The Narragansett Electric Company
d/b/a National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2018 Proposal

December 21, 2016

RIPUC Docket No. 4682

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter

nationalgrid

Raquel J. Webster
Senior Counsel

December 21, 2016

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: National Grid's Proposed FY 2018 Electric Infrastructure, Safety, and Reliability Plan Docket No. 4682

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 2018.[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 Plan to the Rhode Island Division of Public Utilities and Carriers (Division) for review. In refining the Plan, the Company received and responded to discovery requests from the Division and consulted with the Division's representatives regarding the Plan. Accordingly, the proposed spending levels in the Plan reflect adjustments recommended by the Division although consensus on the full Plan has not been reached. Therefore, the Division has informed the Company that it reserves its right to continue reviewing the Plan after filing and propose further adjustments or conditions as part of this proceeding.

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.

[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.

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The Plan separates the general categories of work into discretionary and non-discretionary work and includes a description of the categories of work the Company proposes to perform in fiscal year 2018. The Plan also includes the proposed targeted spending levels for each category of work. In addition to the Plan, this filing includes the pre-filed direct testimony of several witnesses. In joint testimony, James Patterson and Ryan Moe introduce the Plan and describe the its large program components; Melissa A. Little and Aidimarys Martinez sponsor the calculation of the Company's fiscal year 2018 revenue requirement under the Plan; and Adam Crary 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 decrease of $0.09, or 0.1%.

The enclosed Plan, which the Company is submitting to the PUC for review and approval, presents an opportunity to continue facilitating and encouraging investment in the Company's electric utility infrastructure and enhance the Company's ability to continue providing 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.
Al Contente, Division

Testimony of
James H. Patterson, Jr.
& Ryan Moe

JOINT PRE-FILED DIRECT TESTIMONY

OF

JAMES H. PATTERSON, JR.

AND

RYAN A. MOE

December 21, 2016

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. In this role, I am responsible for regulatory filings and regulatory compliance related to the electric distribution operation of The Narragansett Electric Company d/b/a National Grid (the Company or National Grid). I am also responsible for the same types of filings for 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. In 2001, I was promoted to Operations Engineer. In these two roles, I was responsible for the engineering and design of distribution line construction projects. I also participated 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 who required 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. I was also responsible for 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 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 changed to only include Massachusetts and Rhode Island Distribution Line portfolios. In these three positions, I was responsible for creating, monitoring, and executing the work plans for the applicable portfolio of construction projects. On October 1, 2014, I was promoted to my current role.

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

A. Yes, I have represented the Company in negotiations with the Rhode Island Division of Public Utilities and Carriers (Division) regarding the Company's Electric Infrastructure, Safety, and Reliability Plans (Electric ISR Plan or Plan) for Fiscal Years (FY) 2016, 2017, and 2018. I have testified before the PUC in support of the FY 2016 and 2017 Electric ISR Plans in Docket Nos. 4529 and 4592, respectively.

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. In this role, 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.

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

A. In 2006, I graduated from the University at Buffalo with a bachelor's degree in Environmental Design. In September 2008, I began working for National Grid's Real

Estate department. While in the Company's Real Estate department, my responsibilities included mapping the Company's property records along the transmission lines and 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 have represented the Company in negotiations with the Division regarding vegetation management for the Company's Electric ISR Plan for FYs 2015, 2016, 2017, and 2018. In addition, I have testified before the PUC regarding the vegetation management component of the Electric ISR Plan for FYs 2016 and 2017 in Docket Nos. 4529 and 4592, respectively. I have also provided support for Electric ISR reporting since I began working as a Vegetation Strategist.

II. <u>PURPOSE OF JOINT TESTIMONY</u>

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

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

reasonable cost. The proposed FY 2018 Electric ISR Plan document is attached as Exhibit 1 to this testimony.

Q. Please summarize the categories of infrastructure, safety, and reliability spending covered by the FY 2018 Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2018, or the twelve-month fiscal year ending March 31, 2018: 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 2018 Electric ISR Plan, which is provided as Exhibit 1 to this testimony, includes the electric infrastructure, safety, and reliability spending plan for FY 2018 and an annual rate reconciliation mechanism that provides 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 and O&M expenses for a VM program and an I&M program. After the end of the fiscal year, the Company trues 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 reconciles 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 did the Company prepare the capital investment plan for review by the PUC?

A. The Company prepared a draft of the Electric ISR Plan and submitted it to the Division for review. In preparing 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 2018 totaling $100.6 million. This proposed capital spending plan includes a range of project work that is needed to maintain safe and reliable service. The project work that is included in the FY 2018 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, the Company has provided a detailed explanation of the categories of investment 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 2018 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. Accordingly, the Company has included these categories in the proposed Plan.

Q. Please review the FY 2018 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2018 are associated with five key work categories: (1) Customer Request/Public Requirement (formerly called Statutory/Regulatory); (2) Damage Failure (the Non-Discretionary Spending categories of work); (3) Asset Condition; (4) Non-Infrastructure; and (5) System Capacity and Performance (the Discretionary Spending categories of work). The table below summarizes the proposed spending level for each of these key driver categories proposed for FY 2018.

Proposed FY 2018 Capital Investment by Key Driver Category

Spending Rationale	FY 2017 Proposed Budget	%
Customer Request/Public Requirement	$21,853	21.7%
Damage Failure	$11,379	11.3%
Subtotal Non-Discretionary	$33,232	33.0%
Asset Condition	$16,971	16.9%
Non-Infrastructure	$553	0.5%
System Capacity & Performance	$24,092	23.9%
Subtotal Discretionary (Without South Street)	$41,616	41.4%
Asset Condition - South Street Project	$25,773	25.6%
Subtotal Discretionary	$67,389	67.0%
Total Capital Investment in Systems	**$100,621**	**100%**

As shown in the table above, a significant portion of the investment for capital projects in FY 2018 are necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates (i.e. $21.8 million or $21.7 percent). 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). Overall, 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 $11.4 million, or 11.3 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 customer/public requirements and to fix damaged or failed equipment. These investments are mandatory and "non-discretionary" in terms of scope and timing. Together, these items account for approximately $33.2 million, or 33.0 percent of proposed capital investment in FY 2018. 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 Company's control, 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 2018 have been chosen to maintain the overall reliability of the system and collectively total approximately $67.4 million, or 67.0 percent of the Company's proposed FY 2018 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 load 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 large adverse reliability impacts. 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 necessary to improve the overall reliability 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 $24.1 million, or 23.9 percent, of the proposed capital investment in FY 2018.

Projects necessary, due to the poor condition of infrastructure assets, account for approximately $16.9 million, or 16.9 percent, of the proposed capital investment in FY 2018. 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 potential reliability issues.

In Docket No. 4592 (Order No. 22471), the PUC directed the Company to manage the South Street FY 2017 ISR Plan budget separate from other discretionary projects in the Plan. For FY 2018, the Company plans to spend approximately $25.8 million or 25.6 percent of its FY 2018 investment on the South Street project.

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 $553,000 or approximately one half of one percent of the capital investment in FY 2018

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 2018 Electric Plan?

A. Yes. In the FY 2018 Electric Plan, the Company has provided detail on the specific projects within each work category that would be undertaken in FY 2018 as part of the Electric ISR Plan. The Company and the Division have reviewed these planned projects and the overall spending levels, and have reached consensus regarding the appropriate investment levels for FY 2018.

Q. Throughout the fiscal year, will the Company provide periodic updates regarding the various categories of capital work approved in the FY 2018 Electric ISR Plan?

A. Yes. The Company will provide quarterly reports to the Division and the 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 when it submits the reconciliation and rate adjustment filings to the PUC. 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. <u>VEGETATION MANAGEMENT PROGRAM</u>

Q. Please describe the FY 2018 spending levels for the Company's VM Program that the Company and Division have identified as appropriate to maintain safe and reliable distribution service to customers.

A. 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. For FY 2018, the Company proposes to spend approximately $9.4 million for the VM Program. This represents a 7.8% increase from the $8.7 million, which was approved for FY 2017. There are several reasons for this increased spend in FY 2018. First, the Company is scheduled to prune 45 additional miles in FY 2018 compared to FY 2017. Second, the bids for FY 2018 are showing an increased cost per mile, which is due in part to an increase in the number of rural circuits scheduled for work during FY 2018.

V. INSPECTION AND MAINTENANCE PROGRAM

Q. Please describe the FY 2018 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 FY 2018 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 costs within this category include O&M repairs associated with the capital program, inspections, voltage testing, completion of 20 percent of the Contact Voltage Program ordered in Docket No. 4237. This category also includes $25,000 for the on-going long-range system capacity load study and $60,000 for operation and maintenance expenses for the Volt/Var program, as agreed to with the Division. The Company proposes a total I&M Program O&M expense budget of approximately $1.1 million for FY 2018.

VI. CONCLUSION

Q. In your opinion does the FY 2018 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 2018 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. The Company believes that the proposed Plan accomplishes these objectives. As such, the PUC's approval of the proposed FY 2018 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.

Exhibit 1 – JHP & RM
Electric ISR Plan FY2018

The Narragansett Electric Company d/b/a National Grid

Proposed FY 2018 Electric Infrastructure, Safety, and Reliability Plan
Annual Filing

December 21, 2016

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Exhibit 1 – JHP & RM
Section 1
Intro. & Summary

Section 1

Introduction and Summary
FY 2018 Electric ISR Plan Annual Filing

Introduction and Summary
FY 2018 Proposal

Background

National Grid[1] has developed this proposed Fiscal Year 2018 (FY 2018) Electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or Plan) in compliance with Rhode Island's Revenue Decoupling statute, which provides 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 2018 Electric ISR Plan addresses the following categories of costs, as specified in R.I. Gen. Laws § 39-1-27.7.1(d): capital spending on electric infrastructure; operation and maintenance (O&M) expenses on the vegetation management (VM) program; O&M expenses on the inspection and maintenance (I&M) program; and other costs related to maintaining safety and reliability of the electric distribution system. This includes a discussion of O&M 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.

This Introduction and Summary section presents an overview of the proposed FY 2018 Plan for the above-referenced categories of costs, a description of how the Company proposes to calculate the revenue requirement, a description of how the Company will calculate new rates, and customer bill impacts.

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1 The Narragansett Electric Company d/b/a National Grid (National Grid or Company).
2 R.I. Gen. Laws § 39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.

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 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 is submitting this Plan to the PUC for final review and approval.[3]

The Electric ISR Plan provides a description of the Company's proposed electric distribution system safety and reliability activities along with the Company's proposed investments and expenditures contained in the Plan for FY 2018. The proposed Plan itemizes the recommended work activities by general category and provides budgets for capital investment, as well as O&M expenses for the VM and I&M programs.

Consistent with the Revenue Decoupling statute, 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 must then be submitted 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 detailing 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. 4592, the PUC directed the Company to include, as part of its FY 2018 Electric ISR Plan filing, a proposal to report in quarterly and annual reconciliation filings detail on individual projects where the costs differed from the fiscal year-to-date and fiscal year-end budgets, respectively, by more than ten percent (10%).[4] The Company continues to improve adherence to annual project budgets and schedules, which would reduce the number of projects reported. The Company is focusing on three main areas. First, the Company has implemented process improvements to improve scope definition at project initiation by collecting more information from Operations and other local departments during this phase of the project lifecycle. This information may have otherwise been discovered later in the project lifecycle, resulting in budget variances due to changes to the project scope, estimate, and schedule at that time. Second, the Company has consolidated large project estimating under a single department, which will provide consistent estimating practices when developing Conceptual, Planning, and Project Grade estimates. For previous ISR plans, multiple departments were responsible for developing estimates. By applying consistent practices, such as the application of payroll

[4] Docket No. 4592, Order No. 22471 (issued July 11, 2016), at 3.

overheads (i.e. benefits, capital clearing accounts, etc.) to direct charges, the variances between the project estimate grades should decline. Third, at the time of the ISR filing, the Company is striving to have Project grade estimates for many, if not all, of the projects that require construction in the upcoming fiscal year. By improving scope definition, cost estimates, and project maturity, the Company believes that the forecasted cash flows used for the development of the annual ISR budgets will result in fewer annual budget variances.

The Company continues to make progress with establishing a Long Range Plan for the eleven study areas in Rhode Island. Figure 1 below illustrates this progress.

Figure 1
National Grid's Study Areas: Current Priority and Statistics

Rank	Study Area	Load (MVA)	% State Load	# of Feeders	# of Stations	Study Status
1	Providence	364	19%	95	17	96%
2	East Bay	157	8%	23	7	100%
3A	Blackstone Valley North	145	7%	20	5	30%
3B	North Central RI	254	13%	35	10	30%
4	Central RI East	197	10%	38	10	95%
5	South County East	184	10%	21	9	
6	Central RI West	178	9%	30	11	
7	Newport	136	7%	54	14	
8	Blackstone Valley South	198	10%	60	13	
9	Tiverton	30	2%	4	1	
10	South County West	97	5%	12	6	
	Total:	**1,940**	**100%**	**392**	**103**	**42%**

* Study Status Total = % State Load Weighted Total

The Division has requested that large new infrastructure projects, unless compelled by imminent safety or reliability concerns, should be justified under the Long Range Plan before the Company includes such projects in the ISR Plan. The Company is advancing projects identified in the recently completed Providence Long Term, Quonset Point, and Pawtucket Area studies, particularly the South Street and Quonset substation rebuild projects. The Company anticipates completing the Long Range Plan prior to the construction of several multi-year projects, such as projects for the replacement/expansion of the Dyer Street, East Providence, and Warren substations. A number of these new infrastructure projects are discussed in more detail in the Asset Condition category in Section 2 below.

In Summary, the FY 2018 Annual Plan contains $100.6 million of net capital investment, $9.4 million of VM O&M expense, and $1.1 million of I&M O&M expense. The remaining sections of this document will address the Annual Plan in more detail. Section 2 contains the Company's proposed capital investment plan for FY 2018; 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 2018 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. These sections are summarized below.

Section 2: 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 within the Plan. Regarding the ratemaking treatment of capital spending, the Company proposes that capital investments used for establishing rates for FY 2018 be those investments in electric distribution infrastructure assets that the Company anticipates will be placed into service during the fiscal year. The

Company has used its capital budget to identify the relevant projects that would be part of the FY 2018 Electric ISR Plan. The capital budget also provides the Company's rationale regarding the need for and benefit of performing that work to provide safe and reliable service to its customers.

Section 3: Vegetation Management

Section 3 of this proposal contains the Company's VM O&M expense for FY 2018, a discussion of the nature of the work the Company expects to perform, and the expected benefits of such work. This proposal provides details of the proposed VM program for FY 2018. This estimated amount is subject to a true-up to actual VM O&M expense in the Company's annual reconciliation filing.

Section 4: Inspection and Maintenance Program

Section 4 of this proposal contains the Company's I&M O&M expense for FY 2018. This proposal provides details of the proposed I&M program for FY 2018. As with the other projected spending provided in this proposed Plan, this estimated amount will be subject to a true-up to actual I&M O&M expense in the Company's annual reconciliation filing.

Section 5: Electric Revenue Requirement

Section 5 of this proposal 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 expense. 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.

Section 6: Rate Design and Rates

Once the revenue requirement is calculated, it is 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 will apply for purposes of rate design:

- 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 at 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.
- The revenue requirement associated with the VM and I&M programs will be allocated to rate classes based upon the allocation of O&M 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.

Section 7: Bill Impacts

This section contains the bill impacts associated with the proposed rates.

Section 2

Electric Capital Investment Plan
FY 2018 Electric ISR Plan Annual Filing

Electric Capital Investment Plan
FY 2018 Proposal

Background

The Company[5] 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 asset condition.

As shown below in Chart 1a, the Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2015, with SAIFI of 0.937 against a target of 1.05, and SAIDI of 64.30 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days. A comparison of reliability performance in CY 2015 relative to that of previous years is shown in Table 13 below. The Company's performance has shown an improving downward trend over the past several years with major event days excluded.

[5] The Company delivers electricity to 487,378 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 5,052 miles of overhead and 1,033 miles of underground distribution and sub-transmission circuit in a network that includes 92 sub-transmission lines and 388 distribution feeders. The Company relies on 76 distribution substations that house 131 power transformers and 842 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 281,614 distribution poles, 4,387 manholes, and 65,508 overhead (pole-mounted) and underground (pad-mounted or in vault) transformers.

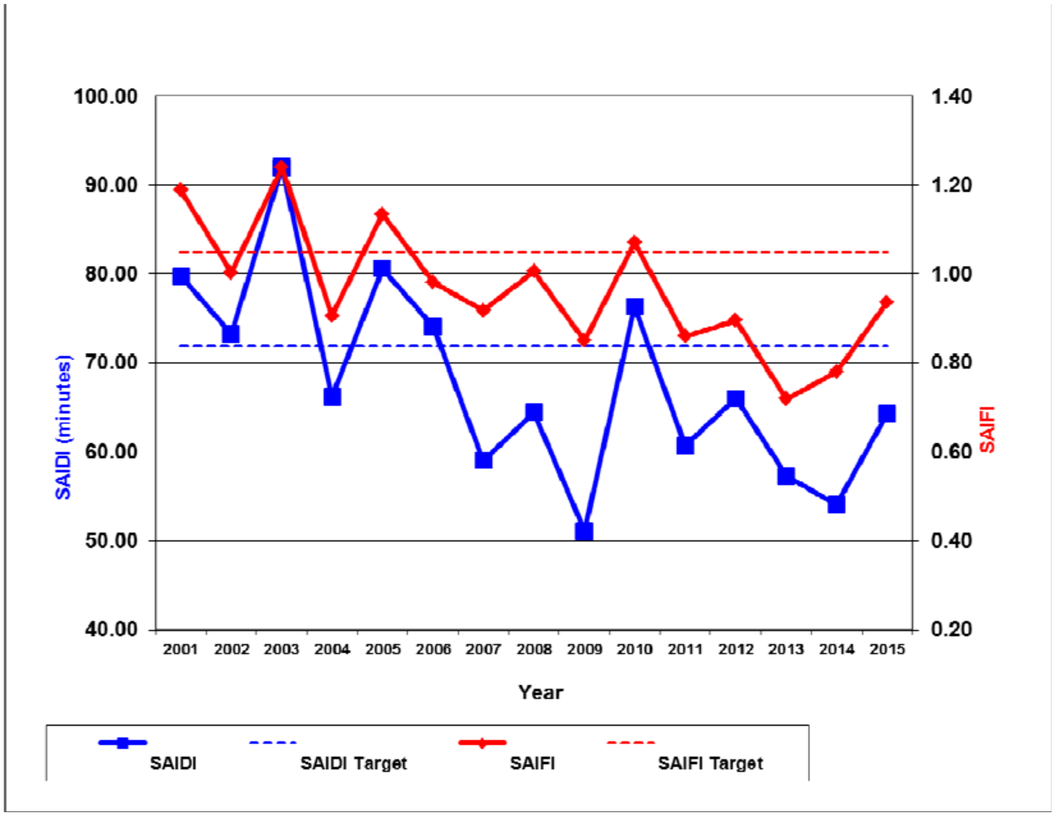
The Plan focuses on the underlying drivers of reliability during the entire year, and including major event days would skew that analysis significantly for the small number of days a year that are major event days. For example, including major event days would underestimate the day-to-day drivers of reliability due to substation or underground equipment, because, typically, overhead equipment is most impacted by major event days, which are usually weather driven events. CY 2015 had one day that was characterized as a major event day. Figure 2 below provides additional details including the event, dates, the total number of customers interrupted, and the daily SAIDI performance metric.

Figure 2

CY 2015 Major Event Days

Event	Dates Excluded	Total Customers Interrupted	Daily SAIDI
Windstorm	08/04/2015	142,171	271.33

Chart 1a
RI Reliability Performance CY 2001 – CY 2015
Regulatory Criteria (Excluding Major Event Days)



For informational purposes, Chart 1b below shows reliability performance from CY 2001 to CY 2015, including major event days.

Chart 1b
RI Reliability Performance CY 2001 – CY 2015
Regulatory Criteria (Including Major Event Days)

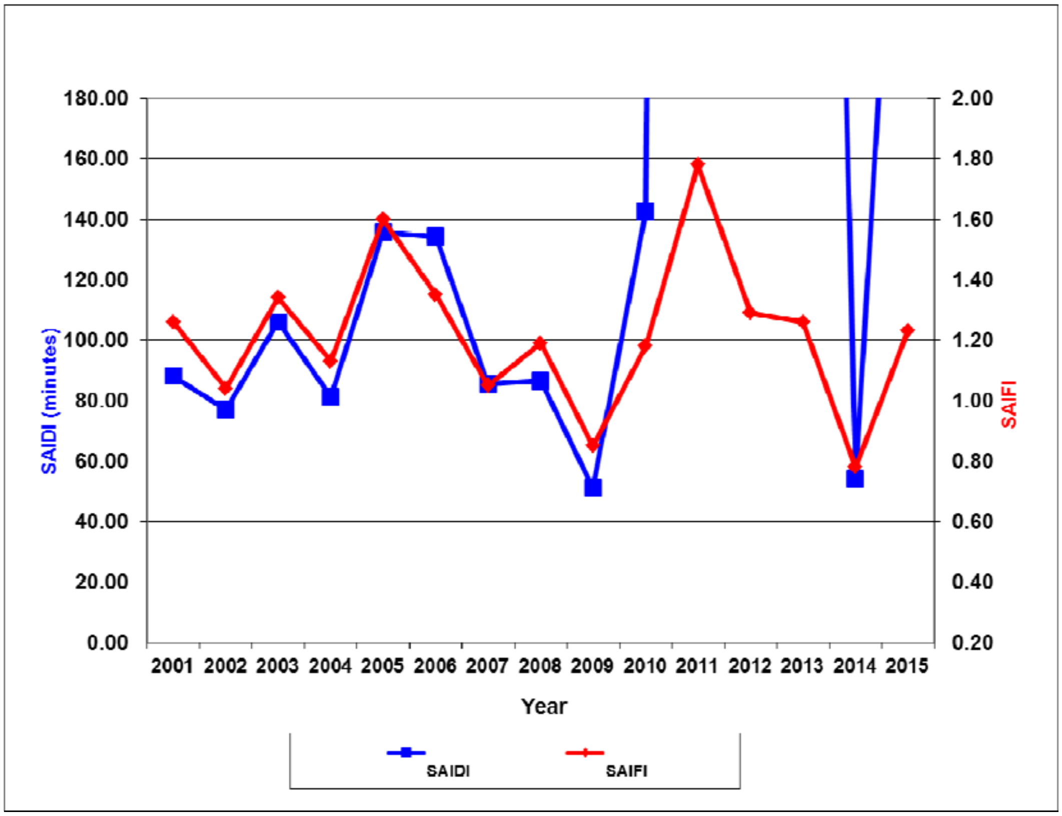


Chart 2 below shows the customers interrupted by cause for CY 2008 through 2015. Chart 3 shows the same information in tabular form.

Chart 2
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2015)

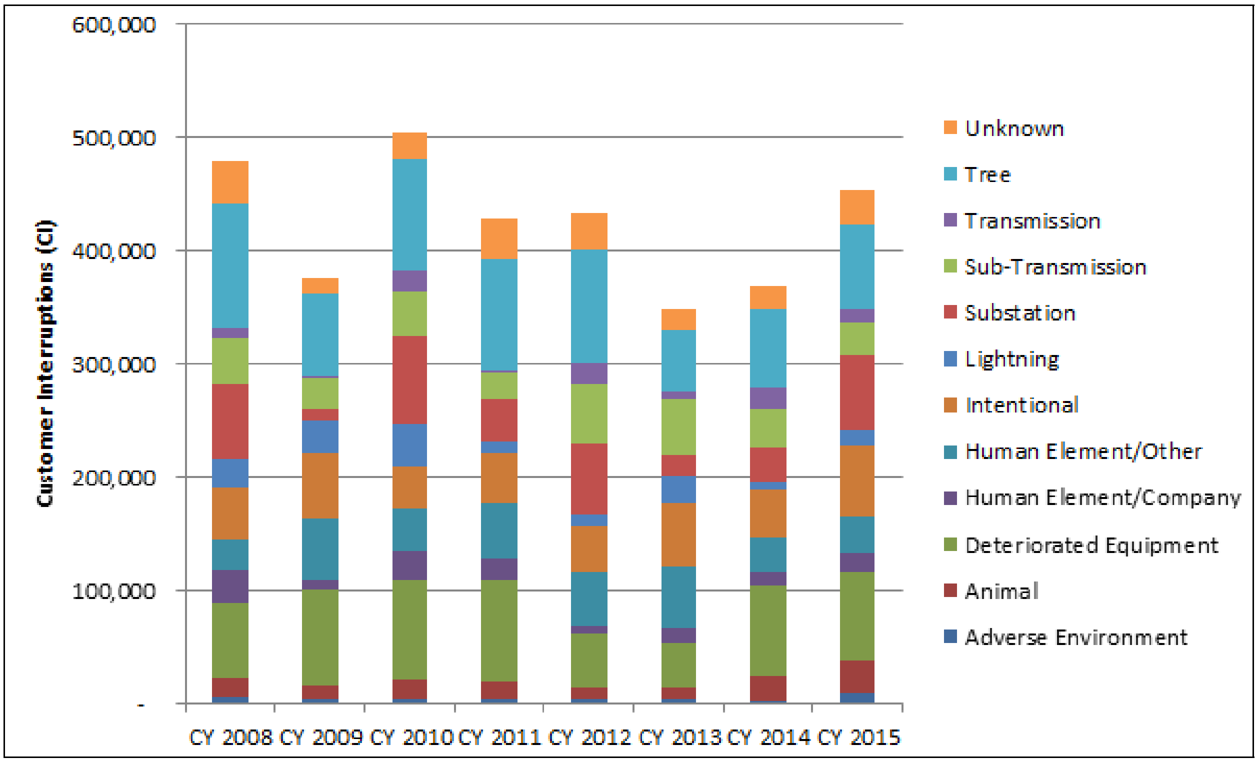


Chart 3
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2015)

Cause	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012	CY 2013	CY 2014	CY 2015
Adverse Environment	5,910	3,926	3,800	4,444	4,778	4,318	3,220	8,677
Animal	16,977	11,769	18,021	15,547	9,912	10,324	21,247	29,831
Deteriorated Equipment	67,114	85,047	87,768	89,743	47,301	39,131	79,260	77,575
Human Element/Company	28,298	8,450	26,047	18,455	7,043	13,481	13,259	16,619
Human Element/Other	27,607	54,275	36,999	48,650	47,404	54,719	29,908	33,049
Intentional	44,887	58,356	37,743	44,526	40,927	55,927	43,132	62,373
Lightning	25,987	27,874	36,859	11,044	9,362	23,310	5,745	14,374
Substation	65,704	10,713	77,189	37,086	63,397	18,882	30,888	65,932
Sub-Transmission	40,845	28,046	40,034	22,524	51,972	48,902	33,556	29,211
Transmission	8,721	25	18,438	2,973	19,099	5,958	18,284	11,594
Tree	109,214	74,116	97,807	97,485	100,459	55,056	70,277	73,248
Unknown	37,501	13,545	23,962	36,065	32,176	19,008	19,657	31,703
Grand Total	**478,765**	**376,142**	**504,667**	**428,542**	**433,830**	**349,016**	**368,433**	**454,186**

Although service quality for the Company is based on a calendar year (CY), capital spending reported in the Electric 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 2016 (ending March 31, 2016). Chart 5 shows the same information in tabular form.

Chart 4
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2016)

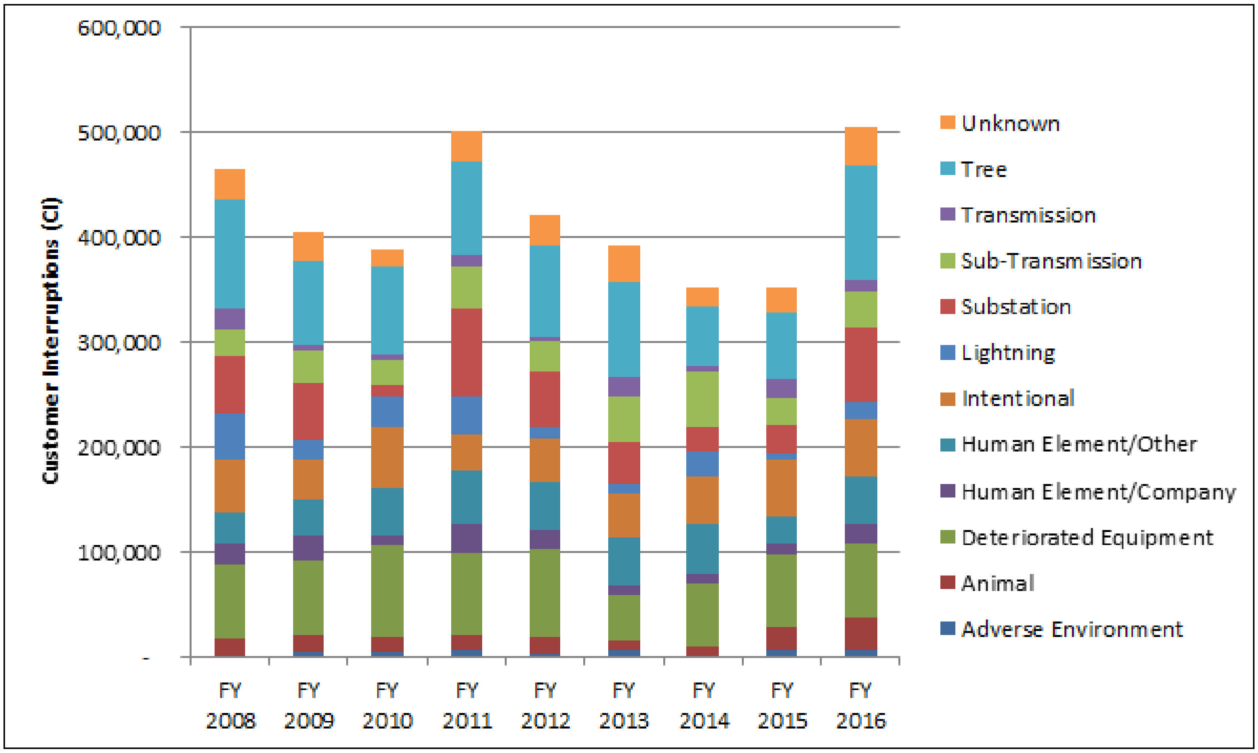


Chart 5
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2016)

Cause	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
Adverse Environment	1,673	5,651	4,018	5,992	3,674	6,584	811	6,786	5,922
Animal	15,103	16,303	14,751	15,335	15,008	9,864	10,098	21,232	32,266
Deteriorated Equipment	71,336	69,296	88,655	78,009	84,052	43,196	59,239	68,992	69,921
Human Element/Company	20,633	24,393	8,846	27,305	17,722	8,500	9,304	11,507	17,943
Human Element/Other	28,547	35,531	44,248	51,837	46,171	45,152	48,008	25,659	45,280
Intentional	50,735	36,569	59,581	33,987	41,879	42,989	44,451	55,268	54,661
Lightning	44,176	19,577	27,874	36,883	11,098	9,362	23,882	5,234	17,639
Substation	55,282	53,391	12,120	82,926	51,866	38,492	23,243	26,527	71,115
Sub-Transmission	24,298	31,628	22,243	39,770	29,805	44,084	53,550	26,191	33,727
Transmission	20,176	6,000	7,093	11,370	2,973	19,099	4,568	18,284	11,594
Tree	104,023	79,977	83,311	88,714	88,474	90,726	56,964	63,009	109,023
Unknown	29,583	26,146	15,807	29,629	29,163	34,143	18,501	23,529	35,829
Grand Total	**465,565**	**404,462**	**388,547**	**501,757**	**421,885**	**392,191**	**352,619**	**352,218**	**504,920**

Trees, substations, and deteriorated equipment were the top three drivers affecting customers, accounting for 50% of all interruptions in FY 2016. It is, therefore, critical that the Company continue to invest in its infrastructure and vegetation management programs to provide reliable electric delivery service to customers.

