2014. For this purpose, incremental electric capital investment is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's base rates, net of depreciation expense attributable to general plant. The total annual FY 2016 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $21,106,176, as reflected in Column (b) on Line 12, and is equal to the sum of Lines 4 and 11.

For illustration purposes only, Column (c) of Page 1 provides the FY 2017 revenue requirement for the respective vintage year capital investments as calculated on Attachment 1, Pages 2, 4, 6, 8 and 10. Notably, these amounts will be trued up to actual investment activity after the conclusion of the FY, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2016 Electric ISR Plan revenue requirement includes $8,884,000 of VM and $3,333,000 of I&M expenses as shown on Page 1, Lines 1 and 2

in Column (b) of the Attachment. As described above, the Electric ISR Plan I&M component includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Program, however the Company's base rates are recovering $163,749 of voltage monitoring costs, so that amount is being deducted on Line 3 in determining total FY 2016 O&M expenses of $12,053,251 as shown on Line 4 of the attachment**.**

Electric Infrastructure Investment

Incremental Capital Investment

Page 2 of Attachment 1 to this Section calculates the revenue requirement of incremental capital investment associated with the Company's FY 2016 Electric ISR Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. The proposed capital investment and cost of removal were obtained from the "FY 2016 Proposed Plant in Service" column on Chart 11 of Section 2 of this Plan. The FY 2016 revenue requirement also includes the incremental capital investment associated with the Company's FY 2015, FY 2014, FY 2013, and FY 2012 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4323 for each of those fiscal years as shown on pages 4, 6, 8 and 10, respectively. Page 12 of Attachment 1 calculates the incremental FY 2012 through FY 2014 ISR capital investment and the related incremental cost of removal and incremental retirements for the FY 2016 electric ISR revenue requirement. The calculations on Page 12 compare ISR-eligible capital investment, cost of removal and retirements for FY 2012 through FY 2014, to the corresponding amounts reflected in Docket No. 4323.

For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: "nondiscretionary" capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and "discretionary" capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined "nondiscretionary" categories. This ISR plan limits the amount of eligible discretionary capital investments made since April 1, 2011 to the lesser of cumulative discretionary capital additions, or the cumulative amount of discretionary project spend as agreed to by the Division and as approved by the Commission since the April 1, 2011 effective date of this ISR mechanism. This limitation on discretionary capital investment will be analyzed as a part of the aforementioned annual reconciliation of the proposed ISR investment to actual investment activity after the conclusion of the fiscal year.

Electric Infrastructure Revenue Requirement

The revenue requirement calculation on incremental electric infrastructure investment for vintage year FY 2016 is shown on Page 2 of Attachment 1. The revenue requirement calculation incorporates the incremental Electric ISR Plan capital investment, cost of removal and retirements. The calculation on Page 2 begins with the determination of the depreciable net incremental capital that will be included in the ISR Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in ISR Plan rate base in determining depreciation expense. Retirements, however, do

not affect rate base as both "plant in service" and the "depreciation reserve" are reduced by the installed value of the plant being retired and therefore have no impact on net plant. For purposes of calculating the revenue requirement, plant retirements have been estimated based on the percentage of retirements to additions during FY 2014, and have been deducted from the total depreciable capital amount as shown on Lines 4 through 6. Incremental book depreciation expense on Line 15 is computed based on the net depreciable additions, from Line 6 at the 3.40 percent composite depreciation rate as approved in Docket No. 4065[19], and as shown on Line 12. The Company has assumed a half year convention for the year of installation. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cost of removal, as shown on Line 10, is combined with the incremental depreciable amount from Line 9 (vintage year ISR Plan allowable capital additions less non-general plant depreciation expense included in base distribution rates) to arrive at the incremental investment on Line 11 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 11, and accumulated depreciation and accumulated deferred tax reserves as shown on Lines 16 and 19, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 17 through 19, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate. The calculation of tax depreciation is described below. The average rate base is shown on Line 24. This amount is multiplied by the pre-tax rate of

[19] The PUC did not change depreciation rates in the Company's base rate filing in Docket No. 4323.

return approved by the Commission in Docket No. 4323, as shown on Line 25, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 26. Incremental depreciation expense is added to this amount on Line 27. The sum of these amounts reflects the annual revenue requirement associated with the capital investment portion of the Company's Electric ISR Plan on Line 29, which is carried forward to Page 1, Line 9, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2015, FY 2014, FY 2013, and FY 2012 incremental ISR Plan capital investments are shown on Pages 4, 6, 8, & 10, respectively. These capital investment revenue requirement amounts are added to the total O&M expenses on Line 4, Page 1, to derive the total FY 2016 Electric ISR Plan revenue requirement of $21,106,176, as shown on Line 12 and represents an incremental $8,855,868 increase from the FY 2015 Electric ISR Plan revenue requirement, as shown on Line 13.

Tax Depreciation Calculation

The tax depreciation calculations for FY 2016, FY 2015, FY 2014, FY 2013, and FY 2012 are provided on Pages 3, 5, 7, 9, and 11 of Attachment 1, respectively. The tax depreciation amount assumes that a portion of the capital investment, as shown on Line 1 of those pages, will be eligible for immediate deduction on the Company's corresponding FY federal income tax return. This immediate deductibility is referred to as the capital repairs

deduction[20]. In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Lines 4 through 12 on Pages 7, 9, and 11. The Company assumes no bonus depreciation for FY 2015 and FY 2016. During 2010, Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the Act), which provided for an extension of bonus depreciation. Specifically, the Act provides for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 2012. The 50 percent bonus depreciation rate was later extended through December 31, 2013.[21]

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate. The amount of depreciation deducted for MACRS is added to the amount of capital repairs deduction plus the bonus depreciation deduction and cost of removal to arrive at total tax depreciation.

[20] During 2009, the Internal Revenue Service (IRS) issued additional guidance, under Internal Revenue Code Section 162, related to certain work considered to be repair and maintenance expense, and eligible for immediate tax deduction for income tax purposes, but capitalized by the Company for book purposes. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in its FY 2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. 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 deferred taxes and lowering the revenue requirement that customers will pay under the capital investment reconciliation mechanism. The Company's federal income tax returns are subject to audit by the IRS. If it is determined in the future that the Company's position on its tax returns on this matter was incorrect, the Company will reflect any related IRS disallowances, plus any associated interest assessed by the IRS, in a subsequent reconciliation filing under the ISR Plan.

[21] The Company anticipates that the IRS will issue further guidance on this issue and, to the extent such guidance differs from the Company's interpretation of the 2010 Act, the Company will reflect any resulting differences in a subsequent reconciliation filing under the ISR Plan.

These annual total tax depreciation amounts are carried forward to Line 13 of Attachment 1, Pages 2, 4, 6, and 8 and Line 11 of Attachment 1, Page 10, for the respective years, and incorporated in the deferred tax calculation.

Property Tax Recovery Adjustment

The Property Tax Recovery Adjustment is shown on Page 13 of Attachment 1. The method used to recover property tax expense under the ISR was modified by the rate case settlement agreement in Docket No. 4323. 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 calculation.

This provision of the settlement agreement became effective for ISR property tax recovery periods subsequent to the January 31, 2014 end of the rate year. The FY 2016 revenue requirement includes a total of $3,057,115 for the net property tax recovery adjustment.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Annual Revenue Requirement Summary

Line No.		As approved Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)
	Operation and Maintenance (O&M) Expenses			
1	Forecasted Vegetation Management (VM)	$7,726,000	$8,884,000	
2	Forecasted Inspection & Maintenance (I&M) O&M Expense	$2,995,000	$3,333,000	
3	Electric Contact Voltage expenses included in R.I.P.U.C. Docket No. 4323	(163,749)	($163,749)	
4	**O&M Expense Component of Revenue Requirement Subtotal**	$10,557,251	$12,053,251	
	Capital Investment			
5	Actual Revenue Requirement on Incremental FY 2012 Capital included in ISR Rase Base	($66,617)	($66,298)	($65,918)
6	Actual Revenue Requirement on Incremental FY 2013 Capital included in ISR Rate Base	($1,359,559)	($1,312,107)	($1,260,912)
7	Actual Revenue Requirement on Incremental FY 2014 Capital included in ISR Rate Base	$1,014,081	$497,128	$466,536
8	Forecasted Annual Revenue Requirement on FY 2015 Capital included in ISR Rate Base	$2,105,152	$4,087,395	$3,846,574
9	Forecasted Annual Revenue Requirement on FY 2016 Capital included in ISR Rate Base	$0	$2,789,692	$5,428,148
10	FY 2016 Property Tax Recovery Adjustment		$3,057,115	
11	**Capital Investment Component of Revenue Requirement Subtotal**	**$1,693,058**	**$9,052,925**	**$8,414,427**
12	**Total Fiscal Year Revenue Requirement**	**$12,250,309**	**$21,106,176**	**$8,414,427**
13	**Total Incremental Fiscal Year Rate Adjustment**		**$8,855,868**	**NA**

Line Notes:
Column (a) - as Approved per R.I.P.U.C. Docket No. 4473
Column (b)

1	Projected Vegetation Management
2	Projected Inspection & Maintenance
4	Line 1 + Line 2 + Line 3
5	Page 10 of 14, Line 27
6	Page 8 of 14, Line 29
7	Page 6 of 14, Line 29
8	Page 4 of 14, Line 29
9	Page 2 of 14, Line 29
10	Page 13 of 14, Line 63
11	Sum of lines 5 through 10
12	Line 4 + Line 11
13	Current Year Line 12 - Prior Year Line 12

The Narragansett Electric Company
d/b/a National Grid
Computation of Electric Capital Investment Revenue Requirement
FY 2016 Investment

