National Grid

The Narragansett Electric Company

Electric Infrastructure, Safety, and Reliability Plan FY 2013 Proposal

December 29, 2011

Docket No. 4307

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Letter

nationalgrid

Thomas R. Teehan
Senior Counsel

December 29, 2011

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02889

RE: National Grid's Proposed FY 2013 Electric Infrastructure, Safety, and Reliability Plan Docket No. __________

Dear Ms. Massaro:

On behalf of National Grid[1], I have enclosed ten (10) copies of the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year 2013 [2]. National Grid has developed this proposed Electric ISR Plan, which is designed to enhance the safety and reliability of the Company's Rhode Island electric distribution system. The proposed Plan was submitted to the Division of Public Utilities and Carriers ("Division") for review. The Company received and responded to discovery requests from the Division and has met with the Division's representatives regarding this proposed Plan. The Division has agreed to the overall spending portion of this plan, but will continue to review and discuss particular Plan provisions, as the Commission conducts its proceeding in this matter.

The 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 driven primarily by condition, continuing a level of feeder hardening and cutout replacement, and operating a cost-effective vegetation management program. The Plan is intended to achieve these safety and reliability goals through a cost-effective, comprehensive work plan. The level of work that the plan provides will sustain and enhance the safety and reliability of the Rhode Island electric distribution infrastructure and directly benefit all Rhode Island electric customers.

The Plan separates the general categories of work into discretionary and non-discretionary work, and it includes a description of the categories of work the Company proposes to perform in fiscal year 2013 as well as the proposed targeted spending levels for each work category. Along with this cover letter and a copy of the Plan, this filing includes the pre-filed direct testimony of four witnesses. Ms. Jennifer Grimsley and Mr. Craig Allen testify to introduce the Plan and describe the Plan's large program components. Mr. William Richer provides the calculation of the Company's fiscal year 2013 revenue requirement under the Plan. Ms. Jeanne Lloyd testifies regarding the calculation of the Infrastructure, Safety and Reliability

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[1] The Narragansett Electric Company d/b/a National Grid (hereinafter referred to as "National Grid" or the "Company").

[2] The Electric ISR Plan is submitted in compliance with the provisions of R.I.G.L. §39-1-27.7.1.

("ISR") factors proposed in this filing and provides the customer bill impacts of 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 rate increase of $0.36 or 0.5% based upon rates approved for billing January 1, 2012.

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

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosure

cc: Steve Scialabba
Leo Wold, Esq.
James Lanni

Testimony of
Jennifer Grimsley &
Craig Allen

PRE-FILED DIRECT TESTIMONY

OF

JENNIFER L. GRIMSLEY

AND

CRAIG M. ALLEN

December 29, 2011

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I. INTRODUCTION

Q. Ms. Grimsley, please state your name and business address.

A. My name is Jennifer L. Grimsley. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. Ms. Grimsley, by whom are you employed and in what position?

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

Q. Ms. Grimsley, please describe your educational background and professional experience.

A. I graduated from Washington University in 1986, earning a bachelor's degree in electrical engineering and from Rivier College in 1991, earning a master's degree in business administration. In 1986, I began my engineering career as an associate engineer with Massachusetts Electric Company ("Mass. Electric") in North Andover. In 1993, I was promoted to district engineering manager for Mass. Electric in Northampton, and have held various engineering and management positions since that time, including Project

Manager for the Reliability Enhancement Program in 2006. In 2007, I became Manager Asset Strategy and Policy and was responsible for developing the strategies to replace distribution assets. I was promoted to Director, Asset Strategy & Policy in 2008. In 2009, I became Executive Advisor to the Chief Operating Officer of Electricity Operations for National Grid. In 2011, I assumed my current role as Director, New England Electric Network Strategy.

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

A. No. However, I have testified before the New Hampshire Public Utilities Commission in Docket DE 11-107, Granite State Electric Company Reliability Enhancement Plan and Vegetation Management Plan, Results and Reconciliation**.**

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

A. My name is Craig M. Allen. My business address is 300 Erie Blvd West, Syracuse, NY 13202.

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

A. I am employed by the Service Company as Manager, Vegetation Strategy. I am responsible for the design, support, and long term planning of vegetation strategies used on National Grid's distribution and transmission assets.

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

A. I graduated from the State of New York - College of Environmental Science and Forestry in 1979, earning an Associates degree in Forest Technology and again in 1981, earning a Bachelor's degree in Forest Resource Management. I hold an arborist certification (#NY0710AU) through the International Society of Arborist. I also hold a Utility Specialist certification through that same organization. I began working for Niagara Mohawk Power Corporation in 1982. I have held various positions in utility vegetation management including Regional Supervisor, Regional Superintendent, System Arborist, Manager of Forestry Delivery, and Manager of Distribution Vegetation Strategy. I assumed my current role as Manager of Vegetation Strategy (T&D) in June of 2011.

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

A. No. However, I have testified in Article VII siting cases in New York.

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

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to present the plan developed by the Company and reviewed by the Rhode Island Division of Public Utilities and Carriers (the "Division") regarding the Company's proposed fiscal year ("FY") 2013 Electric Infrastructure, Safety, and Reliability ("ISR") Plan (the "Electric ISR Plan" or the "Plan")[1]. As is described in the Plan document, implementation of the Electric ISR Plan will allow the Company to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable cost. The proposed Electric ISR Plan document is Exhibit 1 to this testimony.

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

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2013, or the twelve month fiscal year ending March 31, 2013: 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. The Division has agreed to the spending portion of this plan, and will continue to review particular plan provisions as the Rhode Island Public Utilities Commission ("Commission") conducts its proceeding in this matter.

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

A. The Electric ISR Plan, which is provided as Exhibit 1 to this testimony, encompasses the electric infrastructure, safety, and reliability spending plan for FY 2013, as well as an

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[1] The Electric ISR Plan presented in this filing is the second annual plan submitted to the Commission pursuant to the provisions of R.I.G.L. §39-1-27.7.1

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

III. CAPITAL INVESTMENT PLAN

Q. How has the Company formulated the Capital Investment Plan for review by the Commission?

A. The Company's FY 2013 Electric ISR Plan was prepared by the Company and submitted to the Division for review. The Company received and responded to discovery requests from the Division and had meetings and discussions with the Division's representatives and its consultant, Mr. Greg Booth, regarding this proposed Plan. The Division has agreed to the overall spending portion of this Plan, and will continue to review particular Plan provisions as the Commission conducts its proceeding in this matter. In this filing, the Company is putting forth a capital spending plan for FY 2013 in the amount of $56.5

million, encompassing a range of project work that is needed to maintain safe and reliable service. The project work that is included in the Electric ISR Plan is specifically designed to meet system performance objectives and/or customer service requirements, which the Company must address as part of its public service obligation. In the Plan, attached as Exhibit 1, the Company has provided a detailed explanation of the categories of investment that it plans to undertake; the factors motivating the nature and amount of investment to be completed, and the specific projects that will be undertaken in Rhode Island.

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

A. The Company's overall objective in preparing the Electric ISR Plan is to arrive at a capital spending plan that is the optimal balance in terms of making the investments necessary to improve the performance of discreet aspects of the system thereby resulting in maintaining the overall reliability of the system, while also ensuring a cost-effective use of available resources. Therefore, the Plan includes the capital investment needed to: (1) meet state and federal regulatory requirements applicable to the electric system; (2) repair failed or damaged equipment; (3) address load growth/migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by condition. These categories of investment constitute the core of work required for the Company to meet its public-service obligation in Rhode Island and, for this reason, the Company has included these categories in its proposal to be approved by the Commission.

Q. Please review the FY 2013 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2013 are associated with five key work categories: Statutory/Regulatory, Damage Failure, System Capacity and Performance, Asset Condition, and Non-infrastructure. The Chart below summarizes the proposed spending level for each of these key driver categories proposed for FY 2013, as follows:

Proposed FY 2013 Capital Investment by Key Driver Category

SPENDING RATIONALE	**FY 2013 PROPOSED BUDGET**	**%**
Statutory/Regulatory	$ 20,006,000	35%
Damage/Failure	10,422,000	18%
Subtotal	*$ 30,428,000*	*54%*
Asset Condition	11,863,000	21%
Non-Infrastructure	336,000	1%
System Capacity and Performance	13,913,000	25%
Subtotal	*$ 26,112,000*	*46%*
Grand Total	$ 56,540,000	

As shown, a significant portion of the investment for capital projects in FY 2013 are necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates (i.e. $20 million, or 35 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"). For the most part, the scope and timing of this work is defined by others external to the Company.

The need to repair failed and damaged equipment equates to approximately $10.4 million, or 18 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 designates the investment necessary to comply with statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and "non-discretionary" in terms of scope and timing. Together, these items account for approximately $30.4 million, or 54 percent, of proposed capital investment in FY 2013. Since the investments associated with these categories of work are non-discretionary, both in terms of timing and scope and are driven by forces outside the control of the Company, these categories of spending are subject to necessary and unavoidable deviations. As such, mandatory, or non-discretionary, capital investments are to be 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 2013 have been chosen to maintain the overall reliability of the system and collectively amount to approximately $26.1 million, or 46 percent of the Company's proposed FY 2013 capital investment. System capacity and performance projects are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers. Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the Company's system and capacity loading policy. These projects are designed to reduce the degradation of equipment's service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

In addition to accommodating existing load and load growth/migration, the investments in this category are used to install new equipment, such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with system events. This category also includes investment to improve the overall performance of the network that is realized by the reconfiguration of feeders and the installation of feeder ties. System capacity and performance projects account for approximately $13.9 million, or 25 percent, of the proposed capital investment in FY 2013.

Projects necessary due to the poor condition of infrastructure assets account for about $11.9 million, or 21 percent, of the proposed capital investment in FY 2013. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the prospect for reliability issues. Moreover, the large number of aged assets in the Company's service area, as well as Company and industry-wide experience, requires the Company to develop strategies to replace assets based on the condition of those assets to avoid the prospect that a large number of similar assets will fail at the same time or within short windows of time.

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 $336,000 or about one percent of capital investment in FY 2013.

Q. Is the Company able to provide the Commission with detail on the specific projects that will be undertaken in each of the work categories covered in the Electric ISR Plan?

A. Yes. In the Plan, the Company has provided detail on the specific projects within each work category that would be undertaken in FY 2013 as part of the Electric ISR Plan. The Company and the Division have reviewed these planned projects, as well as overall spending levels, and have come to consensus as to the appropriate investment levels for FY 2013.

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

A. Yes. The Company will provide quarterly reports with the Division and Commission on the progress of its Electric ISR programs. Additionally, the Company will provide an annual report on the prior fiscal year's activities at the time it makes its reconciliation and rate adjustment filings. The Company and the Division are aware that in executing the approved Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original plan. In such cases, the Company will include an explanation of any significant deviations in its quarterly reports and in its annual year-end report.

IV. VEGETATION MANAGEMENT PROGRAM

Q. Could you briefly review the FY 2013 spending levels for the Company's VM Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service to customers?

A. Yes. The VM Program that the Company has reviewed with the Division is carefully balanced to implement the program aspects to a degree and in a manner that will achieve the reliability benefits sought by the Company without unduly burdening customers. After discussion with the Division, the Electric ISR Plan allows for approximately $8.3 million in VM spending for FY 2013.

V. INSPECTION AND MAINTENANCE PROGRAM

Q. What are the reliability benefits associated with the Company's I&M Program?

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

Q. Could you briefly review the FY 2013 spending levels for the I&M Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service?

A. The Company proposes an I&M Program O&M expense budget of approximately $2.3 million for FY 2013. The assignment of spending is shown on the chart below.