As shown in Chart 6 below, the Company plans to invest $100.6 million to maintain the safety and reliability of its electric delivery infrastructure in FY 2018, covering the period from April 1, 2017 through March 31, 2018. Chart 7 shows the same information in tabular form. This spending level is approximately 21% higher than the Company's FY 2017 Electric ISR budget of $83.4 million. The increase is primarily driven by the Asset Condition category, as discussed in more detail in section 2. The largest single driver of this increase is the South Street substation asset replacement project, which accounts for approximately $25.8 million in capital expenditures in FY 2018.

Chart 6
Capital Spend by Category FY 2010 – FY 2018

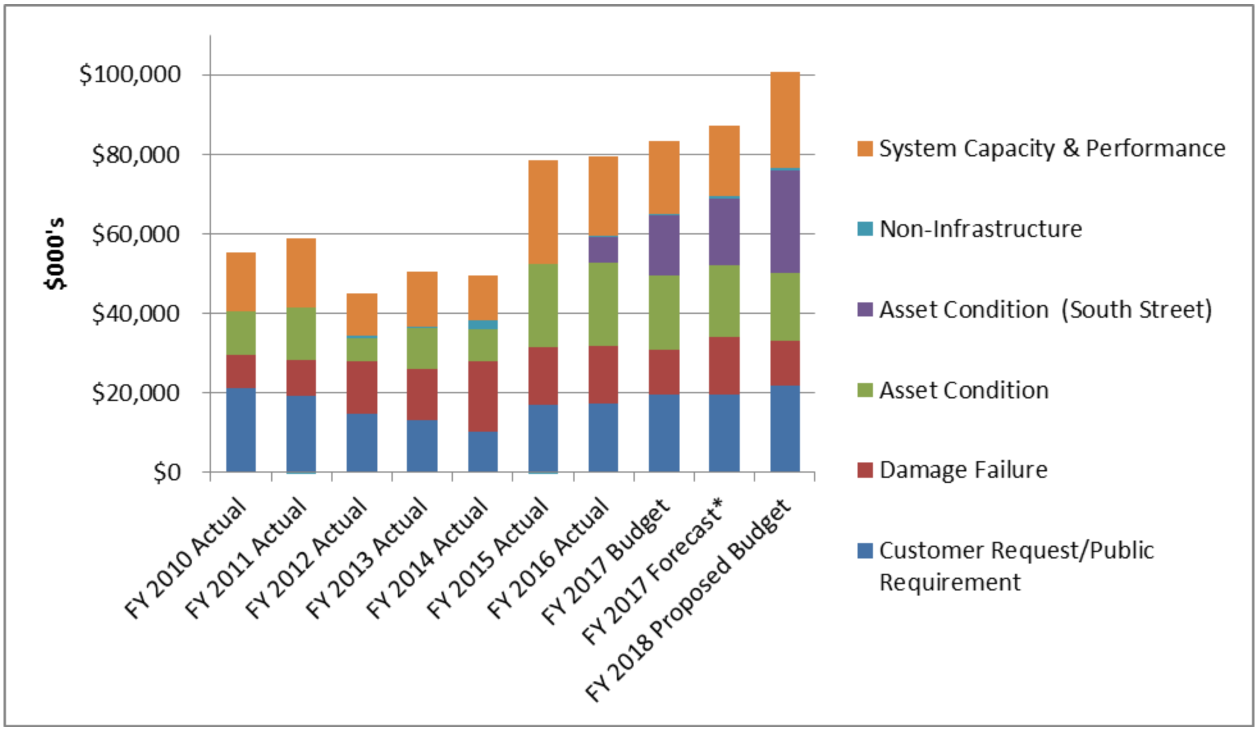


Chart 7
Capital Spend by Category FY 2010 – FY 2018
($000)

Spending Rationale	FY 2010 Actual	FY 2011 Actual	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Budget	FY 2017 Forecast*	FY 2018 Proposed Budget
Customer Request/Public Requirement	$21,172	$19,312	$14,631	$13,075	$10,410	$17,138	$17,412	$19,451	$19,620	$21,853
Damage Failure	$8,345	$9,031	$13,194	$12,993	$17,515	$14,374	$14,531	$11,467	$14,364	$11,378
Asset Condition	$10,941	$13,065	$5,831	$10,320	$8,071	$20,905	$20,951	$18,520	$18,025	$16,972
Asset Condition (South Street)	$0	$0	$0	$0	$0	$0	$6,228	$15,360	$16,973	$25,773
Non-Infrastructure	$151	($847)	$706	$267	$2,269	($346)	$457	$275	$407	$553
System Capacity & Performance	$14,596	$17,454	$10,795	$13,995	$11,249	$25,972	$19,920	$18,368	$17,878	$24,092
Total Capital Investment in Systems	**$55,205**	**$58,015**	**$45,157**	**$50,650**	**$49,514**	**$78,043**	**$79,499**	**$83,441**	**$87,266**	**$100,621**

*FY2017 ISR 2Q Report

[1] Previously called Statutory/Regulatory.

In Docket No. 4592, the PUC directed the Company to provide additional detail in support of the proposed investment for multi-year projects classified as major programs within a category.[6] On August 23, 2016, the Company met with the Division's consultants regarding the proposed FY 2018 Electric ISR spending categories and budgets. During that meeting, the Company provided additional detailed information on major multi-year projects included in the FY 2018 Plan. A summary of information regarding these major multi-year projects is included in Attachment 4. This information varies slightly from the information the Company presented at the August 23, 2016 meeting as the Company continues to refine the project cash flows based on the best information available throughout the development of the Electric ISR Plan.

Chart 8 below provides actual and forecasted Plant-in-Service dating back to FY 2012 (when the Electric ISR was first implemented) through the proposed FY 2018 Plan. Because a portion of the proposed capital spending in FY 2018 is for large substation projects, particularly the South Street substation replacement, that will be completed in FY2019 and beyond, the Company anticipates that the FY 2018 plant-in-service figure will be significantly lower than the capital spending.

[6] Docket No. 4592, Order No. 22471 (issued July 11, 2016), at 2.

Chart 8
Plant-In-Service FY 2012 – FY 2018

Spending Rationale	Plant-in-Service							
	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Proposed	FY 2017 Forecasted	FY 2018 Proposed
Customer Request/Public Requirement	$15,144,000	$11,261,897	$13,844,844	$18,443,062	$19,593,559	$19,971,000	$19,808,000	$20,202,000
Damage Failure	$13,628,000	$12,172,707	$16,928,183	$3,803,602	$16,370,879	$11,425,000	$15,787,000	$12,529,000
Asset Condition	$13,019,000	$6,638,163	$14,639,889	$28,094,392	$18,532,553	$26,481,000	$16,479,000	$22,199,000
Non-Infrastructure	$60,000	$112,879	$1,989,798	$345,779	$110,598	$271,000	$0	$0
System Capacity & Performance	$9,799,000	$14,145,495	$8,726,837	$25,970,206	$16,845,313	$20,330,000	$27,041,000	$19,913,000
Total Plant-in-Service	**$51,650,000**	**$44,331,141**	**$56,129,551**	**$76,657,041**	**$71,452,902**	**$78,478,000**	**$79,115,000**	**74,843,000**

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 2018.

Chart 9
Proposed FY 2018 Capital Spending by Key Driver Category
($000)

Spending Rationale	FY 2018 Proposed Budget	%
Customer Request/Public Requirement	$21,853	21.7%
Damage Failure	$11,379	11.3%
Subtotal Non-Discretionary	$33,232	33.0%
Asset Condition	$16,971	16.9%
Non-Infrastructure	$553	0.5%
System Capacity & Performance	$24,092	23.9%
Subtotal Discretionary (Without South Street)	$41,616	41.4%
Asset Condition - South Street Project	$25,773	25.6%
Subtotal Discretionary	$67,389	67.0%
Total Capital Investment in Systems	**$100,621**	**100%**

As shown above in Chart 9, $21.8 million or 21.7% of the spending for capital projects in FY 2018 is necessary to meet customer requests and public requirements. 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 cities and towns and the Rhode Island Department of Transportation (RIDOT). Overall, the scope and timing of this work is defined by those who are external to the Company.

The amounts required to immediately repair failed and damaged equipment totals approximately $11.4 million, or 11.3%, of the Company's proposed capital investment in FY 2018. 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, statutory and regulatory requirements, and fix damaged or failed equipment as mandatory and non-discretionary in terms of scope and timing. Together, these items total approximately $33.2 million, or 33% of the proposed capital investment in FY 2018.

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 $18.4 million or 76% of the investment dollars categorized as system capacity and performance, or 18% of the total proposed capital budget in FY 2018. 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 more discretion regarding 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 2018 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 24% of the system capacity and performance category, or 6% of the total proposed capital budget in FY 2018. 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 the Company's field operations personnel. Together with load relief projects, these system capacity and performance projects total approximately $24.1 million, or 23.9% of the proposed capital budget in FY 2018.

Projects necessary based on the condition of the infrastructure assets account for $42.7 million, or 42.5% of the proposed capital spending in FY 2018. Of the $42.7 million, the South Street project accounts for $25.8 million, or 25.8% of the proposed capital spending in FY 2018. These projects have been identified to reduce the risk and consequences of unplanned asset failures based on their present condition. The focus of the asset condition 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. Experience with assets that have poor operating characteristics in the field has led the Company to develop 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 $0.5 million, which is less than 1% of the proposed capital budget in FY 2018.

The Company considers the investment required to comply with asset condition, non-infrastructure, and system capacity & performance as discretionary in terms of scope and timing. Together, these items total approximately $67.4 million, or 67% of the proposed capital investment in FY 2018.

Development of the Annual Work Plan

Each year, the Company develops an Annual Work Plan, which is designed to achieve the Company's 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. Programs and projects are categorized by the following spending categories: Customer Requests/Public Requirements, Damage/Failure, System Capacity and Performance, Non-Infrastructure, 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 that a system event will occur and the consequences of the event, 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. Plan inclusion/exclusion for any given project is based on several different factors, including, but not limited to: new project or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed 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. Historical and forward-looking checks are made by 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 is ultimately presented to the 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 2018 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.[7] As previously noted, the Company is striving to have Project grade estimates for many, if not all, of the projects that

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

require construction in the upcoming fiscal year. Increasing the maturity of the projects in the FY 2018 Electric ISR Plan should result in fewer variances to the FY 2018 Electric ISR budget. The Company continuously reviews the capital plan during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, permitting/licensing/agency approvals, system operations, performance, safety, updated estimates, and customer-driven needs that may arise. Based on those changes, the capital plan is updated 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 $1.0 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
- Cost analysis of the proposed project
- Project schedule, milestones, and implementation plan

Once an approved project (greater than $1.0 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 $1.0 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 all construction costs following preliminary and final 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 the 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 some cases, historical trends are used to develop the appropriate reserve levels, especially reserves related to non-discretionary categories that will address emergent, customer or generator requirements, damaged or failed equipment, 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. There are no discretionary reserves in the proposed FY 2018 plan. The discretionary reserves in FY 2019 and beyond will be replaced with specific projects as the Long Term Studies and other tactical initiatives are progressed.

Description of Large Programs and Projects

Attachment 1 to this section provides spending detail on major project categories that support the proposed level of capital spending by key driver shown in Chart 9 above. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available.

Customer Request/Public Requirements

As shown in Attachment 1, the Company has set a budget of $21.9 million to meet its Customer Request/Public requirements in FY 2018. This is approximately 11% higher than the FY 2017 budget of $19.5 million, and $4.2 million, or 24% higher than the actual costs incurred by the Company in this category in FY 2016.

Approximately 63% of the Customer Request/Public Requirement budget is required to establish electric delivery service to new commercial and residential customers. The Company currently expects to spend approximately $13.9 million for this category of work in FY 2018. Importantly, the actual and proposed spending in this category is net of contributions in aid of construction (CIAC) that are received from customers. The proposed FY 2018 budget for this category of work is approximately $4.2 million greater than the FY 2017 budget. The increase is predominately driven by an increase in new business-commercial specific projects. The largest specific project in this category is the Liquefied Natural Gas (LNG) plant on Terminal Road in Providence, Rhode Island. The proposed FY 2018 budget is $2.2 million. The Company still expects to receive a CIAC for this project in FY 2017.

Approximately 12% of the Customer Request/Public Requirement budget is required for public projects. The Company currently expects to spend approximately $2.5 million for this category of work in FY 2018. This is approximately $1.2 million lower than the FY 2017 budget due to the completion of construction on the RIAC TF Green Runway Expansion project in FY 2017. No other large Public Requirement projects are expected in FY 2018. The following projects are included in this category:

- 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 Company anticipates spending approximately $0.2 million 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 the cost to ensure that the Company's assets meet the standards required to enable the attachments. Third-party customers do not reimburse the Company for costs the Company incurs to ensure that the Company's assets meet the standards required to enable attachments. Therefore, this work may result in additional costs for the Company.

Since much of the construction work in the customer requests and public requirements category is variable and requested on short notice, to account for emergent projects, the Company sets budget reserves for the work under this category based on data from previous fiscal years. Since the Company is reimbursed for a portion of this spending, the budget reserves represent the capital the Company expects to spend, net of CIACs and other reimbursements.

Damage/Failure

The Company is proposing an $11.4 million budget for FY 2018 for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. This budget is approximately the same as the $11.5 million budget for FY 2017. Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historic trends, which have risen due to increased identification of work identified by local Operations. 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 2018 (e.g. failed substation transformer). As in FY 2017, the budget set for FY 2018 also includes capital spending to address issues that have been identified for immediate repair as part of the I&M program 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 relatively small substation and/or line failures or those whose size is unknown at the time of the failure. The budget for FY 2018 is built on the assumption of flat failure rates along with inflation assumptions. The Company currently expects to spend approximately $9.3 million for this category of work in FY 2018.

- *Damage/Failure Reserve for Specific Projects* – This is 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. The Company currently expects to spend approximately $0.5 million for this category of work in FY 2018.

- *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. The Company currently expects to spend approximately $1.6 million for this category of work in FY 2018.

Asset Condition

The Company is proposing a $42.7 million budget for FY 2018 to replace assets that must be replaced to maintain reliability performance. This level is approximately 26% higher than the $33.9 million budget for FY 2017, and $18.8 million, or 64% higher than the actual Asset Condition costs incurred by the Company in FY 2016. This increase is driven primarily by the South Street asset replacement project, which has a FY 2018 budget of $25.8 million. In the FY 2017 Electric ISR Plan, the Company proposed a FY 2018 budget of $38.4 million for the Asset Condition category, of which South Street was $20.6 million. As a result of the increase to South Street, the Company re-phased the schedules of several Asset Condition projects to FY 2019 and beyond in order to achieve the $42.7 million budget for the FY 2018 Electric ISR Plan.

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 that detail how current spending levels are expected to improve asset age for metalclad substations and batteries. Unlike other categories of assets, age is used as a primary indicator of asset condition for metal clad substations and batteries. 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 13. The Company is currently developing the analysis for other asset categories.

The key asset condition budget categories are as follows:

- *South Street Project* **–** As shown in Attachment 4, the South Street Substation Project is a major 115/11 kV supply substation serving downtown Providence and the surrounding area. The South Street Substation replacement is driven by asset condition concerns. Specific asset condition issues exist for the transformers, breakers, switches, feeder reactors, and the battery system. The building layout precludes the implementation of modern installation standards, which would allow the Company to replace original equipment. Additionally, spare parts for the protection components are obsolete and unavailable. Therefore, these parts would be irreplaceable in the event of a failure.

Lastly, maintenance work often requires customized, site-specific repairs, which may be costly and time-consuming. The Company proposes to spend approximately $25.8 million on the South Street Project in FY 2018.

- *Southeast Substation* **–** This project is required to address asset condition concerns at the Pawtucket No. 1 substation. The Pawtucket No. 1 substation consists of a four-story brick building that was constructed in 1907 and includes an indoor substation and an outdoor switchyard. In addition to structural issues with the building, the indoor substation includes breakers and relays with condition issues and structures with clearance issues. Electrically, Pawtucket No. 1 station is located on the west side of the Seekonk River and serves half of its load in this area. 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. As shown in Attachment 4, this is a significant multi-year project. At this time, the Company anticipates capital spending in FY 2018 of $0.4 million to progress scope development and to start preliminary design activities.

- *Inspection & Maintenance Program* **–** This program has both capital and O&M components. The proposed capital spending in FY 2018 is $1.6 million. Section 4 includes additional details regarding the capital and O&M components of the I&M program.

- *Strategy to Replace Distribution Substation Batteries* – The Company has more than 107 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 direct current (DC) power for protection, control, and communications within the substation, as well as communication between the substation and the Company's operational control center. One goal of the Company's strategy is to replace batteries that are 20 years or older. Another goal is to ensure that battery systems meet the current operating requirements and perform their designed functions. The Company proposes to spend $0.2 million in FY 2018 to implement this strategy.

- *Dyer Street Replace Indoor Substation* – The purpose of this project is to replace the existing indoor substation at Dyer Street. In FY 2018, the Company proposes to spend approximately $0.4 million to start preliminary engineering and permitting processes. As shown in Attachment 4, this is another multi-year project with capital spending in future fiscal years.

- The *Substation Metalclad Switchgear Replacement Strategy and Program* **–** This program is another important strategy to improve the reliability of substations. This strategy addresses metalclad switchgears that have known operating issues or are of the same type and manufacturer as equipment that has failed at another location. Solutions typically include replacement of 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 4 kV and 23 kV. Of the 45 units, 31 units were installed prior to 1971. Several design factors with older vintage metalclad switchgear stations contribute to bus and/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 2018 budget is funded at $0.6 million and includes the remaining construction work to convert the existing 4 kV load on the Southeast substation to 13 kV. Once the existing 4kV substation is retired, this property will be used for the new Southeast substation that will replace the Pawtucket #1 indoor substation.

- *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 switches. The Company expects to address all of its 480V spot networks by FY 2021. The Company expects to spend approximately $0.4 million on this program in FY 2018.

- *The Relay Replacement Strategy* **–** This strategy will replace 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 because the relays are obsolete. 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 the 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 multi-year plan to replace transformer and under frequency relays that have been identified using the criteria mentioned above. Initially, the Company planned to complete this strategy in FY 2016. However, construction activities will continue into FY 2018 and be completed in FY 2019 due to portfolio management decisions. The Company proposes to spend $0.4 million to implement this strategy in FY 2018.

- *Recloser Replacement Strategy and Program* – The purpose of this program is to address multiple issues and concerns with the 38 in service Form 3A reclosers in regards to operations, maintenance, safety, reliability, and asset condition. These units have been in service for more than 25 years and are exhibiting a variety of problems, all of which have caused multiple malfunctions, including but not limited to battery charging problems, battery failure, and exterior deterioration/rust. Each location will be individually studied to develop the most cost-effective solution for the replacement, which may require one for one replacement, one for many replacements, relocation, and/or elimination. A coordination analysis of the entire circuit will be reviewed and optimized. The Company developed a criticality model to prioritize replacements and proposes to spend $0.4 million to replace out of service and the highest priority locations.

- *The Substation Circuit Breaker and Recloser Strategy and Program* **–** This program targets obsolete and unreliable breaker facilities. The Company has approximately 1038 distribution substation circuit breakers and reclosers in substations that it maintains, refurbishes, and replaces as necessary. The Company has specifically identified units with obsolete technology, such as air magnetic interruption, 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 $1.6 million to implement this strategy in FY 2018.

- *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 purpose of this strategy is to purchase spare transformers and proactively replace transformers that have a high likelihood of failure due to asset condition issues. The transformers at Lafayette Substation #30 and West Cranston #21 are in the FY 2018 plan. The Company proposes to spend $1.5 million on this strategy in FY 2018.

- *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 combination 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 or similar asset. 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 79F1, 79F2 and 2J8 primary circuits, and portions of the network secondary cable system. The Company proposes to spend approximately $3.0 million to continue to implement this strategy in FY 2018.

- *URD Cable Strategy* – This strategy applies to Underground Residential Development (URD) and Underground Commercial Development (UCD) cables 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 effected 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 if insulation injection is a viable option. The Company proposes to spend approximately $2.8 million to continue implementing this strategy in FY 2018.

- *Blanket Projects* – In addition to specific projects, the Company also has asset replacement blanket projects that were established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The amount of funding in the blanket project is reviewed and approved each year based on historical trends in the volume of work required, input from local Operations, and a forecasted impact of inflation on material and labor rates. The current year spending in the project is monitored on a monthly basis. The blankets provide local field engineering and operations with the control accounts to facilitate timely resolution of asset condition issues (i.e. deteriorated equipment). The budgets for the substation and distribution line blanket projects total $2.5 million in FY 2018.

System Capacity and Performance

The Company is proposing a $24.1 million budget for FY 2018 for System Capacity and Performance projects. This level is approximately 32% higher than the $18.4 million budget for FY 2017. The System Capacity and Performance category is comprised of Load Relief and Reliability projects. The Load Relief projects account for $21.1 million or 88% of the proposed System Capacity and Performance spending in FY 2018. The remaining 12% is made up of Reliability projects, which have a proposed FY 2018 spending budget of $3.0 million.

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; and
- 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,[8] 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.

[8] 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 through improved reactive power support.

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. The goal of these guidelines is to develop a combination of wires and non-wires alternatives that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks. As part of this process, the Company conducts analyses at a level of detail commensurate with the scale of the problems and the cost of potential solutions. In Docket No. 4296 (2012), the Company first proposed a pilot non-wires alternative project to the PUC (SRP Pilot). The SRP Pilot was designed to test the capabilities of targeted energy efficiency applications to defer distribution investment. FY 2017 is the final year of the SRP Pilot.

Some of the most significant Load Relief Projects for FY 2018 include:

- *Aquidneck Island Projects* – The southern portion of Aquidneck Island is supplied by a highly utilized supply and distribution system. This 23kV supply system and 4.16kV distribution system has limited capacity to supply load growth and new spot loads, and it is becoming increasingly challenging to supply large spot loads in southern Middletown and in the City of Newport. The Aquidneck Island Projects proposed budget for FY 2018 is $4.3 million. Below are details on the projects with proposed spending in FY 2018.

    - *Newport Substation* – This project will involve the 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 $3.0 million on this project in FY 2018.

- *Jepson Substation* – This project will involve building a new substation in Middletown, RI (Jepson Substation). The substation will consist of two power transformers supplying six 13.8 kV feeders and two power transformers supplying three 23 kV supply lines. The Company proposes to complete final engineering and initiate down payments for long lead items in FY 2018. The Company proposes to spend $1.3 million on this project in FY 2018.

- *Proposed Chase Hill Substation (formerly Hopkinton Substation)* **–** This project will involve 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 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 Company proposes to spend approximately $3.9 million on this project in FY 2018.

- *Substation EMS/RTU (SCADA) Additions Program* **–** The Company is proposing to expand the EMS/RTU program to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies. The Company proposes to spend approximate $1.4 million for this program in FY 2018.

- *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 42 MW. Upon contingency, approximately 27 MW of load (or approximately 6,000 customers) would be un-served until a spare or mobile transformer is installed, resulting in an exposure of 696 MWh. To address flood issues at the 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 the Hunt River substation, addressing the flood issues in a cost effective manner when compared to station reconstruction. The Company proposes to spend $0.3 million on this project in FY 2018.

- *Proposed New London Ave Substation (formerly West Warwick Substation)* – This project involves the 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 approximately $5.7 million on this project in FY 2018.

- *Distribution Line Transformer Strategy* – This annual program mitigates unplanned outage/failure risks due to overloads and asset condition of distribution line transformers. There are approximately 68,000 overhead distribution transformers on the Company's distribution system. Transformer loading is reviewed annually using reports generated by the Company's Geographical Information System (GIS). Transformers with calculated demands exceeding load limits specified in the applicable construction standard are investigated, and overloaded installations are addressed by replacement 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. This strategy is funded at $0.5 million in FY 2018.

- *Flood Contingency Plan* – The concerns raised by the floods experienced in 2010 prompted a study to identify substations at risk of flooding across all of National Grid's service territory. This study used Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRM) to determine whether a substation was within a flood zone, and additional on-site surveys were conducted at locations where potential flooding could occur. As a baseline, the study used the 100-year flood plain (the elevation and regional cover at which there is a 1% probability that flood waters will reach). This was compared to the base elevation of equipment or critical buildings within a substation to determine how deeply equipment or buildings would be submerged during a 100-year flood. Notably, the 100-year flood plain and the FIRM information, is frequently updated by FEMA. Updates typically result in a predicted flood water elevation rise.

Flood barriers will be installed around 12 substation yards so that main points of entry and egress are still available unless significant flooding is anticipated. The flood barriers at each substation will be installed considering their possible 100 year flood levels. The scope of work also includes other materials that will be purchased and put in place as supplemental flood risk reducing elements. These items include pumps, plugs, and generators to displace water inside the substation from general rainfall and leaks in the flood barriers. The FY 2018 budget for this program is approximately $0.2 million, which will be used to progress engineering and permitting activities at a Warren substation.

- *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 substation, which the recommended plan will also address. The Company proposes to spend approximately $2.8 million on this project in FY 2018.

- *Warren 115/12.47 kV Substation* – the Company proposes to spend approximate $0.1 million to progress preliminary engineering on the Warren #5 substation expansion project that has been recommended as part of the East Bay Long Term Study. The project expands the existing substation by creating two new 12.47 kV feeder positions, a new substation capacitor, and new distribution construction to provide additional capacity to the Warren and Barrington municipalities. Completion of the project also facilitates the retirement of the Barrington substation, which has safety and asset condition concerns, the capacity constrained Mink 115/23kV substation, and a significant portion of the 23kV sub-transmission in the area.

- *Highland Drive Feeder Extension* – the Company proposes to spend $1.2 million to finish the distribution system upgrades at the Highland Drive substation in Cumberland, RI. The substation was completed in FY2015; however, portions of the distribution line project have been deferred since then due to portfolio management decisions. The upgrades provide capacity to the Riverside and Staples substations and the Highland Drive Industrial Park.

- *Blanket projects* – In addition to specific projects, the Company also has three blanket projects that were established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The amount of funding in the blanket project is reviewed and approved each year based on the results of the previous annual capacity planning and reliability reviews, historical trends in the volume of work required, and a forecasted impact of inflation on material and labor rates. The current year spending in the project is monitored on a monthly basis. The substation and line load relief blankets provide O&M services and local field engineering with the control accounts to facilitate timely resolution of system and equipment loading and reliability issues. These blanket projects are utilized to respond to issues such as overloaded sections of wire/cable or step-down transformers, the installation of feeder voltage regulators and capacitors, and minor work necessary to facilitate the reallocation of load on existing circuits. The reliability blanket also provides local field engineering with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. The budgets for these three blankets total approximately $1.3 million in FY 2018.

- *VAR Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion*: The Company has historically managed the voltage profile of distribution feeders utilizing substation transformer load tap changers, voltage regulators, and capacitor banks with independent, locally based, conservatively programmed controls. Therefore, the Company is generally able to keep the range of voltages provided to customers along the circuit within the required +/- 5% ANSI range. This results in a default voltage profile which is high at the substation, and near the low range at the end of line under heavy loads. VVO refers to the process of more intelligently using distribution capacitors and regulators in a coordinated manner to flatten the voltage profile based on real time system performance. Once the profile is flattened, the controller can then lower the voltage coming from the substation to drop the voltage to the entire distribution circuit to be closer to the lower end of the ANSI range. By reducing the service voltage, the mix of loads for those customers will operate more efficiently and use less energy. This effect is called CVR.

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 reducing the demand and energy usage through CVR. In FYs 2015, 2016, and 2017, the Company scoped, designed, deployed, and analyzed a small VVO/CVR project area consisting of two substations (Putnam Pike and Tower hill) and seven feeders. Projects completed by other utilities have shown a demand and energy savings of approximately 3%, and the preliminary results from the pilot show a 3.3% demand reduction.

The Company believes that this technology should be further expanded in the Rhode Island service territory. The expansion will leverage the existing back office infrastructure that was installed during the prior small project. The Company will also leverage the lessons learned. The proposal will select areas that have recently undergone a distribution study and have circuit and load characteristics that provide the highest value for the service territory.

To develop an accurate scope of work and budget for this project, the Company leveraged lessons learned and actual costs from the previous small project. The Company utilized a request for proposal (RFP) process during the pilot, and the Company requested proposals for Advanced Volt/VAR management schemes. The Company selected Utilidata, a Rhode Island based company, as the preferred vendor to provide the necessary integrated control system. This includes distribution, substation, and communications necessary to complete the project based on the Company's best estimates at this time. In addition, the Volt/Var project will have ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing. In FY 18, the Company proposes to spend approximately $1.4 million in capital and $60,000 of O&M costs on this project.

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 (COR). To develop its Capital Placed-In-Service figure for this filing, the Company used estimated timing of in-service dates for capital spending being placed into service during FY 2018. 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 2018 proposed amounts for Capital Spending, Plant-in-Service, and COR that have been used in the development of the FY 2018 Electric ISR Plan revenue requirement.