Line No.				Fiscal Year 2016 (a)	Fiscal Year 2017 (b)
	Capital Additions Allowance				
	Non-Discretionary Capital				
1	Non-Discretionary Additions	Section 2 Page 40, Chart 11		$27,910,000	$0
	Discretionary Capital				
2	Lesser of Actual Cumulative Discretionary Capital Additions or Spending, or Approved Spending	Section 2 Page 40, Chart 11		$49,565,000	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$77,475,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$77,475,000	$0
5	Retirements	Line 4 * 5.88%	1/	$4,555,530	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$72,919,470	$72,919,470
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$77,475,000	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$34,443,226	$34,443,226
10	Total Cost of Removal	Section 2 Page 40, Chart 11		$8,200,000	$8,200,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$42,643,226**	**$42,643,226**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%
13	Tax Depreciation	Page 3 of 14, Line 10		$28,032,632	$4,323,327
14	Cumulative Tax Depreciation	Prior Year Line 13 + Current Year Line 14		$28,032,632	$32,355,959
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$1,239,631	$2,479,262
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		$1,239,631	$3,718,893
17	Cumulative Book / Tax Timer	Line 14 - Line 16		$26,793,001	$28,637,066
18	Effective Tax Rate			35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18		$9,377,550	$10,022,973
	Rate Base Calculation:				
20	Cumulative Incremental Capital Included in Rate Base	Line 11		$42,643,226	$42,643,226
21	Accumulated Depreciation	- Line 16		($1,239,631)	($3,718,893)
22	Deferred Tax Reserve	- Line 19		($9,377,550)	($10,022,973)
23	Year End Rate Base	Sum of Lines 20 through 22		$32,026,045	$28,901,360
	Revenue Requirement Calculation:				
24	Average Rate Base	(Prior Year Line 23 + Current Year Line 23) ÷2		$16,013,022	$30,463,703
25	Pre-Tax ROR		2/	9.68%	9.68%
26	Return and Taxes	Line 24 * Line 25		$1,550,061	$2,948,886
27	Book Depreciation	Line 15		$1,239,631	$2,479,262
28	Property Taxes		3/		
29	**Annual Revenue Requirement**	**Sum of Lines 26 through 28**		**$2,789,692**	**$5,428,148**

1/ Based on FY2014 actual retirements as a percent of capital investment

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/ Property taxes calculated on Page 13 of 13 for all vinatge years commencing with FY14 and reflected in total on page 1 at Line 10

The Narragansett Electric Company
d/b/a National Grid
Calculation of Tax Depreciation
On FY 2016 Capital Investment

Line No.				Fiscal Year 2016 (a)	Fiscal Year 2017 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 2 of 14, Line 3		$77,475,000	
2	Capital Repairs Deduction Rate	Per Tax Department	1/	22.70%	
3	Capital Repairs Deduction	Line 2 * Line 3		$17,586,825	
	Remaining Tax Depreciation				
4	Plant Additions	Line 1		$77,475,000	
5	Less Capital Repairs Deductions	Line 3		$17,586,825	
6	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 4 - Line 5		$59,888,175	$59,888,175
7	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%
8	Remaining Tax Depreciation	Line 6 * Line 7		$2,245,807	$4,323,327
9	Cost of Removal	Page 2 of 14, Line 10		$8,200,000	
10	Total Tax Depreciation and Repairs Deduction	Lines 3 + Line 8 + Line 9		$28,032,632	$4,323,327

1/ Capital Repairs percentage is based on a three year average, 2012, 2013 and 2014 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
Computation of Electric Capital Investment Revenue Requirement
FY 2015 Investment

Line No.				Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)
	Capital Additions Allowance					
	Non-Discretionary Capital					
1	Non-Discretionary Additions			$25,495,000	$0	$0
	Discretionary Capital					
2	Lesser of Actual Cumulative Discretionary Capital Additions or Spending, or Approved Spending			$43,443,000	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$68,938,000	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$68,938,000	$0	$0
5	Retirements	Line 4 * 23.58%	1/	$16,255,580	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5, then Prior Year Line 6		$52,682,420	$52,682,420	$52,682,420
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$68,938,000	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8, then Prior Year Line 9		$25,906,226	$25,906,226	$25,906,226
10	Total Cost of Removal			$8,400,000	$8,400,000	$8,400,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$34,306,226**	**$34,306,226**	**$34,306,226**
	Deferred Tax Calculation:					
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 5 of 14, Line 10		$24,952,445	$3,929,053	$3,634,061
14	Cumulative Tax Depreciation	Prior Year Line 13 + Current Year Line 14		$24,952,445	$28,881,498	$32,515,559
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$895,601	$1,791,202	$1,791,202
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		$895,601	$2,686,803	$4,478,005
17	Cumulative Book / Tax Timer	Line 14 - Line 16		$24,056,844	$26,194,695	$28,037,554
18	Effective Tax Rate			35.00%	35.00%	35.000%
19	Deferred Tax Reserve	Line 17 * Line 18		$8,419,895	$9,168,143	$9,813,144
	Rate Base Calculation:					
20	Cumulative Incremental Capital Included in Rate Base	Line 11		$34,306,226	$34,306,226	$34,306,226
21	Accumulated Depreciation	- Line 16		($895,601)	($2,686,803)	($4,478,005)
22	Deferred Tax Reserve	- Line 19		($8,419,895)	($9,168,143)	($9,813,144)
23	Year End Rate Base	Sum of Lines 20 through 22		$24,990,730	$22,451,280	$20,015,077
	Revenue Requirement Calculation:					
24	Average Rate Base	(Prior Year Line 23 + Current Year Line 23) ÷2			$23,721,005	$21,233,179
25	Pre-Tax ROR		2/		9.68%	9.68%
26	Return and Taxes	Line 24 * Line 25			$2,296,193	$2,055,372
27	Book Depreciation	Line 15			$1,791,202	$1,791,202
28	Property Taxes		3/			
29	**Annual Revenue Requirement**	**Sum of Lines 26 through 28**		**N/A**	**$4,087,395**	**$3,846,574**

1/ Assumes 23.58% based on the average of FY 2013 & FY 2012 retirements as a percent of capital investment

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/ Property taxes calculated on Page 13 of 13 for all vinatge years commencing with FY14 and reflected in total on page 1 at Line 10

The Narragansett Electric Company
d/b/a National Grid
Calculation of Tax Depreciation
On FY 2015 Capital Investment

Line No.				Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)
	Capital Repairs Deduction					
1	Plant Additions	Page 4 of 14, Line 3		$68,938,000		
2	Capital Repairs Deduction Rate	Per Tax Department	1/	21.05%		
3	Capital Repairs Deduction	Line 2 * Line 3		$14,511,449		
	Remaining Tax Depreciation					
4	Plant Additions	Line 1		$68,938,000		
5	Less Capital Repairs Deductions	Line 3		$14,511,449		
6	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 4 - Line 5		$54,426,551	$54,426,551	$54,426,551
7	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%	6.677%
8	Remaining Tax Depreciation	Line 6 * Line 7		$2,040,996	$3,929,053	$3,634,061
9	Cost of Removal	Page 4 of 14, Line 10		$8,400,000		
10	Total Tax Depreciation and Repairs Deduction	Lines 3 + Line 8 + Line 9		$24,952,445	$3,929,053	$3,634,061

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
Computation of Electric Capital Investment Revenue Requirement
FY 2014 Investment

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)	Fiscal Year 2016 (c)	Fiscal Year 2017 (d)
	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	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$13,324,266	$0	$0	$0
5	Retirements		1/	($4,165,367)	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Line 4 - Line 5		$17,489,633	$17,489,633	$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	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant	2/	7,173,397			
9	Incremental Depreciable Amount	Line 7 - Line 8		$6,150,869	$6,150,869	$6,150,869	$6,150,869
					$0	$0	$0
10	Total Cost of Removal			($887,841)	($887,841)	($887,841)	($887,841)
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$5,263,028**	**$5,263,028**	**$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%	3.40%	3.40%
13	Tax Depreciation	Page 7 of 14, Line 20		$7,183,146	$394,010	$364,427	$337,138
14	Cumulative Tax Depreciation	Current Year Line 13		$7,183,146	$7,577,156	$7,941,583	$8,278,721
15	Book Depreciation	Line 6 * Line 12 * 50%		$297,324	$297,324	$297,324	$297,324
16	Cumulative Book Depreciation	Current Year Line 15		$297,324	$594,648	$891,971	$1,189,295
17	Cumulative Book / Tax Timer	Line 14 - Line 16		$6,885,822	$6,982,508	$7,049,612	$7,089,426
18	Effective Tax Rate			35.00%	35.000%	35.000%	35.000%
19	Deferred Tax Reserve	Line 17 * Line 18		$2,410,038	$2,443,878	$2,467,364	$2,481,299
	Rate Base Calculation:						
20	Cumulative Incremental Capital Included in Rate Base	Line 11		$5,263,028	$5,263,028	$5,263,028	$5,263,028
21	Accumulated Depreciation	-Line 16		($297,324)	($594,648)	($891,971)	($1,189,295)
22	Deferred Tax Reserve	-Line 19		($2,410,038)	($2,443,878)	($2,467,364)	($2,481,299)
23	Year End Rate Base	Sum of Lines 20 through 22		$2,555,666	$2,224,503	$1,903,692	$1,592,434
	Revenue Requirement Calculation:						
24	Average Rate Base	Current Year Line 23 ÷ 2				$2,064,097	$1,748,063
25	Pre-Tax ROR		3/			9.68%	9.68%
26	Return and Taxes	Line 24 * Line 25				$199,805	$169,213
27	Book Depreciation	Line 15				$297,324	$297,324
28	Property Taxes		4/			$0	$0
29	**Annual Revenue Requirement**	**Sum of Lines 26 through 29**		**N/A**	**N/A**	**$497,128**	**$466,536**

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%

4/ Property taxes calculated on Page 13 of 13 for all vinatge years commencing with FY14 and reflected in total on page 1 at Line 10

The Narragansett Electric Company
d/b/a National Grid
Calculation of Tax Depreciation
On FY 2014 Capital Investment