Inspection and Maintenance Program Costs

	Overhead I&M	Potted Porcelain Cutouts	Feeder Hardening	Total
	(a)	(b)	(c)	(d)
Capital[2]	$1,250,000	$1,765,000	$1,500,000	$4,515,000
Opex Related to Capex	$770,000	$176,500	$530,000	$1,476,500
Repair Related Costs	$609,000	---	---	$609,000
Inspections Related Costs	$185,400	---	---	$185,400
Total Operation and Maintenance Expenses	$1,564,400	$176,500	$530,000	$2,270,900
Total I&M Costs	$2,814,400	$1,941,500	$2,030,000	$6,785,900

VI. CONCLUSION

Q. In your opinion, does the FY 2013 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 2013 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

[2] The Capital costs shown here are included in the proposed $56.5M capital spending plan.

distribution system. The Electric ISR Plan was presented to the Division and reviewed with the Division and its expert advisor, Mr. Greg Booth, of Power Services. Subsequent to this review, adjustments were made to the Electric ISR Plan in light of the Division's input, with the result being an optimal balance between system reliability and cost. In the end, the Commission's approval of the proposed FY 2013 Electric ISR Plan is essential to enabling the Company to maintain a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

National Grid

The Narragansett Electric Company

Electric Infrastructure, Safety, and Reliability Plan FY 2013 Proposal

December 29, 2011

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

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FY 2013
Electric Infrastructure, Safety, and Reliability Plan

Section 1
Introduction and Summary

Exhibit 1 - JLG
Section 1
Intro. & Summary

Introduction and Summary
FY 2013 Proposal

National Grid[1] has developed the following proposed fiscal year ("FY") 2013 electric infrastructure, safety, and reliability ("Electric ISR") plan (the "Electric ISR Plan" or "Plan") in compliance with Rhode Island's statute providing for an annual electric "infrastructure, safety, and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget." [2] The proposed Electric ISR Plan addresses the following categories of costs as specified in R.I.G.L. §39-1-27.7.1(d): capital spending on electric infrastructure; operation and maintenance ("O&M") expenses on vegetation management; O&M expenses on system inspection; and other costs relating to maintaining safety and reliability of the electric distribution system. The proposed Plan was submitted to the Division of Public Utilities and Carriers ("Division") for review. The Company received and responded to discovery requests from the Division and has met with the Division's representatives regarding this proposed Plan. The Division has agreed to the overall spending portion of this plan, but will continue to review and discuss particular Plan provisions as the Commission conducts its proceeding in this matter. The Plan is designed to maintain and upgrade the Company's electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, sustaining asset viability through targeted investments driven primarily by condition, continuing a level inspection and maintenance, including feeder

[1] The Narragansett Electric Company d/b/a National Grid hereinafter referred to as "National Grid" or the "Company."
[2] R.I.G.L. §39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.

hardening and potted porcelain cutout replacement, and operating a cost-effective vegetation management program. The Company now submits this Plan to the Rhode Island Public Utilities Commission ("Commission") for final review and approval.[3]

This Introduction and Summary presents an overview of the proposed FY 2013 Plan for these categories of costs, the resulting FY 2013 revenue requirement associated with the proposed Electric ISR Plan, proposed rates, and the typical bill impacts resulting from the proposed rates.

The Electric ISR Plan provides a description of the Company's proposed electric distribution system safety and reliability activities along with its proposed investments and expenditures contained in the proposed Plan for FY 2013. The proposed Plan itemizes the recommended work activities by general category and provides budgets for capital investment, as well as operation and maintenance ("O&M") expenses for a vegetation management program and an inspection and maintenance program.

Consistent with the legislation, after the end of the fiscal year, the Company will true up the ISR Plan's projected capital and O&M levels used for establishing the revenue requirement to actual or allowed investment and expenditures on a cumulative basis since the inception of the ISR in April 2011 and reconcile the revenue requirement to the revenue billed from the rate adjustments implemented at the beginning of the fiscal year.

As approved in R.I.P.U.C. Docket No. 4218, the Company will continue to file quarterly reports with the Division and Commission on the progress of its Electric ISR programs and, at the time it makes its reconciliation and rate adjustment filing, an annual report on the prior fiscal

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[3] R.I.G.L. §39-1-27.7.1 (d) provides that the Company and the Division are to work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which would then be submitted for Commission review and approval.

year's activities. The Company is cognizant that, 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 in its annual year-end report.

The FY 2013 levels of incremental net capital investment, vegetation management O&M expense, and inspection and maintenance program O&M expense contained in the Company's proposed Plan are $19.6 million, $8.3 million, and $2.3 million, respectively. Each of these categories is addressed below.

Section 2 of this proposal contains the Company's proposed capital investment plan for FY 2013. Section 3 contains the Company's proposed vegetation management program, while Section 4 contains the Company's proposed inspection and maintenance program. Section 5 includes the revenue requirement description and calculations. Sections 6 and 7 include the proposed rates and the bill impacts, respectively.

Electric Capital Investment Plan

The Company's proposed electric capital investment plan contained in Section 2 summarizes capital investments by key drivers, describes the development of the capital plan, and outlines the large programs and projects contained in the Plan. For purposes of the ratemaking treatment of capital spending, the Company proposes that capital investments used for establishing rates for FY 2013 be those investments in electric distribution infrastructure assets that are projected to be actually placed into service during the applicable fiscal year. The Company has used its capital budget to identify the relevant projects that would be part of the FY 2013 Electric ISR Plan and to provide its rationale for the need for, and benefit of, performing that work to provide safe and reliable service to its customers. To better align the projects identified in its capital budget with the customary rate treatment of capital assets, the Company has estimated when they would become a component of rate base, and consequently subject to depreciation and return.

Vegetation Management

Section 3 of this proposal contains the Company's vegetation management O&M expense for FY 2013 and a discussion of the nature of the work anticipated to be performed and the expected benefits. Under the Company's proposed plan, the O&M expense associated with vegetation management activities is the amount estimated to be expended for FY 2013. This estimated amount would be subject to true-up to actual vegetation management O&M expense.

Inspection and Maintenance Program

The Company has also estimated the O&M expense associated with the inspection and maintenance program for FY 2013. Section 4 of this proposal provides details of the proposed inspection and maintenance program for FY 2013. As with the other projected spending provided in this proposed plan, this estimated amount will be subject to true-up to actual inspection and maintenance O&M expense.

Electric Revenue Requirement

Based upon the estimated amounts for the proposed Plan, Section 5 provides a calculation of the revenue requirement resulting from the projected incremental net infrastructure investment and the total annual vegetation management and inspection and maintenance O&M. This section contains a description of the revenue requirement model and a proposed revenue requirement calculation. This calculation forms the basis for the Electric ISR rate adjustment, which would become effective April 1, 2012, upon Commission approval. The pre-tax rate of return on rate base would be that rate of return approved by the Commission in the Company's most recent general rate case (in this case, the one approved by the Commission in Docket No. 4065) and, going forward, it would change as the Commission may approve changes to the rate of return in future proceedings. Any change in the rate of return would be applicable on a prospective basis effective on the date on which the change is effective.

Rate Design

Under the proposed Plan and in accordance with the Company's currently effective Electric Infrastructure, Safety, and Reliability Provision ("Electric ISR Provision"), the revenue requirement calculated will be appropriately allocated to the Company's rate classes. The following provisions will apply for purposes of rate design:

a. The 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 contained in the Company's most recently approved allocated cost of service in the Company's last general rate case. For non-demand-based rate classes, the allocated 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 revenue requirement will be divided by estimated billing demand based on a historical load factor applied to the applicable fiscal year forecasted kWh deliveries for each rate class, resulting at a per-kW factor unique to each rate class.

b. The revenue requirement associated with the vegetation management and inspection and maintenance programs will be allocated to rate classes based upon the allocation of O&M expenses contained in the most recently approved allocated cost of service in the Company's last general rate case. For all rate classes except Rates B-62/G-62, the allocated 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 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 fiscal year forecasted kWh deliveries for each rate class, resulting in a per-kW factor for the rate class. The proposed rates under the Plan are contained in Section 6.

Bill Impacts

The bill impacts associated with the proposed rates contained in Section 6 are provided in Section 7.

Section 2

Electric Capital Investment Plan
FY 2013 Electric ISR Plan

Electric Capital Investment Plan
FY 2013 Proposal

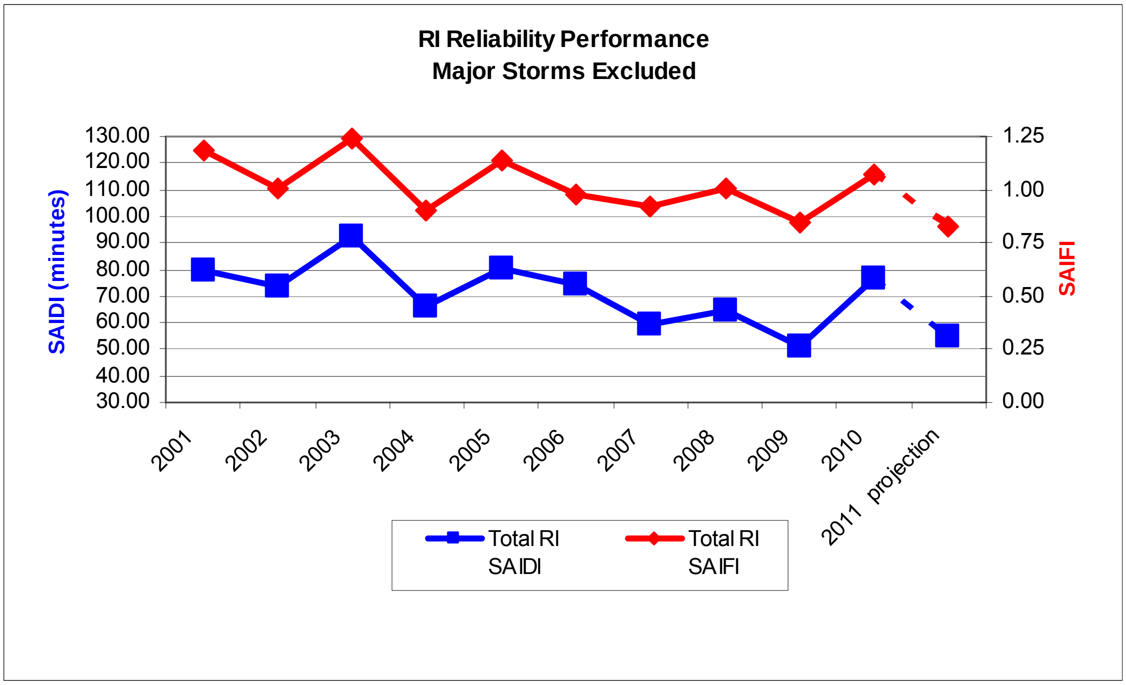
Background

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

As shown below in Chart 1, reliability performance has been on an improving trend in recent years and the Company has met its target for SAIFI and SAIDI for four of the past five years and is projecting to meet the targets in 2011.

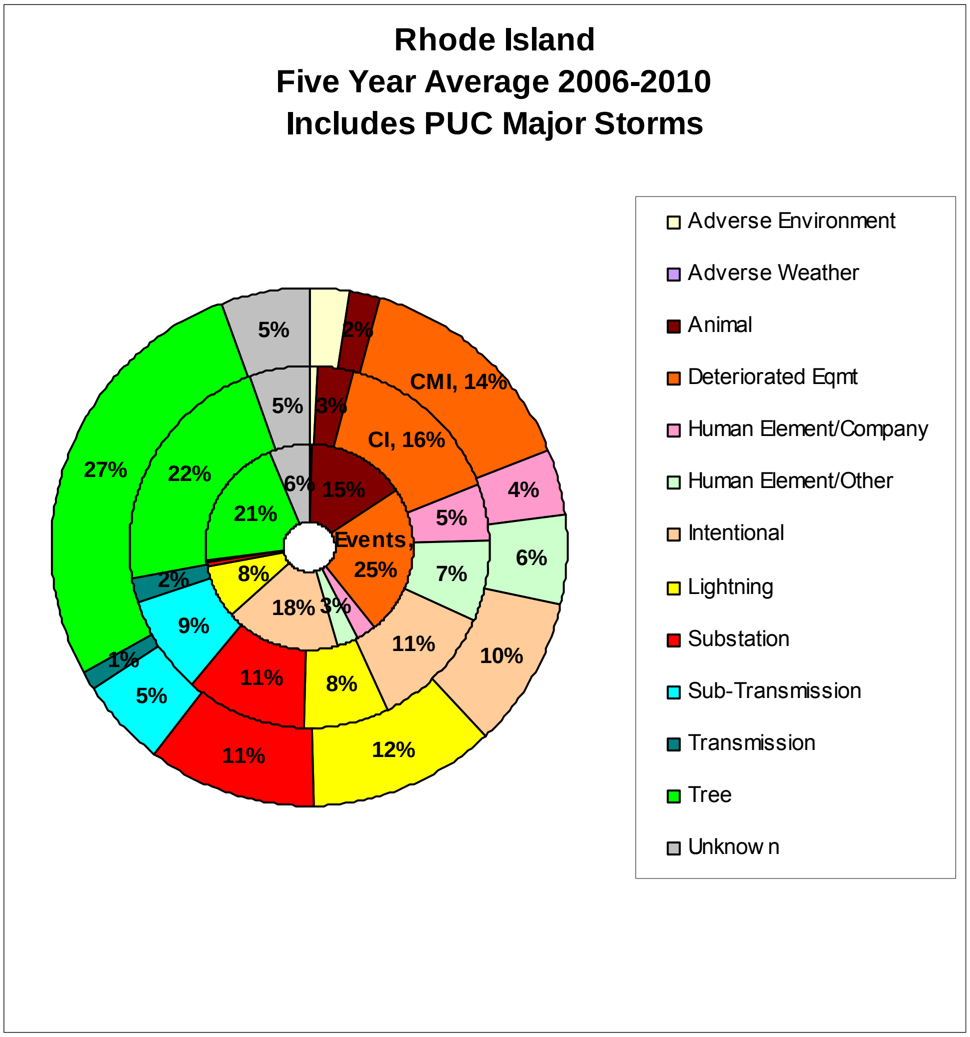
[1] The Company delivers electricity to 484,461 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 Rhode Island cities and towns. To provide this service, the Company owns and maintains 5,283 miles of overhead and 1,117 miles of underground distribution and sub-transmission circuit in a network that includes 99 sub-transmission lines and 388 distribution feeders. The Company relies on 67 substations that house 133 power transformers and 836 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 280,740 distribution poles, 4,812 manholes and 64,290 overhead (pole-mounted) and underground (padmounted or in vaults) transformers.