Chart 11
Proposed FY 2018 Proposed Capital Spending, Plant-in-Service, and COR
($000)

Spending Rationale	Proposed Capital Spending FY 2018	Proposed New Capital Placed-in-Service FY 2018	Estimated COR	New Capital Placed-in-Service + COR
Customer Request/Public Requirement	$21,853	$20,202	$2,607	$22,809
Damage Failure	$11,379	$12,529	$2,870	$15,399
Subtotal Non-Discretionary	$33,232	$32,731	$5,477	$38,208
Asset Condition	$42,744	$22,199	$2,963	$25,162
Non-Infrastructure	$553	$0	$0	$0
System Capacity & Performance	$24,092	$19,913	$1,206	$21,119
Subtotal Discretionary	$67,389	$42,112	$4,169	$46,281
Total Plant-in-Service	**$100,621**	**$74,843**	**$9,646**	**$84,489**

Attachment 1
FY 2018 Capital Spending by Key Driver Category and Budget Classification
($000)

Spending Rationale	Budget Class Codes	FY2012 Actual	FY2013 Actual	FY2014 Actual	FY2015 Actual	FY2016 Actual	FY2017 Budget	FY2017 Forecast *	FY2018 Prelim Budget
Customer Requests/Public Requirements	3rd Party Attachments	$ 464	$ 223	$ 141	$ 305	$ 290	$ 155		$ 204
	Distributed Generation	$ -	$ (675)	$ 195	$ -	$ (933)	$ 529		$ 1,106
	Land and Land Rights	$ 185	$ 128	$ 94	$ 179	$ 143	$ 187		$ 223
	Meters - Dist	$ 1,497	$ 1,455	$ 835	$ 1,824	$ 2,935	$ 2,170		$ 1,786
	New Business - Commercial	$ 3,391	$ 3,722	$ 4,957	$ 3,924	$ 7,568	$ 5,577		$ 8,183
	New Business - Residential	$ 2,833	$ 2,886	$ 3,593	$ 2,870	$ 5,085	$ 3,728		$ 5,616
	Outdoor Lighting - Capital	$ 495	$ 488	$ 758	$ 533	$ 129	$ 541		$ 153
	Public Requirements	$ 1,135	$ (1,231)	$ 4,234	$ 1,418	$ 770	$ 3,814		$ 2,520
	Transformers & Related Equipment	$ 3,075	$ 3,415	$ 2,331	$ 3,634	$ 1,425	$ 2,750		$ 2,060
Customer Requests/Public Requirements Total		$ 13,075	$ 10,411	$ 17,138	$ 14,687	$ 17,412	$ 19,451	$ 19,620	$ 21,853
Damage/Failure	Damage/Failure	$ 9,574	$ 7,795	$ 11,228	$ 8,816	$ 11,327	$ 9,967		$ 9,828
	Major Storms - Dist	$ 3,419	$ 9,720	$ 3,146	$ 1,000	$ 3,204	$ 1,500		$ 1,550
Damage/Failure Total		$ 12,993	$ 17,515	$ 14,374	$ 9,816	$ 14,531	$ 11,467	$ 14,364	$ 11,378
Asset Condition - South St	Asset Replacement - South St	$ -	$ -	$ -	$ -	$ 6,228	$ 15,360		$ 25,773
Asset Condition - South St Total		$ -	$ -	$ -	$ -	$ 6,228	$ 15,360	$ 16,973	$ 25,773
Asset Condition	Asset Replacement	$ 9,767	$ 6,984	$ 14,011	$ 11,807	$ 16,030	$ 14,811		$ 14,955
	Asset Replacement - I&M (NE)	$ 553	$ 1,086	$ 6,681	$ 7,040	$ 4,811	$ 2,510		$ 1,600
	Safety	$ -	$ -	$ 213	$ 514	$ 110	$ 598		$ 417
Asset Condition Total		$ 10,320	$ 8,070	$ 20,905	$ 19,361	$ 20,951	$ 17,919	$ 18,025	$ 16,972
Non-Infrastructure	General Equipment - Dist	$ 118	$ 890	$ (1,245)	$ -	$ (61)	$ -		$ 378
	Corporate/Admin/General	$ 149	$ 191	$ 395	$ 102	$ 331	$ 100		$ -
	Telecommunications Capital - Dist	$ -	$ 1,188	$ 504	$ 175	$ 187	$ 175		$ 175
Non-Infrastructure Total		$ 267	$ 2,269	$ (346)	$ 277	$ 457	$ 275	$ 407	$ 553
System Capacity & Performance	Load Relief	$ 8,837	$ 6,619	$ 22,762	$ 19,052	$ 16,812	$ 15,726		$ 21,079
	Reliability	$ 2,554	$ 3,723	$ 3,210	$ 2,707	$ 3,108	$ 3,243		$ 3,012
	Reliability - Feeder Hardening	$ 2,564	$ 907	$ -	$ -	$ -	$ -		
System Capacity & Performance Total		$ 13,955	$ 11,249	$ 25,972	$ 21,759	$ 19,920	$ 18,969	$ 17,877	$ 24,091
Grand Total		$ 50,610	$ 49,514	$ 78,043	$ 65,900	$ 79,499	$ 83,441	$ 87,266	$ 100,621

* As submitted in Q2 FY2017 ISR Report

Attachment 2
FY 2018 Project Detail for Capital Spending
($000)

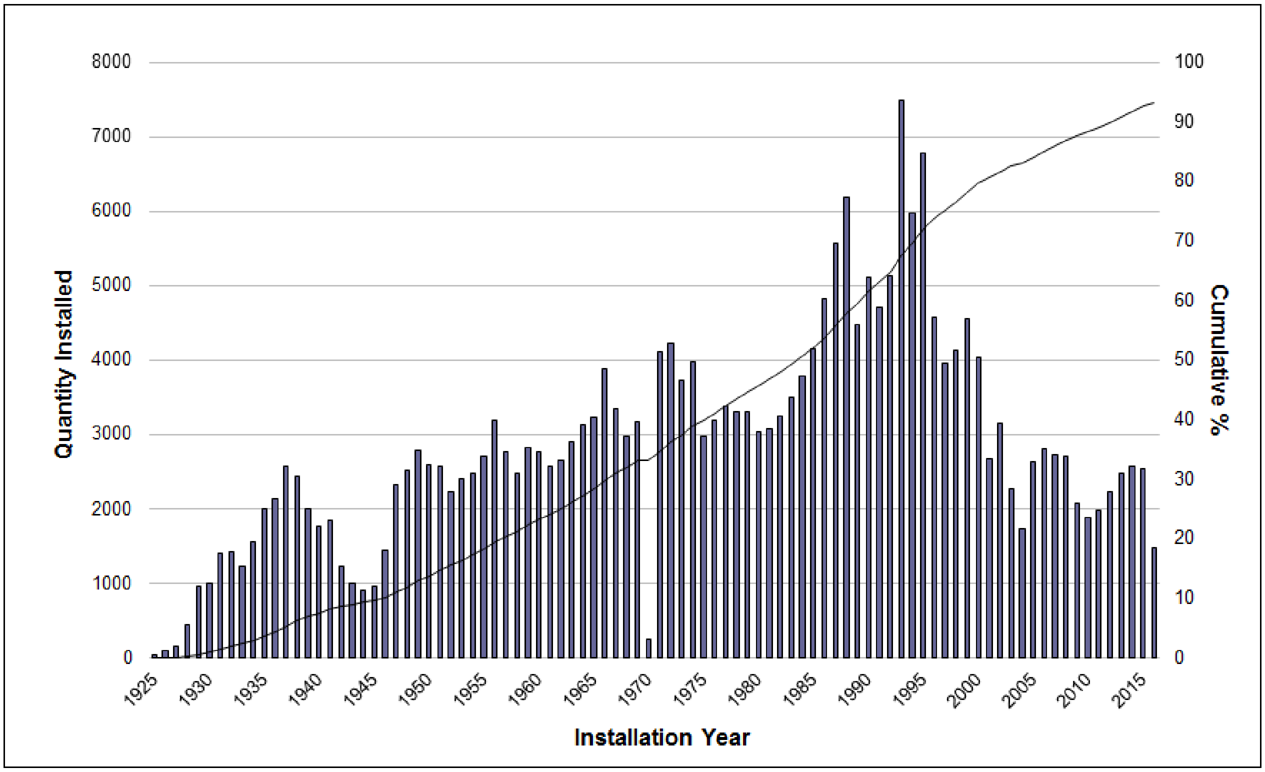
Spending Rationale	Budget Class Codes	Project #	Project Description	FY2018 Capital Budget
Customer Requests/Public Requirements	3rd Party Attachments	COS0022	OCEAN ST-DIST-3RD PARTY ATTCH BLNKT	204
	Distributed Generation	C046386	BITS WAKEFIELD SUB UPGRADES (D-SUB)	21
		C051909	PS&I DIST GEN RI	10
		C063146	DG SVC TO BRANDYWICK N SMITHFIELD,	531
		C068167	DG SVC TO ORBIT ENERGY JOHNSTON, RI	531
		C072386	18056252-D-NIPPAWU-NKNGTWN-FRTWN RD	13
	Land and Land Rights	COS0091	LAND AND LAND RIGHTS RI ELECT	223
	Meters - Dist	CN04904	NARRAGANSETT METER PURCHASES	1,030
		COS0004	OCEAN ST-DIST-METER BLANKET	756
	New Business - Commercial	C046977	RESERVE FOR NEW BUSINESS COMMERCIAL	2,000
		C051203	LNG PLANT SVC TERMINAL RD PRV DLINE	777
		C051204	LNG PLANT SVC TERMINAL RD PRV DSUB	1,507
		COS0011	OCEAN ST-DIST-NEW BUS-COMM BLANKET	3,900
	New Business - Residential	C046978	RESERVE FOR NEW BUSINESS RESIDENTIA	312
		COS0010	OCEAN ST-DIST-NEW BUS-RESID BLANKET	5,305
	Outdoor Lighting - Capital	COS0012	OCEAN ST-DIST-ST LIGHT BLANKET	153
	Public Requirements	C045656	DOTR-BLACKSTONE RIVER BIKEWAY SEG8A	170
		C046970	RESERVE FOR PUBLIC REQUIREMENTS UNI	437
		C047039	DOTR-EAST MAIN RD, PORTSMOUTH	255
		C047075	DOTR-BLACKSTONE RIVER BIKEWAY SEG8C	170
		C050921	DOTR-HI HAZ INTERSECTIONSBRISTOL CO	84
		C054787	DOTR-RICHMOND: KINGSTON RD BR 403	154
		C054830	DOTR-CAROLINA BRIDGES 54,55&56	154
		C056850	RIAC TF GREEN RUNWAY EXPANSION	40
		C059639	DOTR-PROV:VIADUCT BR NB-SMITH ST BR	85
		C068606	DOTR-HIHAZINT-SOUTH-S.K.&N.K.	85
		COS0013	OCEAN ST-DIST-PUBLIC REQUIRE BLANKT	886
	Transformers & Related Equipment	CN04920	NARRAGANSETT TRANSFORMER PURCHASES	2,060
Customer Requests/Public Requirements Total				**21,853**
Damage/Failure	Damage/Failure	C046986	RESERVE FOR DAMAGE/FAILURE UNIDENTI	102
		C051608	RESERVE FOR DAMAGE/FAILURE SUBSTATI	435
		COS0002	OCEAN ST-DIST-SUBS BLANKET	510
		COS0014	OCEAN ST-DIST-DAMAGE&FAILURE BLANKT	8,781
	Major Storms - Dist	C022433	OSD STORM CAP CONFIRM PROGRAM PROJ	1,550
Damage/Failure Total				**11,379**

Asset Condition - South St	**Asset Replacement**	C051212	SOUTH ST REPL INDOOR SUBST D-SUB	**21,506**
		C051213	SOUTH ST REPL INDOOR SUBST D-LINE	**4,267**
Asset Condition - South St Total				**25,773**
Asset Condition	**Asset Replacement**	C025815	OS ARP INSUL, SENSDEV, SURGE ARREST	**250**
		C032019	BATTS/CHARGERS NE SOUTH OS RI	**199**
		C032278	OS ARP BREAKERS & RECLOSERS	**150**
		C035586	RELAY REPLACEMENT STRATEGY CO 49DXT	**49**
		C047375	IRURD MYSTERY FARMS ESTATES	**987**
		C047398	IRURD WIONKHEIGE	**852**
		C048969	RI RAPR ARP	**230**
		C049354	NEC RELAY REPLACEMENT CO.49- SG157	**382**
		C049356	IRURD SILVER MAPLE PHASE 2	**85**
		C049462	IRURD SIGNAL RIDGE, EAST GREENWICH	**230**
		C049910	SOUTHEAST SUB MC RETIREMENT (DLINE)	**587**
		C050070	IRURD PLACEHOLDER RI	**151**
		C050299	IRURD EASTWARD LOOK	**43**
		C051205	DYER ST REPLACE INDOOR SUBST D-SUB	**150**
		C051211	DYER ST REPLACE INDOOR SUBST D-LINE	**251**
		C051824	LAFAYETTE SUB TRANSFORMER REPLACEME	**527**
		C053657	SOUTHEAST SUBSTATION (D-SUB)	**250**
		C053658	SOUTHEAST SUBSTATION (D-LINE)	**185**
		C055343	RI UG CABLE PLACEHOLDER	**25**
		C055359	RI UG CABLE REPL PROGRAM - FDR 79F1	**162**
		C055360	RI UG CABLE REPL PROGRAM - FDR 2J8	**423**
		C055362	RI UG CABLE REPL PROGRAM - FDR 1105	**14**
		C055363	RI UG CABLE REPL PROGRAM - FDR 1127	**7**
		C055364	RI UG CABLE REPL PROGRAM - FDR 13F6	**7**
		C055392	RI UG CABLE REPL PROGRAM - SECONDAR	**1,087**
		C055844	W CRANSTON TRANSFORMER 2 REPLACEME	**1,008**
		C057882	IRURD CHATEAU APTS URD REHAB	**85**
		C057921	IRURD-ROBIN HILLS ESTATES	**80**
		C058045	IRURD-TOCKWOTTON FARM_TF ROAD.	**68**
		C058046	IRURD-TOCKWOTTON FARM_RM WAY.	**68**
		C058285	IRURD CASE FARM ESTATES URD	**60**
		C065830	RECLOSER REPLACEMENT PROGRAM RI	**410**
		C068686	FRANKLIN SQ BREAKER REPLACEMENTS	**1,450**
		C070207	IRURD EVERGREEN APTS URD E. PROVID	**43**
		C071307	RI UG CABLE REPL PROG- FDRS 79F1&F2	**617**
		C074307	RI UG 79F1 DUCT CHARLES & ORMS STS	**658**
		CD00996	ACNW VAULT 46 STRUCTURAL REPAIRS, P	**206**
		CD00997	ACNW VAULT 34 RECONSTRUCTION PROV	**253**
		COS0017	OCEAN ST-DIST-ASSET REPLACE BLANKET	**2,300**
		COS0026	OS-DIST-SUBSTATION ASSET REPL BLNK	**150**
		C075445	RI Royal Disconnect Replacement	**216**
	Asset Replacement - I&M (NE)	C026281	I&M - OS D-LINE OH WORK FROM INSP	**1,600**
	Safety	CD01257	DISTRIBUTION SECONDARY NETWORK ARC	**417**
Asset Condition Total				**16,971**
Non-Infrastructure	**General Equipment - Dist**	COS0006	OCEAN ST-DIST-GENL EQUIP BLANKET	**378**
	Telecommunications Capital - Dist	C040644	TELECOM SMALL CAPITAL WORK - RI	**175**
Non-Infrastructure Total				**553**

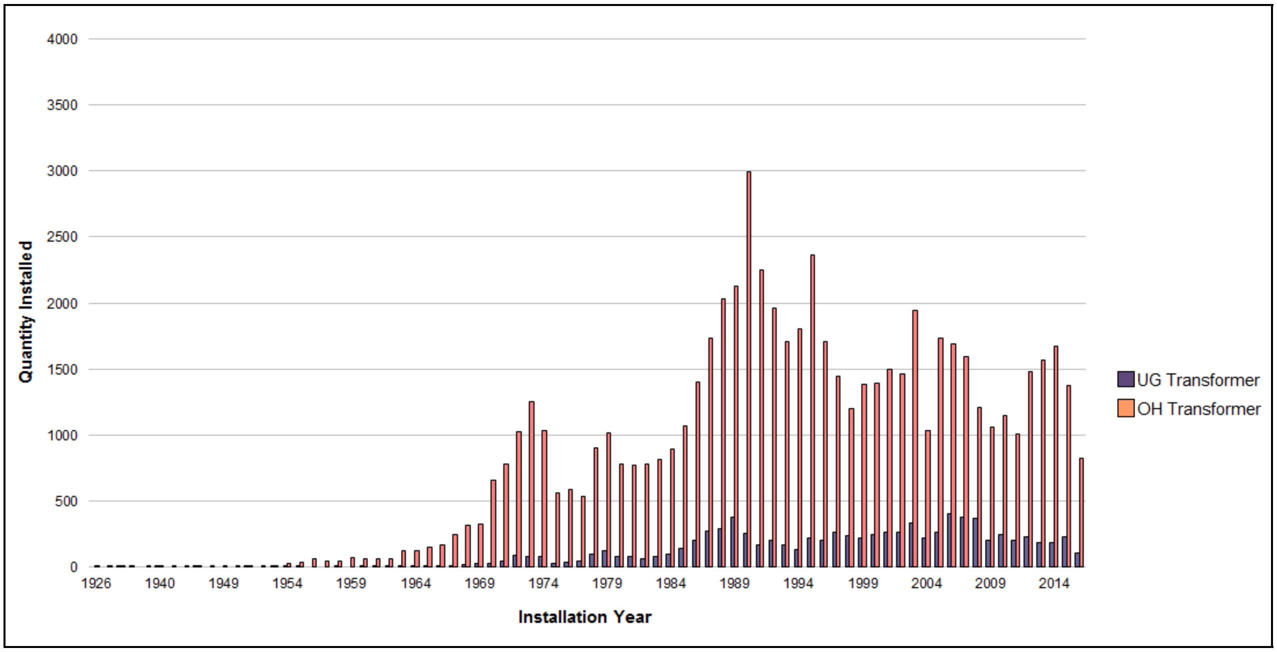
System Capacity & Performance	**Load Relief**	C005505	IE - OS DIST TRANSFORMER UPGRADES	**475**
		C013967	PS&I ACTIVITY - RHODE ISLAND	**242**
		C015158	NEWPORT SUBSTATION (D-SUB)	**1,232**
		C024159	NEWPORT 69KV LINE 63 (D-LINE)	**88**
		C024175	CHASE HILL SUB (D_LINE)	**2,757**
		C024176	CHASE HILL SUB (D-SUB)	**1,099**
		C028628	NEWPORT SUBTRANS & DIST CONVERSION	**1,675**
		C028920	NEW LONDON AVE (D-SUB)	**3,381**
		C028921	NEW LONDON AVE (D-LINE)	**2,288**
		C046352	VOLT VAR DLINE RI PILOT PROJECT	**1,400**
		C051385	CENTRAL FALLS SUB RELIEF	**370**
		C053646	QUONSET SUB EXPANSION (D-SUB)	**2,411**
		C053647	QUONSET SUB EXPANSION (D-LINE)	**378**
		C054054	JEPSON SUBSTATION (D-LINE)	**41**
		C065166	WARREN SUB EXPANSION (D-SUB)	**40**
		C065187	WARREN SUB EXPANSION (D-LINE)	**40**
		CD00652	VERNON RETIREMENT (D-SUB)	**1**
		CD00656	JEPSON SUBSTATION (D-SUB)	**1,264**
		CD00978	NEW HIGHLAND DRIVE SUBSTATION - DLI	**1,329**
		CD01101	KENT COUNTY 2ND TRANSFORMER (D-SUB)	**297**
		CD01104	KENT COUNTY 2ND TRANSFORMER (D-LINE	**15**
		COS0016	OCEAN ST-DIST-LOAD RELIEF BLANKET	**255**
	Reliability	C049679	HARRISON 32 - EMS EXPANSION	**375**
		C049682	WARWICK 52 - EMS EXPANSION	**380**
		C049800	COVENTRY 54 - EMS EXPANSION	**218**
		C050698	DAVISVILLE 84 - EMS EXPANSION	**352**
		C059663	CUTOUT MNTED RECLOSER PROGRAM_RI	**73**
		C059882	FLOOD CONTINGENCY PLAN NECO - D	**200**
		C065470	RECLOSER COMMUNICATION UPGRADE - RI	**236**
		C074433	EMS EXPANSION - BRISTOL 51	**25**
		C074437	EMS EXPANSION - MANTON 69	**30**
		COS0015	OCEAN ST-DIST-RELIABILITY BLANKET	**944**
		COS0025	OS-DIST-SUBSTATION LR/REL BLNKT	**150**
		C075545	EMS EXPANSION - ADMIRAL ST 9	**30**
System Capacity & Performance Total				**24,091**
Grand Total				**100,620**

Attachment 3
Age Profiles

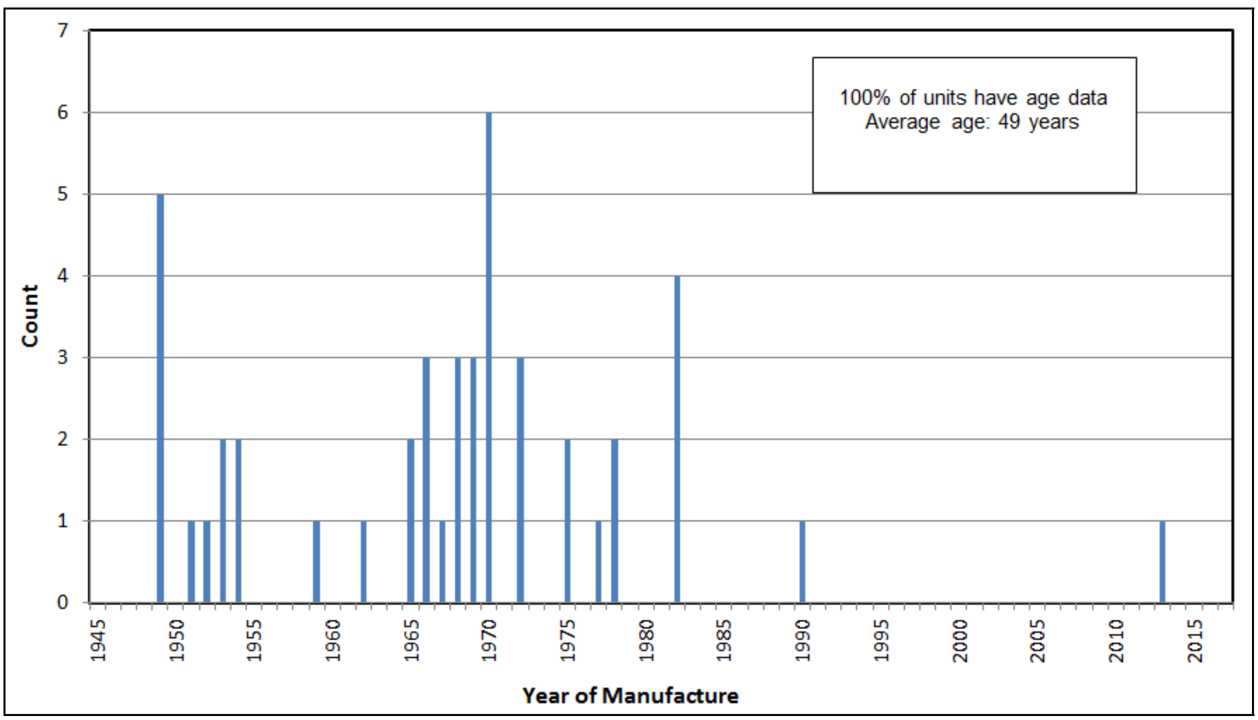
Rhode Island Distribution Pole Age Profile



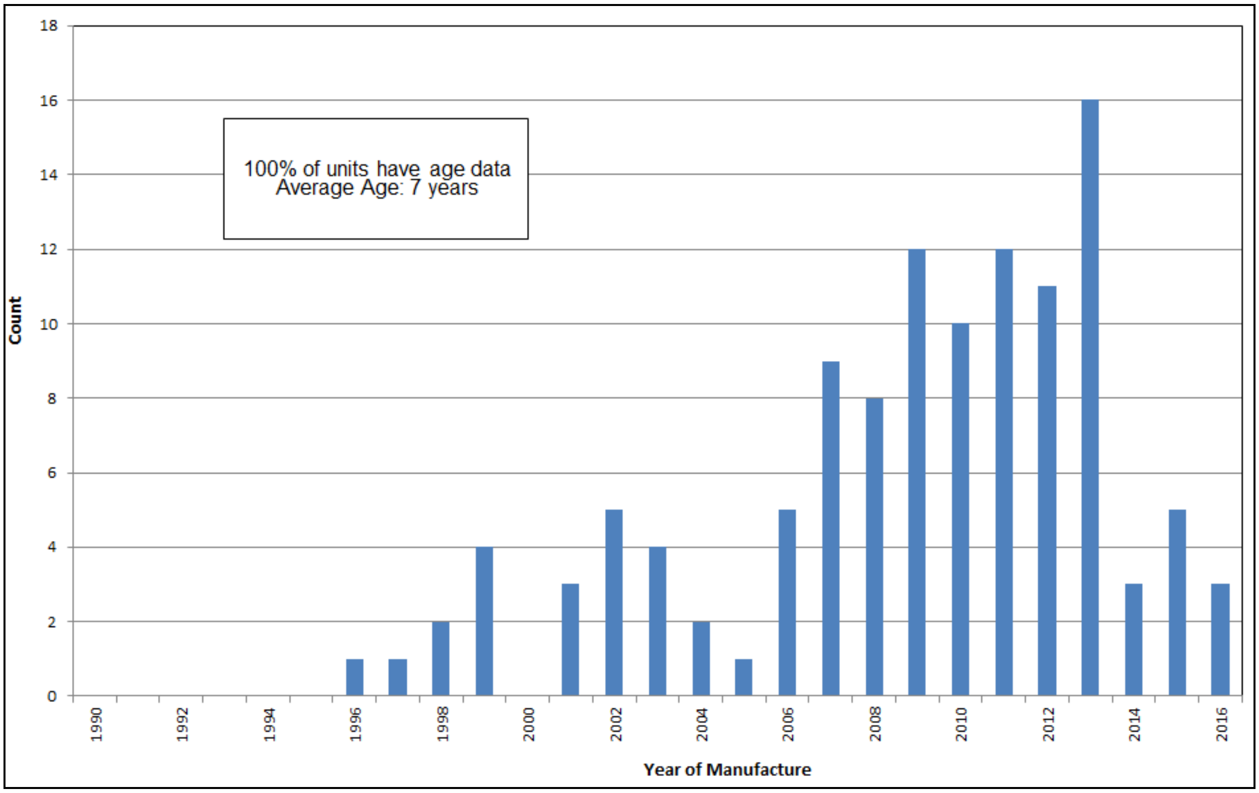
Rhode Island Distribution Transformer Age Profile



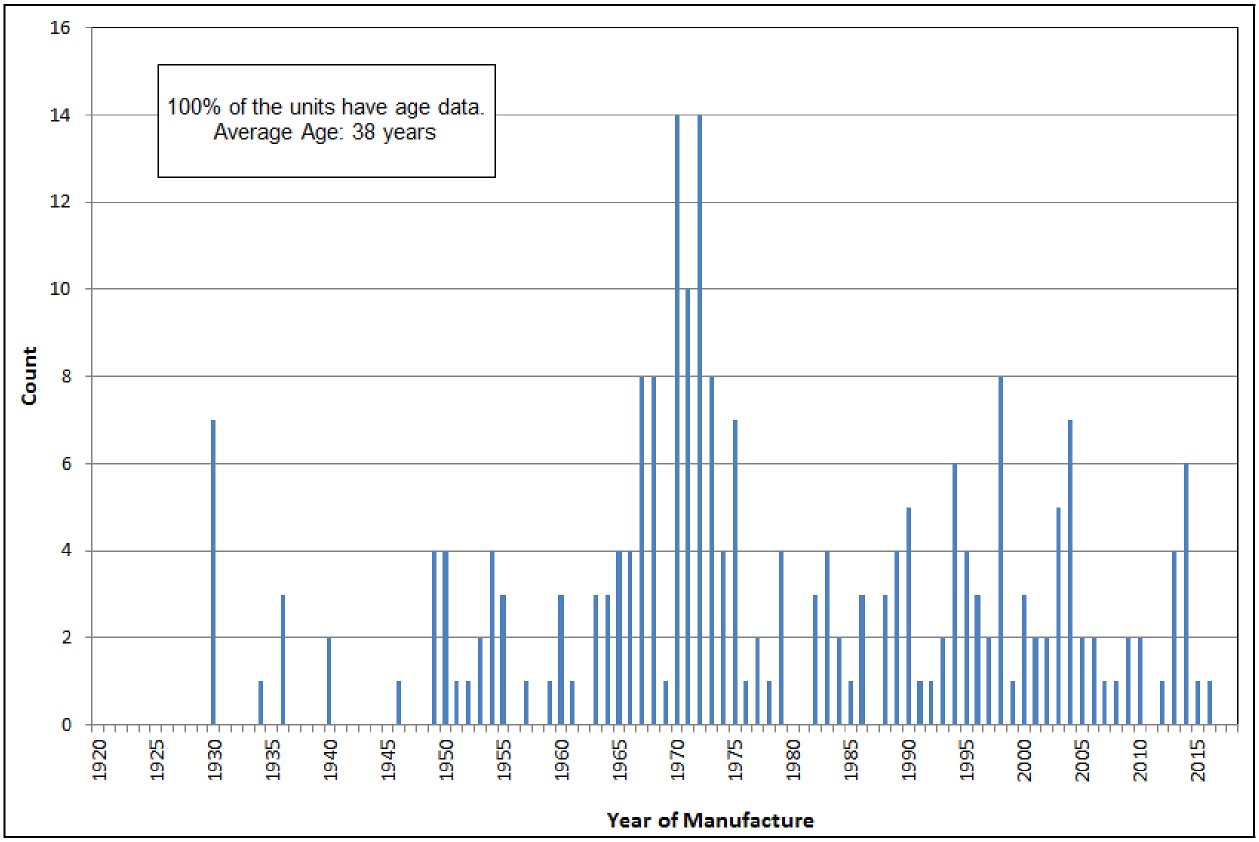
Rhode Island Metalclad Switchgear Age Profile



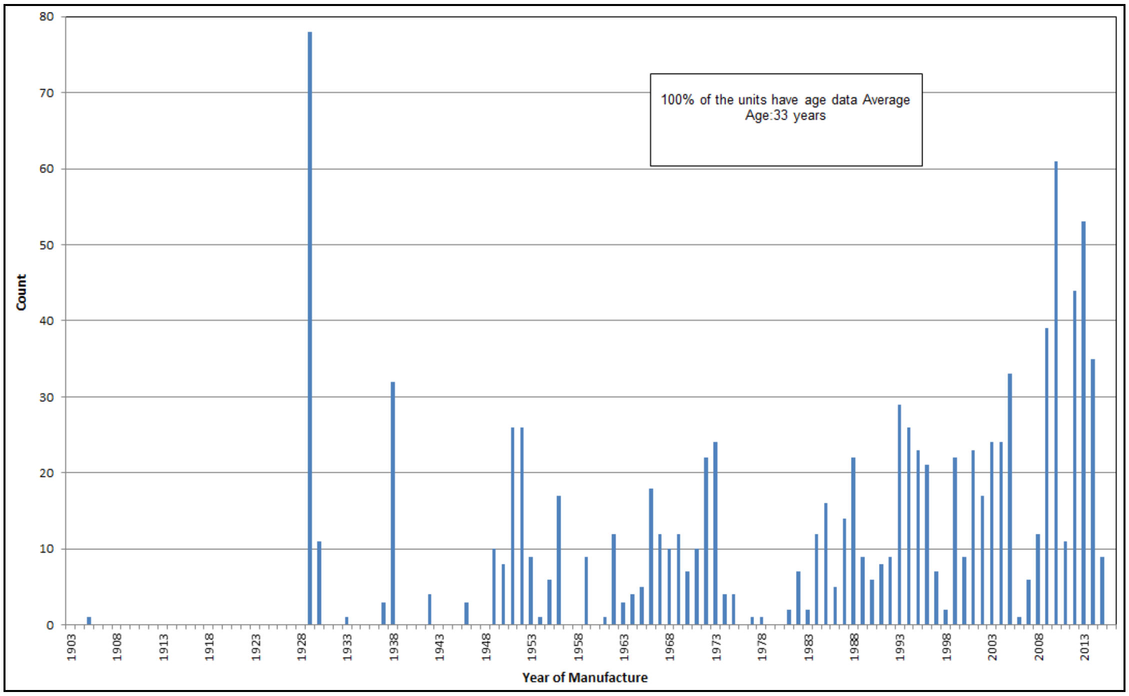
Rhode Island Substation Battery Age Profile



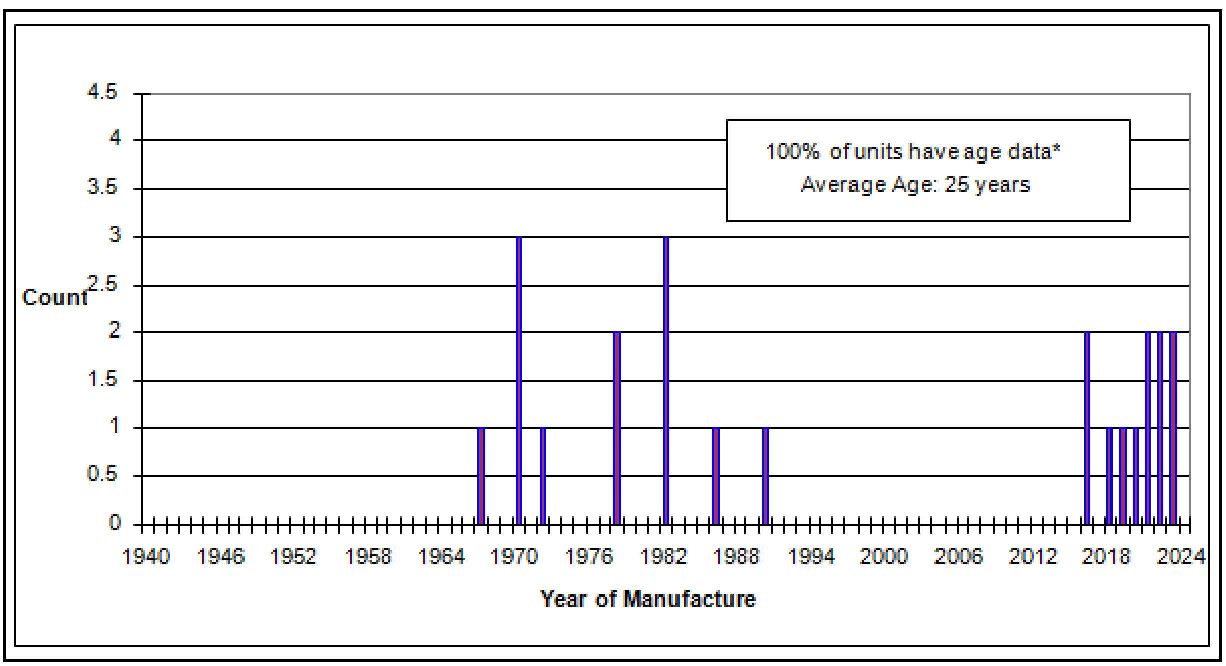
Rhode Island Substation Power Transformer Age Profile