Line No.			Fiscal Year 2014 (a)	Fiscal Year 2015 (b)	Fiscal Year 2016 (c)	Fiscal Year 2017 (c)
	Capital Repairs Deduction					
1	Plant Additions	Page 6 of 14, Line 3	$13,324,266			
2	Capital Repairs Deduction Rate	Per Tax Department	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	100.00%			
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$8,732,724			
9	Bonus Depreciation Rate (April 2013 - December 2013)	1 * 75% * 50%	37.50%			
10	Bonus Depreciation Rate (January 2014 - March 2014)	1 * 25% * 50%	0.00%			
11	Total Bonus Depreciation Rate	Line 9 + Line 10	37.50%			
12	Bonus Depreciation	Line 8 * Line 11	$3,274,772			
	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	$3,274,772			
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$5,457,952	5,457,952	5,457,952	5,457,952
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%	6.177%
18	Remaining Tax Depreciation	Line 16 * Line 17	$204,673	$ 394,010	$ 364,427	$ 337,138
19	Cost of Removal	Page 6 of 14, Line 10	($887,841)			
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18 and 19	$7,183,146	$ 394,010	$ 364,427	$ 337,138

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

The Narragansett Electric Company
d/b/a National Grid
Computation of Electric Capital Investment Revenue Requirement
FY 2013 Investment

Line No.				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)	Fiscal Year 2016 (d)	Fiscal Year 2017 (e)
	Capital Additions Allowance							
	Non-Discretionary Capital							
1	Non-Discretionary Additions			($5,184,396)	$0	$0	$0	$0
	Discretionary Capital							
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending			($1,850,463)	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 2		($7,034,859)	$0	$0	$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	$0	$0
5	Retirements			$5,838,935	$0	$0	$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)	($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	$0	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding		$0	$0	$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)	($7,034,859)	($7,034,859)
10	Total Cost of Removal			($1,895,059)	($1,895,059)	($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)**	**($8,929,918)**	**($8,929,918)**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%	3.40%	3.40%	3.40%
13	Tax Depreciation	Page 7 Line 20		($5,970,630)	($221,954)	($205,290)	($189,917)	($175,651)
14	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		($5,970,630)	($6,192,584)	($6,397,874)	($6,587,791)	($6,763,442)
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Columns (b), (c) & (d) = Line 6 * Line 12		($218,854)	($437,709)	($437,709)	($437,709)	($437,709)
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		($218,854)	($656,563)	($1,094,272)	($1,531,981)	($1,969,690)
17	Cumulative Book / Tax Timer	Line 14 - Line 16		($5,751,776)	($5,536,021)	($5,303,602)	($5,055,810)	($4,793,752)
18	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18		($2,013,121)	($1,937,607)	($1,856,261)	($1,769,533)	($1,677,813)
	Rate Base Calculation:							
20	Cumulative Incremental Capital Included in Rate Base	Line 11		($8,929,918)	($8,929,918)	($8,929,918)	($8,929,918)	($8,929,918)
21	Accumulated Depreciation	- Line 16		$218,854	$656,563	$1,094,272	$1,531,981	$1,969,690
22	Deferred Tax Reserve	- Line 19		$2,013,121	$1,937,607	$1,856,261	$1,769,533	$1,677,813
23	Year End Rate Base	Sum of Lines 20 through 22		($6,697,942)	($6,335,747)	($5,979,385)	($5,628,403)	($5,282,414)
	Revenue Requirement Calculation:							
24	Average Rate Base	(Prior Year Line 23 + Current Year Line 23) ÷2					($5,803,894)	($5,455,409)
25	Pre-Tax ROR		2/				9.68%	9.68%
26	Return and Taxes	Line 24 * Line 25					($561,817)	($528,084)
27	Book Depreciation	Line 15					($437,709)	($437,709)
28	Property Taxes	$0 in Year 1, then Prior Year (Line 11-Line 16) * Property Tax Rate	3/				($312,581)	($295,120)
29	**Annual Revenue Requirement**	**Sum of Lines 26 through 28**		**N/A**	**N/A**	**N/A**	**($1,312,107)**	**($1,260,912)**

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/ Columns (d), (e) assume the Effective Property Tax Rate of 3.99% forecasted for FY 2016 on Page 13, Line 35(h).

The Narragansett Electric Company
d/b/a National Grid
Calculation of Tax Depreciation
On FY 2013 Capital Investment

				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)	Fiscal Year 2016 (d)	Fiscal Year 2017
	Capital Repairs Deduction							
1	Plant Additions	Page 8 of 14, 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 x 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 x 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)	($3,074,585)	($3,074,585)
17	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%	6.677%	6.177%	5.713%
18	Remaining Tax Depreciation	Line 16 x Line 17		($115,297)	($221,954)	($205,290)	($189,917)	($175,651)
19	Cost of Removal	Page 8 of 14, 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)	($189,917)	($175,651)

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

The Narragansett Electric Company
d/b/a National Grid
Computation of Electric Capital Investment Revenue Requirement
FY 2012 Investment

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)	Fiscal Year 2016 (e)	Fiscal Year 2017 (f)
	Capital Additions Allowance		1/						
	Non-Discretionary Capital								
1	Non-Discretionary			($4,019,686)	$0	$0	$0	$0	$0
	Discretionary Capital								
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending			$4,163,942	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$144,256	$0	$0	$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	$0	$0
5	Retirements			$19,938	$0	$0	$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	$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	$144,256	$144,256
8	Cost of Removal			($771,131)	($771,131)	($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)**	**($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%	3.40%	3.40%
11	Tax Depreciation	Page 9 Line 20		($654,965)	$2,107	$1,949	$1,803	$1,667	$1,542
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11		($654,965)	($652,858)	($650,909)	($649,107)	($647,439)	($645,897)
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)	($4,227)	($4,227)
14	Cumulative Book Depreciation	Prior Year Line 14 + Current Year Line 13		($2,113)	($6,340)	($10,567)	($14,794)	($19,021)	($23,247)
15	Cumulative Book / Tax Timer	Line 12 - Line 14		($652,852)	($646,518)	($640,342)	($634,313)	($628,419)	($622,650)
16	Effective Tax Rate			35.00%	35.00%	35.000%	35.000%	35.000%	35.000%
17	Deferred Tax Reserve	Line 15 * Line 16		($228,498)	($226,281)	($224,120)	($222,009)	($219,947)	($217,927)
	Rate Base Calculation:								
18	Cumulative Incremental Capital Included in Rate Base	Line 9		($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)
19	Accumulated Depreciation	- Line 14		$2,113	$6,340	$10,567	$14,794	$19,021	$23,247
20	Deferred Tax Reserve	- Line 17		$228,498	$226,281	$224,120	$222,009	$219,947	$217,927
21	Year End Rate Base	Sum of Lines 18 through 20		($396,264)	($394,254)	($392,188)	($390,072)	($387,908)	($385,700)
	Revenue Requirement Calculation:								
22	Average Rate Base	(Prior Year Line 21 + Current Year Line 21) ÷2						($388,990)	($386,804)
23	Pre-Tax ROR		2/					9.68%	9.68%
24	Return and Taxes	Line 22 * Line 23						($37,654)	($37,443)
25	Book Depreciation	Line 19						($4,227)	($4,227)
26	Property Taxes	$0 in Year 1, then Prior Year (Line 9 - Line 14) * Property Tax Rate	3/					($24,417)	($24,249)
27	**Annual Revenue Requirement**	**Sum of Lines 24 through 26**		**N/A**	**N/A**	**N/A**	**N/A**	**($66,298)**	**($65,918)**

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/ Columns (d), (e) Assume the Effective Property Tax Rate of 3.99% forecasted for FY 2016 on Page 13, Line 35(h).

The Narragansett Electric Company
d/b/a National Grid
Calculation of Tax Depreciation
On FY 2012 Capital Investment

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)	Fiscal Year 2016 (e)	Fiscal Year 2017 (f)
	Capital Repairs Deduction								
1	Plant Additions	Page 10 of 14, 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	$29,184	$29,184
17	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,094	$2,107	$1,949	$1,803	$1,667	$1,542
19	Cost of Removal	Page 10 of 14, 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	$1,667	$1,542

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 2012 - FY 2014 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Actual Fiscal Year 2013 (b)	Actual Fiscal Year 2014 (c)
	Capital Investment				
1	ISR - Eligible Capital Investment	Col (a) FY 2012 ISR Reconciliation Filing Docket No. 4218, Col (b) FY 2013 ISR Reconciliation Filing Docket No. 4307, Col (c) FY 2014 ISR Filing Docket No. 4382	$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 Notes 2(b)+2(d)+3(d); Col (c)=Line Note 3(e)	$48,802,200	$51,366,341	$42,805,284
3	Incremental ISR Capital Investment	Line 3 - Line 4	$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 ISR Reconciliation Filing Docket No. 4307, Col (c) FY 2014 ISR Filing Docket No. 4382	$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	$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) FY 2014 ISR Filing Docket No. 4382	$7,740,446	$14,255,714	$3,299,874
8	ISR - Eligible Retirements/Estimated	Col (a) FY 2012 ISR Filing Docket No. 4218, Col (b) FY 2013 ISR Filing Docket No. 4307	$7,720,508	$8,416,779	$7,465,242
9	Incremental Retirements	Line 7- Line 8	$19,938	$5,838,935	($4,165,368)

The Narragansett Electric Company
d/b/a National Grid
Forecasted Property Tax Recovery Mechanism
(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	$68,938	$4,142	$73,080		($16,256)		$1,427,065
15									
16	Accumulated Depr	$618,783				$46,352	($16,256)	($8,400)	$640,480
17									
18	Net Plant	$751,457							$786,585
19									
20	Property Tax Expense	$27,502							$31,379
21									
22	Effective Prop tax Rate	3.66%							3.99%
23									
24									
25		**End of FY 2015**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2016**
26									
27	Plant In Service	$1,427,065	$77,475	$4,013	$81,488		($4,556)		$1,503,997
28									
29	Accumulated Depr	$640,480				$48,626	($4,556)	($8,200)	$676,350
30									
31	Net Plant	$786,585							$827,647
32									
33	Property Tax Expense	$31,379							$33,017
34									
35	Effective Prop tax Rate	3.99%							3.99%
36									
37									