Chart 1: Reliability Performance



Still, reliability performance primarily depends on the stresses placed on the network from weather conditions and the ability of the system to tolerate those stresses. As shown in Chart 2, nearly 70 percent of the customer minutes interrupted result from the following causes: deteriorated equipment (14 percent), lightning (12 percent), trees (27 percent), sub-transmission events (5 percent), and reliability issues with substations (11 percent). These issues continue to be important factors adversely affecting reliability performance in 2011.

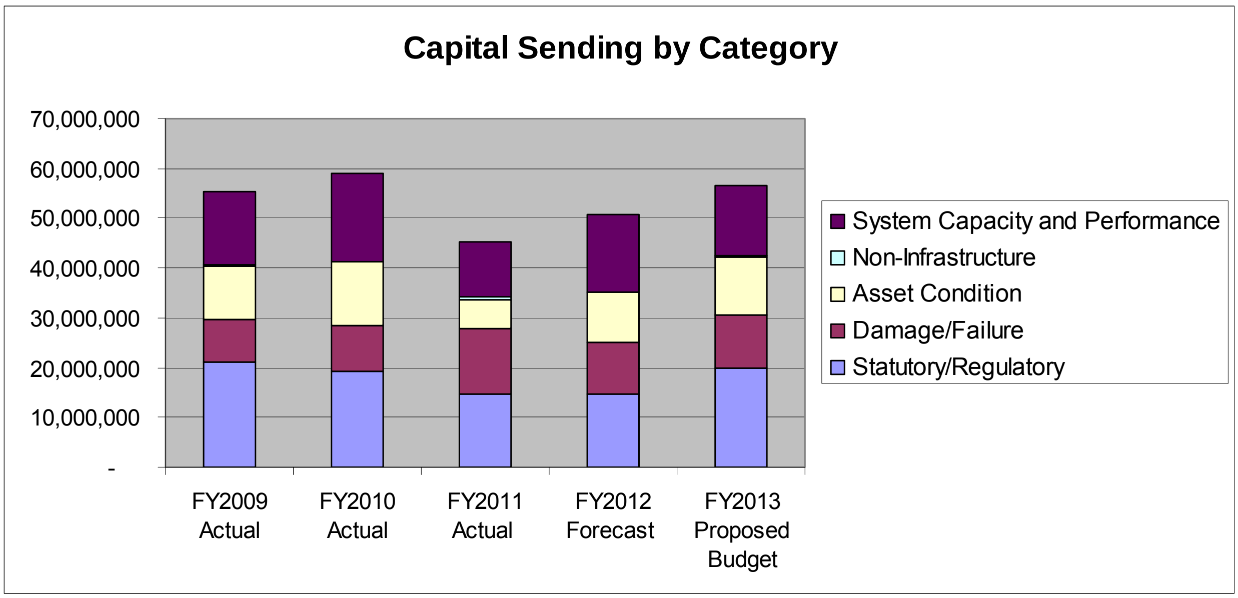
Chart 2: Customer Interruptions by Cause



It is, therefore, critical that the Company remain vigilant with respect to investing in its infrastructure, managing vegetation, and inspecting and maintaining its assets, and that it have the appropriate cost recovery so that the Company can continue to provide reliable electric delivery service to customers.

As shown in Chart 3, the Company plans to invest $56.5 million to maintain the safety and reliability of its electric delivery infrastructure in FY 2013, covering the period from April 2012 through March 2013. This spending level is comparable to the Company's proposed budget for capital improvements on the Rhode Island network during FY 2012[2].

Chart 3: Capital Outlays by Key Driver Category



Because a portion of the proposed capital spending in FY 2013 is for projects (mainly substation projects) that will be completed over multiple years, the Company anticipates that only a portion of that spending will be placed into service in FY 2013. Likewise, a portion of the capital to be placed in service in FY 2013 will also reflect the capital spending for similar multiyear projects that commenced in prior years.

A. Summary of Investment Plan by Key Driver

[2] Forecast for FY 2012 is the 1st quarter forecast. An updated forecast will be included in the FY 2012 2nd quarter ISR update.

As shown above, Chart 3 provides a breakdown of the Company's spending for capital improvements made to the Rhode Island network during the FY 2009 through FY 2011 period, expected outlays in FY 2012, and the proposed spending level in FY 2013 according to five key driver categories: Statutory/Regulatory, Damage Failure, System Capacity and Performance, Asset Condition, and Non-infrastructure. Chart 4 below summarizes the planned spending level for each of these key driver categories proposed for FY 2013.

Chart 4: Proposed FY 2013 Capital Outlays by Key Driver Category

SPENDING RATIONALE	**FY 2013 PROPOSED BUDGET**	**%**
Statutory/Regulatory	$ 20,006,000	35%
Damage/Failure	10,422,000	18%
Subtotal	*$ 30,428,000*	*54%*
Asset Condition	11,863,000	21%
Non-Infrastructure	336,000	1%
System Capacity and Performance	13,913,000	25%
Subtotal	*$ 26,112,000*	*46%*
Grand Total	$ 56,540,000	

As shown in Chart 4, more than a third of the spending for capital projects in FY 2013 is necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements, or mandates. Such investments arise from the Company's regulatory, governmental, or contractual obligations, such as responding to new customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by the Rhode Island Department of Transportation ("RIDOT"). For the most part, the scope and timing of this work is defined by others external to the Company. These projects will account for approximately $20.0 million, or 35 percent, of the proposed capital budget in FY 2013.

The need to repair failed and damaged equipment equates to approximately $10.4 million, or 18 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 Company considers the investment required to comply with statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and 'non-discretionary' in terms of scope and timing. Together, these items amount to approximately $30.4 million, or 54 percent, of proposed capital investment in FY 2013.

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 58 percent of the investment dollars categorized as system capacity and performance, or 14 percent of the proposed capital budget in FY 2013. 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 equipments' service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

The Company has somewhat more discretion with regard to the timing of the other categories and closely monitors the risk associated with delaying such projects due to the potential impact of the consequences of the failure of equipment or systems. The reliability, asset condition, and non-infrastructure projects that the Company will pursue in FY 2013 have been chosen to minimize the likelihood of reliability issues and other problems due to underinvestment in the overall system.

Investments that are required to maintain reliable service to customers accounted for 42 percent of the system capacity and performance category or 10 percent of the total FY 2013 capital budget. These investments include the installation of new equipment such as reclosers that limit the customer impact associated with system events. This category also includes investment to improve the overall performance of the network that is realized by the reconfiguration of feeders and the installation of feeder ties. Together with load relief projects, these performance projects amount to approximately $13.9 million, or 25 percent, of network investment.

Projects necessary due to the poor condition of infrastructure assets account for about $11.9 million, or 21 percent, of the proposed capital outlays in FY 2013. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the 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, 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. These strategies are developed to avoid the possibility that a large number of similar assets will fail at the same time or within short windows of time. The investments made in these assets are prioritized based on their probability 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 aforementioned categories but which are necessary to run the electric system, such as general and telecommunications equipment. In total, capital outlays for non-infrastructure projects will account for about $336,000 and less than one percent of capital outlays in FY 2013.

B. Development of the Annual Capital Plan

Each year, the Company develops an Annual Work Plan designed to achieve its overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. At the outset, the Annual Work Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by spending category: Statutory/Regulatory, Damage/Failure, System Capacity and Performance, and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects.

In order to optimize the plan budget and resources, a risk score is assigned to each project. The project risk score is generated by a project decision support matrix that assigns a project risk score based upon the estimated probability and consequence of a particular system event occurring, including the impact on customers and the public. The project risk score takes into account key performance areas such as safety, reliability, and environmental, while also accounting for criticality. Historical and forward looking checks are made by spending rationale to identify any deviations from expected or historical trends.

Once the mandatory budget level has been established, programs and projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) are reviewed for inclusion in the spending plan. Plan inclusion/exclusion for any given project is based on several different factors, including, but not limited to: project new or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the 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.

The portfolio, along with supporting risk analyses, is presented to the Company's senior executives and ultimately the Board 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 to manage to the approved budget.

The capital plan for FY 2013 presented herein represents the Company's best information regarding the investments it will need to make to sustain the safe, reliable operation of the electric system. As described above, some of the projects are already in progress or soon to 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. The plan is continuously reviewed during the year, for changes in assumptions, constraints, as well as project delays, accelerations, outage coordination, permitting/licensing/agency approvals, and system operations, performance, safety, and customer driven needs that arise. The plan is updated accordingly throughout the current year.

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

To obtain approval, the project sponsor must develop a detailed PSP relevant to the decision process 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 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.

Capital projects are authorized for construction following preliminary engineering. Reauthorization is required if the project cost is expected to exceed the estimate plus an approved variance range identified in the project spending plan. Any reauthorization request must include original authorized amount, the variance amount, the reasons for the variance and the details and costs of the variance drivers, as well as the estimated impact on the current year's spending. Project spending is monitored monthly against authorized levels by the project management and program management groups. Exception reports covering actual or forecasted project spending greater than authorized amounts are presented and reviewed monthly. The Company includes certain reserve line items in its spending plan, by budget category, to allocate funds for projects whose scope and timing have not yet been determined. In such cases, historical trends are used to develop the appropriate reserve levels. As the specific project details become available, inevitable "emergent" projects are added to the plan with funding drawn from the reserve funds. The majority of projects that are emergent are the result of in-year occurrences in mandatory, or 'non-discretionary', project categories such as damaged or failed equipment, customer or generator requirements, or regulatory mandates. Reserve funds are also established for high priority risk score projects that may arise during the current year in response to unforeseen system reliability or loading concerns. The Company tracks and manages budgetary reserves and emergent projects as part of its investment planning and current year spending management processes.

C. Description of Large Programs and Projects

Attachment 1 to this section provides program and project detail on major projects that supports the proposed level of capital outlays by key driver shown on Chart 4. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available at the present time and the risk score associated with the project.

i. Statutory/Regulatory

As shown in Attachment 1, the Company has set a budget of $20.0 million to meet its Statutory/Regulatory requirements in FY 2013. This is slightly below the FY 2012 budget but greater than what the Company spent for this category on average in FY 2009 through FY 2011.

Approximately half of the Statutory/Regulatory budget is required to establish electric delivery service to new customers. The Company currently expects to spend approximately $9.2 million dollars for this category in FY 2013. Excluding the $1.7 million budgeted for one specific customer-related substation project (Shun Pike substation), this level of spend is below the 3-year average spend from FY 2009 through FY 2011 due to declining economic trends. It is important to note that the actual and proposed spending in this category is net of contributions in aid of construction that is received from customers. The Shun Pike substation project, consisting of a new substation in Johnston, RI accounts for approximately $1.7 million of the proposed FY 2013 spending in the Statutory Regulatory sector. This 115-23kV substation will serve SIMS Metal Recycling Plant's new facility.

Required spending for public projects has been up in recent years and the Company expects that it will need to sustain spending at this level. These categories include such projects as:

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

The budget for FY 2013 includes $1.065 million for manhole and duct infrastructure installation in coordination with RIDOT construction of new roads in the vicinity of the I-195 relocation. The schedule for this work is determined by the RIDOT.

Because much of this construction work is variable and requested on short notice, the Company must set a budget based on previous experience since it does not yet have the project detail. Since the Company gets reimbursed for a portion of this spending (especially for work requested by the RIDOT), the budget placeholder represents the capital expected to be spent, net of reimbursements. The Company expects that it will need to spend at approximately the same level as in recent years 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 make sure that the Company’s assets meet the standards required to enable the attachments. The latter is not reimbursed by third party customers and as such may increase the balance spent within this category.

ii. Damage/Failure

The Company is proposing a $10.4 million budget for FY 2013 for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. This is comparable to the average level of spending for this purpose during the FY 2009 to FY 2011 period. Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historic trends. A portion of the damage/failure budget allows for larger project work which 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 2013 (e.g. failed substation transformer). The budget set for FY 2013 also includes capital spending to address the Level 1 issues that have been identified as part of the inspection and maintenance program as described in Section 4.

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

- Damage/Failure Blanket Projects – for relatively small failures within substation or line or those whose size is unknown at the time of the failure. The budget for FY 2013 is built on the assumption of flat failure rates along with inflation assumptions.
- Damage/Failure Reserve for Specific Projects – a reserve to address larger failures that require capital expenditures in excess of $100,000. The reserve is built on recent historic trends of such items and allows the Company to complete unplanned work without having to halt work on projects that are planned to stay on target with the overall capital budget.
- Major Storms – Each year the Company carries a budgeted project for major storm activity that affects the Company's assets. While the actual spend in this category may vary greatly, this reserve, based on average trends over the past

several years, allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required.

iii. Asset Condition

The Company is proposing to spend $11.9 million in FY 2013 to replace assets that need to be replaced to maintain reliability performance, up from the $9.9 million average level of spending during the FY 2009 through FY 2011 period, and greater than the FY 2012 budget of $10.9 million. This reflects a shift in spending from the feeder hardening program, which is in the System Capacity & Performance spending rationale to the more systematic Inspection & Maintenance program in the Asset Condition spending rationale as discussed in Section 4.