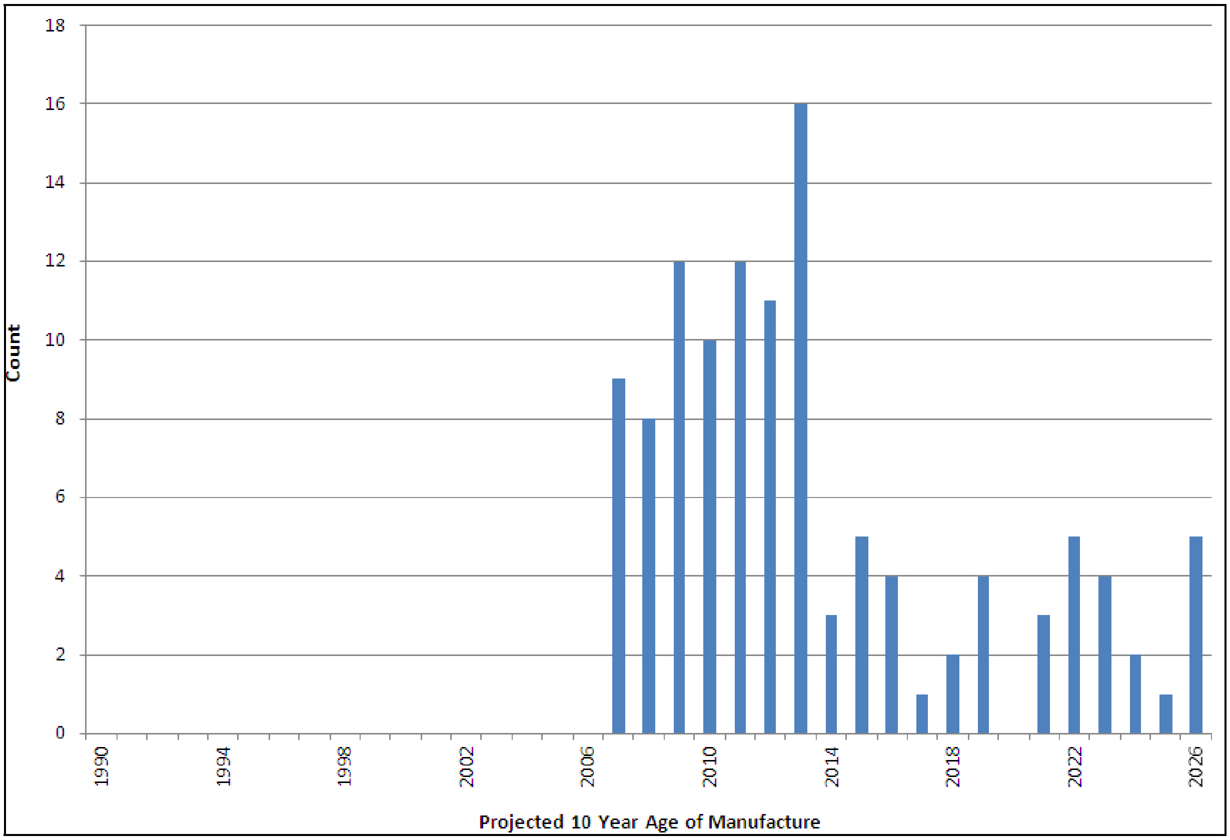
Rhode Island Circuit Breaker and Recloser Age Profile



Rhode Island Metalclad Switchgear Projected 10-Year Age Profile



Rhode Island Substation Battery Projected 10 Year Age Profile



Attachment 4
See also Excel version of this Attachment

Spending Rationale	Budget Class Codes	FY2017 ISR Budget	FY2018 Prelim Capital Budget	FY2019 Prelim Capital Budget	FY2020 Prelim Capital Budget	FY2021 Prelim Capital Budget	FY2022 Prelim Capital Budget
Customer Requests/Public Requirements	3rd Party Attachments	155	204	209	215	221	227
	Distributed Generation	529	1,106	10	10	10	-
	Land and Land Rights	187	223	235	247	259	271
	Meters - Dist	2,170	1,786	1,859	1,946	2,037	2,127
	New Business - Commercial	5,577	8,183	6,638	6,837	7,083	7,393
	New Business - Residential	3,728	5,616	5,872	6,157	6,456	6,760
	Outdoor Lighting - Capital	541	153	157	161	166	170
	Public Requirements	3,814	2,520	1,992	2,239	2,340	2,444
	Transformers & Related Equipment	2,750	2,060	2,132	2,228	2,328	2,421
Customer Requests/Public Requirements Total		19,451	21,853	19,104	20,040	20,899	21,814
Damage/Failure	Damage/Failure	9,967	9,828	11,254	11,664	12,005	12,343
	Major Storms - Dist	1,500	1,550	1,600	1,650	1,700	1,750
Damage/Failure Total		11,467	11,379	12,854	13,314	13,705	14,093
Asset Condition - South St	Asset Replacement	15,360	25,773	4,085	2,040	-	-
Asset Condition - South St Total		15,360	25,773	4,085	2,040	-	-
Asset Condition	Asset Replacement	14,813	14,955	28,402	30,778	32,359	30,875
	Asset Replacement - I&M (NE)	2,510	1,600	2,700	7,125	7,400	7,675
	Safety	598	417	-	-	-	-
Asset Condition Total		17,920	16,971	31,102	37,903	39,759	38,550
Non-Infrastructure	Corporate/Admin/General	-	-	-	-	-	-
	General Equipment - Dist	100	378	385	394	405	412
	Telecommunications Capital - Dist	175	175	175	175	200	250
Non-Infrastructure Total		275	553	560	569	605	662
System Capacity & Performance	Load Relief	15,726	21,079	33,920	22,983	18,879	16,467
	Reliability	3,243	3,012	4,176	5,051	7,053	8,914
System Capacity & Performance Total		18,968	24,091	38,096	28,034	25,932	25,381
Grand Total		83,441	100,620	105,800	101,900	100,900	100,500

RHODE ISLAND
FY2018-2022 Distribution Electric Capital Plan (000's)
December 15, 2016

Switched formula from prior version so that so that decrease shows as a negative value.

ISR Spending Rationale	ISR Category	Current Approval Type	Total Current Estimate (Distribution)	Initial Estimate at time of First Sanction	Estimated Construction Start (earliest portion)	Estimated Construction End (last portion)	Estimated Financial Closure (last portion)	Pre-FY17 Actual Capital Spend	FY2017 Actual Capital Spend (6-MTD)	Total-to-Date Actual Capital spend	Capital Fcast FY17 (7+5 Prelim)	FINAL FY20017 Capital Budget	PRELIMINARY FY2018 Capital Budget	CHANGE FROM PREVIOUS DRAFT FY2018 Inc/(Dec)	December 2016 Adjustments Inc/(Dec)	UPDATED FY2018 Capital Budget	UPDATED FY2019 Capital Budget	UPDATED FY2020 Capital Budget	UPDATED FY2021 Capital Budget	UPDATED FY2022 Capital Budget
System Capacity & Performance	Aquidneck Island (includes former Jepson &Newport projects)	Engineering/Design/Materials/Initial Small Work Only	55,827	53,585	Nov-2015	Sep-2022	Jan-2023	4,531	1,699	6,230	4,302	2,882	4,302	0	0	4,302	20,855	16,616	6,138	-
	Chase Hill (Hopkinton) & Related	Full Implementation +/- 10%	19,085	2,850	Aug-2015	Feb-2018	Apr-2018	7,925	4,467	12,392	3,856	3,690	3,361	495	0	3,856	4,158	-	-	-
	Kent County	Full Implementation +/- 10%	3,610	3,630	Mar-2016	Jul-2017	Jan-2018	878	2,232	3,109	312	1,940	210	102	0	312	-	-	-	-
	New London Ave Substation #150	Engineering/Design/Materials/Initial Small Work Only	15,391	2,900	Oct-2016	Sep-2019	Feb-2020	2,825	324	3,149	5,670	4,090	5,623	47	0	5,670	5,249	229	-	-
	Quonset Sub	Engineering/Design/Materials/Initial Small Work Only	6,104	4,520	Mar-2015	Jan-2018	May-2018	2,066	1,195	3,261	2,789	1,081	2,622	167	0	2,789	48	-	-	-
	Highland Drive	Full Implementation +/- 10%	16,723	6,124	Sep-2013	Jul-2017	Feb-2018	14,393	(1)	14,393	1,329	-	1,329	0	0	1,329	-	-	-	-
	Kilvert St - DSub	Full Implementation +/- 10%	3,764	2,260	Nov-2015	Oct-2016	Feb-2017	2,513	1,408	3,922	-	146	-	0	0	-	-	-	-	-
	Kilvert St - DLine	Full Implementation +/- 10%	3,831	2,820	Oct-2013	Nov-2016	Apr-2017	3,139	320	3,459	-	-	-	0	0	-	-	-	-	-
	Clarke St	Full Implementation +/- 10% Resanction	2,894	1,340	Nov-2014	Dec-2015	Sep-2016	2,566	31	2,597	-	-	-	0	0	-	-	-	-	-
	Warren Substation	Not Yet Sanctioned			Mar-2020	Jun-2022	Dec-2022		-	-	80	-	80	0	0	80	368	1,435	2,153	3,535
	East Bay Study	Not Yet Sanctioned			Mar-2020	Jun-2022	Nov-2022		-	-	130	-	130	0	(130)	(0)	801	2,694	4,041	5,918
Subtotal - Major System Capactiy & Performance Projects									**11,675**		**18,468**	**13,829**	**17,658**	**811**	**(130)**	**18,339**	**31,477**	**20,974**	**12,332**	**9,453**
	Volt/Var	Full Implementation +/- 10%	5,435	3,523	Aug-2014	Mar-2017	Jul-2017	4,284	1,577	5,861	1,400	852	2,000	(600)	0	1,400	1,275	800	1,595	-
	EMS								1,151		1,410	1,295	1,047	363	0	1,410	1,000	1,550	1,737	1,712
	OH Line Tranformer Replacement Program								732		475	475	475	0	0	475	625	650	675	700
	Storm Hardening								7		-	-	-	0	0	-	-	1,096	-	-
	Other Flood								343		200	350	240	148	(188)	200	2,000	1,200	900	-
	Other Load Relief & Reliability								1,418		920	890	478	443	0	921	339	348	-	-
	Blanket Projects - SCP								1,455		1,348	1,278	1,348	0	0	1,348	1,380	1,415	1,450	1,485
	Reserves - SCP								-		-	-	-	0	0	-	-	-	7,242	12,030
System Capacity & Performance Total									**18,359**		**24,221**	**18,968**	**23,245**	**1,165**	**(318)**	**24,093**	**38,096**	**28,034**	**25,932**	**25,381**
Asset Condition	South St Station Rebuild	Engineering/Design/Materials/Initial Small Work Only	58,810	18,240	Mar-2016	Jul-2018	Sep-2018	6,354	16,986	23,340	25,773	15,360	25,783	(10)	0	25,773	4,085	2,040	-	-
	New Southeast Sub	Engineering/Design/Materials/Initial Small Work Only	18,600	18,600	May-2018	May-2021	Mar-2022	74	19	93	435	25	400	35	0	435	3,652	5,887	3,757	95
	Memorial Blvd_Cable Relocation	Full Implementation +/- 10% Resanction	1,615	1,430	Oct-2015	Apr-2016	Oct-2016	1,123	331	1,454	-	532	-	0	0	-	-	-	-	-
	Flood - Westerly	Engineering/Design/Materials/Initial Small Work Only	8,000	9,160	Mar-2019	May-2021	Aug-2021	8	-	8	-	-	-	0	0	-	633	3,054	2,590	852
	Flood - Hope Substation	Powerplant Approval On-line	410	(a)	Apr-2017	Jun-2017	Sep-2017	214	65	278	738	221	738	0	(738)	-	738	-	-	-
	Flood - Warwick Mall Sub	Powerplant Approval On-line	850	(a)	Apr-2017	Aug-2017	Dec-2017	338	3	341	580	-	580	0	(580)	-	580	-	-	-
	Dyer Street - Indoor Sub	Not Yet Sanctioned			Oct-2017	Dec-2020	Dec-2020		26		402	25	402	0	0	402	621	2,070	2,437	-
Subtotal - Asset Replacement Projects									**17,431**		**27,927**	**16,163**	**27,902**	**25**	**(1,317)**	**26,610**	**10,309**	**13,051**	**8,784**	**947**
	Asset Replacement - I&M (NE)								3,321		1,600	2,510	1,605	(5)	0	1,600	2,700	7,125	7,400	7,675
	Battery Replacement								253		199	411	280	(81)	0	199	200	200	210	220
	Metalclad Replacement								2,259		587	2,285	2,057	(1,471)	0	586	5,967	3,861	998	-
	Spare Substation Transformers								-		-	538	-	0	0	-	-	-	-	-
	Substation Transformers								502		1,535	418	1,538	(3)	0	1,535	3,001	449	499	-
	T-Body								92		-	-	-	0	0	-	-	-	-	-
	Relay Replacements								600		431	746	464	(32)	0	431	216	627	661	582
	Substation Breakers & Reclosers								1,536		1,600	1,175	1,600	0	0	1,600	1,205	1,420	1,500	1,600
	Network Arc Flash								383		417	598	417	0	0	417	-	-	-	-
	Recloser Replacement								1		410	-	600	(190)	0	410	410	384	359	258
	RAPR								61		230	182	156	75	0	230	195	200	-	-
	UG Cable								2,760		3,000	2,500	3,000	0	0	3,000	3,500	3,900	4,000	4,250
	URD								2,500		2,750	2,500	2,750	0	0	2,750	3,000	3,500	3,500	3,750
	Other Asset Replacement								854		924	449	906	565	(546)	925	1,218	1,158	185	-
	Blanket Projects - AC								2,358		2,450	2,805	2,703	(253)	0	2,450	2,767	2,842	2,919	2,994
	Reserves - AC								-		-	-	-	0	0	-	500	1,225	8,745	16,275
Asset Condition Total									**34,909**		**44,059**	**33,280**	**45,977**	**(1,371)**	**(1,863)**	**42,742**	**35,187**	**39,943**	**39,759**	**38,550**
Non-Infrastructure	General Equipment								227		378	100	378	0	0	378	385	394	405	412
	Corporate/Admin/General								(24)		-	-	-	0	0	-	-	-	-	-
	Telecommunications								98		175	175	175	0	0	175	175	175	200	250
Non-Infrastructure Total									**301**		**553**	**275**	**553**	**0**	**-**	**553**	**560**	**569**	**605**	**662**
Customer Requests/Public Requirements	Block Island	Full Implementation +/- 10%	2,042		May-2016	Sep-2016	Jun-2017	308	2,232	2,540	21	519	1	20	0	21	-	-	-	-
	3rd Party Attachments								228		204	155	204	0	0	204	209	215	221	227
	Land and Land Rights - Dist								188		223	187	233	(10)	0	223	235	247	259	271
	Meters - Dist								1,493		1,786	2,170	1,786	0	0	1,786	1,859	1,946	2,037	2,127
	New Business - Commercial								6,991		8,183	5,577	7,920	263	0	8,183	6,638	6,837	7,083	7,393
	New Business - Residential								4,429		5,616	3,728	5,616	0	0	5,616	5,872	6,157	6,456	6,760
	Outdoor Lighting - Capital								348		153	541	153	0	0	153	157	161	166	170
	Public Requirements								644		2,520	3,814	2,600	(79)	0	2,520	1,992	2,239	2,340	2,444
	Transformers & Related Equipment								2,250		2,060	2,750	2,060	0	0	2,060	2,132	2,228	2,328	2,421
	Distributed Generation								951		1,085	10	1,073	13	0	1,086	10	10	10	-
Customer Requests/Public Requirements Total									**19,753**		**21,853**	**19,451**	**21,646**	**206**	**-**	**21,853**	**19,104**	**20,040**	**20,899**	**21,814**
Damage/Failure	Damage/Failure								12,309		9,692	8,867	9,692	0	(400)	9,292	9,938	10,222	10,512	10,796
	Major Storms - Dist								1,649		1,550	1,500	1,550	0	0	1,550	1,600	1,650	1,700	1,750
	Reserves - DF								412		1,372	1,100	1,837	0	(1,300)	537	1,314	1,442	1,493	1,547
Damage/Failure Total									**14,370**		**12,614**	**11,467**	**13,079**	**0**	**(1,700)**	**11,379**	**12,853**	**13,314**	**13,705**	**14,093**
Grand Total									**87,692**		**103,300**	**83,441**	**104,500**	**0**	**(3,881)**	**100,620**	**105,800**	**101,900**	**100,900**	**100,500**

Exhibit 1 – JHP & RM
Section 3
Vegetation Mgmt.

Section 3

Vegetation Management Program
FY 2018 Electric ISR Plan Annual Filing

Vegetation Management Program
FY 2018 Proposal

Background

The Company's Vegetation Management (VM) Program is an essential component of the Company's plan to maintain the safety and 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 have a significant impact on reliability. 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 causing an interruption in service.

As shown in Section 2, Chart 5, trees were responsible for approximately 109,000 customer interruptions in FY 2016, which represented 21.6% of the total interruptions. Trees were the leading cause of customer interruptions during FY 2016.

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 and consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a utility best 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. A review of the cycle pruning program from FY 2007 to FY 2016 shows, on average, a 32% improvement in customer interruptions (CI) per circuit in the first year after pruning.

The Company continues to recommend a four-year 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 5,091 miles. To maintain a four-year pruning cycle, 1,273 miles need to be pruned each year. After detailed field analysis of the current circuits due at this time, the FY 2018 plan will require the pruning of 1,304 miles of distribution. The estimated cost for distribution cycle pruning in FY 2018 is $5.5 million.

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 50% of tree-related customer interruptions.

To address this issue, in 2008, the Company implemented the EHTM program 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. Therefore, 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,[9] a study of the Company's EHTM program was performed. From FY 2008 to FY 2016, the results show an average improvement of tree-related Customers

[9] Electric ISR Plan Vegetation Management Cost Benefit Report, filed September 5, 2012.

Interruptions (CI) by circuit of 70% for the first year following project completion, which demonstrates a significant improvement in customer service reliability on targeted circuits.

Due to the spread of the Gypsy Moth throughout Rhode Island, the Company anticipates an increase in tree mortality during FY 2018. In order to be proactive with identifying and removing hazard trees, the Company is proposing an increase of $300,000 to the VM budget, bringing the total to $1.3 million in FY 2018.

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 total cost for the required FY 2017 sub-transmission VM work is $650,000. 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. The Company has 34.94 miles of sideline work currently scheduled and will evaluate additional circuits in the coming months. There are also 220.14 acres of floor work scheduled this fiscal year.

Chart 1
Sub-Transmission Vegetation Management Miles/Acres
(Includes both Distribution and Transmission Assets)

Sideline Pruning and Hazard Tree Removal (Miles)					
FY 2013	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**
28.51	59.52	34.09	82.16	99.00	34.94
Floor Treatment (Acres)					
FY 2013	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**
100.68	222.05	214.97	89.28	119.66	220.14

Police Detail/Flagman – To safely perform the Cycle Pruning and EHTM, the Company is required to hire police details and flagman. For FY 2018, police detail costs are estimated to be \$775,000. 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. Police detail and flagging costs have remained relatively stable for the last few years. 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, 9.3% in FY 2013, 9.0% in FY 2014, 8.4% in FY 2015, 8.4% in FY 2016, and 8.2% in FY 2017. Police and flagging costs will remain at 8.2% for FY 2018.

Importantly, 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 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 a 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 VM program police protection processes are now also coordinated with the Company's electric and gas construction departments. The VM program police protection processes are also coordinated with the Company's community relations department so that the Company can discuss police detail requirements with communities and municipalities in advance of performing the work.

Additionally, since 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 with this effort, the Company has also revised its contracting strategies by placing only one contractor in each municipality during a given year. This allows each contractor to develop a relationship with each town, and to better address communications with public safety officials.

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 with Cycle Pruning and EHTM, the Company has very little discretion over the timing of 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 customer calls, weather, and system requirements. Each core activity separately consumes a small and variable proportion of the overall budget. Overall, for FY 2018, the Company expects to spend $1.225 million for the core activities.

Fiscal Year 2018 Vegetation Management Budget

As detailed in Chart 2 below, the FY 2018 Electric ISR Plan proposes to spend approximately $9.4 million for VM in FY 2018. This represents a 7.8% increase from the $8.7 million which was approved for FY 2017. There are several reasons for this increased spend in FY 2018. First, the Company is scheduled to prune 45 additional miles in FY 2018 compared to FY 2017. Second, the bids for FY 2018 are showing an increased cost per mile, which is due in part to an increase in the number of rural circuits being scheduled for work during the next fiscal year. These rural circuits have higher tree densities and are therefore more expensive to prune. Finally, in order to address the Gypsy Moth problem discussed above, the Company is requesting additional hazard tree funding.

Chart 2
Vegetation Management Spending
($000)

	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018 Proposed
Cycle Prune (Base)	$4,764	$5,110	$4,475	$5,414	$5,050	$5,500
Hazard Tree – EHTM	$1,198	$700	1,000	$1,000	$950	$1,250
Sub-T (off & on road)	$243	$639	$316	$220	$780	$650
Police/Flagman Detail	$766	$769	$650	$750	$714	$775
Core Crew (All Other Activities) (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$1,276	$1,312	$1,285	$1,500	$1,225	$1,225
Total	**$8,247**	**$8,530**	**$7,726**	**$8,884**	**$8,719**	**$9,400**

Exhibit 1 – JHP & RM
Section 4
I&M Plan

Section 4

Inspection and Maintenance Program
FY 2018 Electric ISR Plan Annual Filing

Inspection and Maintenance Program
FY 2018 Proposal

Background

Consistent with the Company's condition-based asset management approach, the Company has implemented an Inspection and Maintenance (I&M) program to achieve a five-year inspection cycle of the overhead and underground assets. This program is intended to address deteriorated assets to ensure that 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. In addition to asset replacement, testing for elevated voltage should minimize potential safety issues related to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. Periodic inspection of equipment 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 also 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 119,000 customer interruptions in FY 2016, accounting for approximately 24% of all customer interruptions in FY 2016. Although the I&M program is not a reliability-based program, the Company believes that the I&M program is an essential component to fulfilling its obligation to provide safe, reliable, and cost effective electric delivery service to customers in Rhode Island. The Company has agreed with the Division to assess the costs and benefits of the I&M program on an ongoing basis.

In FY 2016, the Company completed the final year of the five-year inspection cycle as scheduled, and commenced the second five-year inspection cycle at the beginning of FY 2017. The Plan for FY 2018 signifies the continuation of the second five-year inspection cycle for all distribution feeders.

To date, the Company has designed 42% of the feeders inspected in the first cycle, and has completed repair work on 28%. In prior year budget developments, The Company has attempted to achieve either a five or ten-year construction cycle. However, due to the necessary funding for large projects, such as the South Street substation rebuild, and to achieve an overall FY 2018 capital budget of $100.6 million, the I&M budget has been further reduced. The proposed spending for FY 2018 represents a 36% decrease in capital spending and a 24% decrease in O&M spending over the approved FY 2017 budgets. The Company understands that extending the inspection and construction schedule for repairs presents an asset risk; however, the Company will continue to identify and repair damaged and/or failing assets (i.e. Level 1) within seven days of discovery.

In addition to continuing overhead distribution system inspections, the FY 2018 I&M program will continue to increase inspections on its overhead sub-transmission system. The goal for sub-transmission assets is to be on a five-year inspection cycle that bundles repair work by feeder, similar to the distribution feeder repair work currently being done. To date, the Company has inspected seven sub-transmission feeders. The Company will also continue inspections of its manhole-based underground assets through working inspections in FY 2018.

The Company will continue elevated voltage testing within the Designated Contact Voltage Risk Areas (DCVRA's) designated in Docket No. 4237-A in FY 2018. The Company has tested 100% of the areas, annually, since the inception of the program. However, the Company is recommending a reduction in testing to 20% of the areas in FY 2018. This has resulted in a reduction in O&M costs in FY 2018 relative to prior years.

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

- The first five-year cycle for all distribution overhead I&M inspections was completed on schedule at the end of FY 2016. The proposed Plan is designed to continue year-two of the second five-year inspection cycle and the continuation of repair work for items identified during the initial inspection cycle.
- Sub-transmission overhead I&M inspections will continue in FY 2018. This work will include 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 a five-year cycle.
- Street Light Manual Contact Voltage testing will continue on a three-year cycle.
- Mobile Contact Voltage Testing in FY 2018 will test 20% of the DCVRA's.

- Continue developing the development of the Long Term Plan.
- Continue the Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR) program and required FY 2018 operation and maintenance expenses for the existing pilot program feeders.

Fiscal Year 2018 Inspection and Maintenance Budget

As shown in Chart 1 below, the Company proposes a total I&M program budget of approximately $2.8 million for FY 2018. The associated capital costs, which are included in the capital budgets provided in Section 2 of this Electric ISR Plan, and the Opex related to Capex costs, which are Opex costs necessary to complete the capital construction, are $1.6 million and approximately $0.4 million, respectively. The Inspections and Repairs related costs are $0.6 million, which include a component for completing 20 percent of the Contact Voltage Program as ordered in Docket No. 4237. Costs of $60,000 to continue the development of the Long Term plan and operate and maintain the VVO/CVR program are also included. The total O&M budget for the I&M program is approximately $1.1 million in FY 2018, which is approximately 18% lower than the FY 2017 budget.

Chart 1
FY 2018 I&M Program Costs

	Total
Capital Costs*	**$1,605,000**
Opex Related to Capex	*$361,800*
Inspections and Repair Related Costs	*$623,000*
Long Range Plan Study	*$25,000*
VVO/CVR Program	*$60,000*
Total Operation and Maintenance Expenses	**$1,069,800**
Removal Costs	**$161,000**
Total Program Costs	**$2,835,800**

* Capital Costs are included in the $104.5 million capital budget provided in Section 2 of this Electric ISR Plan.

Exhibit 1 – JHP & RM
Section 5
Revenue Req.

Section 5

Revenue Requirement
FY 2018 Electric ISR Plan Annual Filing

Revenue Requirement
FY 2018 Proposal

Introduction

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 (FY) ended March 31, 2018.

As shown on Attachment 1, Page 1, Column (b), the Company's FY 2018 Electric ISR Plan cumulative revenue requirement is $26,451,131 and consists of 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, (2) the Company's capital investment in electric utility infrastructure, and (3) the FY 2018 Property Tax Recovery Adjustment. Lines 1 and 2 of Column (b) reflect the forecasted FY 2018 revenue requirement related to O&M expenses for VM and I&M of $9,400,000 and $1,069,800, respectively. As described in Section 4 of this document, 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.[10] Contact Voltage Program costs are included in the $1,069,800 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.

[10] R.I. Gen. Laws §39-2-25(6)(c).

The FY 2018 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $16,145,080 is shown on Line 18. This amount includes (1) the $2,267,653 revenue requirement on FY 2018 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 2, (2) the FY 2018 revenue requirements on incremental ISR capital investment for FY 2012 through FY 2017 totaling $11,656,529, (3) the FY 2018 Property Tax Recovery Adjustment of $3,906,950 from Attachment 1, Page 19, (4) a true-up for vintage years FY 2012 through FY 2016 related to the Transmission-related tax Net Operating Loss (NOL) adjustment of ($1,125,115) discussed in more detail below, (5) and a true-up for vintage years FY 2013 through FY 2016 related to the work order write off adjustment in the amount of ($560,347) related to capital investment and ($589) related to Property Tax, also discussed in more detail below. Importantly, the incremental capital investment for the FY 2018 Electric ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4323 for FY 2012, FY 2013 and FY 2014. Incremental electric capital investment for this purpose 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 2018 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $26,451,131, as reflected in Column (b) on Line 19, and is equal to the sum of Lines 4 and 18.

For illustration purposes only, Column (c) of Page 1 provides the FY 2019 revenue requirement for the respective vintage year capital investments. 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.

Also, the Company has adjusted prior vintage year revenue requirement calculations to address (1) a correction to prior year tax NOL amounts reflected in the calculation of deferred taxes and ISR incremental rate base, and (2) an adjustment that was recorded in the financial statements in the Company's recently released FY 2016 annual report, in which it wrote off certain work orders that had been charged to plant in FY 2013 through FY 2016 that should have been charged to expense. The correction to prior year NOLs is necessary to exclude the portion of tax NOLs that are included in Federal Energy Regulatory Commission (FERC) jurisdiction transmission rate base amounts that were incorrectly included in previous vintage year NOL amounts included in ISR rate base.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2018 Electric ISR Plan revenue requirement includes $9,400,000 of VM and $1,069,800 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 2018 O&M expenses of $10,306,051, as shown on Line 4 of the attachment.

Electric Infrastructure Investment

<u>Incremental Capital Investment</u>

Page 2 of Attachment 1 to this Section calculates the revenue requirement of incremental capital investment associated with the Company's FY 2018 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 estimated cost of removal were obtained from Chart 11 of Section 2 in this Plan. The FY 2018 revenue requirement also includes the incremental capital investment associated with the Company's FY 2012 through FY 2017 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4323 for FY 2012 through FY 2014. Page 16 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 2018 electric ISR revenue requirement. The calculations on Page 16 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: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. 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 PUC 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 previously mentioned 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 2018 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 because 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 three-year average percentage of retirements to additions during FY 2014 through FY 2016, and have been deducted from the total depreciable capital amount as shown on Lines 4 through 6. Incremental book depreciation expense on Line 16 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,[11] 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.

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

The rate base calculation incorporates net plant from Line 11 and accumulated depreciation and accumulated deferred tax reserves, as shown on Lines 17 and 23, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 18 through 23, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate, net of any tax NOL and proration adjustment. The calculation of tax depreciation is described below. The average rate base is shown on Line 28. This amount is multiplied by the pre-tax rate of return approved by the PUC in Docket No. 4323, as shown on Line 29, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 30. As reflected on Line 31, incremental depreciation expense is added to this amount. 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 32, which is carried forward to Page 1, Line 11, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2017 through FY 2012 incremental ISR Plan capital investments are shown on Attachment 1 at Pages 4, 6, 8, 10, 12 and 14. The work order write off adjustment is reflected in the revenue requirement calculations, on the respective pages noted above, on Lines 1a, 2a and 10a, for vintage years FY 2016 through FY 2013 capital investment. The cumulative revenue requirement reduction of \$560,347 as a result of the work order write off adjustment for FY 2013 through FY 2016 on capital investment, is reflected on Attachment 1, Page 1, Line 16. Attachment 1, page 24 includes a summary of the amount of the work order write off adjustments by vintage year and the year by year revenue requirement impact of those adjustments. The reduction of \$589 as a result of the work order write off adjustment on the property tax recovery mechanism is reflected on Attachment 1, Page 18. The cumulative revenue requirement effect of the work order write off adjustment for FY 2013 through FY 2016 on property tax is reflected on Attachment 1, Page 1, Line 17. These capital investment revenue requirement and property tax amounts are added to the total O&M expenses on Attachment 1, Page 1, Line 4, to derive the total FY 2018 Electric ISR Plan revenue requirement of $26,597,381, as shown on Page 1, Line 19. This represents a $1,106,443 decrease from the FY 2017 Electric ISR Plan revenue requirement, as shown on Line 20.