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
38												
39	**Property Tax Recovery Calculation**											
40		**Cumulative Increm. ISR Prop. Tax for FY14**				**Cumulative Increm. ISR Prop. Tax for FY15**				**Cumulative Increm. ISR Prop. Tax for FY16**		
41			2 mos									
42	ISR Additions		$9,335				$68,938				$77,475	
43	Book Depreciation: base allowance on ISR eligible plant		($7,173)				($43,032)				($43,032)	
44	Book Depreciation: current year ISR additions		($324)				($896)				($1,240)	
45	COR		$835				$8,400				$8,200	
46												
47	Net Plant Additions		$2,672				$33,411				$41,404	
48												
49	RY Effective Tax Rate		3.98%				3.98%				3.98%	
50	ISR Property Tax Recovery on FY 2014 vintage investment			$106				$105				$91
51	ISR Property Tax Recovery on FY 2015 vintage investment							$1,330				$1,259
52	ISR Property Tax Recovery on FY 2016 vintage investment											$1,649
53												
54	ISR Year Effective Tax Rate	3.66%				3.99%				3.99%		
55	RY Effective Tax Rate	3.98%	-0.32%			3.98%	0.01%			3.98%	0.01%	
56	RY Effective Tax Rate 2 mos for FY 2014		-0.05%									
57	RY Net Plant times 2 mo rate	$746,900	-0.05%	($401)		$746,900	* 0.01%	$53		$746,900	* 0.01%	$52
58	FY 2014 Net Adds times ISR Year Effective Tax rate	$2,672	-0.32%	($9)		$2,632	* 0.01%	$0		$2,296	* 0.01%	$0
59	FY 2015 Net Adds times ISR Year Effective Tax rate					$33,411	* 0.01%	$2		$31,619	* 0.01%	$2
60	FY 2016 Net Adds times ISR Year Effective Tax rate									$41,404	* 0.01%	$3
61				($410)				$56				$57
62												
63	Total ISR Property Tax Recovery			($304)				$1,491				$3,057

The Narragansett Electric Company
d/b/a National Grid
Forecasted Property Tax Recovery Mechanism (continued)
(000s)

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)
27(b),(f)	Page 2, Lines 3, 5
27(c)	FY 2016 forecasted in service amount
27 (h)	27(a) + 27(d) + 27(f)
29(e)	Rate Year depr allowance of $44,986 * (Line 1(d)+1(f)* comp depr rate of 3.40%) + (Line 14(d)+14(f)* comp depr rate of 3.40%) + (Line , 27(d)+27(f)*comp depr rate of 3.40%*50%)
29(g)	Page 2, Line 10
31(h)	Line 27(h) - Line 29(h)
33(h)	Line 20(h) * five year average property tax expense growth rate of 9.8% for calendar years 2008-2013
35(h)	Line 33(h) / 31(h)
41(a) - 63(c)	per FY 2014 Electric ISR Reconciliation R.I.P.U.C. Docket No. 4382
69(c)	Sum of Lines 66(c) through 68(c)
71(c)	Line 63(a) - Line 69(a)
42(f)	Line 14(b)
43(f)	Per Page 4 of 14, Line 8
44(f)	Per Page 4 of 14, Line 16(a)
45(f)	- Line 16(g)
47(f)	Sum of Lines 42(f)-45(f)
49(f)	Line 9(a)
50(g)	((Lines 42(b) + 43(b) + 45(b)) - ((Line 42(b)+ Line 1(f)) * 3.4% composite depn rate * 50% * 2/12) - ((Line 42(b)+Line 1(f)) * 3.4%) * Line 49(f)
51(g)	Line 47(f) * Line 49(f)
54(e)	Line 22(h)
55(e)	Line 9(a)
55(f)	Line 54(e) - Line 55(e)
57(e)	Line 5(a)
58(e)	Line 42(e) -((Line 42(e) +Line 1(f)) *3.4%*50%*2/12) + Line 43(b)+Line 45(b)-((Line 42(e)+Line 1(f)*3.4%)
59(e)	Line 47(f)
57(f)-59(f)	Line 55(f)
57(g)	Line 57(e) * Line 57(f)
58(g)	Line 58(e) * Line 58(f)
59(g)	Line 59(e) * Line 59(f)
61(g)	Sum of Lines 57(g) through 59(g)
63(g)	Line 50(g) + Line 51(g) + Line 61(g)
69(g)	Sum of Lines 66(g) through 68(g)
71(g)	Line 63(g) - Line 69(g)
42(j)	Line 27(d)
43(j)	Per Page 2 of 14, Line 8
44(j)	Per Page 2 of 14, Line 16(a)
45(j)	-Line 29(g)
46(j)	Sum of Lines 42(j) through 45(j)
49(j)	Line 9(a)
50(k)	((Lines 42(b)+43(b)+45(b)) - ((Line 42(b)+ Line 1(f)) * 3.4% composite depn rate * 50% * 2/12) - ((Line 42(b)+Line 1(f)) * 3.4%) - ((Line 42(b)+Line 1(f)) * 3.4%) * Line 49(j)
51(k)	((Lines 42(f) + 43(f) + 45(f)) - ((Line 42(f)+Line 14(f) * 3.4% composite depn rate * 50% * 2/12) - ((Line 42(f)+Line 14(f)) * 3.4%) * Line 49(j)
52(k)	Line 47(j) * Line 49(j)
	Line 53(i) - Line 54(i)
54(i)	Line 35(h)
55(i)	Line 9(a)
57(i)	Line 5(a)
58(i)	((Lines 42(b)+43(b)+45(b)) - ((Line 42(b)+ Line 1(f)) * 3.4% composite depn rate * 50% * 2/12) - ((Line 42(b)+Line 1(f)) * 3.4%) - ((Line 42(b)+Line 1(f)) * 3.4%)
59(i)	Line 59(e)-(Line 42(f)+Line 14(f))*comp depr rate 3.4%)
60(i)	Line 47(j)
55(j)	Line 54(i) - Line 55(i)
56(j)-60(j)	Line 55(j)
57(k)	Line 57(i) * Line 57(j)
58(k)	Line 58(i) * Line 58(j)
59(k)	Line 59(i) * Line 59(j)
60(k)	Line 60(i) * Line 60(j)
61(k)	Sum of Lines 57(k) through 60(k)
63(k)	Sum of Lines 50(k) through 52(k) + Line 61(k)

Section 6

Rate Design

FY 2016 Electric ISR Plan

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors
(for the 12 months beginning April 1, 2015)

Line No.		Residential A16 / A60 (a)	Small Commercial & Industrial C-06 (b)	General Commercial & Industrial G-02 (c)	Large Demand B32 (d)	Large Demand G32 (e)	Optional Large Demand B62 (f)	Optional Large Demand G62 (g)	Street Lighting S05 / S10 / S14 (h)	Electric Propulsion X-01 (i)
(1)	O&M Factor per kWh	$0.00183	$0.00200	$0.00148	$0.00090	$0.00090	n/a	n/a	$0.01372	$0.00147
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.05	n/a	$0.03	$0.32	n/a	n/a
(3)	CapEx kWh Charge	$0.00151	$0.00148	n/a	n/a	n/a	n/a	n/a	$0.00717	$0.00121
(4)	CapEx kW Charge	n/a	n/a	$0.37	$0.04	$0.39	$0.02	$0.23	n/a	n/a
(5)	Base Distribution kW Charge - Back-up Rates	n/a	n/a	n/a	$0.70	n/a	$0.30	n/a	n/a	n/a

Line Description:
(1) Page 2, Line (6); Column (d) applicable to supplemental kWh deliveries only
(2) Column (d) per Page 4, Column (a), Line (4), applicable to backup service only
Column (f) per Page 4, Column (b), Line (4)
Column (g) per Page 2, Column (f), Line (8)
(3) Page 3, Line (6)
(4) Columns (c), (e) and (g) per Page 2, Line (8)
Column (d) per Page 4, Column (a), Line (6), applicable to backup service only
Column (f) per Page 4, Column (b), Line (6)
(5) Column (d) per Page 4, Column (a), Line (8), applicable to backup service only
Column (f) per Page 4, Column (b), Line (8)

The Narragansett Electric Company
FY15 Proposed Operations & Maintenance Factors
(for the 12 months beginning April 1, 2015)

Line No.		Total (a)	Residential A16 / A60 (b)	Small Commercial & Industrial C-06 (c)	General Commercial & Industrial G-02 (d)	Large Demand B32 / G32 (e)	Optional Large Demand B62 / G62 (f)	Street Lighting S05/ S10 / S14 (g)	Electric Propulsion X-01 (h)
(1)	FY2016 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,053,251							
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$35,640	$17,115	$3,503	$5,508	$5,438	$1,306	$2,668	$102
(3)	Percentage of Total	100.00%	48.02%	9.83%	15.45%	15.26%	3.66%	7.49%	0.29%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,053,251	$5,788,198	$1,184,695	$1,862,775	$1,839,102	$441,682	$902,303	$34,496
(5)	Forecasted kWh - April 2015 through March 2016	7,709,114,605	3,146,934,592	590,961,381	1,256,074,652	2,026,919,293	599,126,708	65,765,428	23,332,550
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00183	$0.00200	$0.00148	$0.00090	n/a	$0.01372	$0.00147
(7)	Forecasted kW - April 2015 through March 2016						1,365,799		
(8)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		n/a	n/a	n/a	n/a	$0.32	n/a	n/a

Line Description:
(1) per Section 5: Attachment 1, page 1, line 4, column (b)
(2) per R.I.P.U.C. 4323, Compliance Attachment 3A, (Schedule HSG-1), page 4, line 72
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) Line (4) ÷ Line (7), truncated to 2 decimal places

The Narragansett Electric Company
FY16 Proposed CapEx Factors
(for the 12 months beginning April 1, 2015)