The completion of a new substation in Woonsocket to address asset condition is expected in FY 2013. The new substation creates a permanent solution to the failure of a 345-115-13.8 kV transformer that was temporarily remediated by the installation of a 115-13.8 kV transformer installed at the West Farnum substation. The new substation also ameliorates the capacity constraint at the Riverside Station that was created when a smaller capacity spare transformer was installed to replace a failed transformer. The new substation in Woonsocket will also allow Nasonville substation to supply the increased load at the Pascoag Utility District system. The new substation provides transformer capacity to enable strong distribution feeder ties in the area to serve many of the customers in the event that a single transformer station in the area is out of service. This reduces the potential for widespread customer interruptions.

Underground Cable Strategy - The goal of this strategy is to replace primary underground cable that is in poor condition or has a poor operating history. The Company's present underground cable replacement program is a mixture of reactive "fix on fail" replacement in the Damage/Failure spending rationale and proactive replacement in the Asset Condition spending rationale based on type of construction, asset condition, and failure history for a specific asset and similar assets. Reactive "fix on failure" replacement, which the Company considers mandatory spending, often evolves into proactive replacement of an entire circuit or a localized portion of a circuit, which is considered discretionary spending. Discretionary spending for proactive replacement can be further categorized by that work justified by the need to eliminate repeated in-service failures, work justified by anticipated end-of-life based on historic performance or industry experience, and work made necessary by other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. Examples of distribution cables currently being planned for replacement include the 1111, 1127, and 1135 cables in downtown Providence. The Company proposes to spend approximately $2.3 million on underground cable replacements in FY 2013.

Strategy to Replace Distribution Substation Batteries - The Company has more than 80 battery systems in its distribution substations and these systems play a significant role in the safe and reliable operation of substations. The batteries and chargers in these systems provide DC power for protection, control, and communications within the substation and between substations and control centers. One goal of the Company's strategy is to replace batteries that are over 20 years old in accordance with industry best practice. Another goal of the strategy is to ensure that battery systems meet the current operating requirements and perform their designed function. The Company proposes to spend $430,000 in FY 2013 to implement this strategy.

The Substation Metalclad Switchgear Replacement Strategy and Program is another important strategy to improve the reliability of substations. This strategy replaces switchgear that have known operating issues or are of the same type and manufacturer as equipment that has failed at another location. There are 46 metalclad switchgear in Rhode Island operating between 4kV and 23kV. Of the 46 units, 36 were installed prior to 1979. Several design factors with older vintage metalclad substations contribute to bus failures or component failures.

These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the failures of metalclad switchgear, substations, and busses. 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 distribution strategy is funded at $10,000 in FY 2013 to perform the preliminary engineering work at the Merton 512 substation so that construction can begin in FY 2014.

The Substation Circuit Breaker Strategy and Program targets obsolete and unreliable breaker families. The Company has approximately 836 distribution substation circuit breakers and reclosers in substations that it maintains, refurbishes, and replaces as necessary. Units with obsolete technology, such as air magnetic interruption, have been specifically identified for replacement. Additionally, where cost effective and where their conditions warrant, the Company bundles work and replaces disconnects, control cable, and other equipment associated with these circuit breakers. The Company proposes to spend approximately $1.0 million to implement this strategy in FY 2013.

Replacement RTU Program – Substations - A Remote Terminal Unit ("RTU") is a device used to transfer operational information from a substation to an Energy Management System ("EMS") in a control center. The RTU allows for remote operation and management of the system providing benefits in incident response and recovery and thus improving performance and reliability. As part of this program, the Company will replace RTUs that were installed in the 1980's that are now obsolete and unsupported by the manufacturer and cannot be modified for modern supervisory control and data acquisition. Replacement of these devices will help to ensure reliable operation of the electric system. The program is expected to end in FY 2015 when the remaining three stations are addressed. These stations are of a lower priority and will be addressed in FY 2014 and FY 2015.

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

The protection afforded by relays is critical to the stability of the electric system. The relays are designed to protect high-value system assets from effects of system faults and to quickly isolate system disturbances so that no additional damage can occur, while ensuring continued safe and reliable operation of the system.

The strategy represents a six-year plan to replace transformer and under frequency relays that have been identified using the criteria mentioned above. The Company proposes to spend $800,000 to implement this strategy in FY 2013.

Eldred Substation is one of two 23/4kV stations that supply the island of Jamestown, Rhode Island. Eldred substation supplies the northern half of the island and Clarke St substation supplies the southern half. Combined, these two stations supply approximately 3,120 customers with a peak demand of 10MW. The Eldred substation asset replacement project is required to address asset condition concerns at Eldred substation. A condition assessment of these assets was performed and identified a need to replace three circuit breakers, the station power transformer, an air-break switch, voltage regulators, station fence, and retaining walls. The assessment also identified clearance concerns with the voltage regulators, station breakers, and the PT sensing transformers, which should be addressed utilizing an alternate station design.

The recommended plan is to install two modular feeders at Eldred substation. Each modular feeder will consist of a 23/4.16kV, 3.75/4.68 MVA transformer, 800A recloser, and 3-167kVA regulators. Additionally, new feeder getaways will be installed and the area distribution will be modified to consolidate three feeder positions into two feeder positions. This project will address asset condition, safety clearance issues, and operational concerns, and supports the following strategies:

- Distribution Substation Circuit Breaker & Recloser Strategy
- Disconnects and Motor Operated Disconnects Strategy
- Voltage Regulator Strategy
- Distribution Substation Transformer Strategy

The project proposes to spend $286,000 in FY 2013.

Ductline Governor St Providence – The proposed project to construct a manhole/duct system on Governor Street in Providence will provide a route to bypass an existing ductline on nearby Ives Street which is unusable due to severe deterioration of the ducts. This project will implement a proactive plan to install the underground facilities necessary for future cable replacement programs in the area, while limiting risk in the event of in-service failures. This project proposes to spend $1.0 million in FY 2013.

Flood Mitigation Projects – As discussed in the FY 2012 ISR, major river flooding on the Pawtuxet River, Pawcatuck River, and Blackstone River from March 30 through April 1, 2010 resulted in substations located in those areas to be de-energized due to excessive water levels. Chart 5 shows the substations that were affected by the flood waters.

Chart 5: Substations Affected by the March 2010 Floods

Substation Name	**Substation Address**	**Voltage**	**Impact River**
Pontiac Sub	14 Ross Simon Dr – Cranston	115kV-12.47kV	Pawtuxet
Sockanosett Sub	19 Electronic Dr – Warwick	115kV-23kV	Pawtuxet
Westerly Sub	69 Canal St – Westerly	34kV-12.47kV	Pawcatuck
Hope Sub	15 Hope Furnace Rd – Scituate	23kV-12.47kV	Pawtuxet
Pawtuxet Sub	70 Bellows St – Warwick	23kV-4.16kV	Pawtuxet
Warwick Mall Sub	400 Bald Hill Rd – Warwick	23kV-12.47kV	Pawtuxet
Hunt River Sub	5890 Post Rd – Warwick	34kV-12.47kV	Pawtuxet
Riverside Sub	1000 Florence Dr Ext – Woonsocket	115kV-13.8kV	Blackstone

Flood waters, reaching between three feet and eight feet, were brackish and contained raw sewage, debris, and other contaminants. The impacted areas represented a significant health and safety risk to personnel, reliability impacts to customers, as well as significant damage to mechanical, electrical, control, and communications equipment in these substations and their control houses.

The Westerly, Sockanosset, and Pontiac substations were the most affected substations from the flood waters and sustained the most damage. In the cases of Westerly and Sockanosett, temporary repairs and temporary equipment replacement were made to fully restore these locations to service. The other locations were also fully restored to service.

The proposed solutions being evaluated will protect the system against flood conditions comparable to those experienced in the spring of 2010 or to the Federal Emergency Management Agency's published 100-year flood elevation, whichever is higher. Each solution will allow the substation to remain in-service during a flood event. Each location was also evaluated for installation of flood protection barriers; however, none of the substations were determined to be suitable candidates.

Plans for FY 2013 include continuation of substation engineering, procurement of equipment, permitting and licensing, and the start of construction on several projects to address flood mitigation. The majority of these projects will be multi-year projects. Projects in the FY 2013 budget include:

- Hopkinton and Langworthy Substation Expansions – Installation of a second 115/12.47kV transformer and four distribution feeders at the Hopkinton substation[3] and installation of a Mobile Integrated Substation ("MITS") and one 12.47kV distribution feeder at Langworthy substation, which will support the retirement of Westerly and Hope Valley substations.
- Installation of an elevated 23 kV metalclad substation and control house on existing property at the Sockanosett substation.
- Elevation of the transformers and control equipment at the Pontiac substation including control house replacement and worker access equipment.
- Retirement of the Hunt River substation, which is dependent on completion of the Coventry substation[4].

Engineering is underway and will continue in FY 2013 to determine final solutions for the following:

- Replacement of circuit reclosers and elevation of control equipment at the Warwick Mall substation.

[3] This is in addition to Hopkinton Substation project discussed below in System Capacity and Performance.
[4] Coventry substation improvements discussed below in System Capacity and Performance.

- Installation of a new elevated control house and elevation of the control equipment at Hope substation.
- Distribution solutions that will result in the possible retirement of the Pawtuxet substation.

iv. System Capacity and Reliability

The Company has set a budget of $13.9 million for system capacity and reliability projects in FY 2013. This is down from the $15.8 million that the Company budgeted in FY 2012 and slightly below the average level of spending during the FY 2009 through FY 2011 period. The Planning Criteria (Load Relief) projects account for $8.1 million or 58 percent of the proposed spending in FY 2013. This is down from the $9.5 million that the Company budgeted in FY 2012. Substation projects account for approximately 40 percent of that required investment.

These 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 in four power supply areas (“PSAs”) in Rhode Island. The explanatory variables in this model include historical and forecasted economic conditions at the county level[5], historical peak load data for each PSA, 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 each PSA 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 for each PSA under a given set of economic conditions. Based on the historical experience, there is only a five percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

The forecast of peak load for each PSA generated with the model incorporates the energy efficiency (“EE”) savings achieved through 2010 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 2010 from the load forecast for each PSA. The incremental system-wide EE savings is apportioned to each PSA based on its proportion of total system-wide load.

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[5] This data and forecasts are provided by Moody’s Economy.com.

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

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

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. The goal is to seek the combination of wires and non-wires alternatives that solves capacity deficiencies in a cost effective manner that also considers the potential benefits and risks. As part of this process, the Company would conduct analysis at a level of detail commensurate with the scale of the problems and the cost of potential solutions. The Company proposed a pilot non-wires alternative project to the Commission on November 1, 2011 which will test the capabilities of targeted energy efficiency applications to defer distribution investment.

Some of the most significant Planning Criteria Projects include:

- **New West Warwick Substation** - Construction of a new 115-12.47 kV substation 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.
- **New Hopkinton Substation** - Construction of a new 115/12.47 kV metal-clad substation in Hopkinton and three 12.47 kV distribution feeders is proposed. This project will provide contingency relief at Wood River substation, increase voltage reliability in the area, and support retirement of the Ashaway substation.
- **New Coventry Substation** - Construction of a new 34.5/12.47 kV Mobile Integrated Transportable Substation ("MITS") in Coventry and one 12.47 kV distribution feeder to provide thermal relief to area distribution feeders and support projected growth in the area.
- **New Newport Substation** - 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 13.8kV distribution systems during contingencies.

- **Johnston Substation 12.47kV Substation Expansion** - This project will expand a newer 12.47kV bus section and upgrade the 40MVA #3 Transformer to a 55MVA unit. This project will address capacity issues with four heavily loaded feeders west of the station, asset condition issues in the old 12.47 switchyard, and loss of supply cables in the older 12.47kV switchyard as a result of the failure of a three-winding transformer in the spring of 2009 (which resulted in a loss of one of two 12.47 kV supply lines in the older half of the station). Temporary cables presently tie the new 12.47kV bus to the old 12.47 bus sections, increasing customer exposure.
- **Kilvert St – Install Transformer #2 -** Transformer #1 at Kilvert St. substation is a 33/44/55 MVA 115/12.47 kV transformer loaded to 26.4 MVA, during the summer peak of 2011. A failure of the existing Kilvert Transformer #1 will result in outages, yielding approximately 18.4 MVA of unserved load. The mobile installation estimate in the event of a failure of Transformer #1 is twenty-four hours. The installation of a second transformer at Kilvert St. substation is recommended to resolve this issue. Furthermore, a recommendation has been made within the 15-year planning horizon to install an additional feeder at Kilvert St. substation.
- **Highland Drive Substation** - This project includes the construction of a new 115/13.8 kV low profile substation, six 13.8kV distribution feeders, and all related distribution line work in Cumberland, Rhode Island. This project will provide contingency relief at Riverside substation and Staples substation,

relieving the Riverside 108W55 and Staples 112W43 and 112W41 feeders due to spot load at the CVS Park. This project replaces the Staples substation project for the addition of a 13.8 kV circuit breaker.