Tax Depreciation Calculation

The tax depreciation calculation for FY 2018 is provided on Attachment 1, Page 3. The tax depreciation amount assumes that a portion of the capital investment, as shown on Line 1 of Page 3, 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.[12] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Page 3, Lines 4 through 12 for FY 2018. In 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

[12] In 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 which is 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.

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 and then extended further through December 31, 2017 through the Protecting Americans from Tax Hikes (PATH) Act. The PATH Act also extended bonus depreciation through 2019 with the rate phasing down to 40 percent in 2018 and 30 percent in 2019. In accordance with the PATH Act, capital investments made from January 2012 through December 2017 are eligible for 50 bonus depreciation and capital investments made from January 2018 through March 2018 are eligible for 40 percent bonus depreciation, as shown on Page 3, Lines 9 and 10.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System (MACRS) tax depreciation rate. Also, the IRS clarified its tangible property regulations, and, consequently, the Company submitted a §481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. This election was submitted to the PUC, as required under IRS rules, on December 17, 2015. The late partial disposition election was made to protect the Company's deduction of cost of removal (COR). Otherwise, the Company would have been required to make a §481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100% deductible. The vintage FY 2015 through FY 2018 tax depreciation calculations in this filing now include an additional tax deduction related to this change in accounting issue. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, MACRS depreciation, the tax loss on retirements, and cost of removal.

These annual total tax depreciation amounts are carried forward to Page 2 of Attachment 1, and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for FY 2017 through FY 2012 on Attachment 1, Pages 5, 7, 9, 11, 13 and 15.

Federal Net Operating Loss

Tax net operating losses (NOLs) are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. This does not mean that the Company is suffering losses in its financial statements; instead, the Company's tax NOLs are the result of the significant tax deductions that have been generated in recent years by the bonus depreciation and capital repairs tax deductions. In addition to first-year bonus tax depreciation, the US tax code allows the Company to classify certain costs as repairs expense, which the Company takes as an immediate deduction on its income tax return; however, these costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions have exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2015, with the exception of FY 2011. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future. If the company is able to utilize any of its currently accumulated NOLs in future tax years, the benefit will flow to customers in the particular fiscal year the benefit is reflected in the Company's federal income tax return.

NOLs are an offset to the Company's accumulated deferred income taxes. Accumulated deferred income taxes, which equals the difference between book depreciation and tax depreciation on ISR capital investment times the effective rate, are included as a credit or reduction in the calculation of rate base. However, since the Company was not able to fully utilize all of its tax deductions, tax NOLs were recorded which offset a portion of the rate base reduction for accumulated deferred income taxes.

As indicated above, the Company has generated NOLs on its fiscal year tax returns from FY 2009 to FY 2015, with the exception of FY 2011. In addition, the Company will be filing its FY 2016 federal income tax return in December 2016, and will again reflect tax deductions that will exceed taxable income which will generate new NOLs for FY 2016. The Company is also currently estimating that deductions will exceed taxable income in FY 2017. The Company is currently estimating that in FY 2018 there will be taxable income; therefore, the NOL amount is zero. In past Electric ISR Plan filings, the Company had not been reflecting NOLs in those filings for any fiscal years for which federal income tax returns had not been filed. The filing of the Company's federal income tax returns in the month of December following the completion of the fiscal year has lagged the filing of each fiscal year's Electric ISR Plan submission by approximately 24 months. This phenomenon has caused the Company to understate its Electric ISR Plan revenue requirements in prior years, resulting in significant increases to the Company's revenue requirement filed with its annual reconciliation of actual Electric ISR to the estimated investment amounts included in the Electric ISR Plan. These annual reconciliations are filed by August 1 following the completion of each fiscal year, and in recent years, also had to be trued up to reflect the impact of NOLs that were generated in fiscal year tax returns that were not known and not estimated when the Electric ISR Plan for those years was prepared. The PUC expressed concern about this phenomenon after the Company filed its FY 2017 Electric ISR Plan in Docket No. 4592. That plan was filed in November 2015 prior to the December 2015 filing of the Company's FY 2015 federal income tax return in which new NOLs were generated. During the course of the proceeding in Docket No. 4592, after the Company's FY 2015 tax return had been filed, the PUC requested that the Company update its FY 2017 Electric ISR Plan revenue requirement to include the FY 2015 NOL since it was known, and to mitigate the impact of NOLs on the subsequent Electric ISR Plan reconciliation filings. In response to those developments in the FY 2017 Electric ISR Plan filing, and since other elements of the Plan are also based on estimates, the Company is reflecting estimates of NOLs it will likely be generating on its FY 2016 federal income tax return and an estimate of NOLs it is likely to generate in FY 2017. Actual and estimated NOLs can be found in the FY 2017, FY 2016, FY 2015, FY 2014, FY 2013, and FY 2012 revenue requirement calculations on Pages 4, 6, 8, 10, 12, and 14, respectively. If the Company is able to utilize any of its currently accumulated NOLs in future tax years that benefit will be flowed through to customers.

In addition, the FY 2018 Electric ISR Plan includes an adjustment to the NOLs as a result of an error reflected in prior years' Electric ISR reconciliation filings. This adjustment to the NOLs is included in the FY 2018 revenue requirement calculation on vintage years' FY 2016 through FY 2012 investment. The adjustment reduces the total electric NOL in these fiscal years to reflect only the portion that relates to Distribution-related NOL. In prior Electric ISR Reconciliation filings, the total Electric NOL, which includes NOL for both Distribution-related NOL and Transmission-related NOL, was included in the revenue requirement calculation. The Company also owns Transmission facilities; however, pursuant to the terms of the FERC approved Integrated Facilities Agreement, New England Power Company is the single National Grid subsidiary that provides integrated alternating current (AC) transmission service across

New England. In this regard, New England Power Company operates and controls National Grid's AC facilities used for wholesale transmission purposes, including those transmission facilities owned by the Company, as a single integrated system for the provision of open access transmission service in New England. Therefore, New England Power Company's transmission revenue requirement reflects the cost to compensate the Company for their transmission facilities pursuant to the FERC approved formula rate in Schedule III-B of New England Power Company Tariff No. 1. In the Integrated Facilities Agreement transmission revenue requirement calculation, the Transmission-related NOL is included in the Transmission-related accumulated deferred taxes. This is calculated by applying the Gross Plant Allocation Factor percentage to the electric deferred tax balance as recorded in FERC Account No. 190. The NOLs reflected in the FY 2018 Electric ISR Plan revenue requirement calculation in vintage years FY 2016 through FY 2012 have been reduced by the amount of NOL included in rate base in developing these transmission rates. The Distribution-related NOL for vintage year FY 2017 was derived by deducting the estimated Transmission-related NOL, based on a two-year average of CY 2015 and CY 2014 Transmission Gross Plant Allocation Factor percentages, from the estimate of the total Electric NOL for vintage year FY 2017. This adjustment can be found on Page 21, Lines 11 through 15 of Attachment 1.

Accumulated Deferred Income Tax Proration Adjustment

The Electric ISR Plan includes a proration calculation regarding the accumulated deferred income tax (ADIT) balance included in rate base. The calculation fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). This regulation stipulates normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly. The penalty of a normalization violation is the loss of all federal income tax deductions for accelerated depreciation, including bonus depreciation. Any regulatory filing that includes capital expenditures, book depreciation expense and ADIT related to those capital expenditures must follow the normalization requirements. When the regulatory filing is based on a future period, the deferred tax must be prorated to reflect the period of time that the ADIT balances are in rate base. This filing includes FY 2018 and FY 2019 proration calculations at Page 25 and 26, respectively, the effects of which are included in each year's respective revenue requirement.

Property Tax Recovery Adjustment

The Property Tax Recovery Adjustment is shown on Pages 18 through 20 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 2018 revenue requirement includes $3,906,950 for the net property tax recovery adjustment, with an additional adjustment of ($589) relating to the impact of the work order write-off.

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 2017 (a)	Fiscal Year 2018 (b)	Fiscal Year 2019 (c)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$8,719,042	$9,400,000	
2	Current Year Inspection & Maintenance (I&M)	$1,291,750	$1,069,800	
3	Electric Contact Voltage expenses included in RIPUC Docket No. 4323	($163,749)	($163,749)	
4	**Total O&M Expense Component of Revenue Requirement**	**$9,847,043**	**$10,306,051**	
	Capital Investment:			
5	Actual Revenue Requirement on Incremental FY 2012 Capital included in ISR Rase Base	$441,364	$268,500	$268,929
6	Actual Revenue Requirement on Incremental FY 2013 Capital included in ISR Rate Base	($1,042,177)	($1,074,896)	($1,019,664)
7	Actual Revenue Requirement on Incremental FY 2014 Capital included in ISR Rate Base	$959,924	$706,927	$659,372
8	Actual Revenue Requirement on FY 2015 Capital included in ISR Rate Base	$3,559,643	$3,758,934	$3,566,424
9	Actual Revenue Requirement on FY 2016 Capital included in ISR Rate Base	$5,428,148	$3,581,663	$3,429,733
10	Forecasted Annual Revenue Requirement on FY 2017 Capital included in ISR Rate Base	$2,711,630	$4,415,399	$4,209,003
11	Forecasted Annual Revenue Requirement on FY 2018 Capital included in ISR Rate Base	$0	$2,267,653	$4,172,061
12	Subtotal	$12,058,532	$13,924,182	$15,285,858
13	FY 2017 Property Tax Recovery Adjustment	$5,798,249		
14	FY 2018 Property Tax Recovery Adjustment		$3,906,950	
15	True-Up for FY 2012 through FY 2016 Transmission - Related Net Operating Losses ("NOL")		($1,125,115)	
16	True-Up for FY 2013 through FY 2016 Work Order Write Off Adjustment: Capital Investment		($560,347)	
17	True-Up for FY 2013 through FY 2016 Work Order Write Off Adjustment: Property Tax		($589)	
18	**Total Capital Investment Component of Revenue Requirement**	**$17,856,781**	**$16,145,080**	
19	**Total Fiscal Year Revenue Requirement**	**$27,703,824**	**$26,451,131**	
20	**Total Updated Fiscal Year Rate Adjustment**		**($1,252,693)**	

Column (a) - as Approved per RIPUC Docket No. 4539
Column (b)

1	Vegetation Management per Section 3, Page 5 of 5, Chart 2
2	Inspection & Maintenance per Section 4, Page 3 of 3, Chart 1
4	Line 1 + Line 2 + Line 3
5	Page 14 of 26, Line 30
6	Page 12 of 26, Line 32
7	Page 10 of 26, Line 32
8	Page 8 of 26, Line 32
9	Page 6 of 26, Line 32
10	Page 4 of 26, Line 31
11	Page 2 of 26, Line 32
12	Sum of Lines 5 through 11
14	Page 19 of 26, Line 97
15	Page 23 of 26, Line 12
16	Page 24 of 26, Line 10
17	Page 18 of 26, Line 62b
18	Sum of Lines 12 through 17
19	Sum of Lines 4 + 18
20	Current Year Line 19 - Prior Year Line 19

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*	Section 2, Page 27 of 27, Chart 11		$32,731,000	$0
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Section 2, Page 27 of 27, Chart 11		$42,112,000	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$74,843,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$74,843,000	$0
5	Retirements	Line 4 * 21.99%	1/	$16,457,400	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$58,385,600	$58,385,600
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$74,843,000	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$31,811,226	$31,811,226
10	Cost of Removal	Section 2, Page 27 of 27, Chart 11		$9,646,000	$9,646,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$41,457,226**	**$41,457,226**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%
13	Vintage Year Tax Depreciation:				
14	2018 Spend	Page 3 of 26, Line 21		$57,010,767	$2,193,014
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$57,010,767	$59,203,781
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50% ; Column (b) = Line 6 * Line 12		$992,555	$1,985,110
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$992,555	$2,977,666
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$56,018,212	$56,226,115
19	Effective Tax Rate			35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$19,606,374	$19,679,140
21	Less: FY 2018 Federal NOL	Page 21 of 26, Line12(n)		$0	$0
22	Less: Proration Adjustment	Col (a) = Page 25 of 26, Line 40; Col (b) = Page 26 of 26, Line 40		($5,486,704)	($39,506)
23	Net Deferred Tax Reserve	Sum of Lines 20 through 22		$14,119,670	$19,639,634
	Rate Base Calculation:				
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$41,457,226	$41,457,226
25	Accumulated Depreciation	-Line 17		($992,555)	($2,977,666)
26	Deferred Tax Reserve	-Line 23		($14,119,670)	($19,639,634)
27	Year End Rate Base	Sum of Lines 24 through 26		$26,345,000	$18,839,926
	Revenue Requirement Calculation:				
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$13,172,500	$22,592,463
29	Pre-Tax ROR		2/	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,275,098	$2,186,950
31	Book Depreciation	Line 16		$992,555	$1,985,110
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$2,267,653**	**$4,172,061**

1/ Based on three year average FY 2016, FY 2015, and FY 2014 actual retirements as a percent of capital investment

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%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2018 Incremental Capital Investments

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 2 of 26, Line 3		$74,843,000	
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.38%	
3	Capital Repairs Deduction	Line 1 * Line 2		$17,498,293	
	Bonus Depreciation				
4	Plant Additions	Line 1		$74,843,000	
5	Less Capital Repairs Deduction	Line 3		$17,498,293	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$57,344,707	
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$56,771,260	
9	Bonus Depreciation Rate (April 2017 - December 2017)	1 * 75% * 50%		37.50%	
10	Bonus Depreciation Rate (January 2018 - March 2018)	1 * 25% * 40%		10.00%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10		47.50%	
12	Bonus Depreciation	Line 8 * Line 11		$26,966,349	
	Remaining Tax Depreciation				
13	Plant Additions	Line 1		$74,843,000	
14	Less Capital Repairs Deduction	Line 3		$17,498,293	
15	Less Bonus Depreciation	Line 12		$26,966,349	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$30,378,358	$30,378,358
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,139,188	$2,193,014
19	FY18 Loss incurred due to retirements	Per Tax Department	2/	$1,760,937	
20	Cost of Removal	Page 2 of 26, Line 10		$9,646,000	
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$57,010,767	$2,193,014

1/ Capital Repairs percentage is based on a three year average 2013, 2014, and 2015 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions.

2/ FY 2018 estimated tax loss on retirements is based on FY 2016 actuals (Page 7 of 26, Line 19).

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2017 Actual Incremental Capital Investment

Line No.				Fiscal Year 2017 (a)	Fiscal Year 2018 (b)	Fiscal Year 2019 (c)
	Capital Additions Allowance					
	Non-Discretionary Capital					
1	Non-Discretionary Additions	Per RIPUC Docket No. 4592		$31,396,000	$0	$0
	Discretionary Capital					
2	Lesser of Actual Cumulative Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4592		$47,082,000	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$78,478,000	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$78,478,000	$0	$0
5	Retirements	Line 4 * 20.44%	1/	$16,040,903	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$62,437,097	$62,437,097	$62,437,097
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$78,478,000	$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; Column (b) = Prior Year Line 9		$35,446,226	$35,446,226	$35,446,226
10	Total Cost of Removal	Per Company's books		$9,800,000	$9,800,000	$9,800,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$45,246,226**	**$45,246,226**	**$45,246,226**
	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%
13	Tax Depreciation	Page 5 of 26, Line 21		$60,552,688	$2,211,545	$2,045,503
14	Cumulative Tax Depreciation	Prior Year Line 14 + Current Year Line 13		$60,552,688	$62,764,233	$64,809,736
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$1,061,431	$2,122,861	$2,122,861
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		$1,061,431	$3,184,292	$5,307,153
17	Cumulative Book / Tax Timer	Line 14 - Line 16		$59,491,257	$59,579,941	$59,502,583
18	Effective Tax Rate			35.00%	35.00%	35.000%
19	Deferred Tax Reserve	Line 17 * Line 18		$20,821,940	$20,852,979	$20,825,904
20	Less: FY 2017 Federal NOL	Page 21 of 26, Line12(m)		($1,388,912)	($1,388,912)	($1,388,912)
21	Less: Proration Adjustment	Col (b) = Page 25 of 26, Line 40; Col (c) = Page 26 of 26, Line 40		$0	($16,852)	$14,700
22	Net Deferred Tax Reserve	Sum of Lines 19 through 21		$19,433,028	$19,447,215	$19,451,691
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$45,246,226	$45,246,226	$45,246,226
24	Accumulated Depreciation	-Line 16		($1,061,431)	($3,184,292)	($5,307,153)
25	Deferred Tax Reserve	-Line 22		($19,433,028)	($19,447,215)	($19,451,691)
26	Year End Rate Base	Sum of Lines 23 through 25		$24,751,768	$22,614,719	$20,487,382
	Revenue Requirement Calculation:					
27	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$12,375,884	$23,683,244	$21,551,051
28	Pre-Tax ROR		2/	9.68%	9.68%	9.68%
29	Return and Taxes	Line 27 * Line 28		$1,197,986	$2,292,538	$2,086,142
30	Book Depreciation	Line 15		$1,061,431	$2,122,861	$2,122,861
31	**Annual Revenue Requirement**	**Line 29 + Line 30**		**$2,259,417**	**$4,415,399**	**$4,209,003**

1/ Based on FY2015 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%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2017 Incremental Capital Investments

Line No.				Fiscal Year 2017 (a)	Fiscal Year 2018 (b)	Fiscal Year 2019 (c)
	Capital Repairs Deduction					
1	Plant Additions	Page 4 of 26, Line 3		$78,478,000		
2	Capital Repairs Deduction Rate	Per Tax Department	1/	22.70%		
3	Capital Repairs Deduction	Line 1 * Line 2		$17,814,506		
	Bonus Depreciation					
4	Plant Additions	Line 1		$78,478,000		
5	Less Capital Repairs Deduction	Line 3		$17,814,506		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$60,663,494		
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$60,056,859		
9	Bonus Depreciation Rate (April 2016 - December 2016)	1 * 75% * 50%		37.50%		
10	Bonus Depreciation Rate (January 2017 - March 2017)	1 * 25% * 50%		12.50%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%		
12	Bonus Depreciation	Line 8 * Line 11		$30,028,430		
	Remaining Tax Depreciation					
13	Plant Additions	Line 1		$78,478,000		
14	Less Capital Repairs Deductions	Line 3		$17,814,506		
15	Less Bonus Depreciation	Line 12		$30,028,430		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$30,635,064	$30,635,064	$30,635,064
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,148,815	$2,211,545	$2,045,503
19	FY17 Loss incurred due to retirements	Per Tax Department	2/	$1,760,937		
20	Cost of Removal	Page 4 of 26, Line 10		$9,800,000		
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$60,552,688	$2,211,545	$2,045,503

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.

2/ FY 2017 estimated tax loss on retirements is based on FY 2016 actuals (Page 7 of 26, Line 19).

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2016 Actual Incremental Capital Investment

Line No.				Fiscal Year 2016 (a)	Fiscal Year 2017 (b)	Fiscal Year 2018 (c)	Fiscal Year 2019 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*	Per RIPUC Docket No. 4539		$35,964,438	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books		$672,272	$0	$0	$0
	Discretionary Capital						
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4539		$35,488,464	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books		($121,728)	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 1a + Line 2 + Line 2a		$72,003,445	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$72,003,445	$0	$0	$0
5	Retirements		1/	$28,489,814	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$43,513,631	$43,513,631	$43,513,631	$43,513,631
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$72,003,445	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$28,971,671	$28,971,671	$28,971,671	$28,971,671
10	Cost of Removal		2/	$8,192,983	$8,192,983	$8,192,983	$8,192,983
10a	Work Order Write Off Adjustment	Per Company's books		($19,884)	($19,884)	($19,884)	($19,884)
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**		**$37,144,770**	**$37,144,770**	**$37,144,770**	**$37,144,770**
	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	Vintage Year Tax Depreciation:						
14	2016 Spend	Page 7 of 26, Line 21		$54,883,892	$2,029,089	$1,876,746	$1,736,208
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$54,883,892	$56,912,981	$58,789,727	$60,525,935
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$739,732	$1,479,463	$1,479,463	$1,479,463
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$739,732	$2,219,195	$3,698,659	$5,178,122
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$54,144,160	$54,693,786	$55,091,068	$55,347,813
19	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$18,950,456	$19,142,825	$19,281,874	$19,371,734
21	Less: FY 2016 Federal NOL	Page 21 of 26, Line12(l)		($6,705,697)	($6,705,697)	($6,705,697)	($6,705,697)
22	Less: Proration Adjustment	Col = Page 25 of 26, Line 40; Col = Page 26 of 26, Line 40		$0	$0	($75,493)	($48,787)
23	Net Deferred Tax Reserve	Sum of Lines 20 through 22		$12,244,759	$12,437,128	$12,500,684	$12,617,250
	Rate Base Calculation:						
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$37,144,770	$37,144,770	$37,144,770	$37,144,770
25	Accumulated Depreciation	-Line 17		($739,732)	($2,219,195)	($3,698,659)	($5,178,122)
26	Deferred Tax Reserve	-Line 23		($12,244,759)	($12,437,128)	($12,500,684)	($12,617,250)
27	Year End Rate Base	Sum of Lines 24 through 26		$24,160,279	$22,488,447	$20,945,427	$19,349,398
	Revenue Requirement Calculation:						
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$12,080,139	$23,324,363	$21,716,937	$20,147,412
29	Pre-Tax ROR		3/	9.68%	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,169,358	$2,257,798	$2,102,199	$1,950,270
31	Book Depreciation	Line 16		$739,732	$1,479,463	$1,479,463	$1,479,463
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$1,909,089**	**$3,737,262**	**$3,581,663**	**$3,429,733**
33	As Approved in RIPUC Docket No. 4539			$2,048,986	$4,017,908	$3,864,033	$3,713,798
34	Transmission-related NOL adjustment			($169,161)	($338,321)	($338,321)	($338,321)
35	Work Order Write Off Adjustment			$29,263	$57,675	$55,951	$54,256

1/ Actual Retirements

2/ Actual Cost of Removal

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

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

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2016 Incremental Capital Investments

Line No.				Fiscal Year 2016 (a)	Fiscal Year 2017 (a)	Fiscal Year 2018 (a)	Fiscal Year 2019 (a)
	Capital Repairs Deduction						
1	Plant Additions	Page 6 of 26, Line 3		$72,003,445			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	22.70%			
3	Capital Repairs Deduction	Line 1 * Line 2		$16,344,782			
	Bonus Depreciation						
4	Plant Additions	Line 1		$72,003,445			
5	Less Capital Repairs Deduction	Line 3		$16,344,782			
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$55,658,663			
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%			
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$55,102,076			
9	Bonus Depreciation Rate (April 2015 - December 2015)	1 * 75% * 50%		37.50%			
10	Bonus Depreciation Rate (January 2016 - March 2016)	1 * 25% * 50%		12.50%			
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%			
12	Bonus Depreciation	Line 8 * Line 11		$27,551,038			
	Remaining Tax Depreciation						
13	Plant Additions	Line 1		$72,003,445			
14	Less Capital Repairs Deduction	Line 3		$16,344,782			
15	Less Bonus Depreciation	Line 12		$27,551,038			
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$28,107,625	$28,107,625	$28,107,625	$28,107,625
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,054,036	$2,029,089	$1,876,746	$1,736,208
19	FY16 Loss incurred due to retirements	Per Tax Department		$1,760,937			
20	Cost of Removal	Page 6 of 26, Line 10 + Line 10a		$8,173,099			
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$54,883,892	$2,029,089	$1,876,746	$1,736,208

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
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2015 Actual Incremental Capital Investment

Line No.				Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)	Fiscal Year 2018 (d)	Fiscal Year 2019 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*	Per RIPUC Docket No. 4473		$22,246,664	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books		$ (268,138)				
	Discretionary Capital							
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4473		$54,410,377	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books		$ (48,499)				
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 1a + Line 2 + Line 2a		$76,340,403	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$76,340,403	$0	$0	$0	$0
5	Retirements		1/	$15,666,095	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$60,674,308	$60,674,308	60,674,308	60,674,308	60,674,308
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$76,340,403	$0	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$33,308,629	$33,308,629	$33,308,629	$33,308,629	$33,308,629
10	Cost of Removal	Docket No. 4473 FY15 Reconciliation, Att. JHP-1, Page 4, Table 2	2/	$6,988,398	$6,988,398	$6,988,398	$6,988,398	$6,988,398
10a	Work Order Write Off Adjustment	Per Company's books		$22,398	$22,398	$22,398	$22,398	$22,398
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**		**$40,319,425**	**$40,319,425**	**$40,319,425**	**$40,319,425**	**$40,319,425**
	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%	3.40%
13	Vintage Year Tax Depreciation:							
14	2015 Spend	Page 9 of 26, Line 22		$71,871,022	$2,120,892	$1,961,656	$1,814,760	$1,678,440
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$71,871,022	$73,991,914	75,953,570	77,768,330	79,446,770
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$1,031,463	$2,062,926	$2,062,926	$2,062,926	$2,062,926
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,031,463	$3,094,390	$5,157,316	$7,220,243	$9,283,169
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$70,839,559	$70,897,524	$ 70,796,254	$ 70,548,087	$ 70,163,601
19	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$24,793,846	$24,814,134	$24,778,689	$24,691,831	$24,557,260
21	Less: FY 2015 Federal NOL	Page 21 of 26, Line 12(k)		($8,148,936)	($8,148,936)	($8,148,936)	($8,148,936)	($8,148,936)
22	Less: Proration Adjustment	Col (d) = Page 25 of 26, Line 40; Col (e) = Page 26 of 26, Line 40		$0	$0	$0	$47,157	$73,061
23	Net Deferred Tax Reserve	Sum of Lines 20 through 22		$16,644,909	$16,665,197	$16,629,752	$16,590,051	$16,481,385
	Rate Base Calculation:							
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$40,319,425	$40,319,425	$40,319,425	$40,319,425	$40,319,425
25	Accumulated Depreciation	-Line 17		($1,031,463)	($3,094,390)	($5,157,316)	($7,220,243)	($9,283,169)
26	Deferred Tax Reserve	-Line 23		($16,644,909)	($16,665,197)	($16,629,752)	($16,590,051)	($16,481,385)
27	Year End Rate Base	Sum of Lines 24 through 26		$22,643,053	$20,559,839	$18,532,357	$16,509,131	$14,554,871
	Revenue Requirement Calculation:							
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$11,321,526	$21,601,446	$19,546,098	$17,520,744	$15,532,001
29	Pre-Tax ROR		3/	9.68%	9.68%	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,095,924	$2,091,020	$1,892,062	$1,696,008	$1,503,498
31	Book Depreciation	Line 16		$1,031,463	$2,062,926	$2,062,926	$2,062,926	$2,062,926
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$2,127,387**	**$4,153,946**	**$3,954,989**	**$3,758,934**	**$3,566,424**
33	As Approved in RIPUC Docket No. 4539			$2,335,465	$4,569,615	$4,369,693	$4,172,667	$3,979,199
34	Transmission-related NOL adjustment			($191,621)	($383,242)	($383,242)	($383,242)	($383,242)
35	Work Order Write Off Adjustment			($16,457)	($32,427)	($31,462)	($30,490)	($29,532)

1/ Actual Retirements

2/ Actual Cost of Removal

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

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

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2015 Incremental Capital Investments

Line No.				Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)	Fiscal Year 2018 (d)	Fiscal Year 2019 (e)
	Capital Repairs Deduction							
1	Plant Additions	Page 8 of 26, Line 3		$76,340,403				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.10%				
3	Capital Repairs Deduction	Line 1 * Line 2		$17,634,633				
	Bonus Depreciation							
4	Plant Additions	Line 1		$76,340,403				
5	Less Capital Repairs Deduction	Line 3		$17,634,633				
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$58,705,770				
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.91%				
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$58,652,935				
9	Bonus Depreciation Rate (April 2014 - December 2014)	1 * 75% * 50%		37.50%				
10	Bonus Depreciation Rate (January 2015 - March 2015)	1 * 25% * 50%		12.50%				
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%				
12	Bonus Depreciation	Line 8 * Line 11		$29,326,468				
	Remaining Tax Depreciation							
13	Plant Additions	Line 1		$76,340,403				
14	Less Capital Repairs Deduction	Line 3		$17,634,633				
15	Less Bonus Depreciation	Line 12		$29,326,468				
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$29,379,302	$29,379,302	$29,379,302	$29,379,302	$29,379,302
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,101,724	$2,120,892	$1,961,656	$1,814,760	$ 1,678,440
19	481(a) adjustment for partial retirements	Per Tax Department		$14,395,754				
20	FY15 Loss incurred due to retirements	Per Tax Department		$2,401,647				
21	Cost of Removal	Page 8 of 26, Line 10 + Line 10a		$7,010,796				
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18,19, 20, and 21		$71,871,022	$2,120,892	$1,961,656	$1,814,760	$1,678,440

1/ Capital Repairs percentage is based on the actual results of the FY 2015 tax return.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2014 Actual Incremental Capital Investment

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)	Fiscal Year 2016 (c)	Fiscal Year 2017 (d)	Fiscal Year 2018 (e)	Fiscal Year 2019 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*	Per RIPUC Docket No. 4382		$6,923,860	$0	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books		($472,942)					
	Discretionary Capital								
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4382		$6,400,406	$0	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books		$ (8,965)					
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 1a + Line 2 + Line 2a		$12,842,359	$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		$12,842,359	$0	$0	$0	$0	$0
5	Retirements	Page 16 of 26, Line 9(c)	1/	($4,165,367)	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$17,007,726	17,007,726	17,007,726	17,007,726	17,007,726	17,007,726
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$12,842,359	$0	$0	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant	2/	$7,173,397	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$5,668,962	$5,668,962	$5,668,962	$5,668,962	$5,668,962	$5,668,962
10	Total Cost of Removal	Page 16 of 26, Line 6(c)		($887,841)	($887,841)	($887,841)	($887,841)	($887,841)	($887,841)
10a	Work Order Write Off Adjustment	Per Company's books		($37,062)	($37,062)	($37,062)	($37,062)	($37,062)	($37,062)
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**		**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**
	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%	3.40%	3.40%
13	Vintage Year Tax Depreciation:								
14	2014 Spend	Page 11 of 26, Line 20		$7,826,326	$306,845	$283,808	$262,555	$242,832	$224,640
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$7,826,326	$8,133,171	$8,416,979	$8,679,534	$8,922,366	$9,147,006
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$289,131	$578,263	$578,263	$578,263	$578,263	$578,263
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$289,131	$867,394	$1,445,657	$2,023,919	$2,602,182	$3,180,445
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$7,537,194	$7,265,777	$6,971,322	$6,655,614	$6,320,184	$5,966,562
19	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$2,638,018	$2,543,022	$2,439,963	$2,329,465	$2,212,064	$2,088,297
21	Less: FY 2014 Federal NOL	Page 21 of 26, Line 12(j)		($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)
22	Less: Proration Adjustment	Col (e) = Page 25 of 26, Line 40; Col (f) = Page 26 of 26, Line 40		$0	$0	$0	$0	$63,739	$67,196
23	Net Deferred Tax Reserve	Sum of Lines 20 through 22		$1,437,210	$1,342,214	$1,239,155	$1,128,657	$1,074,996	$954,685
	Rate Base Calculation:								
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$4,744,059	$4,744,059	$4,744,059	$4,744,059	$4,744,059	$4,744,059
25	Accumulated Depreciation	-Line 17		($289,131)	($867,394)	($1,445,657)	($2,023,919)	($2,602,182)	($3,180,445)
26	Deferred Tax Reserve	-Line 23		($1,437,210)	($1,342,214)	($1,239,155)	($1,128,657)	($1,074,996)	($954,685)
27	Year End Rate Base	Sum of Lines 24 through 26		$3,017,717	$2,534,451	$2,059,247	$1,591,482	$1,066,881	$608,929
	Revenue Requirement Calculation:								
28	Average Rate Base	Col (a) = Line 27 * 23.23%; Col (b) = (Prior Year Line 27 + Current Year Line 27)/2	3/	$670,654	$2,776,084	$2,296,849	$1,825,365	$1,329,182	$837,905
29	Pre-Tax ROR		4/	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$64,919	$268,725	$222,335	$176,695	$128,665	$81,109
31	Book Depreciation	Line 16		$289,131	$578,263	$578,263	$578,263	$578,263	$578,263
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$354,051**	**$846,988**	**$800,598**	**$754,958**	**$706,927**	**$659,372**
33	As Approved in RIPUC Docket No. 4539			$373,851	$900,001	$852,205	$805,187	$755,737	$706,781
34	Transmission-related NOL adjustment			$0	$0	$0	$0	$0	$0
35	Work Order Write Off Adjustment			($19,800)	($53,014)	($51,607)	($50,229)	($48,810)	($47,409)

1/ Actual Retirements

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

3/ 23.23% per RIPUC Docket No. 4382 (FY 2014 Elec ISR reconciliation), Attachment WRR-1-Revised, Page 12.