Line No.		Total	Residential A16 / A60	Small Commercial & Industrial C-06	General Commercial & Industrial G-02	Large Demand B32 / G32	Optional Large Demand B62 / G62	Street Lighting S05/ S10 / S14	Electric Propulsion X-01
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
(1)	Proposed FY2016 Capital Investment Component of Revenue Requirement	$9,052,925							
(2)	Total Rate Base ($000s)	$561,738	$296,490	$54,542	$82,460	$77,651	$19,545	$29,286	$1,764
(3)	Percentage of Total	100.00%	52.78%	9.71%	14.68%	13.82%	3.48%	5.21%	0.31%
(4)	Allocated Proposed Revenue Requirement	$9,052,925	$4,778,205	$878,996	$1,328,919	$1,251,420	$314,987	$471,976	$28,422
(5)	Forecasted kWh - April 2015 through March 2016	7,709,114,605	3,146,934,592	590,961,381	1,256,074,652	2,026,919,293	599,126,708	65,765,428	23,332,550
(6)	Proposed CapEx Factor - kWh charge		$0.00151	$0.00148	n/a	n/a	n/a	$0.00717	$0.00121
(7)	Forecasted kW - April 2015 through March 2016				3,514,854	3,139,672	1,365,799		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$0.37	$0.39	$0.23	n/a	n/a

Line Description:
(1) per Section 5: Attachment 1, Page 1, Line (11), Column (b)
(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 Company forecasts
(6) For non demand-based rate classes, Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) For demand-based rate classes, Line (4) ÷ Line (7), truncated to 2 decimal places
Note: charges apply to kW>10 for rate class G-02 and kW>200 for rate class B32/G32

The Narragansett Electric Company
Calculation of Operations & Maintenance and CapEx Factors and Base Distribution Charge for Back-up Service Rates

Line No.		Large Demand B32 (a)	Optional Large Demand B62 (b)
	Operations & Maintenance Factors		
(1)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$1,839,102	$441,682
(2)	Forecasted kW - April 2015 through March 2016	3,139,672	1,365,799
(3)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW	$0.58	$0.32
(4)	Discounted O&M kW Factor effective 4/01/2015	$0.05	$0.03
	CapEx Factors		
(5)	Proposed CapEx kW Factor Charge effective 4/01/2015	$0.39	$0.23
(6)	Discounted CapEx kW Factor Charge effective 4/1/2015	$0.04	$0.02
	Base Distribution Charge		
(7)	Base Distribution kW Charge (before 90% discount) per most recent rate case	$6.96	$2.99
(8)	Discounted Base Distribution kW Factor Charge effective 4/1/2015	$0.70	$0.30
(9)	Sum of O&M and CapEx Factors and Base Distribution Charge for Back-up Service Rates	$0.79	$0.35

Line Description:
(1) Page 2, Line (4)
(2) per Company Forecasts
(3) Line (1) ÷ Line (2), truncated to 2 decimal places
(4) Line (3) x .10, truncated to two decimal places
(5) Page 3, Line (8)
(6) Line (5) x .10, truncated to two decimal places
(7) per R.I.P.U.C. 4323 Compliance Attachment 3D, (Schedule JAL-4), Page 5, Line (36) and Page 6, Line (14), Column (b)
(8) Line (7) x .10, truncated to two decimal places
(9) Line (4) + Line (6) + Line (8)

The Narragansett Electric Co.
Calculation of Base Distribution Charge, CapEx and Operations & Maintenance Factors for Back-up Service Rates

Line No.		Total (a)	Large Demand B32 (b)	Optional Large Demand B62 (c)
	Operations and Maintenance Factor			
(1)	FY2015 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,053,251		
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$35,640	$5,438	$1,306
(3)	Percentage of Total		15.26%	3.66%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense		$1,839,102	$441,682
(5)	Forecasted kWh - April 2015 through March 2016		3,139,672	1,365,799
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		$0.58	$0.32

	Adjustment to Base Distribution per kW Charge	Large Demand B32	Optional Large Demand B62
(7)	Base Distribution kW Charge (before 90% discount) per most recent rate case	$6.96	$2.99
(8)	Proposed O&M kW Factor effective 4/01/2015	$0.58	$0.32
(9)	Proposed CapEx kW Factor Charge effective 4/01/2015	$0.39	$0.23
(10)	Total Undiscounted ISR kW Charges	$0.97	$0.55
(11)	Total per kW Charge	$7.93	$3.54
(12)	Discount Rate applied to Total Distribution kW charge	90%	90%
(13)	**Discounted per kW Charge**	**$0.79**	**$0.35**
(14)	Sum of Proposed CapEx and O&M per kW Factors	$0.97	$0.55
(15)	Proposed Base Distribution kW Charge for 04/01/2014	($0.18)	($0.20)

Line Descriptions:
(1) per Section 5: Attachment 1, page 1, line 3, column (b)
(2) from Page 2, line (2)
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 2 decimal places
(7) per R.I.P.U.C. 4323 Compliance Attachment 3D, (Schedule JAL-4), page 5, line 36 and page 6, line 14, column (b)
(8) Line (6)
(9) from Page 3, line (8)
(10) Line (8) + Line (9)
(11) Line (7) + Line (10)
(12) per tariff
(13) Line (11) x (1 - Line (12))
(14) Line (10)
(15) Line (13) - Line (14)

Section 7

Bill Impacts

FY 2016 Electric ISR Plan

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Rates Applicable to A-16 Rate Customers

Monthly kWh	Present Rates Standard Offer Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Standard Offer Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$30.15	$13.06	$17.09	$30.39	$13.06	$17.33	$0.24	0.8%	13.7%
300	$54.34	$26.13	$28.21	$54.81	$26.13	$28.68	$0.47	0.9%	17.5%
400	$70.46	$34.83	$35.63	$71.08	$34.83	$36.25	$0.62	0.9%	11.8%
500	$86.58	$43.54	$43.04	$87.36	$43.54	$43.82	$0.78	0.9%	10.8%
600	$102.70	$52.24	$50.46	$103.63	$52.24	$51.39	$0.93	0.9%	9.4%
700	$118.82	$60.95	$57.87	$119.91	$60.95	$58.96	$1.09	0.9%	7.7%
1,000	$167.18	$87.07	$80.11	$168.75	$87.07	$81.68	$1.57	0.9%	15.0%
2,000	$328.41	$174.15	$154.26	$331.54	$174.15	$157.39	$3.13	1.0%	14.1%

Present Rates		
Customer Charge		$5.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (1)	kWh x	$0.03821
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Proposed Rates		
Customer Charge		$5.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (2)	kWh x	$0.03971
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Note (1): includes the current CapEx Factor of 0.027¢/kWh and the current O&M Factor of 0.157¢/kWh
Note (2): includes the proposed CapEx Factor of 0.151¢/kWh and the proposed O&M Factor of 0.183¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$22.84	$13.06	$9.78	$23.07	$13.06	$10.01	$0.23	1.0%	10.7%
300	$44.91	$26.12	$18.79	$45.38	$26.12	$19.26	$0.47	1.0%	23.2%
400	$59.64	$34.83	$24.81	$60.26	$34.83	$25.43	$0.62	1.0%	14.9%
500	$74.36	$43.54	$30.82	$75.14	$43.54	$31.60	$0.78	1.0%	12.2%
600	$89.07	$52.24	$36.83	$90.01	$52.24	$37.77	$0.94	1.1%	9.6%
700	$103.79	$60.95	$42.84	$104.88	$60.95	$43.93	$1.09	1.1%	7.3%
1,000	$147.95	$87.07	$60.88	$149.51	$87.07	$62.44	$1.56	1.1%	12.3%
2,000	$295.14	$174.15	$120.99	$298.26	$174.15	$124.11	$3.12	1.1%	9.8%

Present Rates		
Customer Charge		$0.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (1)	kWh x	$0.02474
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Proposed Rates		
Customer Charge		$0.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (2)	kWh x	$0.02624
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Note (1): includes the current CapEx Factor of 0.027¢/kWh and the current O&M Factor of 0.157¢/kWh
Note (2): includes the proposed CapEx Factor of 0.151¢/kWh and the proposed O&M Factor of 0.183¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$52.29	$24.17	$28.12	$52.67	$24.17	$28.50	$0.38	0.7%	35.2%
500	$93.41	$48.34	$45.07	$94.17	$48.34	$45.83	$0.76	0.8%	17.0%
1,000	$175.64	$96.68	$78.96	$177.16	$96.68	$80.48	$1.52	0.9%	19.0%
1,500	$257.87	$145.02	$112.85	$260.15	$145.02	$115.13	$2.28	0.9%	9.8%
2,000	$340.09	$193.35	$146.74	$343.13	$193.35	$149.78	$3.04	0.9%	19.1%

Present Rates		
Customer Charge		$10.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02003
Distribution Energy Charge (1)	kWh x	$0.03428
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates		
Customer Charge		$10.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02003
Distribution Energy Charge (2)	kWh x	$0.03574
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1: includes the current CapEx Factor of 0.027¢/kWh and the current O&M Factor of 0.175¢/kWh
Note (2): includes the proposed CapEx Factor of 0.148¢/kWh and the proposed O&M Factor of 0.200¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$743.01	$386.71	$356.30	$747.01	$386.71	$360.30	$4.00	0.5%
50	10,000	$1,722.32	$966.77	$755.55	$1,737.01	$966.77	$770.24	$14.69	0.9%
100	20,000	$3,354.51	$1,933.54	$1,420.97	$3,387.01	$1,933.54	$1,453.47	$32.50	1.0%
150	30,000	$4,986.70	$2,900.31	$2,086.39	$5,037.01	$2,900.31	$2,136.70	$50.31	1.0%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.92
Distribution Energy Charge (3)	kWh x	$0.00574
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (2)	kW x	$5.22
Distribution Energy Charge (4)	kWh x	$0.00595
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.37/kW
Note (3): includes the current O&M Factor of 0.127¢/kWh
Note (4): includes the proposed O&M Factor of 0.148¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$986.74	$580.06	$406.68	$991.17	$580.06	$411.11	$4.43	0.4%
50	15,000	$2,331.65	$1,450.16	$881.49	$2,347.43	$1,450.16	$897.27	$15.78	0.7%
100	30,000	$4,573.15	$2,900.31	$1,672.84	$4,607.84	$2,900.31	$1,707.53	$34.69	0.8%
150	45,000	$6,814.67	$4,350.47	$2,464.20	$6,868.26	$4,350.47	$2,517.79	$53.59	0.8%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.92
Distribution Energy Charge (3)	kWh x	$0.00574
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (2	kW x	$5.22
Distribution Energy Charge (4)	kWh x	$0.00595
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.37/kW
Note (3): includes the current O&M Factor of 0.127¢/kWh
Note (4): includes the proposed O&M Factor of 0.148¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$1,230.47	$773.42	$457.05	$1,235.35	$773.42	$461.93	$4.88	0.4%
50	20,000	$2,940.97	$1,933.54	$1,007.43	$2,957.84	$1,933.54	$1,024.30	$16.87	0.6%
100	40,000	$5,791.80	$3,867.08	$1,924.72	$5,828.67	$3,867.08	$1,961.59	$36.87	0.6%
150	60,000	$8,642.64	$5,800.63	$2,842.01	$8,699.52	$5,800.63	$2,898.89	$56.88	0.7%