In addition to these projects, the Company also has a Distribution Line Transformer Strategy to mitigate unplanned outage/failure risks due to overloads and asset condition of distribution line transformers. There are approximately 64,000 distribution transformers on the Company's distribution system. Transformer loading is reviewed annually using reports generated by the Company's Geographical Information System ("GIS") system. 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 Overhead and Underground Inspection and Maintenance Strategy. Poor condition units are replaced based on inspection results. The strategy is in addition to replacements that are performed during customer-service upgrades, public requirements projects, and system-improvement projects. The main benefit of this strategy is the maximization of asset utilization and sustained reliability performance. The Distribution Line Transformer strategy is funded at $1.3 million in FY 2013.

The Company also has a Distribution Load Relief Blanket to provide the necessary funding for other load relief projects. These projects are 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 review, historical trends in the volume of work required, as well as a forecasted impact of inflation on material and labor rates. The current year spending in the project is monitored on a monthly basis. The blankets also provide local field engineering with the control accounts to facilitate timely resolution of system and equipment loading 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. These blanket projects are budgeted at $285,000 in FY 2013.

In addition to the Load Relief Projects identified above, the Company is also proposing to spend approximately $5.8 million in FY 2013 on several programs designed to maintain system reliability, which is less than the Company's spending level for these programs from FY 2009 through FY 2011[6]. Such programs include:

Feeder Hardening Strategy - The Feeder Hardening strategy identifies feeders with characteristics indicating the potential for significant reliability performance improvements related to deteriorated overhead equipment and/or lightning interruptions. This is a reliability-focused strategy designed to meet state regulatory targets. Feeders in this program undergo replacement of deteriorated equipment, installation of lightning arresters and animal guards, and correction of non-standard grounding and bonding issues. The FY 2013 funding for feeder hardening is intended to complete the feeder hardening program, and is considerably less on an annual basis than the Company has spent in the past for this program. The Feeder Hardening strategy is funded at approximately $1.5 million in FY 2013. Going forward, the inspection &

[6] This reflects a shift in spending from the feeder hardening program, which is in the System Capacity & Performance spending rationale to the more systematic Inspection & Maintenance program in the Asset Condition spending rationale.

maintenance program will replace feeder hardening as discussed in Section 4. For FY 2013, the combined capital funding for both feeder hardening and inspection & maintenance is approximately the same as the feeder hardening spend from FY 2009 through FY 2011.

Distribution Line Recloser Installation - The recloser application strategy is a reliability-focused strategy to install line reclosers on overhead distribution lines. Line reclosers are used to isolate permanent faults on the distribution system and minimize exposure of a fault to customers. Ideally reclosers are installed at locations which limit the size of the interruption to the fewest number of customers possible and/or reduce the mainline exposure on the feeder breaker. The benefits of this program are reduced outage duration and outage frequency. The Distribution Line Recloser Strategy is funded at approximately $210,000 in FY 2013.

Potted Porcelain Cutout Replacement - This strategy is a reliability-focused strategy to eliminate potted porcelain cutouts to reduce potential safety hazards for employees and increase reliability as measured by SAIDI/SAIFI. Fuse cutouts provide over-current protection for the electric distribution system; however, potted porcelain cutouts experience a high rate of failures. National Grid installed porcelain cutouts throughout its service area in the early to mid-1980s through early 2001, during which time potted porcelain cutouts were the style used most extensively in the utility industry. Beginning in 2006, National Grid adopted a policy of replacing all potted porcelain cutouts on the Company’s system to respond to equipment failures and the associated safety risk posed by this equipment. The inspection and maintenance program incorporates the components of the potted porcelain cutout replacement strategy after FY 2013. The potted porcelain cutout strategy is funded at approximately $1.8 million in FY 2013.

Distribution Reliability Blanket - In addition to specific projects (i.e. those $100,000 or greater) the Company also budgets for work less than $100,000 under a Distribution Reliability Blanket Project. The amount of funding in each divisional blanket project is reviewed and approved each year based on the results of the previous annual reliability review, historical trends in the volume of work required, as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The blankets also provide local field engineering in each operating division with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. These blanket projects are budgeted at approximately $1.2 million in FY 2013.

Emergent Reliability Project Reserve - This reserve replaces the Pockets of Poor Performance Strategy. This reserve will be used to fund projects that are identified by the review of localized reliability issues. The goal is to identify and correct repeat device interruptions and to help identify future reliability “hotspots” and support the timely correction of localized problems before they become larger issues. The Company is placing $250,000 in this reserve for these projects in FY 2013.

Substation EMS/RTU (SCADA) Additions Program - The Company is proposing to expand the EMS/RTU program to improve reliability performance, increase operational effectiveness, and to provide data for asset expansion or operational studies. The findings of KEMA Consulting recent studies indicate that SCADA systems, when used to monitor and control the distribution feeder breakers, can provide a 15 percent to 20 percent reduction in average customer outage duration (CAIDI) when compared with a similar feeder that is not equipped with SCADA facilities. Moreover, these systems will provide a rich source of data required to fine tune the capacity planning process and extend asset lives. The Company proposes a $900,000 budget for this program in FY 2013.

D. Recovery of Electric ISR Plan Capital Investment

As discussed in Section 5 of the Electric ISR Plan, the Company's FY 2013 revenue requirement is calculated based on the Company's projected capital amounts to be placed into service in FY 2013 plus associated cost of removal. The Company has used estimated timing of in-service dates for capital spending being placed into service during FY 2013 to develop its Capital Placed In-Service figure used in the revenue requirement calculation. Each year, as part of the Company's annual reconciliation, the revenue requirement related to mandatory, or nondiscretionary in-service amounts, or that are attributable to the statutory/regulatory and damage failure categories, will be trued up based on the lesser of actual non-discretionary spending or actual non-discretionary capital investments placed into service on a cumulative basis since the inception of the ISR in April 2011. The revenue requirement associated with all other capital investments will be 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 ISR in April 2011. Due to the multi-year nature of certain projects, current and prior year(s) capital spending may be included in the FY 2013 plant in-service amount when a project is placed into service during FY 2013. Similarly, the capital portion of a project included in the FY 2013 spending plan that will be placed into service in future fiscal periods will be included in subsequent revenue requirement calculations during that project's in-service year. Chart 6 provides detail as to total FY 2013 amounts used in the development of the revenue requirement.

Chart 6: Proposed FY 2013 Capital Outlays, Plant In Service, and Cost of Removal (COR)

Spending Rationale	**Proposed Capital Outlays FY2013**	**New Capital Placed in Service FY 2013**	**Estimated Cost of Removal**	**New Capital in Service Plus COR**
Statutory/Regulatory	20,006,000	18,406,000	1,693,400	20,099,400
Damage/Failure	10,422,000	10,213,000	1,672,280	11,885,280
Subtotal	*30,428,000*	*28,619,000*	*3,365,680*	*31,984,680*
Asset Condition	11,863,000	10,120,000	2,256,490	12,376,490
Non-Infrastructure	336,000	336,000	27,900	363,900
System Capacity and Performance	13,913,000	12,291,000	1,424,930	13,715,930
Subtotal	*26,112,000*	*22,747,000*	*3,709,320*	*26,456,320*
Grand Total	56,540,000	51,366,000	7,075,000	58,441,000

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASSIFICATION	FY 2009 Actual	FY 2010 Actual	FY 2011 Actual	FY 2012 Forecast*	FY 2013 Budget
Statutory/Regulatory	3rd Party Attachments	873,018	780,847	(909,712)		705,000
	Land and Land Rights - Dist	310,128	274,560	281,215		297,000
	Meters - Dist	2,135,191	2,042,048	2,214,951		1,815,000
	New Business - Commercial	6,993,422	4,705,078	4,286,660		5,950,000
	New Business - Residential	2,856,774	3,256,239	3,529,650		3,304,000
	Outdoor Lighting - Capital	1,236,779	941,164	401,745		571,000
	Outdoor Lighting - Capital MV	-	61,933	9,619		-
	Public Requirements	1,465,029	3,121,260	1,539,416		3,709,000
	Transformers & Related Equipment	5,301,415	4,128,756	3,277,796		3,655,000
Statutory/Regulatory Total		21,171,755	19,311,884	14,631,341	14,619,000	20,006,000
Damage/Failure	Damage/Failure	7,488,952	9,143,559	8,330,840		9,772,000
	Major Storms - Dist	856,490	(112,426)	4,863,261		650,000
Damage/Failure Total		8,345,442	9,031,133	13,194,101	10,303,000	10,422,000
Asset Condition	__Woonsocket & Related	57,883	1,043,789	2,892,943		825,000
	Asset Replacement	10,793,745	11,530,572	2,711,164		8,583,000
	Asset Replacement - I&M (NE)	112,553	490,942	226,693		1,250,000
	Safety	(22,943)	-	-		-
	____Flood Damage Avoidance Engineering Studies					1,205,000
Asset Condition Total		10,941,238	13,065,303	5,830,800	10,176,000	11,863,000
Non-Infrastructure	Corporate/Admin/General	(3,464)	(1,238,810)	645,055		-
	General Equipment	154,236	391,872	60,548		186,000
	Telecommunications Capital - Dist	-	-	-		150,000
Non-Infrastructure Total		150,773	(846,938)	705,604	37,000	336,000
System Capacity and Perforn	__Coventry & Related	89,324	558,222	80,307		975,000
	__Hopkinton & Related	96,615	547,535	185,856		800,000
	__Newport & Related	715,163	2,926,839	2,333,100		450,000
	__West Warwick & Related	-	114,900	15,829		325,000
	Load Relief	5,988,143	4,650,580	3,396,843		5,576,000
	Reliability	3,878,186	5,768,069	2,798,644		4,287,000
	Reliability - FEEDER HARDENING	3,828,491	2,888,145	1,948,135		1,500,000
System Capacity and Performance Total		14,595,921	17,454,289	10,758,714	15,586,000	13,913,000
Grand Total		**55,205,130**	**58,015,670**	**45,120,559**	**50,721,000**	**56,540,000**

* Forecast provided is the FY 2012 2nd Quarter ISR forecast, as filed on November 21, 2011.

Project Detail for Proposed FY 2013 Capital Outlays

SPENDING RATIONALE	RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY 2013 PROPOSED BUDGET
Statutory/ Regulatory	3rd Party Attachments	COS022	Ocean St-Dist-3rd Party Attch Blnkt	49	555,000
		CD0328	12870 Lightower RI Fiber Make Ready Project	49	150,000
	3rd Party Attachments Total				705,000
	Land and Land Rights - Dist	COS009	Ocean St-Dist-Land/Rights Blanket	49	297,000
	Land and Land Rights - Dist Total				297,000
	Meters - Dist	CN4904	Narragansett Meter Purchases	49	1,147,000
		COS004	Ocean St-Dist-Meter Blanket	49	668,000
	Meters - Dist Total				1,815,000
	New Business - Commercial	COS011	Ocean St-Dist-New Bus-Comm Blanket	49	3,000,000
		RESERVE 049_011 LINE	Reserve for New Business Commercial Unidentified Specifics & Schedule Changes	49	1,250,000
		PPM 17063	17063 Shun Pike Sub - 23kV	49	1,600,000
		PPM 17064	17064 Shun Pike Sub - 23kV Line Portion	49	100,000
	New Business - Commercial Total				5,950,000
	New Business - Residential	COS010	Ocean St-Dist-New Bus-Resid Blanket	49	3,194,000
		RESERVE 049_010 LINE	Reserve for New Business Residential Unidentified Specifics & Schedule Changes	49	110,000
	New Business - Residential Total				3,304,000
	Outdoor Lighting - Capital	COS012	Ocean St-Dist-St Light Blanket	49	571,000
	Outdoor Lighting - Capital Total				571,000
	Public Requirements	C35087	DOTR-Apponaug Circulator Imprv Warw	49	500,000
		C35145	DOTR-Cranston Hi Haz Intersect Imp	49	60,000
		CD0076	DOTR-Atwells Avenue Bridge No. 975,	49	30,000
		CD0135	I-195 Contract 14 - Providence	49	840,000
		COS013	Ocean St-Dist-Public Require Blankt	49	1,054,000
		RESERVE 049_013 LINE	Reserve for Public Requirements Unidentified Specifics & Schedule Changes	49	850,000
		PPM 4486	04486 I-195 Contract 15 - Providence	49	225,000
		CD0189	11411 DOTR-Central Bridge No. 182 Replacement, Barrington	49	150,000
	Public Requirements Total				3,709,000
	Transformers & Related Equipment	CN4920	Narragansett Transformer Purchases	49	3,655,000
	Transformers & Related Equipment Total				3,655,000
Statutory/Regulatory Total					20,006,000
Damage/Failure	Damage/Failure	C18593	DxT Substation Dmg/Fail Reserve C49	49	175,000
		COS002	Ocean St-Dist-Subs Blanket	49	649,000
		COS014	Ocean St-Dist-Damage&Failure Blankt	49	7,648,000
		RESERVE 049_014 LINE	Reserve for Damage/Failure Unidentified Specifics & Schedule Changes	49	1,300,000
	Damage/Failure Total				9,772,000
	Major Storms - Dist	C22433	OSD Storm Cap Confirm Proj FY08	49	650,000
	Major Storms - Dist Total				650,000
Damage/Failure Total					10,422,000
Asset Condition	__Woonsocket & Related	C03693	Woonsocket Sub New 115/13 kV Sub	41	300,000
		C15200	Woonscket Sub - 3 Dist. fdrs	41	275,000
		C24279	Woonsocket Sub New 13 kV S/gear	41	250,000
	__Woonsocket & Related Total				825,000
	Asset Replacement	C14326	I&M - OS D-Line UG Work From Insp	42	250,000
		C17454	NPCC UF Relay Replacement CO:49	49	25,000
		C23852	Inst Ductline Governor St. Prov.	30	1,000,000
		C25815	OS ARP Insul, SensDev, Surge Arrest	21	405,000
		C26058	OS ARP Spare Substation Transformer	34	350,000