4/ Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323

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

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2014 Incremental Capital Investments

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)	Fiscal Year 2016 (c)	Fiscal Year 2017 (d)	Fiscal Year 2018 (e)	Fiscal Year 2019 (f)
	Capital Repairs Deduction								
1	Plant Additions	Page 10 of 26, Line 3		$12,842,359					
2	Capital Repairs Deduction Rate	Per Tax Department	1/	34.46%					
3	Capital Repairs Deduction	Line 1 * Line 2		$4,425,477					
	Bonus Depreciation								
4	Plant Additions	Line 1		$12,842,359					
5	Less Capital Repairs Deduction	Line 3		$4,425,477					
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$8,416,882					
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%					
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$8,332,713					
9	Bonus Depreciation Rate (April 2013 - December 2013)	1 * 75% * 50%		37.50%					
10	Bonus Depreciation Rate (January 2014 - March 2014)	1 * 25% * 50%		12.50%					
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%					
12	Bonus Depreciation	Line 8 * Line 11		$4,166,357					
	Remaining Tax Depreciation								
13	Plant Additions	Line 1		$12,842,359					
14	Less Capital Repairs Deduction	Line 3		$4,425,477					
15	Less Bonus Depreciation	Line 12		$4,166,357					
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$4,250,525	$4,250,525	$4,250,525	$4,250,525	$4,250,525	$4,250,525
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
18	Remaining Tax Depreciation	Line 16 * Line 17		$159,395	$ 306,845	$ 283,808	$262,555	$242,832	$224,640
19	Cost of Removal	Page 10 of 26, Line 10 + Line 10a		($924,903)					
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18 and 19		$7,826,326	$306,845	$283,808	$262,555	$242,832	$224,640

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

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2013 Actual Incremental Capital Investment

Line No.			Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)	Fiscal Year 2016 (d)	Fiscal Year 2017 (e)	Fiscal Year 2018 (f)	Fiscal Year 2019 (g)
	Capital Additions Allowance								
	Non-Discretionary Capital								
1	Non-Discretionary Additions	Per RIPUC Docket No. 4307	($5,184,396)	$0	$0	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books	($576,955)	$0	$0	$0	$0	$0	$0
	Discretionary Capital								
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending	Per RIPUC Docket No. 4307	($1,850,463)	$0	$0	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books	($207,197)	$0	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 1a + Line 2 + Line 2a	($7,819,012)	$0	$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	($7,819,012)	$0	$0	$0	$0	$0	$0
5	Retirements		$5,838,935	$0	$0	$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	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3	($7,819,012)	$0	$0	$0	$0	$0	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Columns (b), (c) & (d) = Prior Year Line 9	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)
10	Total Cost of Removal		($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)
10a	Work Order Write Off Adjustment	Per Company's books	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**
	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%	3.40%	3.40%
13	Tax Depreciation	Page 13 of 26, Line 20	($6,531,672)	($246,695)	($228,173)	($211,087)	($195,230)	($180,604)	($167,038)
14	Cumulative Tax Depreciation	Prior Year Line 13 + Current Year Line 14	($6,531,672)	($6,778,367)	($7,006,540)	($7,217,627)	($7,412,857)	($7,593,461)	($7,760,499)
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Columns (b), (c) & (d) = Line 6 * Line 12	($232,185)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15	($232,185)	($696,555)	($1,160,925)	($1,625,296)	($2,089,666)	($2,554,036)	($3,018,406)
17	Cumulative Book / Tax Timer	Line 14 - Line 16	($6,299,487)	($6,081,812)	($5,845,615)	($5,592,331)	($5,323,191)	($5,039,425)	($4,742,093)
18	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18	($2,204,820)	($2,128,634)	($2,045,965)	($1,957,316)	($1,863,117)	($1,763,799)	($1,659,732)
20	Less: FY 2013 Federal NOL	Page 21 of 26, Line 12(i)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)
21	Less: Proration Adjustment	Col (a) through (f) = n/a; Col (g)=Page 25 of 26, Line 40; Col (h)=Page 26 of 26, Line 40	$0	$0	$0	$0	$0	($53,922)	($56,500)
22	Net Deferred Tax Reserve	Sum of Lines 19 through 21	($4,547,202)	($4,471,016)	($4,388,347)	($4,299,697)	($4,205,498)	($4,160,102)	($4,058,614)
	Rate Base Calculation:								
23	Cumulative Incremental Capital Included in Rate Base	Line 11	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)
24	Accumulated Depreciation	-Line 16	$232,185	$696,555	$1,160,925	$1,625,296	$2,089,666	$2,554,036	$3,018,406
25	Deferred Tax Reserve	-Line 22	$4,547,202	$4,471,016	$4,388,347	$4,299,697	$4,205,498	$4,160,102	$4,058,614
26	Year End Rate Base	Sum of Lines 23 through 25	($5,041,435)	($4,653,251)	($4,271,550)	($3,895,829)	($3,525,658)	($3,106,684)	($2,743,802)
	Revenue Requirement Calculation:								
27	Average Rate Base	Column (a) = Current Year Line 26 ÷ 2; Column (b) = (Prior Year Line 26 + Current Year Line 26) ÷ 2	($2,520,717)	($4,847,343)	($4,462,400)	($4,083,689)	($3,710,743)	($3,316,171)	($2,925,243)
28	Pre-Tax ROR	1/	9.84%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
29	Return and Taxes	Line 27 * Line 28	($248,039)	($469,223)	($431,960)	($395,301)	($359,200)	($321,005)	($283,163)
30	Book Depreciation	Line 15	($232,185)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)
31	Property Taxes	Year 1 = $0, then Prior Year (Line 11 - Line 16) * Current Year Effective Property Tax rate 2/	$0	($350,952)	($374,039)	($324,300)	($335,967)	($289,520)	($272,130)
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**	**($480,224)**	**($1,284,545)**	**($1,270,370)**	**($1,183,971)**	**($1,159,537)**	**($1,074,896)**	**($1,019,664)**
33	FY 2013 Revenue Requirement as reconciled through the FY 2016 Reconciliation Filing RIPUC Docket No. 4539		($433,148)	($1,160,601)	($1,133,816)	($1,075,239)	($1,042,296)	($963,881)	($912,008)
34	Transmission-related NOL adjustment		$0	$0	$0	$0	$0	$0	$0
35	Work Order Write Off Adjustment		($47,076)	($123,944)	($136,554)	($108,732)	($117,241)	($111,015)	($107,656)

1/ 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%

2/ FY 2018 effective property tax rate of 3.75% per Page 19 of 26, Line 72(h)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2013 Incremental Capital Investments

			Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)	Fiscal Year 2016 (d)	Fiscal Year 2017 (e)	Fiscal Year 2018 (f)	Fiscal Year 2019 (g)
	Capital Repairs Deduction								
1	Plant Additions	Page 12 of 26, Line 3	($7,819,012)						
2	Capital Repairs Deduction Rate	1/	12.59%						
3	Capital Repairs Deduction	Line 1 * Line 2	($984,414)						
	Bonus Depreciation								
4	Plant Additions	Line 1	($7,819,012)						
5	Less Capital Repairs Deduction	Line 3	($984,414)						
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	($6,834,598)						
7	Percent of Plant Eligible for Bonus Depreciation		100.00%						
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	($6,834,598)						
9	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%	37.50%						
10	Bonus Depreciation Rate (January 2013 - March 2013)	1 * 25% * 50%	12.50%						
11	Total Bonus Depreciation Rate	Line 9 + Line 10	50.00%						
12	Bonus Depreciation	Line 8 * Line 11	($3,417,299)						
	Remaining Tax Depreciation								
13	Plant Additions	Line 1	($7,819,012)						
14	Less Capital Repairs Deduction	Line 3	($984,414)						
15	Less Bonus Depreciation	Line 12	($3,417,299)						
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
18	Remaining Tax Depreciation	Line 16 * Line 17	($128,149)	($246,695)	($228,173)	($211,087)	($195,230)	($180,604)	($167,038)
19	Cost of Removal	Page 12 of 26, Line 10 + Line 10a	($2,001,810)						
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	($6,531,672)	($246,695)	($228,173)	($211,087)	($195,230)	($180,604)	($167,038)

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

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 Revenue Requirement on FY 2012 Actual Incremental Capital Investment

Line No.			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)	Fiscal Year 2016 (e)	Fiscal Year 2017 (f)	Fiscal Year 2018 (g)	Fiscal Year 2019 (h)
	Capital Additions Allowance									
	Non-Discretionary Capital									
1	Non-Discretionary	Per RIPUC Docket No. 4218	($4,019,686)	$0	$0	$0	$0	$0	$0	$0
	Discretionary Capital									
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending	Per RIPUC Docket No. 4218	$4,163,942	$0	$0	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2	$144,256	$0	$0	$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	$0	$0
5	Retirements		$19,938	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b) through (h) = Prior Year Line 6	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318
	Change in Net Capital Included in Rate Base									
7	Incremental Capital Amount	Column (a) = Line 4, Columns (b) through (h) = Prior Year Line 7	$144,256	$144,256	$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)	($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)**	**($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%	3.40%	3.40%
11	Tax Depreciation	Page 15 of 26, Line 20	($654,965)	$2,107	$1,949	$1,803	$1,667	$1,542	$1,427	$1,320
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11	($654,965)	($652,858)	($650,909)	($649,107)	($647,439)	($645,897)	($644,471)	($643,151)
13	Book Depreciation	Column (a) = -Line 6 * Line 10 * 50%; Columns (b) through (h)= Line 6 * Line 10	($2,113)	($4,227)	($4,227)	($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)	($27,474)	($31,701)
15	Cumulative Book / Tax Timer	Line 12 - Line 14	($652,852)	($646,518)	($640,342)	($634,313)	($628,419)	($622,650)	($616,996)	($611,450)
16	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
17	Deferred Tax Reserve	Line 15 * Line 16	($228,498)	($226,281)	($224,120)	($222,009)	($219,947)	($217,927)	($215,949)	($214,007)
18	Less: FY 2013 Federal NOL	Page 21 of 26, Line 12(h)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)
19	Less: Proration Adjustment	Col (a) through (f) = n/a; Col (g) =Page 25 of 26, Line 40; Col (h)=Page 26 of 26, Line 40	$0	$0	$0	$0	$0	$0	($1,074)	($1,054)
20	Net Deferred Tax Reserve	Sum of Lines 17 through 19	($3,663,490)	($3,661,274)	($3,659,112)	($3,657,002)	($3,654,939)	($3,652,920)	($3,652,015)	($3,650,054)
	Rate Base Calculation:									
21	Cumulative Incremental Capital Included in Rate Base	Line 9	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)
22	Accumulated Depreciation	-Line 14	$2,113	$6,340	$10,567	$14,794	$19,021	$23,247	$27,474	$31,701
23	Deferred Tax Reserve	-Line 20	$3,663,490	$3,661,274	$3,659,112	$3,657,002	$3,654,939	$3,652,920	$3,652,015	$3,650,054
24	Year End Rate Base	Sum of Lines 21 through 23	$3,038,729	$3,040,739	$3,042,804	$3,044,921	$3,047,085	$3,049,292	$3,052,615	$3,054,880
	Revenue Requirement Calculation:									
25	Average Rate Base	(Prior Year Line 24 + Current Year Line 24) ÷2	$1,519,364	$3,039,734	$3,041,771	$3,043,862	$3,046,003	$3,048,188	$3,050,953	$3,053,747
26	Pre-Tax ROR	1/	9.30%	9.84%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
27	Return and Taxes	Line 25 * Line 26	$141,301	$299,110	$294,443	$294,646	$294,853	$295,065	$295,332	$295,603
28	Book Depreciation	Line 13	($2,113)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)
29	Property Taxes	Year 1 = $0, then Prior Year (Line 9 - Line 14) * Current Year Effective Property Tax rate 2/	$0	($21,523)	($22,710)	($24,344)	($23,626)	($24,918)	($22,605)	($22,447)
30	**Annual Revenue Requirement**	**Sum of Lines 27 through 29**	**$139,188**	**$273,360**	**$267,506**	**$266,075**	**$267,000**	**$265,920**	**$268,500**	**$268,929**
31	FY 2012 Revenue Requirement as reconciled through the FY 2016 Reconciliation Filing RIPUC Docket No. 4539		$179,897	$359,506	$352,252	$350,820	$351,745	$350,665	$353,245	$353,674
32	Transmission-related NOL adjustment		($40,709)	($86,146)	($84,746)	($84,745)	($84,745)	($84,745)	($84,745)	($84,745)

1/ 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%

2/ FY 2018 effective property tax rate of 3.75% per Page 19 of 26, Line 72(h)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Incremental Capital Investments

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)	Fiscal Year 2016 (e)	Fiscal Year 2017 (f)	Fiscal Year 2018 (g)	Fiscal Year 2019 (h)
	Capital Repairs Deduction										
1	Plant Additions	Page 14 of 26, Line 3		$144,256							
2	Capital Repairs Deduction Rate	Per Tax Department	1/	21.05%							
3	Capital Repairs Deduction	Line 1 * Line 2		$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	$29,184	$29,184
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,094	$2,107	$1,949	$1,803	$1,667	$1,542	$1,427	$1,320
19	Cost of Removal	Page 14 of 26, 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	$1,427	$1,320

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
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2012 - 2014 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Actual Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Investment				
1	ISR - Eligible Capital Investment	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) = FY 2013 ISR Reconciliation Filing Docket No. 4307; Col (c) = FY 2014 ISR Reconcilation Filing Docket No. 4382	$48,946,456	$44,331,141	$56,129,551
1a	Work Order Write Off Adjustment	Per Company's books	$0	($784,153)	($481,907)
2	ISR - Eligible Capital Additions included in Rate Base per R.I.P.U.C. Docket No. 4323	Schedule MDL-3-ELEC Page 53, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Col (c)= Line Note 3(e)	$48,802,200	$51,366,341	$42,805,284
3	Incremental ISR Capital Investment	Line 1 + Line 1a - Line 2	$144,256	($7,819,353)	$12,842,360
	Cost of Removal				
4	ISR - Eligible Cost of Removal	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b)= FY 2013 Reconciliation Filing Docket No. 4307; Col (c) = FY 2014 ISR Reconciliation Filing Docket No. 4382	$5,807,869	5,179,941	$5,007,992
4a	Work Order Write Off Adjustment	Per Company's books	$0	($106,751)	($37,062)
5	ISR - Eligible Cost of Removal in Rate Base per R.I.P.U.C. Docket No. 4323	Workpaper MDL-19-ELEC Page 2, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Line Note 3(e)	$6,579,000	$7,075,000	$5,895,833
6	Incremental Cost of Removal	Line 4 + Line 4a - Line 5	($771,131)	($2,001,810)	($924,903)
	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 Reconciliation Filing Docket No. 4382	$7,740,446	$14,255,714	$3,299,874
8	ISR - Eligible Retirements/Estimated	Col (a)= FY 2012 ISR Proposal Filing Docket No. 4218; Col (b)= FY 2013 ISR Proposal Filing Docket No. 4307; Col (c) = Line 2 (c) * 17.44% Retirement rate per Docket 4323 (Workpaper MDL-19-ELEC Page 3)	$7,720,508	$8,416,779	$7,465,242
9	Incremental Retirements	Line 7 - Line 8	$19,938	$5,838,935	($4,165,367)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2016 Capital Investment

Line No.	**Discretionary Capital**		**Actuals** (a)
1	Cumulative FY 2015 Discretionary Capital **ADDITIONS**	Docket No. 4473 FY15 Reconciliation Att. AST-1 Page 12, Line 4	$123,541,880
2	FY 2016 Discretionary Capital **ADDITIONS**	Attachment JHP-1, Page 3, Table 1	$35,488,464
3	Cumulative Actual Discretionary Capital Additions	Line 1 + Line 2	$159,030,344
4	Cumulative FY 2015 Discretionary Capital **SPENDING**	Docket No. 4473 FY15 Reconciliation Att. AST-1 Page 12, Line 7	$144,500,411
5	FY 2016 Discretionary Capital **SPENDING**	Attachment JHP-1, Page 5, Table 3	$47,556,053
6	Cumulative Actual Discretionary Capital Spending	Line 4 + Line 5	$192,056,464
			As Approved in Docket No. 4539
7	Cumulative FY 2015 Approved Discretionary Capital **SPENDING**	Docket No. 4473 FY15 Reconciliation Att. AST-1 Page 12, Line 10	$127,736,150
8	FY 2016 Approved Discretionary Capital **SPENDING**	Docket No. 4539 FY16 Proposal, Section 2, Page 45, Chart 11	$46,476,000
9	Cumulative Actual Approved Discretionary Capital Spending	Line 7 + Line 8	$174,212,150
			Total Allowed
10	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 3, Line 6, or Line 9	$159,030,344
11	Prior Year Cumulative Allowed Disretionary Capital Included in Rate Base	Docket No. 4473 FY15 Reconciliation Filing Att. AST-1, Page 12, Line 11	$123,541,880
12	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 10 - Line 11	**$35,488,464**

The Narragansett Electric Company
d/b/a National Grid
FY 2018 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		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	$9,275	$1,885	$11,160		$550		$1,370,180			
2												
3	Accumulated Depr	$611,570				$7,498	$550	($828)	$618,789			
4												
5	Net Plant	$746,900							$751,391			
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	$1,370,180	$76,340	$5,801	$82,141		($15,666)		$1,436,655			
15												
16	Accumulated Depr	$618,789				$46,514	($15,666)	($6,988)	$642,649			
17												
18	Net Plant	$751,391							$794,006			
19												
20	Property Tax Expense	$27,502							$32,549			
21												
22	Effective Prop tax Rate	3.66%							4.10%			
23												
24	**Effective tax Rate Calculation**	End of FY 2015	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2016			
25												
26	Plant In Service	$1,436,655	$72,003	$17,773	$89,777		($28,490)		$1,497,942			
27												
28	Accumulated Depr	$642,649				$48,686	($28,490)	($8,193)	$654,652			
29												
30	Net Plant	$794,006							$843,290			
31												
32	Property Tax Expense	$32,549							$31,580			
33												
34	Effective Prop tax Rate	4.10%							3.74%			
35												
36		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
37	**Property Tax Recovery Calculation**											
38		**Cumulative Increm. ISR Prop. Tax for FY14**				**Cumulative Increm. ISR Prop. Tax for FY15**				**Cumulative Increm. ISR Prop. Tax for FY16**		
39			2 mos									
40	ISR Additions		$9,275				$76,340				$72,003	
41	Book Depreciation: base allowance on ISR eligible plant		($7,173)				($43,032)				($43,032)	
42	Book Depreciation: current year ISR additions		($324)				($1,031)				($740)	
43	COR		$828				$6,988				$8,193	
44												
45	Net Plant Additions		$2,605				$39,266				$36,425	
46												
47	RY Effective Tax Rate		3.98%				3.98%				3.98%	
48	ISR Property Tax Recovery on FY 2014 vintage investment			$104				$102				$89
49	ISR Property Tax Recovery on FY 2015 vintage investment							$1,564				$1,523
50	ISR Property Tax Recovery on FY 2016 vintage investment											$1,451
51												
52												
53	ISR Year Effective Tax Rate	3.66%				4.10%				3.74%		
54	RY Effective Tax Rate	3.98%	-0.32%			3.98%	0.12%			3.98%	-0.24%	
55	RY Effective Tax Rate 2 mos for FY 2014		-0.05%									
56	RY Net Plant times 2 mo rate	$746,900	-0.05%	($401)		$746,900	* 0.12%	$875		$746,900	* -0.24%	($1,773)
57	FY 2014 Net Adds times ISR Year Effective Tax rate	$2,605	-0.32%	($8)		$2,568	* 0.12%	$3		$2,234	* -0.24%	($5)
58	FY 2015 Net Adds times ISR Year Effective Tax rate					$39,266	* 0.12%	$46		$38,234	* -0.24%	($91)
59	FY 2016 Net Adds times ISR Year Effective Tax rate									$36,425	* -0.24%	($86)
60	Total Property Tax due to rate differential			($409)				$924				($1,869)
61												
62	Total ISR Property Tax Recovery			($306)				$2,590				$1,193
62a	As Approved in RIPUC Docket No. 4539			($304)				$2,590				$1,192
62b	Work Order Write Off Adjustment			(2)				(0)				2

The Narragansett Electric Company
d/b/a National Grid
FY 2018 ISR Property Tax Recovery Adjustment (continued)
(000s)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**End of FY 2016**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2017**
63	Plant In Service	$1,497,942	$78,478	$3,550	$82,028		($16,041)		$1,563,929
64	Accumulated Depr	$654,652				$50,850	($16,041)	($9,800)	$679,661
65	Net Plant	$843,290							$884,268
66	Property Tax Expense	$31,580							$36,250
67	Effective Prop tax Rate	3.74%							4.10%
	Effective tax Rate Calculation	**End of FY 2017**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2018**
68	Plant In Service	$1,563,929	$74,843	$3,100	$77,943		($16,457)		$1,625,415
69	Accumulated Depr	$679,661				$53,017	($16,457)	($9,646)	$706,575
70	Net Plant	$884,268							$918,840
71	Property Tax Expense	$36,250							$34,409
72	Effective Prop tax Rate	4.10%							3.74%

	Property Tax Recovery Calculation	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Cumulative Increm. ISR Prop. Tax for FY17				**Cumulative Increm. ISR Prop. Tax for FY18**			
73	ISR Additions		$78,478				$74,843		
74	Book Depreciation: base allowance on ISR eligible plant		($43,032)				($43,032)		
75	Book Depreciation: current year ISR additions		($1,061)				($993)		
76	COR		$9,800				$9,646		
77									
78	Net Plant Additions		$44,185				$40,465		
79									
80	RY Effective Tax Rate		3.98%				3.98%		
81	ISR Property Tax Recovery on FY 2014 vintage investment			$76					$62
82	ISR Property Tax Recovery on FY 2015 vintage investment			$1,440					$1,358
83	ISR Property Tax Recovery on FY 2016 vintage investment			$1,392					$1,333
84	ISR Property Tax Recovery on FY 2017 vintage investment			$1,760					$1,675
85	ISR Property Tax Recovery on FY 2018 vintage investment								$1,611
86	ISR Year Effective Tax Rate	4.10%					3.74%		
87	RY Effective Tax Rate	3.98%	0.12%				3.98%	-0.24%	
88	RY Effective Tax Rate 2 mos for FY 2014								
89	RY Net Plant times 2 mo rate	$746,900	* 0.12%	$875			$746,900	* -0.24%	($1,773)
90	FY 2014 Net Adds times ISR Year Effective Tax rate	$1,900	* 0.12%	$2			$1,566	* -0.24%	($4)
91	FY 2015 Net Adds times ISR Year Effective Tax rate	$36,171	* 0.12%	$42			$34,108	* -0.24%	($81)
92	FY 2016 Net Adds times ISR Year Effective Tax rate	$34,945	* 0.12%	$41			$33,466	* -0.24%	($79)
93	FY 2017 Net Adds times ISR Year Effective Tax rate	$44,185	* 0.12%	$52			$42,062	* -0.24%	($100)
94	FY 2018 Net Adds times ISR Year Effective Tax rate						$40,465	* -0.24%	($96)
95	Total Property Tax due to rate differential			$1,013					($2,133)
96									
97	Total ISR Property Tax Recovery			$5,680					$3,907

The Narragansett Electric Company
d/b/a National Grid
FY 2018 ISR Property Tax Recovery Adjustment (continued)
(000s)

Line Notes	
1(a)-9(a)	Per Rate Year cost of service
1(b) - 9(h)	Per FY 2014 Electric ISR Reconciliation Filing per Docket 4382
14(a)-22(h)	Per FY 2015 Electric ISR Reconciliation Filing per Docket 4473
26(a)-34(h)	Per FY 2016 Electric ISR Reconciliation Filing per Docket 4539
40(a) - 62(c)	Per FY 2014 Electric ISR Reconciliation Filing per Docket 4382
40(e)-62(g)	Per FY 2015 Electric ISR Reconciliation Filing per Docket 4473
40(i)-62(k)	Per FY 2016 Electric ISR Reconciliation Filing per Docket 4539
63(a) - 67(h)	Per FY 2017 Electric ISR Compliance Filing per Docket 4592
68(a)	Per Line 63(h)
68(b)	Per Page 3 of 26, Line 1
68(c)	FY 2018 forecasted in service amount
68(d)	Line 68(b) + Line 68(c)
68(f)	Per Page 2 of 26, Line 5
68(h)	Line 68(a) + Line 68(d) +Line 68(f)
69(a)	Per Line 64(h)
69(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 , 26(d)+26(f)*comp depr rate of 3.40%) + (Line , 63(d)+63(f)*comp depr rate of 3.40%) + (Line 68(d) +68(f)*comp depr rate of 3.40%*50%)
69(f)	Line 68(f)
69(g)	Per Page 2 of 26, Line 10
69(h)	Line 69(a) + Line 69(e) + Line 69(f) + Line 69(g)
71(a)	Line 66(h)
71(h)	Line 70(h) * Line 72(h)
72(a)	Line 67(h)
72(h)	Line 34(h); effective tax rate per FY 2016 Electric ISR Reconciliation Filing per Docket 4539

Line Notes	
73(a) - 97(c)	Per FY 2017 Electric ISR Compliance Filing per Docket 4592
73(f)	Line 68(b)
74(f)	Per Page 2 of 26, Line 8
75(f)	Per Page 2 of 26, Line 16
76(f)	Per Line 69(g)
78(f)	Sum of Lines 73 through 76
80(f)	Line 9(a)
81(h)	Line 80(f) * Line 90(f)
82(h)	Line 80(f) * Line 91(f)
83(h)	Line 80(f) * Line 92(f)
84(h)	Line 80(f) * Line 93(f)
85(h)	Line 80(f) * Line 94(f)
86(f)	Line 72(h)
87(f)	Line 9(a)
87(g)	Line 86(f) - Line 87(f)
89(f)	Line 5(a)
90(f)	Line 90(a) - ((Line 40(b)+Line 1(f))*3.40%)
91(f)	Line 91(a) - ((Line 40(f)+Line 14(f))*3.40%)
92(f)	Line 92(a) - ((Line 40(j)+Line 26(f))*3.40%)
93(f)	Line 93(a) - ((Line 73(b)+Line 63(f))*3.40%)
94(f)	Line 78(f)
89(g)-94(g)	Line 87(g)
89(h)-94(h)	Lines 89(f) through 94(f), Col (f) * Col (g)
95(h)	Sum of Lines 89(h) through 94(h)
97(h)	Sum of Lines 81(h) through 85(h) + Line 95(h)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
									CY 2011	CY 2012	Jan-2013	Feb 13 - Jan 14			
1	Total Base Rate Plant DIT Provision								$15,856,458	$5,546,827	$521,151	($1,967,911)			
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
2	Total Base Rate Plant DIT Provision								$13,279,050	$4,353,286	($1,639,926)	$0	$0	$0	$0
3	Incremental FY 12	($228,498)	($226,281)	($224,120)	($222,009)	($219,947)	($217,927)	($215,949)	($228,498)	$2,217	$2,161	$2,110	$2,063	$2,019	$1,979
4	Incremental FY 13		($2,013,121)	($1,937,607)	($2,045,965)	($1,957,316)	($1,863,117)	($1,763,799)		($2,013,121)	$75,514	($108,358)	$88,649	$94,199	$99,318
5	Incremental FY 14			$2,763,058	$2,543,022	$2,439,963	$2,329,465	$2,212,064			$2,763,058	($220,036)	($103,059)	($110,498)	($117,401)
6	FY 2015				$24,793,846	$24,814,134	$24,778,689	$24,691,831				$24,793,846	$20,288	($35,445)	($86,858)
7	FY 2016					$18,950,456	$19,142,825	$19,281,874					$18,950,456	$192,369	$139,049
8	FY 2017						$20,821,940	$20,852,979						$20,821,940	$31,039
9	FY 2018							$19,606,374							$19,606,374
10	TOTAL Plant DIT Provision	($228,498)	($2,239,403)	$601,331	$25,068,893	$44,027,290	$64,991,874	$84,665,375	$13,050,552	$2,342,381	$1,200,808	$24,467,561	$18,958,397	$20,964,585	$19,673,500
11	Distribution-related NOL								$3,434,992	$8,552,548	$13,179,356	$8,148,936	$6,705,697	$1,388,912	$0
12	Lesser of Distribution-related NOL or DIT Provision								$3,434,992	$2,342,381	$1,200,808	$8,148,936	$6,705,697	$1,388,912	$0
13	Total NOL								$4,310,461	$11,442,811	$19,452,677	$12,108,052	$10,200,749	$2,073,004	$0
14	NOL recovered in transmission rates								$875,468	$2,890,262	$6,273,321	$3,959,116	$3,495,052	$684,091	$0
15	Distribution-related NOL								$3,434,992	$8,552,548	$13,179,356	$8,148,936	$6,705,697	$1,388,912	$0

1(h) Per Dkt 4323 Compliance filing Attachment 1, Page 64 of 71, Line 19(e) less Line 19(a)
1(i)-1(k) Per Dkt 4323 Compliance filing Attachment 1, Page 70 of 71, Lines 32, 42, and 48
3(a)-9(g) ADIT per vintage year ISR revenue requirement calculations
3(h) -9(n) Year over year change in ADIT shown in Cols (a) through (e)
10 Sum of Lines 2 through 9
11 Line 15
12 Lesser of Line 10 or 11
13 Per Tax Department
14 Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 13
15 Line 13 - Line 14

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
True-Up for FY 2012 through FY 2018 Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Revenue Requirement Year						
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
1	Return on Rate Base	9.30%	9.84%	9.68%	9.68%	9.68%	9.68%	9.68%
		Vintage Capital Investment Year						
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
2	Lesser of NOL or DIT Provision	$ 3,434,992	$ 2,342,381	$ 1,200,808	$ 8,148,936	$ 6,705,697	$ 1,388,912	$ -

	<u>Revenue Requirement Increase due to NOL</u>							
		Revenue Requirement Year						
	Vintage Capital Investment Year	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
3	FY 2012	$ 159,727	$ 338,003	$ 332,507	$ 332,507	$ 332,507	$ 332,507	$ 332,507
4	FY 2013	$ -	$ 115,245	$ 226,743	$ 226,743	$ 226,743	$ 226,743	$ 226,743
5	FY 2014	$ -	$ -	$ 25,833	$ 116,238	$ 116,238	$ 116,238	$ 116,238
6	FY 2015	$ -	$ -	$ -	$ 394,409	$ 788,817	$ 788,817	$ 788,817
7	FY 2016	$ -	$ -	$ -	$ -	$ 324,556	$ 649,111	$ 649,111
8	FY 2017	$ -	$ -	$ -	$ -	$ -	$ 67,223	$ 134,447
9	FY 2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	TOTAL	**$ 159,727**	**$ 453,248**	**$ 585,082**	**$ 1,069,897**	**$ 1,788,861**	**$ 2,180,640**	**$ 2,247,863**