Present Rates		
Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.92
Distribution Energy Charge (3)	kWh x	$0.00574
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates		
Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (2)	kW x	$5.22
Distribution Energy Charge (4)	kWh x	$0.00595
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.37/kW
Note (3): includes the current O&M Factor of 0.127¢/kWh
Note (4): includes the proposed O&M Factor of 0.148¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$1,474.20	$966.77	$507.43	$1,479.51	$966.77	$512.74	$5.31	0.4%
50	25,000	$3,550.29	$2,416.93	$1,133.36	$3,568.26	$2,416.93	$1,151.33	$17.97	0.5%
100	50,000	$7,010.44	$4,833.85	$2,176.59	$7,049.51	$4,833.85	$2,215.66	$39.07	0.6%
150	75,000	$10,470.60	$7,250.78	$3,219.82	$10,530.76	$7,250.78	$3,279.98	$60.16	0.6%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.92
Distribution Energy Charge (3)	kWh x	$0.00574
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (2)	kW x	$5.22
Distribution Energy Charge (4)	kWh x	$0.00595
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.37/kW
Note (3): includes the current O&M Factor of 0.127¢/kWh
Note (4): includes the proposed O&M Factor of 0.148¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Rates Applicable to G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
			Standard			Standard			
kW	kWh	Total	Offer	Delivery	Total	Offer	Delivery	Amount	% of Total
20	12,000	$1,717.93	$1,160.13	$557.80	$1,723.68	$1,160.13	$563.55	$5.75	0.3%
50	30,000	$4,159.61	$2,900.31	$1,259.30	$4,178.67	$2,900.31	$1,278.36	$19.06	0.5%
100	60,000	$8,229.10	$5,800.63	$2,428.47	$8,270.35	$5,800.63	$2,469.72	$41.25	0.5%
150	90,000	$12,298.58	$8,700.94	$3,597.64	$12,362.01	$8,700.94	$3,661.07	$63.43	0.5%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.92
Distribution Energy Charge (3)	kWh x	$0.00574
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW (2)	kW x	$5.22
Distribution Energy Charge (4)	kWh x	$0.00595
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.37/kW
Note (3): includes the current O&M Factor of 0.127¢/kWh
Note (4): includes the proposed O&M Factor of 0.148¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$6,474.31	$3,879.17	$2,595.14	$6,479.31	$3,879.17	$2,600.14	$5.00	0.1%
750	150,000	$24,073.16	$14,546.88	$9,526.28	$24,275.24	$14,546.88	$9,728.36	$202.08	0.8%
1,000	200,000	$32,072.63	$19,395.83	$12,676.80	$32,364.30	$19,395.83	$12,968.47	$291.67	0.9%
1,500	300,000	$48,071.59	$29,093.75	$18,977.84	$48,542.43	$29,093.75	$19,448.68	$470.84	1.0%
2,500	500,000	$80,069.51	$48,489.58	$31,579.93	$80,898.67	$48,489.58	$32,409.09	$829.16	1.0%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (1)	kW x	$3.77
Distribution Energy Charge (3)	kWh x	$0.00614
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (2)	kW x	$4.09
Distribution Energy Charge (4)	kWh x	$0.00626
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.39/kW
Note (3): includes the current O&M Factor of 0.078¢/kWh
Note (4): includes the proposed O&M Factor of 0.090¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$8,927.22	$5,818.75	$3,108.47	$8,934.72	$5,818.75	$3,115.97	$7.50	0.1%
750	225,000	$33,271.59	$21,820.31	$11,451.28	$33,483.05	$21,820.31	$11,662.74	$211.46	0.6%
1,000	300,000	$44,337.22	$29,093.75	$15,243.47	$44,641.39	$29,093.75	$15,547.64	$304.17	0.7%
1,500	450,000	$66,468.47	$43,640.63	$22,827.84	$66,958.06	$43,640.63	$23,317.43	$489.59	0.7%
2,500	750,000	$110,730.97	$72,734.38	$37,996.59	$111,591.39	$72,734.38	$38,857.01	$860.42	0.8%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (1)	kW x	$3.77
Distribution Energy Charge (3)	kWh x	$0.00614
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (2)	kW x	$4.09
Distribution Energy Charge (4)	kWh x	$0.00626
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.39/kW
Note (3): includes the current O&M Factor of 0.078¢/kWh
Note (4): includes the proposed O&M Factor of 0.090¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Rates Applicable to G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
			Standard			Standard			
kW	kWh	Total	Offer	Delivery	Total	Offer	Delivery	Amount	% of Total
200	80,000	$11,380.13	$7,758.33	$3,621.80	$11,390.13	$7,758.33	$3,631.80	$10.00	0.1%
750	300,000	$42,470.03	$29,093.75	$13,376.28	$42,690.86	$29,093.75	$13,597.11	$220.83	0.5%
1,000	400,000	$56,601.81	$38,791.67	$17,810.14	$56,918.47	$38,791.67	$18,126.80	$316.66	0.6%
1,500	600,000	$84,865.34	$58,187.50	$26,677.84	$85,373.68	$58,187.50	$27,186.18	$508.34	0.6%
2,500	1,000,000	$141,392.43	$96,979.17	$44,413.26	$142,284.10	$96,979.17	$45,304.93	$891.67	0.6%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (1)	kW x	$3.77
Distribution Energy Charge (3)	kWh x	$0.00614
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (2)	kW x	$4.09
Distribution Energy Charge (4)	kWh x	$0.00626
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.39/kW
Note (3): includes the current O&M Factor of 0.078¢/kWh
Note (4): includes the proposed O&M Factor of 0.090¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$13,833.06	$9,697.92	$4,135.14	$13,845.56	$9,697.92	$4,147.64	$12.50	0.1%
750	375,000	$51,668.47	$36,367.19	$15,301.28	$51,898.68	$36,367.19	$15,531.49	$230.21	0.4%
1,000	500,000	$68,866.38	$48,489.58	$20,376.80	$69,195.55	$48,489.58	$20,705.97	$329.17	0.5%
1,500	750,000	$103,262.22	$72,734.38	$30,527.84	$103,789.31	$72,734.38	$31,054.93	$527.09	0.5%
2,500	1,250,000	$172,053.89	$121,223.96	$50,829.93	$172,976.80	$121,223.96	$51,752.84	$922.91	0.5%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (1)	kW x	$3.77
Distribution Energy Charge (3)	kWh x	$0.00614
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (2)	kW x	$4.09
Distribution Energy Charge (4)	kWh x	$0.00626
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.39/kW
Note (3): includes the current O&M Factor of 0.078¢/kWh
Note (4): includes the proposed O&M Factor of 0.090¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$16,285.97	$11,637.50	$4,648.47	$16,300.97	$11,637.50	$4,663.47	$15.00	0.1%
750	450,000	$60,866.91	$43,640.63	$17,226.28	$61,106.49	$43,640.63	$17,465.86	$239.58	0.4%
1,000	600,000	$81,130.97	$58,187.50	$22,943.47	$81,472.64	$58,187.50	$23,285.14	$341.67	0.4%
1,500	900,000	$121,659.09	$87,281.25	$34,377.84	$122,204.93	$87,281.25	$34,923.68	$545.84	0.4%
2,500	1,500,000	$202,715.34	$145,468.75	$57,246.59	$203,669.51	$145,468.75	$58,200.76	$954.17	0.5%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (1)	kW x	$3.77
Distribution Energy Charge (3)	kWh x	$0.00614
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW (2)	kW x	$4.09
Distribution Energy Charge (4)	kWh x	$0.00626
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current CapEx Factor of $0.07/kW
Note (2): Includes the proposed CapEx Factor of $0.39/kW
Note (3): includes the current O&M Factor of 0.078¢/kWh
Note (4): includes the proposed O&M Factor of 0.090¢/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$109,090.34	$58,187.50	$50,902.84	$109,715.34	$58,187.50	$51,527.84	$625.00	0.6%
5,000	1,000,000	$170,011.18	$96,979.17	$73,032.01	$171,052.85	$96,979.17	$74,073.68	$1,041.67	0.6%
7,500	1,500,000	$246,162.22	$145,468.75	$100,693.47	$247,724.72	$145,468.75	$102,255.97	$1,562.50	0.6%
10,000	2,000,000	$322,313.26	$193,958.33	$128,354.93	$324,396.59	$193,958.33	$130,438.26	$2,083.33	0.6%
20,000	4,000,000	$626,917.43	$387,916.67	$239,000.76	$631,084.10	$387,916.67	$243,167.43	$4,166.67	0.7%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (1)	kW x	$3.34
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (2)	kW x	$3.54
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current O&M kW Charge of $0.31/kW and the current CapEx kW Charge of $0.04/kW
Note (2): Includes the proposed O&M kW Charge of $0.32/kW and the proposed CapEx kW Charge of $0.23/kW