SPENDING RATIONALE	RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY 2013 PROPOSED BUDGET
		C26763	RI Small Capital	49	100,000
		C28364	Kent County Relocation 3309 Line	24	150,000
		C32019	Batts/Chargers NE South OS RI	39	250,000
		C32028	Regulator Repl-NE South OS RI	36	200,000
		C32278	OS ARP Breakers & Reclosers	34	1,000,000
		C35586	Relay Replacement Strategy Co 49DxT	34	800,000
		COS017	Ocean St-Dist-Asset Replace Blanket	49	1,136,000
		RESERVE 049_017 LINE	Reserve for Asset Replacement Unidentified Specifics & Schedule Changes	34	(366,000)
		RESERVE 049_017 SUB	Reserve for Asset Replacement Unidentified Specifics & Schedule Changes (substation)	34	(692,000)
		C31777	03586 OS IE UG Cable Replacement Program	36	1,000,000
		C33843	03061 BatteryRplStrategyCo49DxT	39	180,000
		C36414	09290 1102A & 1102B Cable Replacement	36	80,000
		C36416	09291 1158 Cable Replacement	39	90,000
		C20297	03740 Sac AB Repl Prog Phase 7 NEC DxT	49	400,000
		C36100	09301 Front St Convert 4kV to 13kV Load	34	90,000
		CD0392	15716 Fdr 1111 Inst Cable - Weybosset/Union Sts., Providence	30	400,000
		CD0396	15719 Fdr 1135 Inst Cable - Eddy St., Providence	30	500,000
		CD0397	15718 Fdr 1127 Inst Cable - Dyer/Dorrance Sts., Providence	30	400,000
		C36093	09310 Elmwood#7Replace 23KV Groun Bank	34	50,000
		C36110	09315 Merton Sub Replace Metal Clad	39	10,000
		PPM 11694	11694 Eldred Sub Asset Replacement	36	26,000
		PPM 11696	11696 Eldred Sub Asset Replacement	36	260,000
		PPM 13247	13247 102W51_Carriage Drive_Rplc Direct buried cable URD	30	489,000
	Asset Replacement Total				8,583,000
	Asset Replacement - I&M (NE)	C26281	IE - OS D-Line Work Found by Insp.	42	1,250,000
	Asset Replacement - I&M (NE) Total				1,250,000
	____Flood Damage Avoidance Engine	PPM 17346	Hunt River Substation - removal costs	36	10,000
		PPM 9802	Sockanosset - Preliminary Engineering 23kV metalclad and control house installation on a raised foundation	49	200,000
		PPM 17337	Pontiac flood mitigation measures	36	200,000
		PPM 17339	Pawtuxet Sub - Preliminary Eng	36	10,000
		PPM 17349	Riverside Substation - removal costs	36	10,000
		PPM 11969	11969 Langworthy Substation (D Sub)	36	250,000
		PPM 11970	11970 Langworthy Substation (D Line)	34	25,000
		PPM 11973	11973 Hopkinton Phase 2 (D Sub)	34	450,000
		PPM 11974	11974 Hopkinton Phase 2 (D Line)	34	50,000
	____Flood Damage Avoidance Engineering Studies Total				1,205,000
Asset Condition Total					11,863,000
Non-Infrastructure	General Equipment	COS006	Ocean St-Dist-Genl Equip Blanket	49	186,000
	General Equipment Total				186,000
	Telecommunications Capital - Dist	COS021	Ocean St-Dist-Telecomm Blanket	49	150,000
	Telecommunications Capital - Dist Total				150,000
Non-Infrastructure Total					336,000
System Capacity and Performance	__Coventry & Related	C24179	Coventry MITS (Dist Sub)	41	875,000
		C24180	Coventry MITS (Dist Line)	41	100,000
	__Coventry & Related Total				975,000
	__Hopkinton & Related	C24175	Hopkinton Substation (Dist Line)	36	50,000
		C24176	Hopkinton Substation (Dist Sub)	36	350,000
		C33050	New Hopkinton RI Substation	36	400,000
	__Hopkinton & Related Total				800,000

SPENDING RATIONALE	RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY 2013 PROPOSED BUDGET
	__Newport & Related	C15158	Newport Mall Substation	41	200,000
		C24159	Newport Sub Transmission Line Tap	41	50,000
		C28628	NEWPORT Load Relief - Phase 2	41	100,000
		PPM 17046	17046 Gate 2 Substation	41	100,000
	__Newport & Related Total				450,000
	__West Warwick & Related	C28920	Install Distr. Sub - West Warwick	39	150,000
		C28921	Install 4 dist. Fdrs West Warwick	39	25,000
		C32002	W. Warwick 115/12.5kV Sub	39	150,000
	__West Warwick & Related Total				325,000
	Load Relief	C05505	IE - OS Dist Transformer Upgrades	30	1,300,000
		C13967	PS&I Activity - Rhode Island	36	175,000
		C23012	63F6 Ext 2 PH down Ten Rod Rd	48	200,000
		C24221	Load Relief to 9J3 - Brown Street	36	400,000
		C27222	West Farnum - Rem. Dist. Equipment	41	50,000
		C27245	Relocate 23kV 2227 & 22230	34	350,000
		C28851	Recon. 38F5 and 2227 Greenville Ave	27	300,000
		C28884	Install Johnston 18F10 Feeder	37	100,000
		C28900	Recond. 2228 Johnston sub - Randall	36	750,000
		C28932	Recon. 0.5 Miles Segment of 2232	21	700,000
		COS016	Ocean St-Dist-Load Relief Blanket	49	285,000
		RESERVE 049_016 SUB	Reserve for Load Relief Unidentified Specifics & Schedule Changes (substation)	34	(1,142,000)
		RESERVE 049_016 LINE	Reserve for Load Relief Unidentified Specifics & Schedule Changes	34	(516,000)
		C32450	03492 Nasonville 127W43	31	600,000
		C33535	04443 Johnston Sub 12.47 kV Expansion	35	250,000
		C36522	09312 Kilvert St 87 - Install TB#2 (DSub)	39	100,000
		C34002	03435 Johnston Sub 12kV Epansion Getaways	35	50,000
		C36397	04403 Clarkson - new 13F10 feeder (line)	30	200,000
		PPM 11646	11646 38K23 Line Upgrade	30	300,000
		PPM 11915	11915 New Highland Drive Substation - DSub	42	500,000
		PPM 11916	11916 New Highland Drive Substation - DLine	42	200,000
		PPM 12728	12728 Harrison Feeder Upgrades	27	400,000
		PPM 13243	13243 KENTS CORNER transformer contingency and 47J4 feeder Load Relief	37	24,000
	Load Relief Total				5,576,000
	Reliability	C05485	IE - OS Recloser Installations	41	210,000
		C05524	IE - OS Cutout Replacements	41	1,765,000
		COS015	Ocean St-Dist-Reliability Blanket	49	1,162,000
		C32575	3626 Emergent Reliability Project Reserve	41	250,000
		C35726	04432 EMS- Narragansett Electric	30	600,000
		PPM 17312	17312 EMS Add-Peacedale 59	41	300,000
	Reliability Total				4,287,000
	Reliability - FEEDER HARDENING	C05461	FH - OS Feeder Hardening	45	1,500,000
	Reliability - FEEDER HARDENING Total				1,500,000
System Capacity and Performance Total					13,913,000
Grand Total					**56,540,000**

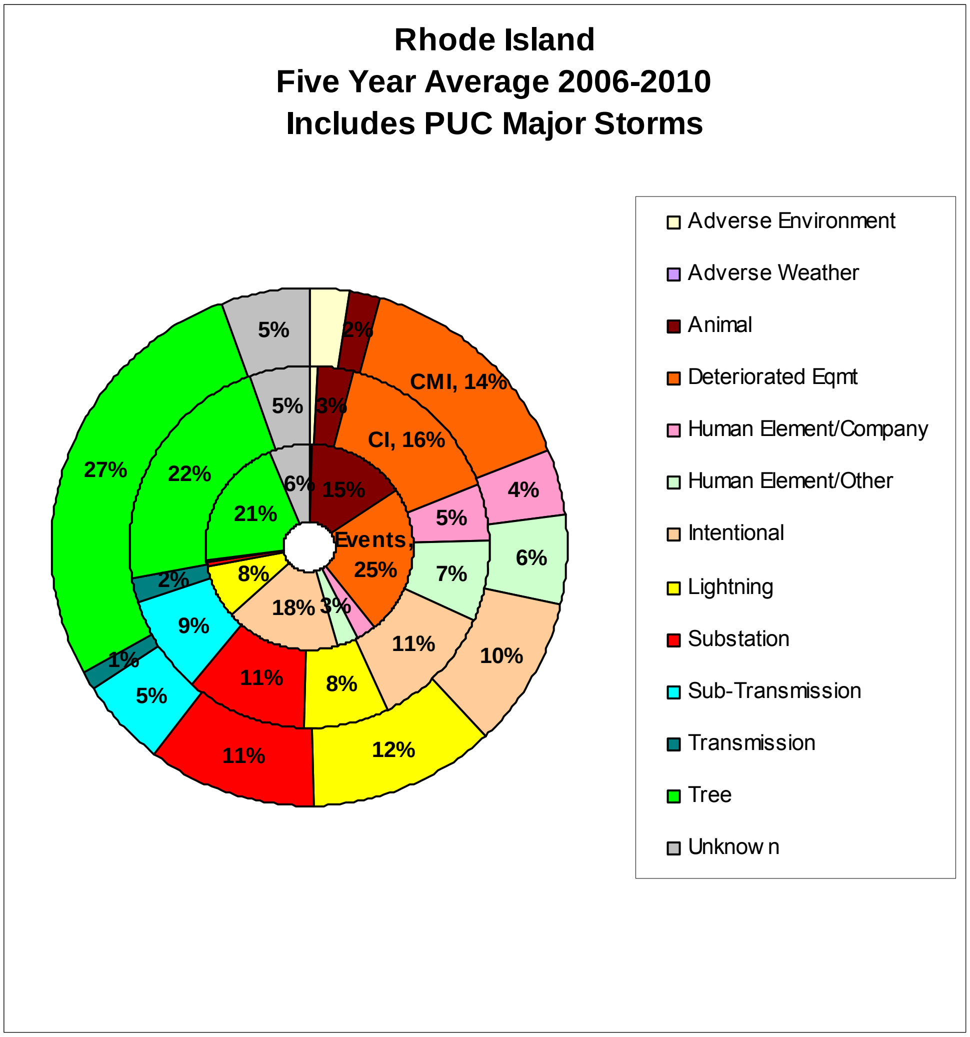
Exhibit 1 – JLG
Section 3
Veg. Mgmt

Section 3
Vegetation Management Program
FY 2013 Electric ISR Plan

Vegetation Management Program
FY 2013 Proposal

The Company's Vegetation Management ("VM") Program is an essential component of the Company's plan to maintain the safety and the reliability of its electric distribution network. Trees are an important safety concern for several reasons. Tree contact with the electric distribution system increases the risk of electric shock to the public, slows the restoration of critical infrastructure, and may increase the risk of fire. Trees can also be a significant deterrent to reliability since tree contact with the distribution system during windy/stormy conditions may cause a phase to phase fault, which will trip either a line fuse, pole recloser, or a station breaker and cause an interruption on a distribution circuit. As shown in Chart 1, trees were responsible for almost 22 percent of number of customer interruptions ("CI") over the past five years.

Chart 1: Customer Interruptions by Cause



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 consists of several different activities, as described below, each addressing a different aspect of utility vegetation management.

Cycle Pruning - The Company spends approximately two-thirds of its VM budget on Cycle Pruning, a program 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 consists of the scheduling of every distribution circuit for pruning based on a dimension specification on a fixed timeframe or rotation.

Cycle Pruning is designed to maintain an acceptable clearance between overhead conductors and vegetation so to minimize the safety risk to the public and utility workforce. A stable, consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a best utility practice.

Consistent circuit pruning also helps maintain service reliability and supports efficient management of the overhead network. Managing the vegetation along the network helps to avoid interruptions caused by phase to phase tree contact and makes the network more accessible to line crews so they can restore power more 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.