1(a) Per Docket No. 4065
1(b)-(c) Per vintage year revenue requirement calculations at Page 12 of 26, and Page 10 of 26, respectively
2 Per Page 21 of 26, Line 12
3 Line 2(a) * Line 1(a) * 50%; Line 2(a) * Line 1(b); Line 2(a) * Line 1(c); Line 2(a) * Line 1(d); Line 2(a) * Line 1(e)
4 Line 2(b) * Line 1(b) * 50%; Line 2(b) * Line 1(c); Line 2(b) * Line 1(d); Line 2(b) * Line 1(e)
5 Line 2(c) * Line 1(c) * 23.23%; Line 2(c) * Line 1(d); Line 2(c) * Line 1(e)
6 Line 2(d) * Line 1(d) * 50%; Line 2(d) * Line 1(e); Line 2(d) * Line 1(f); Line 2(d) * Line 1(g)
7 Line 2(e) * Line 1(e) * 50%; Line 2(e) * Line 1(f); Line 2(e) * Line 1(g)
8 Line 2(f) * Line 1(f) * 50%; Line 2(f) * Line 1(g)
9 Line 2(g) * Line 1(g) * 50%
10 Sum of Lines 3 through 9

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
True-Up for FY 2012 through FY 2016 Transmission - Related Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Revenue Requirement Year						
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
1	Return on Rate Base	9.30%	9.84%	9.68%	9.68%	9.68%	9.68%	9.68%
		Vintage Capital Investment Year						
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
2	Lesser of total NOL or DIT Provision (as previously filed)	$ 4,310,461	$ 2,342,381	$ 1,200,808	$ 12,108,052	$ 10,200,749	$ 2,073,004	$ -
2a	Lesser of Distribution-related NOL or DIT Provision	$ 3,434,992	$ 2,342,381	$ 1,200,808	$ 8,148,936	$ 6,705,697	$ 1,388,912	$ -
3	Transmission-related NOL adjustment	$ (875,469)	$ 0	$ 0	$ (3,959,116)	$ (3,495,052)	$ (684,092)	$ -
	Revenue Requirement Increase due to NOL							
		Revenue Requirement Year						
	Vintage Capital Investment Year	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
4	FY 2012	$ (40,709)	$ (86,146)	$ (84,745)	$ (84,745)	$ (84,745)	$ (84,745)	$ (84,745)
5	FY 2013	$ -	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
6	FY 2014	$ -	$ -	$ 0	$ 0	$ 0	$ 0	$ 0
7	FY 2015	$ -	$ -	$ -	$ (191,621)	$ (383,242)	$ (383,242)	$ (383,242)
8	FY 2016	$ -	$ -	$ -	$ -	$ (169,161)	$ (338,321)	$ (338,321)
9	FY 2017	$ -	$ -	$ -	$ -	$ -	$ (33,110)	$ (66,220)
10	FY 2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	TOTAL	**$ (40,709)**	**$ (86,146)**	**$ (84,745)**	**$ (276,367)**	**$ (637,148)**	**$ (839,419)**	**$ (872,529)**
12	**Total FY 2012 through FY 2016 revenue requirement impact**							**$ (1,125,115)**

1 Per Docket No. 4065
2 Per Docket No. 4539
2a Per Page 21 of 26, Line 12
3 Line 2a - Line 2
4 Line 3(a) * Line 1(a) * 50%; Line 3(a) * Line 1(b); Line 3(a) * Line 1(c); Line 3(a) * Line 1(d); Line 3(a) * Line 1(e); Line 3(a) * Line 1(f); Line 3(a) * Line 1(g)
5 Line 3(b) * Line3(b) * 50%; Line 3(b) * Line 1(c); Line 3(b) * Line 1(d); Line 3(b) * Line 1(e); Line 3(b) * Line 1(f); Line 3(b) * Line 1(g)
6 Line 3(c) * Line 1(c) * 22.22%; Line 3(c) * Line 1(d); Line 3(c) * Line 1(e); Line 3(c) * Line 1(f); Line 3(c) * Line 1(g)
7 Line 3(d) * Line 1(d) * 50%; Line 3(d) * Line 1(e); Line 3(d) * Line 1(f); Line 3(d) * Line 1(g)
8 Line 3(e) * Line 1(e) * 50%; Line 3(e) * Line 1(f); Line 3(e) * Line 1(g)
9 Line 3(f) * Line 1(f) * 50%; Line 3(f) * Line 1(g)
10 Line 3(g) * Line 1(g) * 50%
11 Sum of Lines 4 through 10
12 Line 11(a) + Line 11(b) + Line 11(c) + Line 11(d) + Line 11(e)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
True-Up for FY 2013 through FY 2016 Work Order Write Off Adjustment

		(a)	(b)	(c)	(d)	(e)	(f)
				Vintage Capital Investment Year			
		FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
1	Total Net Plant in Service (as previously filed)	$ (8,929,918)	$ 5,263,028	$ 40,613,665	$ 36,614,111	$ 45,246,226	$ 41,457,226
1a	Total Net Plant in Service	$ (9,820,822)	$ 4,744,059	$ 40,319,425	$ 37,144,770	$ 45,246,226	$ 41,457,226
2	Work Order Write Off Adjustment	$ (890,904)	$ (518,969)	$ (294,240)	$ 530,659	$ -	$ -

Revenue Requirement Decrease due to Work Order Write Off Adjustment

				Revenue Requirement Year			
	Vintage Capital Investment Year	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
3	FY 2013	$ (47,076)	$ (123,944)	$ (136,554)	$ (108,732)	$ (117,241)	$ (111,015)
4	FY 2014	$ -	$ (19,800)	$ (53,014)	$ (51,607)	$ (50,229)	$ (48,810)
5	FY 2015	$ -	$ -	$ (16,457)	$ (32,427)	$ (31,462)	$ (30,490)
6	FY 2016	$ -	$ -	$ -	$ 29,263	$ 57,675	$ 55,951
7	FY 2017	$ -	$ -	$ -	$ -	$ -	$ -
8	FY 2018	$ -	$ -	$ -	$ -	$ -	$ -
9	TOTAL	**$ (47,076)**	**$ (143,744)**	**$ (206,024)**	**$ (163,502)**	**$ (141,257)**	**$ (134,363)**
10	**Total FY 2013 through FY 2016 revenue requirement impact**						**$ (560,347)**

1 Per Docket No. 4539
1(a) Per FY 2013 through FY 2016 Total Net Plant in Service reflected in the vintage year revenue requirement calculations
2 Line 1a - Line 1
3 Col (a) through Col (f) = Page 12 of 26 , Line 35
4 Col (a) through Col (f) = Page 10 of 26 , Line 35
5 Col (a) through Col (f) = Page 8 of 26 , Line 35
6 Col (a) through Col (f) = Page 6 of 26 , Line 35
9 Sum of Lines 3 through 8
10 Line 9(a) + Line 9(b) + Line 9(c) + Line 9(d)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of FY 2018 Net Deferred Tax Reserve Proration

Line No.	Deferred Tax Subject to Proration		(a)=Sum of (b) through (h) Total	(b) Vintage Year 2018	(c) Vintage Year 2017	(d) Vintage Year 2016	(e) Vintage Year 2015	(f) Vintage Year 2014	(g) Vintage Year 2013	(h) Vintage Year 2012
1	Book Depreciation	Col (b) = Page 2 of 26, Line 16; Col (c) = Page 4 of 26, Line 15; Col (d) = Page 6 of 26, Line 16; Col (e) = Page 8 of 26, Line 16; Col (f) = Page 10 of 26, Line 16; Col (g) = Page 12 of 26, Line 15; Col (h) = Page 14 of 26, Line 13	$6,767,472	$992,555	$2,122,861	$1,479,463	$2,062,926	$578,263	($464,370)	($4,227)
2	Bonus Depreciation	Page 3 of 26, Line 12	($26,966,349)	($26,966,349)	$0	$0	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (b) = Page 3 of 26, Line 18; Col (c) = Page 5 of 26, Line 18; Col (d) = Page 7 of 26, Line 18; Col (e) = Page 9 of 26, Line 18; Col (f) = Page 11 of 26, Line 18; Col (g) = Page 13 of 26, Line 18; Col (h) = Page 15 of 26, Line 18	($7,105,894)	($1,139,188)	($2,211,545)	($1,876,746)	($1,814,760)	(242,832)	$180,604	($1,427)
4	FY18 tax (gain)/loss on retirements	Page 3 of 26, Line 19	($1,760,937)	($1,760,937)	$0	$0	$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($29,065,708)	($28,873,919)	($88,684)	($397,283)	$248,166	$335,430	($283,766)	($5,653)
6	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($10,172,998)	($10,105,872)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
	Deferred Tax Not Subject to Proration									
8	Capital Repairs Deduction	Page 3 of 26, Line 3	($17,498,293)	($17,498,293)						
9	Cost of Removal	Page 3 of 26, Line 20	($9,646,000)	($9,646,000)						
10	Book/Tax Depreciation Timing Difference at 3/31/2017		$0	$0						
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($27,144,293)	($27,144,293)						
12	Effective Tax Rate		35.00%	35.00%						
13	Deferred Tax Reserve	Line 11 * Line 12	($9,500,503)	($9,500,503)						
14	Total Deferred Tax Reserve	Line 7 + Line 13	($19,673,500)	($19,606,374)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
15	Net Operating Loss	Page 2 of 26, Line 21	$0	$0						
16	Net Deferred Tax Reserve	Line 14 + Line 15	($19,673,500)	($19,606,374)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
	Allocation of FY 2018 Estimated Federal NOL									
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($28,873,919)	($28,873,919)						
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($27,144,293)	($27,144,293)						
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($56,018,212)	($56,018,212)						
20	Total FY 2018 Federal NOL	(Page 2 of 26, Line 21) / 35%	$0	$0						
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0						
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0						
23	Effective Tax Rate		35.00%	35.00%						
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0						
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($10,172,998)	($10,105,872)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)

Line No.	Proration Calculation	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (r)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
26	April 2017	30	91.78%	($778,072)	($772,938)	($2,374)	($10,635)	$6,643	$8,979	($7,596)	($151)
27	May 2017	31	83.29%	($706,071)	($701,412)	($2,154)	($9,651)	$6,029	$8,148	($6,893)	($137)
28	June 2017	30	75.07%	($636,393)	($632,194)	($1,942)	($8,698)	$5,434	$7,344	($6,213)	($124)
29	July 2017	31	66.58%	($564,392)	($560,668)	($1,722)	($7,714)	$4,819	$6,513	($5,510)	($110)
30	August 2017	31	58.08%	($492,392)	($489,143)	($1,502)	($6,730)	$4,204	$5,682	($4,807)	($96)
31	September 2017	30	49.86%	($422,714)	($419,924)	($1,290)	($5,778)	$3,609	$4,878	($4,127)	($82)
32	October 2017	31	41.37%	($350,713)	($348,399)	($1,070)	($4,794)	$2,994	$4,047	($3,424)	($68)
33	November 2017	30	33.15%	($281,035)	($279,180)	($857)	($3,841)	$2,400	$3,243	($2,744)	($55)
34	December 2017	31	24.66%	($209,034)	($207,655)	($638)	($2,857)	$1,785	$2,412	($2,041)	($41)
35	January 2018	31	16.16%	($137,034)	($136,129)	($418)	($1,873)	$1,170	$1,581	($1,338)	($27)
36	February 2018	28	8.49%	($72,001)	($71,526)	($220)	($984)	$615	$831	($703)	($14)
37	March 2018	31	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
38	Total	365		($4,649,850)	($4,619,168)	($14,187)	($63,556)	$39,701	$53,661	($45,396)	($904)
39	Deferred Tax Without Proration	Line 25		($10,172,998)	($10,105,872)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
40	Proration Adjustment	Line 38 - Line 39		$5,523,148	$5,486,704	$16,852	$75,493	($47,157)	($63,739)	$53,922	$1,074

Column Notes:
(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of FY 2019 Net Deferred Tax Reserve Proration

Line No.	Deferred Tax Subject to Proration		(a)=Sum of (b) through (h) Total	(b) Vintage Year 2018	(c) Vintage Year 2017	(d) Vintage Year 2016	(e) Vintage Year 2015	(f) Vintage Year 2014	(g) Vintage Year 2013	(h) Vintage Year 2012
1	Book Depreciation	Col (b) = Page 2 of 26, Line 16; Col (c) = Page 4 of 26, Line 15; Col (d) = Page 6 of 26, Line 16; Col (e) = Page 8 of 26, Line 16; Col (f) = Page 10 of 26, Line 16; Col (g) = Page 12 of 26, Line 15; Col (h) = Page 14 of 26, Line 13	$7,760,027	$1,985,110	$2,122,861	$1,479,463	$2,062,926	$578,263	($464,370)	($4,227)
2	Bonus Depreciation		$0	$0	$0	$0	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (b) = Page 3 of 26, Line 18; Col (c) = Page 5 of 26, Line 18; Col (d) = Page 7 of 26, Line 18; Col (e) = Page 9 of 26, Line 18; Col (f) = Page 11 of 26, Line 18; Col (g) = Page 13 of 26, Line 18; Col (h) = Page 15 of 26, Line 18	($7,712,088)	($2,193,014)	($2,045,503)	($1,736,208)	($1,678,440)	($224,640)	$167,038	($1,320)
4	FY18 tax (gain)/loss on retirements		$0	$0	$0	$0	$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$47,940	($207,904)	$77,358	($256,745)	$384,486	$353,622	($297,333)	($5,547)
6	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$16,779	($72,766)	$27,075	($89,861)	$134,570	$123,768	($104,066)	($1,941)
	Deferred Tax Not Subject to Proration									
8	Capital Repairs Deduction		$0	$0						
9	Cost of Removal		$0	$0						
10	Book/Tax Depreciation Timing Difference at 3/31/2017		$0	$0						
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0						
12	Effective Tax Rate		35.00%	35.00%						
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0						
14	Total Deferred Tax Reserve	Line 7 + Line 13	$16,779	($72,766)	$27,075	($89,861)	$134,570	$123,768	($104,066)	($1,941)
15	Net Operating Loss		$0	$0						
16	Net Deferred Tax Reserve	Line 14 + Line 15	$16,779	($72,766)	$27,075	($89,861)	$134,570	$123,768	($104,066)	($1,941)
	Allocation of FY 2018 Estimated Federal NOL									
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($207,904)	($207,904)						
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0						
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($207,904)	($207,904)						
20	Total FY 2018 Federal NOL		$0	$0						
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0						
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0						
23	Effective Tax Rate		35.00%	35.00%						
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0						
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$16,779	($72,766)	$27,075	($89,861)	$134,570	$123,768	($104,066)	($1,941)

Line No.	Proration Calculation	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (r)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
26	April 2017	30	91.78%	$1,283	($5,565)	$2,071	($6,873)	$10,292	$9,466	($7,959)	($148)
27	May 2017	31	83.29%	$1,165	($5,050)	$1,879	($6,237)	$9,340	$8,590	($7,223)	($135)
28	June 2017	30	75.07%	$1,050	($4,552)	$1,694	($5,621)	$8,418	$7,743	($6,510)	($121)
29	July 2017	31	66.58%	$931	($4,037)	$1,502	($4,985)	$7,466	$6,867	($5,774)	($108)
30	August 2017	31	58.08%	$812	($3,522)	$1,310	($4,349)	$6,513	$5,991	($5,037)	($94)
31	September 2017	30	49.86%	$697	($3,024)	$1,125	($3,734)	$5,592	$5,143	($4,324)	($81)
32	October 2017	31	41.37%	$578	($2,509)	$933	($3,098)	$4,639	$4,267	($3,588)	($67)
33	November 2017	30	33.15%	$464	($2,010)	$748	($2,482)	$3,718	$3,419	($2,875)	($54)
34	December 2017	31	24.66%	$345	($1,495)	$556	($1,846)	$2,765	$2,543	($2,138)	($40)
35	January 2018	31	16.16%	$226	($980)	$365	($1,210)	$1,813	$1,667	($1,402)	($26)
36	February 2018	28	8.49%	$119	($515)	$192	($636)	$952	$876	($737)	($14)
37	March 2018	31	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
38	Total	365		$7,669	($33,260)	$12,376	($41,073)	$61,509	$56,572	($47,566)	($887)
39	Deferred Tax Without Proration	Line 25		$16,779	($72,766)	$27,075	($89,861)	$134,570	$123,768	($104,066)	($1,941)
40	Proration Adjustment	Line 38 - Line 39		($9,110)	$39,506	($14,700)	$48,787	($73,061)	($67,196)	$56,500	$1,054

Column Notes:
(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

Section 6

Rate Design and Rates
FY 2018 Electric ISR Plan Annual Filing

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors
(for the 12 months beginning April 1, 2017)

		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	$0.00163	$0.00169	$0.00122	$0.00079	$0.00079	n/a	n/a	$0.01273	$0.00123
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.04	n/a	$0.03	$0.36	n/a	n/a
(3)	CapEx kWh Charge	$0.00281	$0.00262	n/a	n/a	n/a	n/a	n/a	$0.01389	$0.00212
(4)	CapEx kW Charge	n/a	n/a	$0.65	$0.07	$0.69	$0.05	$0.54	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

(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 3, 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
FY18 Proposed Operations & Maintenance Factors
(for the 12 months beginning April 1, 2017)

		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)	FY2018 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$10,306,051							
(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	$10,306,051	$4,949,160	$1,012,966	$1,592,753	$1,572,511	$377,657	$771,508	$29,495
(5)	Forecasted kWh - April 2017 through March 2018	7,423,513,683	3,027,852,906	596,142,607	1,295,163,245	1,988,885,728	431,021,320	60,569,751	23,878,126
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00163	$0.00169	$0.00122	$0.00079	n/a	$0.01273	$0.00123
(7)	Forecasted kW - April 2017 through March 2018						1,037,528		
(8)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		n/a	n/a	n/a	n/a	$0.36	n/a	n/a

(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
FY18 Proposed CapEx Factors
(for the 12 months beginning April 1, 2017)

		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)	Proposed FY2018 Capital Investment Component of Revenue Requirement	$16,145,080							
(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	$16,145,080	$8,521,500	$1,567,610	$2,370,008	$2,231,796	$561,750	$841,728	$50,688
(5)	Forecasted kWh - April 2017 through March 2018	7,423,513,683	3,027,852,906	596,142,607	1,295,163,245	1,988,885,728	431,021,320	60,569,751	23,878,126
(6)	Proposed CapEx Factor - kWh charge		$0.00281	$0.00262	n/a	n/a	n/a	$0.01389	$0.00212
(7)	Forecasted kW - April 2017 through March 2018				3,595,715	3,204,270	1,037,528		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$0.65	$0.69	$0.54	n/a	n/a

(1) per Section 5: Attachment 1, page 1, Line (18), 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

		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	$1,572,511	$377,657
(2)	Forecasted kW - April 2017 through March 2018	3,204,270	1,037,528
(3)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW	$0.49	$0.36
(4)	Discounted O&M kW Factor effective 4/01/2017	$0.04	$0.03
	CapEx Factors		
(5)	Proposed CapEx kW Factor Charge effective 4/01/2017	$0.69	$0.54
(6)	Discounted CapEx kW Factor Charge effective 4/1/2017	$0.07	$0.05
	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 4/1/2017	$0.70	$0.30
(9)	Sum of O&M and CapEx Factors and Base Distribution Charge for Back-up Service Rates	$0.81	$0.38

(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)

Exhibit 1 – JHP & RM
Section 7
Bill Impacts

Section 7

Bill Impacts
FY 2018 Electric ISR Plan Annual Filing

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

Monthly kWh	Present Rates				Proposed Rates				Increase (Decrease)								Percentage of Customers
									$				% of Total Bill				
	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	
150	$18.51	$12.27	$1.28	$32.06	$18.49	$12.27	$1.28	$32.04	($0.02)	$0.00	$0.00	($0.02)	-0.1%	0.0%	0.0%	-0.1%	13.7%
300	$31.08	$24.54	$2.32	$57.94	$31.03	$24.54	$2.32	$57.89	($0.05)	$0.00	$0.00	($0.05)	-0.1%	0.0%	0.0%	-0.1%	17.5%
400	$39.45	$32.72	$3.01	$75.18	$39.39	$32.72	$3.00	$75.11	($0.06)	$0.00	($0.01)	($0.07)	-0.1%	0.0%	0.0%	-0.1%	11.8%
500	$47.83	$40.90	$3.70	$92.43	$47.75	$40.90	$3.69	$92.34	($0.08)	$0.00	($0.01)	($0.09)	-0.1%	0.0%	0.0%	-0.1%	10.8%
600	$56.21	$49.07	$4.39	$109.67	$56.10	$49.07	$4.38	$109.55	($0.11)	$0.00	($0.01)	($0.12)	-0.1%	0.0%	0.0%	-0.1%	9.4%
700	$64.58	$57.25	$5.08	$126.91	$64.46	$57.25	$5.07	$126.78	($0.12)	$0.00	($0.01)	($0.13)	-0.1%	0.0%	0.0%	-0.1%	7.7%
1,200	$106.46	$98.15	$8.53	$213.14	$106.26	$98.15	$8.52	$212.93	($0.20)	$0.00	($0.01)	($0.21)	-0.1%	0.0%	0.0%	-0.1%	15.0%
2,000	$173.47	$163.58	$14.04	$351.09	$173.13	$163.58	$14.03	$350.74	($0.34)	$0.00	($0.01)	($0.35)	-0.1%	0.0%	0.0%	-0.1%	14.1%

		Present Rates		Proposed Rates	
Customer Charge		$5.00		$5.00	
RE Growth Factor		$0.22		$0.22	
LIHEAP Charge		$0.73		$0.73	
Transmission Energy Charge	kWh x	$0.02705		$0.02705	
Distribution Energy Charge	kWh x	$0.04278	(1)	$0.04261	(2)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08179		$0.08179	

Note (1): includes the current CapEx Factor of 0.307¢/kWh and the current O&M Factor of 0.154¢/kWh

Note (2): includes the proposed CapEx Factor of 0.281¢/kWh and the proposed O&M Factor of 0.163¢/kWh

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

Monthly	Present Rates				Proposed Rates				Increase (Decrease)								Percentage
									$				% of Total Bill				
kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	of Customers
150	$11.49	$12.27	$0.99	$24.75	$11.47	$12.27	$0.99	$24.73	($0.02)	$0.00	$0.00	($0.02)	-0.1%	0.0%	0.0%	-0.1%	13.7%
300	$22.04	$24.54	$1.94	$48.52	$21.99	$24.54	$1.94	$48.47	($0.05)	$0.00	$0.00	($0.05)	-0.1%	0.0%	0.0%	-0.1%	17.5%
400	$29.07	$32.72	$2.57	$64.36	$29.00	$32.72	$2.57	$64.29	($0.07)	$0.00	$0.00	($0.07)	-0.1%	0.0%	0.0%	-0.1%	11.8%
500	$36.10	$40.90	$3.21	$80.21	$36.01	$40.90	$3.20	$80.11	($0.09)	$0.00	($0.01)	($0.10)	-0.1%	0.0%	0.0%	-0.1%	10.8%
600	$43.12	$49.07	$3.84	$96.03	$43.02	$49.07	$3.84	$95.93	($0.10)	$0.00	$0.00	($0.10)	-0.1%	0.0%	0.0%	-0.1%	9.4%
700	$50.15	$57.25	$4.48	$111.88	$50.03	$57.25	$4.47	$111.75	($0.12)	$0.00	($0.01)	($0.13)	-0.1%	0.0%	0.0%	-0.1%	7.7%
1,200	$85.30	$98.15	$7.64	$191.09	$85.09	$98.15	$7.64	$190.88	($0.21)	$0.00	$0.00	($0.21)	-0.1%	0.0%	0.0%	-0.1%	15.0%
2,000	$141.53	$163.58	$12.71	$317.82	$141.19	$163.58	$12.70	$317.47	($0.34)	$0.00	($0.01)	($0.35)	-0.1%	0.0%	0.0%	-0.1%	14.1%

		Present Rates		Proposed Rates	
Customer Charge		$0.00		$0.00	
RE Growth Factor		$0.22		$0.22	
LIHEAP Charge		$0.73		$0.73	
Transmission Energy Charge	kWh x	$0.02705		$0.02705	
Distribution Energy Charge	kWh x	$0.02931	(1)	$0.02914	(2)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08179		$0.08179	

Note (1): includes the current CapEx Factor of 0.307¢/kWh and the current O&M Factor of 0.154¢/kWh

Note (2): includes the proposed CapEx Factor of 0.281¢/kWh and the proposed O&M Factor of 0.163¢/kWh

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

Monthly kWh	Present Rates				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	
250	$30.52	$20.99	$2.15	$53.66	$30.48	$20.99	$2.14	$53.61	($0.04)	$0.00	($0.01)	($0.05)	-0.1%	0.0%	0.0%	-0.1%	35.2%
500	$50.05	$41.98	$3.83	$95.86	$49.96	$41.98	$3.83	$95.77	($0.09)	$0.00	$0.00	($0.09)	-0.1%	0.0%	0.0%	-0.1%	17.0%
1,000	$89.10	$83.96	$7.21	$180.27	$88.93	$83.96	$7.20	$180.09	($0.17)	$0.00	($0.01)	($0.18)	-0.1%	0.0%	0.0%	-0.1%	19.0%
1,500	$128.16	$125.94	$10.59	$264.69	$127.90	$125.94	$10.58	$264.42	($0.26)	$0.00	($0.01)	($0.27)	-0.1%	0.0%	0.0%	-0.1%	9.8%
2,000	$167.21	$167.92	$13.96	$349.09	$166.87	$167.92	$13.95	$348.74	($0.34)	$0.00	($0.01)	($0.35)	-0.1%	0.0%	0.0%	-0.1%	19.1%

		Present Rates		Proposed Rates	
Customer Charge		$10.00		$10.00	
RE Growth Factor		$0.26		$0.26	
LIHEAP Charge		$0.73		$0.73	
Transmission Energy Charge	kWh x	$0.02566		$0.02566	
Distribution Energy Charge	kWh x	$0.03852	(1)	$0.03835	(2)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08396		$0.08396	

Note (1): includes the current CapEx Factor of 0.288¢/kWh and the current O&M Factor of 0.160¢/kWh

Note (2): includes the proposed CapEx Factor of 0.262¢/kWh and the proposed O&M Factor of 0.169¢/kWh

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

Hours Use: 200

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	4000	$393.35	$335.84	$30.38	$759.57	$392.95	$335.84	$30.37	$759.16	($0.40)	$0.00	($0.01)	($0.41)	-0.1%	0.0%	0.0%	-0.1%
50	10000	$859.79	$839.60	$70.81	$1,770.20	$857.59	$839.60	$70.72	$1,767.91	($2.20)	$0.00	($0.09)	($2.29)	-0.1%	0.0%	0.0%	-0.1%
100	20000	$1,637.19	$1,679.20	$138.18	$3,454.57	$1,631.99	$1,679.20	$137.97	$3,449.16	($5.20)	$0.00	($0.21)	($5.41)	-0.2%	0.0%	0.0%	-0.2%
150	30000	$2,414.59	$2,518.80	$205.56	$5,138.95	$2,406.39	$2,518.80	$205.22	$5,130.41	($8.20)	$0.00	($0.34)	($8.54)	-0.2%	0.0%	0.0%	-0.2%

		Present Rates		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$2.46		$2.46	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.59		$3.59	
Transmission Energy Charge	kWh x	$0.01068		$0.01068	
Distribution Demand Charge-xcs 10 kW	kW x	$5.58	(1)	$5.50	(2)
Distribution Energy Charge	kWh x	$0.00728	(3)	$0.00738	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08396		$0.08396	

Note (1): includes the current CapEx Factor of 0.73¢

Note (2): includes the proposed CapEx Factor of 0.65¢

Note (3): includes the current O&M Factor of 0.117¢/kWh

Note (4): includes the proposed O&M Factor of 0.122¢/kWh

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

Hours Use: 300

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	6000	$457.13	$503.76	$40.04	$1,000.93	$456.93	$503.76	$40.03	$1,000.72	($0.20)	$0.00	($0.01)	($0.21)	0.0%	0.0%	0.0%	0.0%
50	15000	$1,019.24	$1,259.40	$94.94	$2,373.58	$1,017.54	$1,259.40	$94.87	$2,371.81	($1.70)	$0.00	($0.07)	($1.77)	-0.1%	0.0%	0.0%	-0.1%
100	30000	$1,956.09	$2,518.80	$186.45	$4,661.34	$1,951.89	$2,518.80	$186.28	$4,656.97	($4.20)	$0.00	($0.17)	($4.37)	-0.1%	0.0%	0.0%	-0.1%
150	45000	$2,892.94	$3,778.20	$277.96	$6,949.10	$2,886.24	$3,778.20	$277.69	$6,942.13	($6.70)	$0.00	($0.27)	($6.97)	-0.1%	0.0%	0.0%	-0.1%

		Present Rates		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$2.46		$2.46	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.59		$3.59	
Transmission Energy Charge	kWh x	$0.01068		$0.01068	
Distribution Demand Charge-xcs 10 kW	kW x	$5.58	(1)	$5.50	(2)
Distribution Energy Charge	kWh x	$0.00728	(3)	$0.00738	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08396		$0.08396	

Note (1): includes the current CapEx Factor of 0.73¢

Note (2): includes the proposed CapEx Factor of 0.65¢

Note (3): includes the current O&M Factor of 0.117¢/kWh

Note (4): includes the proposed O&M Factor of 0.122¢/kWh

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

Hours Use: 400

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	8000	$520.91	$671.68	$49.69	$1,242.28	$520.91	$671.68	$49.69	$1,242.28	$0.00	$0.00	$0.00	$0.00	0.0%	0.0%	0.0%	0.0%
50	20000	$1,178.69	$1,679.20	$119.08	$2,976.97	$1,177.49	$1,679.20	$119.03	$2,975.72	($1.20)	$0.00	($0.05)	($1.25)	0.0%	0.0%	0.0%	0.0%
100	40000	$2,274.99	$3,358.40	$234.72	$5,868.11	$2,271.79	$3,358.40	$234.59	$5,864.78	($3.20)	$0.00	($0.13)	($3.33)	-0.1%	0.0%	0.0%	-0.1%
150	60000	$3,371.29	$5,037.60	$350.37	$8,759.26	$3,366.09	$5,037.60	$350.15	$8,753.84	($5.20)	$0.00	($0.22)	($5.42)	-0.1%	0.0%	0.0%	-0.1%

		Present Rates		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$2.46		$2.46	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.59		$3.59	
Transmission Energy Charge	kWh x	$0.01068		$0.01068	
Distribution Demand Charge-xcs 10 kW	kW x	$5.58	(1)	$5.50	(2)
Distribution Energy Charge	kWh x	$0.00728	(3)	$0.00738	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08396		$0.08396	

Note (1): includes the current CapEx Factor of 0.73¢

Note (2): includes the proposed CapEx Factor of 0.65¢

Note (3): includes the current O&M Factor of 0.117¢/kWh

Note (4): includes the proposed O&M Factor of 0.122¢/kWh

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

Hours Use: 500

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	10000	$584.69	$839.60	$59.35	$1,483.64	$584.89	$839.60	$59.35	$1,483.84	$0.20	$0.00	$0.00	$0.20	0.0%	0.0%	0.0%	0.0%
50	25000	$1,338.14	$2,099.00	$143.21	$3,580.35	$1,337.44	$2,099.00	$143.19	$3,579.63	($0.70)	$0.00	($0.02)	($0.72)	0.0%	0.0%	0.0%	0.0%
100	50000	$2,593.89	$4,198.00	$283.00	$7,074.89	$2,591.69	$4,198.00	$282.90	$7,072.59	($2.20)	$0.00	($0.10)	($2.30)	0.0%	0.0%	0.0%	0.0%
150	75000	$3,849.64	$6,297.00	$422.78	$10,569.42	$3,845.94	$6,297.00	$422.62	$10,565.56	($3.70)	$0.00	($0.16)	($3.86)	0.0%	0.0%	0.0%	0.0%