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$144,843.47	$87,281.25	$57,562.22	$145,468.47	$87,281.25	$58,187.22	$625.00	0.4%
5,000	1,500,000	$229,599.72	$145,468.75	$84,130.97	$230,641.39	$145,468.75	$85,172.64	$1,041.67	0.5%
7,500	2,250,000	$335,545.04	$218,203.13	$117,341.91	$337,107.54	$218,203.13	$118,904.41	$1,562.50	0.5%
10,000	3,000,000	$441,490.34	$290,937.50	$150,552.84	$443,573.68	$290,937.50	$152,636.18	$2,083.34	0.5%
20,000	6,000,000	$865,271.59	$581,875.00	$283,396.59	$869,438.26	$581,875.00	$287,563.26	$4,166.67	0.5%

Present Rates		
Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (1)	kW x	$3.34
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates		
Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (2)	kW x	$3.54
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current O&M kW Charge of $0.31/kW and the current CapEx kW Charge of $0.04/kW
Note (2): Includes the proposed O&M kW Charge of $0.32/kW and the proposed CapEx kW Charge of $0.23/kW

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$180,596.59	$116,375.00	$64,221.59	$181,221.59	$116,375.00	$64,846.59	$625.00	0.3%
5,000	2,000,000	$289,188.26	$193,958.33	$95,229.93	$290,229.92	$193,958.33	$96,271.59	$1,041.66	0.4%
7,500	3,000,000	$424,927.84	$290,937.50	$133,990.34	$426,490.34	$290,937.50	$135,552.84	$1,562.50	0.4%
10,000	4,000,000	$560,667.43	$387,916.67	$172,750.76	$562,750.76	$387,916.67	$174,834.09	$2,083.33	0.4%
20,000	8,000,000	$1,103,625.76	$775,833.33	$327,792.43	$1,107,792.42	$775,833.33	$331,959.09	$4,166.66	0.4%

Present Rates		
Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (1)	kW x	$3.34
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates		
Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (2)	kW x	$3.54
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current O&M kW Charge of $0.31/kW and the current CapEx kW Charge of $0.04/kW
Note (2): Includes the proposed O&M kW Charge of $0.32/kW and the proposed CapEx kW Charge of $0.23/kW

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$216,349.72	$145,468.75	$70,880.97	$216,974.72	$145,468.75	$71,505.97	$625.00	0.3%
5,000	2,500,000	$348,776.81	$242,447.92	$106,328.89	$349,818.47	$242,447.92	$107,370.55	$1,041.66	0.3%
7,500	3,750,000	$514,310.66	$363,671.88	$150,638.78	$515,873.16	$363,671.88	$152,201.28	$1,562.50	0.3%
10,000	5,000,000	$679,844.51	$484,895.83	$194,948.68	$681,927.84	$484,895.83	$197,032.01	$2,083.33	0.3%
20,000	10,000,000	$1,341,979.93	$969,791.67	$372,188.26	$1,346,146.60	$969,791.67	$376,354.93	$4,166.67	0.3%

Present Rates		
Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (1)	kW x	$3.34
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates		
Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (2)	kW x	$3.54
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current O&M kW Charge of $0.31/kW and the current CapEx kW Charge of $0.04/kW
Note (2): Includes the proposed O&M kW Charge of $0.32/kW and the proposed CapEx kW Charge of $0.23/kW

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
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	$252,102.84	$174,562.50	$77,540.34	$252,727.84	$174,562.50	$78,165.34	$625.00	0.2%
5,000	3,000,000	$408,365.34	$290,937.50	$117,427.84	$409,407.01	$290,937.50	$118,469.51	$1,041.67	0.3%
7,500	4,500,000	$603,693.47	$436,406.25	$167,287.22	$605,255.97	$436,406.25	$168,849.72	$1,562.50	0.3%
10,000	6,000,000	$799,021.59	$581,875.00	$217,146.59	$801,104.93	$581,875.00	$219,229.93	$2,083.34	0.3%
20,000	12,000,000	$1,580,334.09	$1,163,750.00	$416,584.09	$1,584,500.76	$1,163,750.00	$420,750.76	$4,166.67	0.3%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (1)	kW x	$3.34
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge (2)	kW x	$3.54
Distribution Energy Charge	kWh x	($0.00015)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.09310

Note (1): Includes the current O&M kW Charge of $0.31/kW and the current CapEx kW Charge of $0.04/kW
Note (2): Includes the proposed O&M kW Charge of $0.32/kW and the proposed CapEx kW Charge of $0.23/kW

PRE-FILED DIRECT TESTIMONY

OF

AMY S. TABOR

December 23, 2014

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

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 filed testimony or testified before the Rhode Island Public Utilities Commission (the PUC)?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 5 of the Fiscal Year (FY) 2016 Electric Infrastructure, Safety, and Reliability Plan (ISR Plan) which describes the calculation of the Company's revenue requirement for FY 2016 in Attachment 1 of that section. This revenue requirement is based on the Electric ISR Plan operation and maintenance (O&M) expenses and capital investment described in the testimony of Mr. James H. Patterson and Mr. Ryan A. Moe.

III. ISR PLAN REVENUE REQUIREMENT

Q. Please summarize the revenue requirement for the Company's FY 2016 Electric ISR Plan.

A. As shown on Page 1, Column (b) of the Attachment 1, the Company's FY 2016 Electric ISR Plan revenue requirement totals $21,106,176 and includes the following elements: (1) operation and maintenance (O&M) expense associated with the Company's vegetation management (VM) activities and the Company's Inspection and Maintenance (I&M) Program, both totaling $12,053,251, (2) the FY 2016 revenue requirement

associated with the Company's incremental capital investment in electric utility infrastructure of $9,052,925, which includes the $2,789,692 revenue requirement on FY 2016 proposed incremental ISR capital investment, plus the FY 2015, FY 2014, FY 2013, and FY 2012 revenue requirements on incremental ISR capital investment of $4,087,395, $497,128, $(1,312,107), and $(66,298), and the Property Tax Recovery Adjustment of $3,057,115. Importantly, these amounts will be trued up to actual O&M and capital investment activity after the conclusion of the FY, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

For illustration purposes only, Column (c), Page 1 of Attachment 1 provides the FY 2017 revenue requirement. A detailed description of the calculation of the Company's revenue requirement for FY 2016 can be found in Section 5 of the 2016 Electric ISR Plan.

Q. Does this conclude your testimony?

A. Yes, it does.

PRE-FILED DIRECT TESTIMONY

OF

JEANNE A. LLOYD

December 23, 2014

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Jeanne A. Lloyd, 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 Principal Program Manager in Electric Pricing, New England in the Regulation and Pricing group of National Grid USA Service Company, Inc. This department provides rate related support to The Narragansett Electric Company.

Q. Please describe your educational background and training.

A. In 1980, I graduated from Bradley University in Peoria, Illinois with a Bachelor's Degree in English. In December 1982, I received a Master of Arts Degree in Economics from Northern Illinois University in De Kalb, Illinois.

Q. Please describe your professional experience?

A I was employed by Eastern Utilities Association (EUA) Service Corporation in December 1990 as an Analyst in the Rate Department. I was promoted to Senior Rate Analyst on January 1, 1993. As a Senior Rate Analyst, my responsibilities included the study, analysis, and design of the retail electric service rates, rate riders, and special contracts for the EUA retail companies. After the merger of New England Electric System and

EUA in April 2000, I joined the Distribution Regulatory Services Department as a Principal Financial Analyst. I assumed my present position October 1, 2006. Prior to my employment at EUA, I was on the staff of the Missouri Public Service Commission in Jefferson City, Missouri in the position of research economist. My responsibilities included presenting both written and oral testimony before the Missouri Commission in the areas of cost of service and rate design for electric and natural gas rate proceedings.

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

A. Yes. I have testified before the PUC on numerous occasions in support of various rate-related issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Cap Ex and Operation and Maintenance (O&M)factors resulting from the Company's FY2016 Electric Infrastructure, Safety and Reliability (ISR) Plan proposed in this filing and to provide the customer bill impacts of the proposed rate changes. In addition, my testimony describes the Company's proposal to revise the calculation of the distribution kW charges associated with the Company's Back-up Retail Delivery Service tariffs.

II. INFRASTRUCTURE, SAFETY AND RELIABILITY PROVISION

Q. Please describe the Company's ISR Plan tariff provision.

A. The Company's electric ISR Provision, R.I.P.U.C. No. 2118[1], describes the process for establishing and implementing annual rate adjustments designed to recover the costs associated with the electric ISR Plan. The tariff consists of two separate mechanisms: 1) an Infrastructure Investment Mechanism (IIM), which is designed to recover the costs associated with incremental capital investment; and 2) an Operation and Maintenance Mechanism (O&MM), which is designed to recover certain annual O&M expenses pertaining to Inspection and Maintenance (I&M) and Vegetation Management (VM) activities.

A. Infrastructure Investment Mechanism (IIM)

Q. Please describe the operation of the IIM.

A. The IIM provides for the recovery of incremental annual capital investment through CapEx Factors. In conjunction with the filing of the annual electric ISR Plan by January 1 of each year, the Company proposes CapEx Factors for each rate class, which are designed to recover the cumulative revenue requirement associated with the estimated and actual fiscal year capital investment commencing with the Company's fiscal year ending March 31. The proposed CapEx Factors become effective for consumption on and after April 1 of each year upon PUC approval.

[1]The current electric ISR Provision became effective on February 1, 2013.

Q. How are the CapEx Factors designed?

A. First, the cumulative revenue requirement approved by the PUC and which will reflect both an estimate of incremental capital investment for the upcoming fiscal year plus the cumulative prior years' actual incremental capital investment, is allocated to each of the Company's rate classes based upon the rate base allocator. The rate base allocator is the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the PUC that contained an allocated cost of service study.