The core element for the Cycle Pruning program is the determination of the optimal schedule or length of time between pruning events on a circuit. This optimal pruning cycle or interval is set based on the balance of three factors: vegetation growth rates, amount of clearance to be created while pruning, and cost. The assumed vegetation growth rate is based on the length of the growing season and the growth characteristics of the predominant tree species in the state. The clearance to be created at time of pruning depends on multiple factors such as aesthetics, the effect on the environment, customer acceptance, and overall societal impact. This growth rate is balanced against acceptable levels of pruning clearance and implementation cost efficiency. For example, tree growth rates of 1.5 feet per year would require the removal of six feet of tree growth every four years. Shorter intervals like 1 or 2 years would require the removal of 1.5 feet or 3.0 feet, respectively. However the operational costs of moving crews through the circuit that often makes the cycle cost prohibitive. Longer cycles like 6 years would require clearances of 9 to 10 feet on average. However, this approach leaves roadside tree aesthetics that are generally not acceptable by the public. This balance between growth, clearance, and cost is what determines the optimal pruning cycle. The Company continues to believe that an average four year cycle is the appropriate target for Rhode Island.

As noted in last year's filing, beginning in 2003, the Company converted to a circuit-based approach for Cycle Pruning in order to improve the service reliability response of the program. As also noted, the Company continues to use a reliability ranking model, called the Tree Model, which is based on historic tree-related interruption data to appropriately balance the circuit pruning interval with the reliability performance when creating the annual work plan for Cycle Pruning. The circuit ranking combined with field assessment of the actual vegetation grow-in conditions provides the input details necessary to ensure that circuits selected for the annual work plan are the highest priority for the program and should produce the best reliability return for the dollar.

As noted earlier, the Company contends that a four year interval is the optimum pruning cycle for the Rhode Island overhead distribution assets. As reported last year, to maintain a four year pruning interval, approximately 1,300 miles must be pruned each year. Due to an aggressive procurement process, the Cycle Pruning bids came in favorable against the budget and allowed the Company to not only schedule the 1,300 base miles but also include another 116 of "Recovery Mileage" in the FY 2012 work plan which were necessary to pull the overdue circuits back to a four year interval.

Chart 2: Cycle Pruning Mileage FY 2011 to FY 2015

Year	FY 2011 Actual	FY 2012 Expected	FY 2013 Proposed	FY 2014 Forecast	FY 2015 Forecast
Mileage	828	1,300	1,300	1,300	1,300
Recovery Mileage		116			
Total Annual Mileage	828	1,416	1,300	1,300	1,300

Enhanced Hazard Tree Mitigation ("EHTM") - As noted in last year's plan, hazard tree removal, as part of a complete utility vegetation management program, has become a best industry practice. Full tree and large limb failures have been shown to account for a significant portion of CI, not only in Rhode Island but also in other states. Using three years of tree related interruption data for Rhode Island one can see that fallen trees account for 50 percent of tree-related CI. In fact, during the recent Hurricane Irene event, that figure was even higher, with 67 percent of the Company's tree-related customer interruptions caused by full tree failures rather than growth or limb failures. The frequency of tree fells in the Hurricane Irene event was 17 percent higher than the Company's most recent three year average.

To address the issue of fallen trees, the EHTM program was implemented in 2007 to identify and remove dying or structurally weakened trees and overhanging leads along the three phase sections of distribution circuits. The three phase portion of the circuit is the most susceptible to tree caused faults and also serves the highest number of customers per exposed mile, thus intuitively providing the highest benefit per hazard tree removal dollar. EHTM uses an industry leading tree risk assessment protocol to identify hazard trees. The EHTM portion of the program historically accounts for approximately 10 percent of the overall VM budget.

The EHTM program provides two significant benefits. First, 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. Improvements in CI as high as 60 percent have occurred on circuits where EHTM has been used on the mainline portion of targeted circuits in Rhode Island. The EHTM program can therefore, significantly improve the customer's service reliability on those targeted circuits.

Second, the hazard tree mitigation program generates significant savings with regard to the Company's O&M and capital budgets. Hazard trees are designated as such because they have a high probability of failing and causing damage to Company equipment as witnessed during the Hurricane Irene event. Although the Company has not specifically tracked the cost to repair the damage from fallen trees and limbs, the expected cost to ameliorate damage caused by fallen trees and limbs can be imputed based on experience. The direct costs to repair the damage caused by a fallen tree or limb can fall within the following range:

- $200 (a one person crew to clear a limb and replace a fuse)
- $1,950 (two line crews to switch and install new conductor and a vegetation crew to remove the fallen tree)
- $13,450 (multiple line crews to replace transformer, pole and cleanup spill from transformer and a vegetation crew to remove the fallen tree)

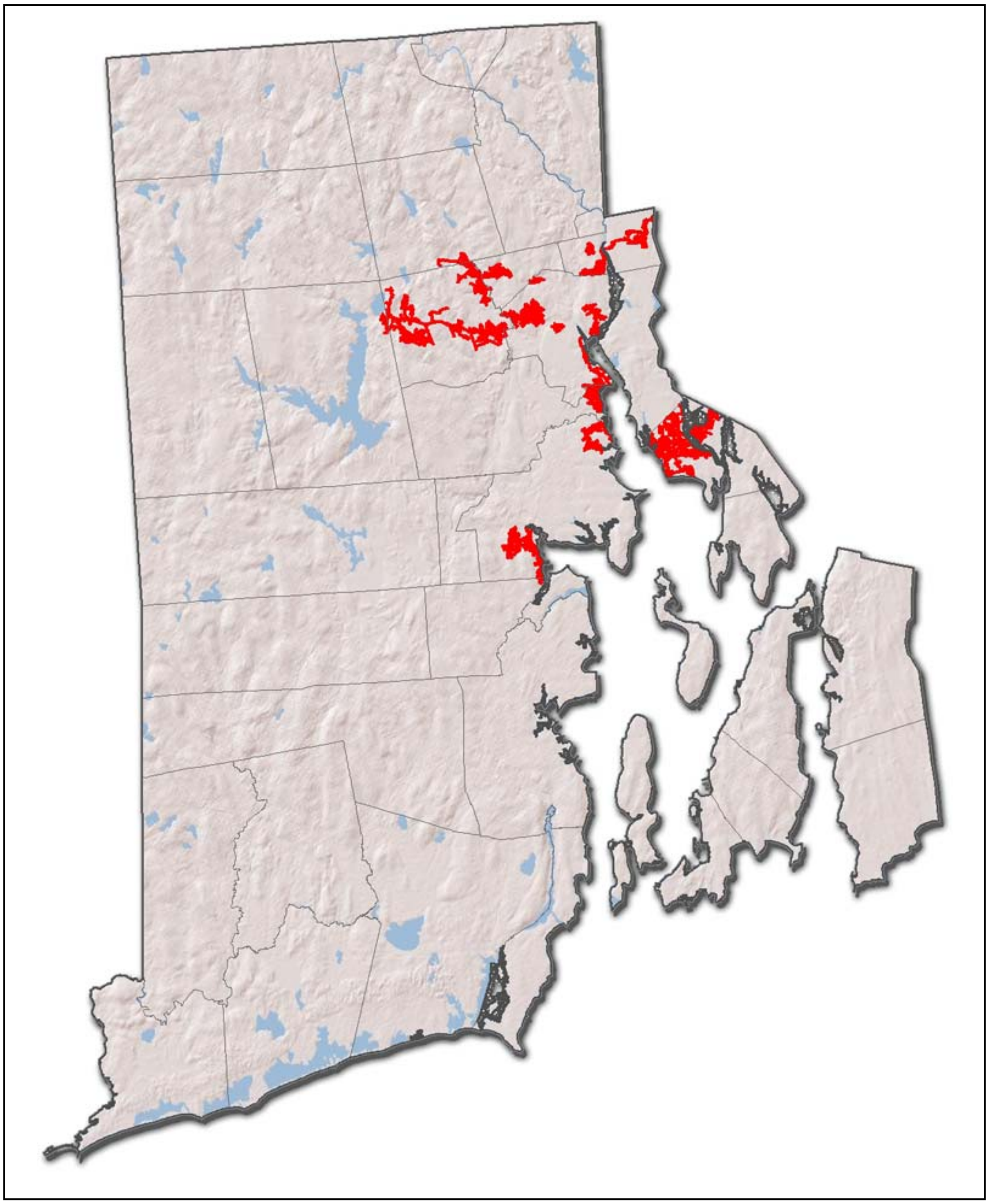
Even if it is conservatively assumed that 60 percent of the damage from hazard trees is at the low end, 20 percent is at the middle part, and 20 percent is at the high-end of this range, the expected cost to restore the system to its normal configuration following an event caused by a hazard tree would be approximately $3,200 per occurrence (i.e. (0.6 x $200) + (0.2 x $1,950) + (0.2 x $13,450) = $3,200).

With the average direct cost to remove a hazard tree at $820, a benefit/cost ratio of approximately 4:1 ($3,200 ÷ $820) clearly supports the removal of the hazard tree even without considering the added positive impacts on customer satisfaction, reliability, and safety. The Company has removed 2,727 hazardous trees since the EHTM program began in 2007 at an approximate cost of $2.2 million (2,727 x $820) and removing these trees has created a cost avoidance of an estimated $8.7 million (2,727 x $3,200). In this way the cost of hazard tree mitigation is estimated to be a significant savings over the potential costs of repair from tree failure.

Post Irene Considerations - As noted above, the Company's interruption records show that during the Hurricane Irene event the Company experienced a 17 percent increase in the frequency of full tree failures above a three year average and a 34 percent increase in the number of customers affected by tree fells. While that in itself illustrates how costly and difficult the restoration was for that storm, in this case the trends are stated here to illustrate another point. If more trees failed from within the utility forest (those trees within falling distance of the electric distribution asset) than usual, then it is a reasonable assumption that a significant number of the remaining trees within striking distance of the line also have sustained damage. For that reason, the Company believes that, due to the nature of this significant event, it will be necessary to add an additional one-time investment into the EHTM program in order to mitigate the hurricane tree damage within the hardest hit areas of the storm. The map below (Figure 1) represents tree fells by circuit along with a listing in Chart 3 of the nineteen (19) hardest hit circuits for tree fell interruptions. The Company proposes to inspect circuits in a prioritized manner based on tree exposure and the number of customers served, and to remove any identified hazard trees and/or storm damaged trees found within the three phase main line section of those circuits. This inspection work will be targeted from the substation out to the first protective device on the feeder. In certain instances based on the configuration of the feeder, the Company may elect to expand the inspection out to the second protective device.

Based on an estimate of 5 trees per mile, $820 dollars per tree and 89.57 miles of three phase circuit to inspect the Company proposes a one-time addition to the EHTM program budget for FY 2013 of $367,000. At this point, it is presumed that beginning in FY 2014 the budgeted spend for EHTM will return to the $750,000 level plus any update for inflation.

Figure 1: Hurricane Irene Map of Circuits with a Tree Fell Frequency of >2 per Mile



■ **Circuits with a Tree Fell Frequency of >2 per mile**

Chart 3: Hurricane Irene List of Circuits with a Tree Fell Frequency of >2 per Mile

Circuit Number	Overhead Miles	Tree Failures	Tree Failures Per Mile	Overhead 3 Phase Miles
49_53_50F2 6.94		31	4.5	2.77
49_53_12J2 1.71		6	3.5	1.33
49_53_106J1 2.36		8	3.4	1.63
49_53_76F7 17.39		59	3.4	9.90
49_53_18F6 28.12		91	3.2	8.81
49_53_38F4 15.27		47	3.1	6.77
49_53_4F1 20.59		57	2.8	7.29
49_53_4F2 28.95		78	2.7	12.27
49_53_77J2 3.40		9	2.6	1.50
49_56_57J2 5.31		14	2.6	2.97
49_53_18F8 12.99		33	2.5	3.96
49_53_71J3 2.07		5	2.4	1.66
49_56_22F2 16.96		39	2.3	7.03
49_53_107W83 7.69		17	2.2	3.29
49_53_28J2 4.64		10	2.2	2.53
49_56_57J5 6.13		13	2.1	2.91
49_53_107W61 5.68		12	2.1	4.09
49_53_69F3 19.03		40	2.1	7.21
49_53_77J3 2.44		5	2.1	1.66
		Total 3 Phase Miles:		**89.57**

Police Detail/Flagman - In order to safely perform the Cycle Pruning and EHTM, the Company must hire police details and flagman. The levels of required details vary by town and traffic/road condition. This portion of the VM budget is driven by the work plan and on the hourly rates set by the municipalities. Police/Flag details generally consume between 2 percent and 6 percent of the annual budget.

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

This 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 emergency calls to remove sporadic trees/limbs from wires and to perform vegetation work necessary to restore power to customers is another important core activity performed by forestry crews. Spending for each core activity varies from year-to-year depending on the customer calls, weather, and system requirements. Each core activity separately consumes a small and variable proportion of the overall budget, but taken together these activities generally account for between 15 percent and 20 percent of the VM budget.