		Present Rates		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$2.46		$2.46	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.59		$3.59	
Transmission Energy Charge	kWh x	$0.01068		$0.01068	
Distribution Demand Charge-xcs 10 kW	kW x	$5.58	(1)	$5.50	(2)
Distribution Energy Charge	kWh x	$0.00728	(3)	$0.00738	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08396		$0.08396	

Note (1): includes the current CapEx Factor of 0.73¢

Note (2): includes the proposed CapEx Factor of 0.65¢

Note (3): includes the current O&M Factor of 0.117¢/kWh

Note (4): includes the proposed O&M Factor of 0.122¢/kWh

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

Hours Use: 600

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	12000	$648.47	$1,007.52	$69.00	$1,724.99	$648.87	$1,007.52	$69.02	$1,725.41	$0.40	$0.00	$0.02	$0.42	0.0%	0.0%	0.0%	0.0%
50	30000	$1,497.59	$2,518.80	$167.35	$4,183.74	$1,497.39	$2,518.80	$167.34	$4,183.53	($0.20)	$0.00	($0.01)	($0.21)	0.0%	0.0%	0.0%	0.0%
100	60000	$2,912.79	$5,037.60	$331.27	$8,281.66	$2,911.59	$5,037.60	$331.22	$8,280.41	($1.20)	$0.00	($0.05)	($1.25)	0.0%	0.0%	0.0%	0.0%
150	90000	$4,327.99	$7,556.40	$495.18	$12,379.57	$4,325.79	$7,556.40	$495.09	$12,377.28	($2.20)	$0.00	($0.09)	($2.29)	0.0%	0.0%	0.0%	0.0%

		Present Rates		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$2.46		$2.46	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.59		$3.59	
Transmission Energy Charge	kWh x	$0.01068		$0.01068	
Distribution Demand Charge-xcs 10 kW	kW x	$5.58	(1)	$5.50	(2)
Distribution Energy Charge	kWh x	$0.00728	(3)	$0.00738	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.08396		$0.08396	

Note (1): includes the current CapEx Factor of 0.73¢

Note (2): includes the proposed CapEx Factor of 0.65¢

Note (3): includes the current O&M Factor of 0.117¢/kWh

Note (4): includes the proposed O&M Factor of 0.122¢/kWh

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

Hours Use: 200

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	40,000	$2,920.71	$1,998.40	$204.96	$5,124.07	$2,923.11	$1,998.40	$205.06	$5,126.57	$2.40	$0.00	$0.10	$2.50	0.0%	0.0%	0.0%	0.0%
750	150,000	$11,075.01	$7,494.00	$773.71	$19,342.72	$11,056.51	$7,494.00	$772.94	$19,323.45	($18.50)	$0.00	($0.77)	($19.27)	-0.1%	0.0%	0.0%	-0.1%
1,000	200,000	$14,781.51	$9,992.00	$1,032.23	$25,805.74	$14,753.51	$9,992.00	$1,031.06	$25,776.57	($28.00)	$0.00	($1.17)	($29.17)	-0.1%	0.0%	0.0%	-0.1%
1,500	300,000	$22,194.51	$14,988.00	$1,549.27	$38,731.78	$22,147.51	$14,988.00	$1,547.31	$38,682.82	($47.00)	$0.00	($1.96)	($48.96)	-0.1%	0.0%	0.0%	-0.1%
2,500	500,000	$37,020.51	$24,980.00	$2,583.35	$64,583.86	$36,935.51	$24,980.00	$2,579.81	$64,495.32	($85.00)	$0.00	($3.54)	($88.54)	-0.1%	0.0%	0.0%	-0.1%

		Present Rates		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$17.78		$17.78	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.97		$3.97	
Transmission Energy Charge	kWh x	$0.01047		$0.01047	
Distribution Demand Charge-xcs 10 kW	kW x	$4.44	(1)	$4.39	(2)
Distribution Energy Charge	kWh x	$0.00768	(3)	$0.00774	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.74¢/kW

Note (2): includes the proposed CapEx Factor of 0.69¢/kW

Note (3): includes the current O&M Factor of 0.073¢/kWh

Note (4): includes the proposed O&M Factor of 0.079¢/kWh

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

Hours Use: 300

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	60,000	$3,562.31	$2,997.60	$273.33	$6,833.24	$3,565.91	$2,997.60	$273.48	$6,836.99	$3.60	$0.00	$0.15	$3.75	0.1%	0.0%	0.0%	0.1%
750	225,000	$13,481.01	$11,241.00	$1,030.08	$25,752.09	$13,467.01	$11,241.00	$1,029.50	$25,737.51	($14.00)	$0.00	($0.58)	($14.58)	-0.1%	0.0%	0.0%	-0.1%
1,000	300,000	$17,989.51	$14,988.00	$1,374.06	$34,351.57	$17,967.51	$14,988.00	$1,373.15	$34,328.66	($22.00)	$0.00	($0.91)	($22.91)	-0.1%	0.0%	0.0%	-0.1%
1,500	450,000	$27,006.51	$22,482.00	$2,062.02	$51,550.53	$26,968.51	$22,482.00	$2,060.44	$51,510.95	($38.00)	$0.00	($1.58)	($39.58)	-0.1%	0.0%	0.0%	-0.1%
2,500	750,000	$45,040.51	$37,470.00	$3,437.94	$85,948.45	$44,970.51	$37,470.00	$3,435.02	$85,875.53	($70.00)	$0.00	($2.92)	($72.92)	-0.1%	0.0%	0.0%	-0.1%

		Present Rates		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$17.78		$17.78	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.97		$3.97	
Transmission Energy Charge	kWh x	$0.01047		$0.01047	
Distribution Demand Charge-xcs 10 kW	kW x	$4.44	(1)	$4.39	(2)
Distribution Energy Charge	kWh x	$0.00768	(3)	$0.00774	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.74¢/kW

Note (2): includes the proposed CapEx Factor of 0.69¢/kW

Note (3): includes the current O&M Factor of 0.073¢/kWh

Note (4): includes the proposed O&M Factor of 0.079¢/kWh

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

Hours Use: 400

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	80,000	$4,203.91	$3,996.80	$341.70	$8,542.41	$4,208.71	$3,996.80	$341.90	$8,547.41	$4.80	$0.00	$0.20	$5.00	0.1%	0.0%	0.0%	0.1%
750	300,000	$15,887.01	$14,988.00	$1,286.46	$32,161.47	$15,877.51	$14,988.00	$1,286.06	$32,151.57	($9.50)	$0.00	($0.40)	($9.90)	0.0%	0.0%	0.0%	0.0%
1,000	400,000	$21,197.51	$19,984.00	$1,715.90	$42,897.41	$21,181.51	$19,984.00	$1,715.23	$42,880.74	($16.00)	$0.00	($0.67)	($16.67)	0.0%	0.0%	0.0%	0.0%
1,500	600,000	$31,818.51	$29,976.00	$2,574.77	$64,369.28	$31,789.51	$29,976.00	$2,573.56	$64,339.07	($29.00)	$0.00	($1.21)	($30.21)	0.0%	0.0%	0.0%	0.0%
2,500	1,000,000	$53,060.51	$49,960.00	$4,292.52	$107,313.03	$53,005.51	$49,960.00	$4,290.23	$107,255.74	($55.00)	$0.00	($2.29)	($57.29)	-0.1%	0.0%	0.0%	-0.1%

		Present Rates		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$17.78		$17.78	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.97		$3.97	
Transmission Energy Charge	kWh x	$0.01047		$0.01047	
Distribution Demand Charge-xcs 10 kW	kW x	$4.44	(1)	$4.39	(2)
Distribution Energy Charge	kWh x	$0.00768	(3)	$0.00774	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.74¢/kW

Note (2): includes the proposed CapEx Factor of 0.69¢/kW

Note (3): includes the current O&M Factor of 0.073¢/kWh

Note (4): includes the proposed O&M Factor of 0.079¢/kWh

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

Hours Use: 500

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	100,000	$4,845.51	$4,996.00	$410.06	$10,251.57	$4,851.51	$4,996.00	$410.31	$10,257.82	$6.00	$0.00	$0.25	$6.25	0.1%	0.0%	0.0%	0.1%
750	375,000	$18,293.01	$18,735.00	$1,542.83	$38,570.84	$18,288.01	$18,735.00	$1,542.63	$38,565.64	($5.00)	$0.00	($0.20)	($5.20)	0.0%	0.0%	0.0%	0.0%
1,000	500,000	$24,405.51	$24,980.00	$2,057.73	$51,443.24	$24,395.51	$24,980.00	$2,057.31	$51,432.82	($10.00)	$0.00	($0.42)	($10.42)	0.0%	0.0%	0.0%	0.0%
1,500	750,000	$36,630.51	$37,470.00	$3,087.52	$77,188.03	$36,610.51	$37,470.00	$3,086.69	$77,167.20	($20.00)	$0.00	($0.83)	($20.83)	0.0%	0.0%	0.0%	0.0%
2,500	1,250,000	$61,080.51	$62,450.00	$5,147.10	$128,677.61	$61,040.51	$62,450.00	$5,145.44	$128,635.95	($40.00)	$0.00	($1.66)	($41.66)	0.0%	0.0%	0.0%	0.0%

		Present Rates		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$17.78		$17.78	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.97		$3.97	
Transmission Energy Charge	kWh x	$0.01047		$0.01047	
Distribution Demand Charge-xcs 10 kW	kW x	$4.44	(1)	$4.39	(2)
Distribution Energy Charge	kWh x	$0.00768	(3)	$0.00774	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.74¢/kW

Note (2): includes the proposed CapEx Factor of 0.69¢/kW

Note (3): includes the current O&M Factor of 0.073¢/kWh

Note (4): includes the proposed O&M Factor of 0.079¢/kWh

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

Hours Use: 600

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	120,000	$5,487.11	$5,995.20	$478.43	$11,960.74	$5,494.31	$5,995.20	$478.73	$11,968.24	$7.20	$0.00	$0.30	$7.50	0.1%	0.0%	0.0%	0.1%
750	450,000	$20,699.01	$22,482.00	$1,799.21	$44,980.22	$20,698.51	$22,482.00	$1,799.19	$44,979.70	($0.50)	$0.00	($0.02)	($0.52)	0.0%	0.0%	0.0%	0.0%
1,000	600,000	$27,613.51	$29,976.00	$2,399.56	$59,989.07	$27,609.51	$29,976.00	$2,399.40	$59,984.91	($4.00)	$0.00	($0.16)	($4.16)	0.0%	0.0%	0.0%	0.0%
1,500	900,000	$41,442.51	$44,964.00	$3,600.27	$90,006.78	$41,431.51	$44,964.00	$3,599.81	$89,995.32	($11.00)	$0.00	($0.46)	($11.46)	0.0%	0.0%	0.0%	0.0%
2,500	1,500,000	$69,100.51	$74,940.00	$6,001.69	$150,042.20	$69,075.51	$74,940.00	$6,000.65	$150,016.16	($25.00)	$0.00	($1.04)	($26.04)	0.0%	0.0%	0.0%	0.0%

		Present Rates		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$17.78		$17.78	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.97		$3.97	
Transmission Energy Charge	kWh x	$0.01047		$0.01047	
Distribution Demand Charge-xcs 10 kW	kW x	$4.44	(1)	$4.39	(2)
Distribution Energy Charge	kWh x	$0.00768	(3)	$0.00774	(4)
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.74¢/kW

Note (2): includes the proposed CapEx Factor of 0.69¢/kW

Note (3): includes the current O&M Factor of 0.073¢/kWh

Note (4): includes the proposed O&M Factor of 0.079¢/kWh

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

Hours Use: 200

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	600,000	$56,065.80	$29,976.00	$3,585.08	$89,626.88	$56,305.80	$29,976.00	$3,595.08	$89,876.88	$240.00	$0.00	$10.00	$250.00	0.3%	0.0%	0.0%	0.3%
5,000	1,000,000	$81,877.80	$49,960.00	$5,493.24	$137,331.04	$82,277.80	$49,960.00	$5,509.91	$137,747.71	$400.00	$0.00	$16.67	$416.67	0.3%	0.0%	0.0%	0.3%
7,500	1,500,000	$114,142.80	$74,940.00	$7,878.45	$196,961.25	$114,742.80	$74,940.00	$7,903.45	$197,586.25	$600.00	$0.00	$25.00	$625.00	0.3%	0.0%	0.0%	0.3%
10,000	2,000,000	$146,407.80	$99,920.00	$10,263.66	$256,591.46	$147,207.80	$99,920.00	$10,296.99	$257,424.79	$800.00	$0.00	$33.33	$833.33	0.3%	0.0%	0.0%	0.3%
20,000	4,000,000	$275,467.80	$199,840.00	$19,804.49	$495,112.29	$277,067.80	$199,840.00	$19,871.16	$496,778.96	$1,600.00	$0.00	$66.67	$1,666.67	0.3%	0.0%	0.0%	0.3%

		Present Rates		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$347.07		$347.07	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.22		$3.22	
Transmission Energy Charge	kWh x	$0.01378		$0.01378	
Distribution Demand Charge-xcs 10 kW	kW x	$3.81	(1)	$3.89	(2)
Distribution Energy Charge	kWh x	$0.00167		$0.00167	
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.52¢/kW and the current O&M Factor of 0.30¢/kW

Note (2): includes the proposed CapEx Factor of 0.54¢/kW and the current O&M Factor of 0.36¢/kW

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

Hours Use: 300

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	900,000	$64,879.80	$44,964.00	$4,576.83	$114,420.63	$65,119.80	$44,964.00	$4,586.83	$114,670.63	$240.00	$0.00	$10.00	$250.00	0.2%	0.0%	0.0%	0.2%
5,000	1,500,000	$96,567.80	$74,940.00	$7,146.16	$178,653.96	$96,967.80	$74,940.00	$7,162.83	$179,070.63	$400.00	$0.00	$16.67	$416.67	0.2%	0.0%	0.0%	0.2%
7,500	2,250,000	$136,177.80	$112,410.00	$10,357.83	$258,945.63	$136,777.80	$112,410.00	$10,382.83	$259,570.63	$600.00	$0.00	$25.00	$625.00	0.2%	0.0%	0.0%	0.2%
10,000	3,000,000	$175,787.80	$149,880.00	$13,569.49	$339,237.29	$176,587.80	$149,880.00	$13,602.83	$340,070.63	$800.00	$0.00	$33.34	$833.34	0.2%	0.0%	0.0%	0.2%
20,000	6,000,000	$334,227.80	$299,760.00	$26,416.16	$660,403.96	$335,827.80	$299,760.00	$26,482.83	$662,070.63	$1,600.00	$0.00	$66.67	$1,666.67	0.2%	0.0%	0.0%	0.3%

		Present Rates		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$347.07		$347.07	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.22		$3.22	
Transmission Energy Charge	kWh x	$0.01378		$0.01378	
Distribution Demand Charge-xcs 10 kW	kW x	$3.81	(1)	$3.89	(2)
Distribution Energy Charge	kWh x	$0.00167		$0.00167	
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.52¢/kW and the current O&M Factor of 0.30¢/kW

Note (2): includes the proposed CapEx Factor of 0.54¢/kW and the current O&M Factor of 0.36¢/kW

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

Hours Use: 400

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	1,200,000	$73,693.80	$59,952.00	$5,568.58	$139,214.38	$73,933.80	$59,952.00	$5,578.58	$139,464.38	$240.00	$0.00	$10.00	$250.00	0.2%	0.0%	0.0%	0.2%
5,000	2,000,000	$111,257.80	$99,920.00	$8,799.08	$219,976.88	$111,657.80	$99,920.00	$8,815.74	$220,393.54	$400.00	$0.00	$16.66	$416.66	0.2%	0.0%	0.0%	0.2%
7,500	3,000,000	$158,212.80	$149,880.00	$12,837.20	$320,930.00	$158,812.80	$149,880.00	$12,862.20	$321,555.00	$600.00	$0.00	$25.00	$625.00	0.2%	0.0%	0.0%	0.2%
10,000	4,000,000	$205,167.80	$199,840.00	$16,875.33	$421,883.13	$205,967.80	$199,840.00	$16,908.66	$422,716.46	$800.00	$0.00	$33.33	$833.33	0.2%	0.0%	0.0%	0.2%
20,000	8,000,000	$392,987.80	$399,680.00	$33,027.83	$825,695.63	$394,587.80	$399,680.00	$33,094.49	$827,362.29	$1,600.00	$0.00	$66.66	$1,666.66	0.2%	0.0%	0.0%	0.2%

		Present Rates		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$347.07		$347.07	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.22		$3.22	
Transmission Energy Charge	kWh x	$0.01378		$0.01378	
Distribution Demand Charge-xcs 10 kW	kW x	$3.81	(1)	$3.89	(2)
Distribution Energy Charge	kWh x	$0.00167		$0.00167	
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.52¢/kW and the current O&M Factor of 0.30¢/kW

Note (2): includes the proposed CapEx Factor of 0.54¢/kW and the current O&M Factor of 0.36¢/kW

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

Hours Use: 500

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	1,500,000	$82,507.80	$74,940.00	$6,560.33	$164,008.13	$82,747.80	$74,940.00	$6,570.33	$164,258.13	$240.00	$0.00	$10.00	$250.00	0.1%	0.0%	0.0%	0.2%
5,000	2,500,000	$125,947.80	$124,900.00	$10,451.99	$261,299.79	$126,347.80	$124,900.00	$10,468.66	$261,716.46	$400.00	$0.00	$16.67	$416.67	0.2%	0.0%	0.0%	0.2%
7,500	3,750,000	$180,247.80	$187,350.00	$15,316.58	$382,914.38	$180,847.80	$187,350.00	$15,341.58	$383,539.38	$600.00	$0.00	$25.00	$625.00	0.2%	0.0%	0.0%	0.2%
10,000	5,000,000	$234,547.80	$249,800.00	$20,181.16	$504,528.96	$235,347.80	$249,800.00	$20,214.49	$505,362.29	$800.00	$0.00	$33.33	$833.33	0.2%	0.0%	0.0%	0.2%
20,000	10,000,000	$451,747.80	$499,600.00	$39,639.49	$990,987.29	$453,347.80	$499,600.00	$39,706.16	$992,653.96	$1,600.00	$0.00	$66.67	$1,666.67	0.2%	0.0%	0.0%	0.2%

		Present Rates		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$347.07		$347.07	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.22		$3.22	
Transmission Energy Charge	kWh x	$0.01378		$0.01378	
Distribution Demand Charge-xcs 10 kW	kW x	$3.81	(1)	$3.89	(2)
Distribution Energy Charge	kWh x	$0.00167		$0.00167	
Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.52¢/kW and the current O&M Factor of 0.30¢/kW

Note (2): includes the proposed CapEx Factor of 0.54¢/kW and the current O&M Factor of 0.36¢/kW

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

Hours Use: 600

Monthly Power		Present Rates				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	1,800,000	$91,321.80	$89,928.00	$7,552.08	$188,801.88	$91,561.80	$89,928.00	$7,562.08	$189,051.88	$240.00	$0.00	$10.00	$250.00	0.1%	0.0%	0.0%	0.1%
5,000	3,000,000	$140,637.80	$149,880.00	$12,104.91	$302,622.71	$141,037.80	$149,880.00	$12,121.58	$303,039.38	$400.00	$0.00	$16.67	$416.67	0.1%	0.0%	0.0%	0.1%
7,500	4,500,000	$202,282.80	$224,820.00	$17,795.95	$444,898.75	$202,882.80	$224,820.00	$17,820.95	$445,523.75	$600.00	$0.00	$25.00	$625.00	0.1%	0.0%	0.0%	0.1%
10,000	6,000,000	$263,927.80	$299,760.00	$23,486.99	$587,174.79	$264,727.80	$299,760.00	$23,520.33	$588,008.13	$800.00	$0.00	$33.34	$833.34	0.1%	0.0%	0.0%	0.1%
20,000	12,000,000	$510,507.80	$599,520.00	$46,251.16	$1,156,278.96	$512,107.80	$599,520.00	$46,317.83	$1,157,945.63	$1,600.00	$0.00	$66.67	$1,666.67	0.1%	0.0%	0.0%	0.1%

		Present Rates		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$347.07		$347.07	
LIHEAP Charge		$0.73		$0.73	
Transmission Demand Charge	kW x	$3.22		$3.22	
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Transition Energy Charge	kWh x	($0.00058)		($0.00058)	
Energy Efficiency Program Charge	kWh x	$0.01107		$0.01107	
Renewable Energy Distribution Charge	kWh x	$0.00344		$0.00344	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.04996		$0.04996	

Note (1): includes the current CapEx Factor of 0.52¢/kW and the current O&M Factor of 0.30¢/kW

Note (2): includes the proposed CapEx Factor of 0.54¢/kW and the current O&M Factor of 0.36¢/kW

JOINT PRE-FILED DIRECT TESTIMONY

OF

MELISSA A. LITTLE

AND

AIDIMARYS MARTINEZ

December 21, 2016

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Ms. Little, please state your full name and business address.

A. My name is Melissa A. Little, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position and responsibilities at National Grid.

A. I am a Lead Specialist for 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 requirement 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 (Company).

Q. Please describe your education and professional experience.

A. In 2000, I earned a Bachelor of Science degree in Accounting Information Systems from Bentley College (now Bentley University) in Waltham, Massachusetts. In September 2000, I joined PricewaterhouseCoopers LLP in Boston, Massachusetts, where I worked as an associate in the Assurance practice. In November 2004, I joined National Grid in the Service Company as an analyst in the general accounting group. After the merger of National Grid and KeySpan in 2007, I joined the Regulation and Pricing department as a senior analyst in the Regulatory Accounting function, also supporting the Niagara Mohawk Power Corporation revenue requirement team. After moving to the New England revenue requirement team, I was promoted to my current position in July 2011.

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

A. Yes. Among other testimony, I submitted pre-filed testimony in the following matters to support the Company's revenue requirement: the Company's Fiscal Year (FY) 2017 Gas Infrastructure, Safety, and Reliability (Gas ISR) Plan filing in Docket No. 4590; FY 2016 Gas ISR Plan filing and reconciliation filing in Docket No. 4540; and FY 2015 Gas ISR Plan reconciliation filing in Docket No. 4474.

Q. Ms. Martinez, please state your full name and business address.

A. My name is Aidimarys Martinez, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position at National Grid and responsibilities in that position.

A. I am a Lead Analyst for New England Revenue Requirements in the Regulation and Pricing department of the Service Company.

Q. Please describe your education and professional experience.

A. In 2000, I earned a Bachelor of Science degree in Accounting and Business Administration from the University of Puerto Rico. During college, I interned at Arthur Andersen LLP in San Juan, Puerto Rico, where I worked as a tax analyst. I also interned at PaineWebber Company in New York, New York, where I worked as an accounting analyst. In February 2001, I joined Accenture in Boston, Massachusetts, where I worked as a consultant for companies such as EMC, Boston Scientific and National Grid. In August 2004, I joined National Grid in the Transmission Business as an analyst in the Finance department. Since that time, I have held various positions in National Grid's Finance organization, supporting various companies. In July 2016, I joined the Regulation and Pricing department, supporting the New England Revenue Requirement team.

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

A. No.

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your joint testimony?

A. The purpose of our joint testimony is to sponsor Section 5 of the FY 2018 Electric ISR Plan, which describes the calculation of the Company's revenue requirement for FY 2018 in Attachment 1 of that section. The revenue requirement is based on the FY 2018

Electric ISR Plan operation and maintenance (O&M) expenses and capital investment, which are described in the joint testimony of Mr. James Patterson and Mr. Ryan Moe.

III. ISR PLAN REVENUE REQUIREMENT

Q. Please summarize the revenue requirement for the Company's FY 2018 Electric ISR Plan.

A. As shown on Page 1, Column (b) of Attachment 1, the Company's FY 2018 Electric ISR Plan revenue requirement totals $26,451,131 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 $10,306,051; (2) the FY 2018 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $16,145,080, which includes the $2,267,653 revenue requirement on FY 2018 proposed incremental ISR capital investment, plus the FY 2018 revenue requirements on incremental ISR capital investment for FY 2012 through FY 2017, totaling $11,656,529; (3) FY 2018 Property Tax Recovery Adjustment of $3,906,950; (4) true-up for vintage years FY 2013 through FY 2016 related to the work order write off adjustment (discussed below), totaling $(560,347) related to capital investment and $(589) related to Property Tax; and (4) true-up for vintage years FY 2012 through FY 2016 related to the Transmission-related NOL adjustment of $(1,125,115), also discussed below. Importantly, these amounts will be trued up to actual O&M and capital investment activity after the conclusion of the fiscal year, 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 2019 revenue requirement. Please see Section 5 of the FY 2018 Electric ISR Plan for a detailed description of the calculation of the Company's revenue requirement.

Q. Did the Company calculate the FY 2018 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions?

A. Yes, the Company calculated the FY 2018 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions with the following five exceptions:

1. As noted in Section 5 of the FY 2018 Electric ISR Plan, the Company adjusted prior vintage year revenue requirement calculations to address an adjustment that was recorded in the financial statements in the Company's FY 2016 annual report in which the Company wrote off certain work orders that had been charged to plant in prior years but which should have been charged to expense.

2. As noted in Section 5 of the FY 2018 Electric ISR Plan, the Company is adjusting prior vintage year revenue requirement calculations to correct prior year Net Operating Loss (NOL) amounts reflected in the calculation of deferred taxes and ISR

incremental rate base. This correction to prior year NOLs is necessary to exclude the portion of tax NOLs that are included in Federal Energy Regulatory Commission (FERC) jurisdiction transmission rate base amounts that were incorrectly included in previous vintage year NOL amounts included in the Electric ISR rate base.

3. As noted in Section 5 of the FY 2018 Electric ISR Plan, the Company is reflecting estimates of the NOL deferred taxes it will generate when it files its FY 2016 federal income tax return in mid-December 2016. In previous Electric ISR Plan filings, the Company had not reflected NOLs for any fiscal years for which federal income tax returns had not been filed. The filing of the Company's federal income tax returns in the month of December following the completion of the Company's fiscal year has lagged the filing of each fiscal year's Electric ISR Plan submission by approximately 24 months. This phenomenon caused the Company to understate its Electric ISR Plan revenue requirements in prior years, which resulted in significant increases to the Company's revenue requirement, as reflected in the Company's annual reconciliation of actual Plan investment activity with the investment amounts included in the Electric ISR Plan. The annual reconciliations are filed by August 1 of each year following the completion of the fiscal year. In recent years, the annual reconciliations also had to be trued up to reflect the impact of NOLs generated in fiscal year tax returns that were not known at the time and, therefore, not estimated when the Company prepared its Electric ISR Plans for those years. The PUC expressed

concern about this phenomenon after the Company filed its FY 2017 Electric ISR Plan in Docket No. 4592. The Company filed its FY 2017 Electric ISR Plan with the PUC in December 2015, prior to the December 2015 filing of the Company's FY 2015 federal income tax return in which new NOLs were generated. During the travel of the FY 2017 Electric ISR proceeding and after the Company filed its FY 2015 tax return, the PUC requested that the Company update its FY 2017 Electric ISR Plan revenue requirement to include the FY 2015 NOL to mitigate the impact of NOLs on the subsequent Electric ISR Plan reconciliation filings. In response to the developments in the FY 2017 Electric ISR Plan filing and because other elements of the Plan are also based on estimates, the Company is reflecting estimates of NOLs it expects to generate on its FY 2016 federal income tax return, as mentioned above. In addition, the FY 2018 Electric ISR Plan revenue requirement calculation includes estimates of NOLs the Company is likely to generate in FY 2017.

4. As noted in Section 5 of the FY 2018 Electric ISR Plan, the Company is including a prorated calculation with respect to the accumulated deferred income tax (ADIT) balance included in rate base. The calculation fulfills requirements in IRS Regulation 26 C.F.R. §1.167(l)-1(h)(6). This regulation sets forth normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly.

5. As noted in Section 5 of the FY 2018 Electric ISR Plan, the IRS clarified its tangible property regulations. Consequently, the Company submitted a § 481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. On December 17, 2015, the Company submitted this election to the PUC, as required by applicable IRS rules. The late partial disposition election was made to protect the Company's deduction of cost of removal (COR). Otherwise, the Company would have been required to make a § 481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100% deductible. The vintage FY 2015 through FY 2018 tax depreciation calculations in this filing now include an additional tax deduction related to this change in accounting issue.

Q. Does the Company plan to update the revenue requirement calculation subsequent to the date of this filing?

A. Yes. The Company plans to submit an updated revenue requirement to reflect the actual NOL deferred taxes generated for FY 2016 based on the Company's December 2016 federal income tax return.

Q. Does this conclude your testimony?

A. Yes.

Testimony of
Adam S. Crary

PRE-FILED DIRECT TESTIMONY

OF

ADAM S. CRARY

December 21, 2016

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

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

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

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

Q. Please describe your educational background and training.

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

Q. Please describe your professional experience?

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

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

A. Yes. I previously testified in the Renewable Energy (RE) Growth Program proceeding, Docket No. 4589A and in the fiscal year (FY) 2015 Electric Infrastructure, Safety and Reliability (ISR) Plan Reconciliation proceeding, Docket No. 4473. I have also submitted Pre-Filed Direct Testimony in the FY 2015 Electric Revenue Decoupling Mechanism Reconciliation Filing, Docket No. 4566, the FY17 Electric ISR Plan, Docket No. 4592, and submitted pre-filed Direct Joint Testimony in the 2016 RE Growth Program Factor Filing, Docket No. 4626. I most recently testified in the 2016 Annual Retail Rates Filing, Docket No. 4599.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Capital Expenditures and O&M factors resulting from the Company's FY 2018 Infrastructure, Safety and Reliability (ISR) Plan proposed in this filing and to provide the customer bill impacts of the proposed rate changes.

II. <u>INFRASTRUCTURE, SAFETY AND RELIABILITY PROVISION</u>

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

A. The Company's ISR Provision, RIPUC No. 2118[1], describes the process for establishing

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

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) designed to recover the costs associated with incremental capital investment; and (2) an Operation and Maintenance Mechanism (O&MM) designed to recover certain annual Operation and Maintenance (O&M) expenses pertaining to Inspection and Maintenance (I&M) and Vegetation Management (VM) activities.

A. <u>INFRASTRUCTURE INVESTMENT MECHANISM</u>

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 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 on and after April 1 of each year upon PUC approval.

Q. How are the CapEx Factors designed?

A. First, the cumulative revenue requirement approved by the PUC, 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 are 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. Please explain why is the cumulative revenue requirement is 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 reflected in future CapEx Reconciling Factors.

B. OPERATION AND MAINTENANCE MECHANISM

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 upon 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 includes only 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 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. <u>PROPOSED FACTORS</u>

A. <u>CAPEX FACTORS</u>

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 2018. The cumulative revenue requirement of $16,145,080[2] is developed in the joint testimony of Company Witnesses, Melissa A. Little and AidiMarys Martinez. 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 described above using forecasted billing units for the period April 1, 2017 through March 31, 2018. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, page 3.

B. <u>O&M FACTORS</u>

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

[2] See Section 5: Attachment 1, Page 1, Line 18, column (b) of the ISR Plan.

with I&M and VM activities for FY 2018. As developed in the joint testimony of Ms. Little and Ms. Martinez, these expenses total $10,306,051.[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. O&M Factors are designed as I describe above.

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. <u>BILL IMPACTS</u>

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 decrease of $0.09, or 0.1%.

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

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 2017 and will propose additional rate changes for effect, April 1, 2017. 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 effect, April 1, 2017.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.