Next, unit charges for each rate class will be developed from the allocated revenue requirement. For non-demand rate classes, a per kWh charge is calculated by dividing the cumulative rate class revenue requirement by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect. For demand-based rate classes, Rate G-02, Rates G-32/B-32, and Rates G-62/B-62, the CapEx Factors are per kW charges and are calculated by dividing the allocated cumulative revenue requirement for each rate class by the forecasted kW billing demand.

Q. Why is the cumulative revenue requirement allocated using a rate base allocator?

A. The cumulative revenue requirement associated with incremental capital investment is allocated in a manner that is similar to the way the revenue requirement on capital investment would be allocated if an allocated cost of service study were performed. Since capital investment is primarily related to plant in service, which forms the largest

part of rate base, allocating the incremental capital using the most recently approved rate base allocator is an appropriate way to spread the revenue requirement to each of the rate classes.

Q. Are the cumulative revenue requirement, which contains, in part, an estimate of incremental capital investment, and revenue generated from the CapEx Factors subject to reconciliation?

A. Yes. The Company submits a filing by August 1 of each year (the Reconciliation Filing) in which the Company proposes CapEx Reconciling Factors to become effective for the twelve months beginning October 1. In the Reconciliation Filing, the Company compares the actual cumulative revenue requirement to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over or under recovery of the actual cumulative revenue requirement is credited to or recovered from customers through the CapEx Reconciling Factors. The amount approved for recovery or crediting through the CapEx Reconciling Factors is also subject to reconciliation with actual amounts billed through the CapEx Reconciling Factors, and any difference is reflected in future CapEx Reconciling Factors.

B. Operation and Maintenance Mechanism (O&MM)

Q. Please describe the operation of the O&MM.

A. The O&MM provides for the recovery of O&M budgeted expense associated with the

Company's I&M and VM activities. The O&M Factors for each rate class are designed to recover the sum of the annual forecasted I&M expense and forecasted VM expense for the upcoming fiscal year, as approved by the PUC in the Company's annual electric ISR Plan Filing.

Q. How are the O&M Factors designed?

A. To determine the revenue to be collected from each rate class through the O&M Factors, the forecasted I&M and VM expense is allocated to each of the Company's rate classes based on the O&M allocator derived from allocated distribution O&M expense (i.e., FERC accounts 580-598). This distribution O&M allocator is the percentage of total distribution O&M expense allocated to each rate class taken from the most recent proceeding before the PUC that contained an allocated cost of service study. Once the rate class O&M revenue requirement has been determined, per unit rates are developed for each rate class. For Rates G-62/B-62, the O&M Factor is in the form of a demand, or per kW, charge and is calculated by dividing the allocated O&M expense for the combined rate class by the forecasted kW billing demand. For all other rate classes, a per kWh charge is developed by dividing the allocated O&M expense by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect.

Q. Why are the I&M and VM expenses allocated using a distribution O&M allocator?

A. As with the allocation of the revenue requirement on capital investment, the O&M

expense is allocated in a manner that is similar to the way these costs would be allocated if an allocated cost of service study were performed. Therefore, the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last base rate proceeding is used to spread these costs to each of the rate classes.

Q. Regarding Rates G-02 and B-32/G-32, why are the CapEx Factors designed as demand (per kW) charges and the O&M Factors as per kWh charges?

A. The current distribution charges for Rates G-02 and B-32/G-32 include both demand and kWh charges. The designs of the CapEx and O&M Factors for these rate classes are intended to not significantly change the relationship between the existing charges and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts.

Q. Regarding Rate B-62/G-62, why are both the CapEx Factor and the O&M Factor designed as demand (per kW) charges?

A. Presently, the distribution charges for Rate B-62/G-62 include a demand charge, and the CapEx and O&M Factors maintain that design.

Q. Are the O&M Factors subject to reconciliation?

A. Yes. In the Company's annual electric ISR Reconciliation Filing, the Company proposes an O&M Reconciling Factor to become effective for the twelve months beginning

October 1. The Company compares the actual I&M and VM O&M expense to actual billed revenue generated from the O&M Factors for the applicable reconciliation period, and any over or under recovery of actual expense is credited to or recovered from customers through the O&M Reconciling Factor. The O&M Reconciling Factor is a uniform per kWh charge applicable to all rate classes. The amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation with actual amounts billed through the O&M Reconciling Factor and any difference reflected in future O&M Reconciling Factors.

III. PROPOSED FACTORS

A. CapEx Factors

Q. Please describe the calculation of the proposed CapEx Factors.

A. The CapEx Factors are designed to recover the cumulative revenue requirement related to incremental capital investments through the end of FY 2016. The cumulative revenue requirement of $9,052,925[2] is developed in the testimony of Company Witness Amy S. Tabor. The cumulative revenue requirement is allocated to the rate classes based on the total rate base allocator, consistent with the provisions of the general base rate proceeding Settlement Agreement in Docket No. 4323, and the factors are designed as I've described above using forecasted billing units for the period April 1, 2015 through March 31, 2016.

[2] See Section 5: Attachment 1, Page 1, Line 11, column (b) of the electric ISR Plan.

The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, page 3.

B. O&M Factors

Q. Please describe the calculation of the proposed O&M Factors.

A. The proposed O&M Factors are designed to recover forecasted O&M expense associated with I&M and VM activities for FY 2016. As developed in the testimony of Ms. Tabor, these expenses total $12,053,251[3]. The Company has allocated these O&M expenses using an allocator based on distribution O&M from the allocated cost of service study consistent with the provisions of the general base rate proceeding Settlement Agreement in Docket No. 4323, which the Company believes maintains consistency in how these costs would be reflected in base rates, and O&M Factors are designed as I describe above.

C. Distribution kW Factors applicable to the Back-up Retail Delivery Service

Q. Why is the Company proposing adjustments to the distribution kW factors applicable to the Back-up Retail Delivery Service?

A. Pursuant to R.I.P.U.C. Tariff No. 2137 and 2138, both effective February 1, 2013, the Distribution kW charge applicable to Back-up Retail Delivery Service is equal to the base distribution kW charge applicable to Back-up service, as approved in the Company's

[3]See Section 5: Attachment 1, Page 1, Line 4, column (b) of the ISR Plan.

most recent base rate proceeding, plus the approved O&M and CapEx Factors applicable to Back-up Service, both pursuant to the Company's approved electric ISR Plan, multiplied by a factor of 10% to reflect a 90% discount. Since the Company is proposing new O&M and CapEx Factors in this filing, the discounted distribution kW charges applicable to back-up service must be re-calculated to reflect the 90% discount on the proposed factors.

Q. Please describe the calculation of the proposed distribution kW factors associated with the Back-up Retail Delivery Service tariffs.

A. The calculation of the distribution kW factors associated with the Back-up Retail Delivery Service tariffs is presented in Section 6, page 4 of the proposed FY 2016 Electric ISR Plan (Rate Design). The Back-up Service charges that apply to Rate B-32 and B-62 are developed from the revenue requirement and charges applicable to the companion full-requirements Rates G-32 and G-62. The O&M kW Factors are calculated on lines 1 through 4 of Section 6, page 4. First, the O&M is converted into a per kW charge for both classes by dividing the O&M revenue requirement applicable to each class developed on page 2 of Section 6 by the classes' forecasted kW billing demands. Next, a factor representing a discount of 90% is applied to the per kW charges, resulting in the proposed discounted Rate B-32/B-62 O&M kW Factors. The discounted CapEx kW Factors are calculated on lines 5 and 6. Since the CapEx Factors proposed for both Rates G-32 and G-62 are per kW charges, the only step necessary to determine the

Cap-Ex kW Factors applicable to Back-up Service is to apply the 10% discount factor to the proposed CapEx kW charges for Rates G-32 and G-62, respectively. The base distribution kW charges are calculated as the product of the base distribution kW charges approved in Docket No. 4323 multiplied by 10%.

Q. Is this method of calculating the Back-up Service demand charges different than the methodology used in previous electric ISR filings?

A. Yes, the method proposed by the Company in this filing results in a change to the way the individual CapEx and O&M Factors for Back-up Service are calculated. However, the total Back-up Service demand charge is the same regardless of the methodology, and, since the base distribution demand charge and the ISR factors are aggregated for bill presentation, the method used to calculate the individual ISR Factors will not affect the charge that appears on customer bills. For purposes of comparison, page 5 of Section 6 includes the calculation of the Back-up Service demand charges based upon the methodology used in previous filings. As shown on line 13 of Section 6, page 5, the total Back-up Service demand charge is identical to the charge proposed in this filing, presented on line 9 of Section 6 page 4

Q. Why is the Company proposing a change to the way the individual charge components of the Back-up Service demand charge are calculated?

A. Under the previous methodology, the Back-up Service demand discount was reflected

entirely in the base demand component of the charge, resulting in a negative base distribution demand charge, and the impact of billing out a negative demand charge is recovered through the Company's Revenue Decoupling Mechanism. By applying the 90% discount to the O&M and CapEx Factor as proposed in this filing, the discount associated with those charges will be reflected in each of those components and will be recovered more appropriately through the ISR reconciliation factors.

Q. Is the Company providing a summary of all proposed factors?

A. Yes. The Summary of Proposed Factors is presented in Section 6, page 1.

IV. BILL IMPACTS

Q. Has the Company prepared monthly bill impacts illustrating the effect of the proposed ISR Factors?

A. Yes. The monthly bill impacts for each rate class are shown on Section 7 of the ISR Plan. For a residential customer receiving Standard Offer Service and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $0.78, or 0.9%.

V. SUMMARY OF RETAIL DELIVERY RATES

Q. Is the Company including a revised Summary of Retail Delivery Rates tariff, R.I.P.U.C. No. 2095, in this filing?

A. No, the Company is not revising this tariff at this time. The Company will submit its annual reconciliation filing in February 2015and will propose additional rate changes for April 1, 2015. Therefore, the Company will submit a compliance filing following the PUC's decision in both the reconciliation filing docket and this docket that will include the Summary of Retail Delivery rates tariff reflecting all of the approved rate changes for April 1, 2015.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.