Fiscal Year 2013 Vegetation Management Budget

The Electric ISR Plan proposes to spend approximately $8.3 million for VM in FY 2013. This includes approximately $5.2 million for cycle pruning, $750,000 for EHTM, and $367,000 in Post Irene EHTM. As shown in Chart 4 below, this budget is comparable to what the Company spent to implement its VM program in FY 2009 (except for the Post Irene dollars) but up considerably from the suppressed level of spending dedicated to VM in FY 2010 and FY 2011.

Chart 4: Vegetation Management Spending
(‘000s)

	FY2009	FY2010	FY2011	FY2012 Forecast*	FY2013 Proposed
Cycle Prune (Base)	$5,574	$4,552	$2,732	$5,300	$5,150
Hazard Tree – EHTM	$757	$709	$235	$700	$750
Post Irene EHTM					$367
Sub-T (off & on road)	$436	$302	$235	$461	$290
Police/Flagman Detail	$187	$241	$215	$479	$488
All Other Activities (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$903	$1,078	$1,189	$1,268	$1,211
Total	**$7,858**	**$6,882**	**$4,606**	**$8,208**	**$8,256**

* Represents the FY 2012 2nd Quarter ISR forecast, as filed on November 21, 2011.

Exhibit 1 – JLG
Section 4
I & M Plan

Section 4

Inspection and Maintenance Plan
FY 2013 Electric ISR Plan

Inspection and Maintenance Program
FY 2013 Proposal

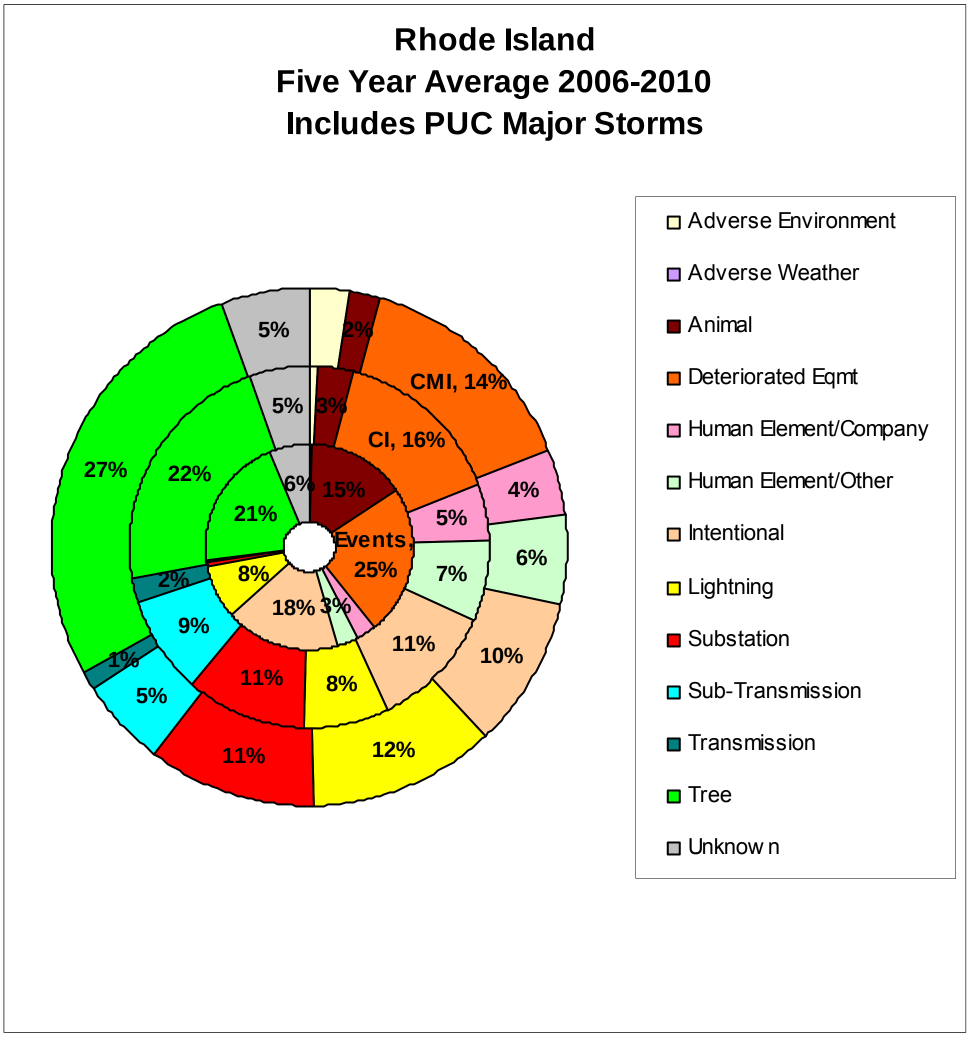
Consistent with the Company's transition to a proactive asset management approach, the Company began to implement a comprehensive proactive inspection and maintenance ("I&M") program ("I&M Program") beginning in October 2009. This strategy requires a step change increase in the number of inspections, maintenance, and asset replacement actions that the Company will take proactively compared to the number of such actions that it had taken in the past.

Prior to October 2009, the Company did not use a formalized, consistent approach to perform proactive periodic system-wide inspections that identify and prioritize potential reliability risks. The Company has traditionally taken a "fix on fail" approach to addressing reliability issues caused by trees, animal contact, lightning, and deteriorated equipment. As part of this approach, the crews in local operating areas have performed infrared inspections, feeder patrols, and padmount inspections, but these inspections have traditionally been performed on an ad hoc basis in localized areas. The Company addressed problems of an immediate nature, but other issues were not always documented or addressed. This approach was reactive and repair-oriented.

In contrast to the past approach, as part of the I&M Program, the Company proactively inspects overhead distribution equipment on a six-year cycle. With this approach, the Company will obtain new inspection results on approximately 17 percent of its overhead distribution system so that it will have comprehensive system-wide information on the condition of all overhead components within six years. These proactive inspections identify and provide for the timely condition-based replacement of visibly damaged or deteriorated assets prior to the next inspection cycle. Specifically, the inspections identify and prioritize issues between a Level 1, which is an issue which requires immediate attention, and Level 4, which is information used for asset decision making and to aid inspectors during the subsequent inspections.

Collecting this type of comprehensive system-wide information on the condition of all overhead system components generates several benefits for customers. Proactive inspections generate incremental proactive maintenance expense to address issues that create safety and reliability risks for customers. This includes the bonding and grounding of existing facilities, the installation of lightning arrestors and animal guards, and fixing distribution poles that are leaning excessively. Taking such action proactively helps the Company maintain reliability performance and improve customer satisfaction. Indeed, as shown in Chart 1 below, lightning accounts for 12 percent of customer minutes interrupted. Proactive maintenance also helps to ensure that assets achieve their expected life.

Chart 1: Customer Interruptions by Cause



Proactive inspections also generate proactive and condition-based replacement of distribution assets including poles, cutouts, transformers, and switches, and this approach will help to accomplish the following:

- Maintain positive reliability performance and customer satisfaction.
  - Replacing deteriorated equipment (which currently accounts for 16 percent of customer interruptions) before it fails will clearly help to reduce customer interruptions compared to the fix-on-fail approach.
  - Coordinating the replacement of multiple system components across the system will multiply the reliability benefits compared to the current

approach that addresses limited performance deficiencies on select feeders.

- Extend the lives of existing assets since replacing weak or vulnerable assets on the system avoids collateral damage to other assets when the weakened asset fails.
- Avoid unnecessary or premature investments based on age alone since the asset replacements would be condition-based.
- Create a longer term planning horizon and thereby expand the opportunity for efficient procurement and dispatch of needed resources compared to the current fix-on-fail approach.

The Company believes that the I&M Program is essential to fulfilling its obligation to provide reliable and cost effective electric delivery service to customers in an area that has an aging infrastructure such as that which exists in Rhode Island. The multiple safety and reliability goals of the I&M Program will be discernible by customers because the operating integrity of the distribution system will be raised and maintained at a relatively higher level. The validity of the I&M strategy has been demonstrated in New York during the past several years and the best practices from the Company's experience in New York have been incorporated into the roll out of the I&M Program in Rhode Island.

Fiscal Year 2013 Inspection and Maintenance Budget

As shown in Chart 2 below, the Company proposes an I&M Program Operation and Maintenance ("O&M") expense budget of approximately $2.3 million for fiscal year ("FY") 2013. The Company deferred the capital work associated with the proactive I&M Program during FY 2012 and only performed the inspection work itself. The intent was to complete Feeder Hardening in FY 2012 and transition fully to the I&M Program in FY 2013. However, at the end of FY 2012 the Company will have four feeders left in the original feeder hardening program (127W40, 127W41, 22F2, 69F3) which have engineering and design completed and is proposing performing feeder hardening on these feeders in FY 2013. In addition, the Company is proposing the I&M construction be started in FY 2013 with Level 2 work on approximately 10 to 15 feeders, which represents approximately 40% of the inspections completed to date. The I&M Program O&M budget includes approximately $2.3 million for total O&M expenses for feeder hardening, the overhead I&M program, and the replacement of potted porcelain cutouts, which have total capital costs of approximately $4.5 million, and are included in the reliability and asset condition portions of the proposed capital budget discussed in Section 2 regarding Electric Capital Investment.

Chart 2: Inspection and Maintenance Program Costs

	Overhead I&M	Potted Porcelain Cutouts	Feeder Hardening	Total
	(a)	(b)	(c)	(d)
Capital[1]	$1,250,000	$1,765,000	$1,500,000	$4,515,000
Opex Related to Capex	$770,000	$176,500	$530,000	$1,476,500
Repair Related Costs	$609,000	---	---	$609,000
Inspections Related Costs	$185,400	---	---	$185,400
Total Operation and Maintenance Expenses	$1,564,400	$176,500	$530,000	$2,270,900
Total I&M Costs	$2,814,400	$1,941,500	$2,030,000	$6,785,900

[1] The Capital costs shown here are included in the proposed $56.5M Electric Capital Investment Plan in Section 2.

Exhibit 1 – JLG
Section 5
Revenue Req.

Section 5
Revenue Requirement
FY 2013 Electric ISR Plan

Revenue Requirement
FY 2013 Proposal

The attached proposed revenue requirement calculation reflects the revenue requirement related to the Company's proposed investment in its Electric Infrastructure, Safety, and Reliability ("ISR") Plan ("ISR Plan").

As shown on Page 1, Column (b) of the attachment, the Company's fiscal year ("FY") 2013 Electric ISR Plan revenue requirement amounts to $14,429,525 and consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities and for system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's Inspection and Maintenance ("I&M") Program, and (2) the Company's capital investment in electric utility infrastructure. Line 3 of that column reflects the forecasted FY 2013 revenue requirement related to O&M expenses, or $10,526,900.

The FY 2013 revenue requirement associated with the Company's cumulative forecasted capital investment in electric utility infrastructure of $3,902,625 is shown on Line 11, consisting of the $1,127,207 revenue requirement on FY 2013 proposed ISR capital investment, as calculated on Attachment 1, Page 2, plus the $2,775,419 FY 2013 revenue requirement on the FY 2012 ISR capital investment approved in the FY 2012 ISR Plan, as calculated on Attachment 1, Page 3. The total annual FY 2013 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $14,429,525, as reflected in Column (b) on Line 13, and is equal to the sum of Lines 3 and 11. Finally, Line 17 reflects the incremental FY revenue requirement of $4,499,500 required to deliver the Company's Electric ISR Plan.

For illustration purposes only, Column (c) of Page 1 provides the FY 2014 revenue requirement for the respective vintage year proposed capital investments as calculated on Attachment 1, Pages 2 and 3. It is important to note that these proposed amounts will be trued up to actual investment activity after the conclusion of the respective FY, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2013 Electric ISR Plan revenue requirement includes $10,526,900 of VM and I&M O&M expenses as shown on Page 1, Line 3 in Column (b) of the attachment. In accordance with the Company's last general rate case in R.I.P.U.C. Docket No. 4065, the Company was recovering $6,549,368 in base distribution rates associated with its VM and I&M O&M expenses. However, because the ISR Plan revenue requirement represents the Company's total cost associated with its ISR Plan, including VM and I&M O&M expenses, the Company implemented a permanent credit to base distribution rates for the $6,549,368 that was being recovered through base distribution rates, as shown on Attachment 1, Page 1, Line 15 in Column (a). As a result, VM and I&M O&M expenses are being recovered exclusively under the Electric ISR tariff and not through base distribution rates.

Electric Infrastructure Investment

As noted above, Pages 2 and 3 of the attachment calculate the revenue requirement of incremental capital investment associated with the Company's FY 2013 ISR Plan plus the FY 2013 revenue requirement on the capital investment approved in the Company's FY 2012 ISR

Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. Incremental electric capital investment for this purpose is intended to represent the net change in rate base for electric infrastructure investments since the establishment of the ISR Mechanism, or April 1, 2011, and 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. These amounts are shown on Lines 1 through 13.

For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: 'nondiscretionary' capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and 'discretionary' capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined 'nondiscretionary' categories. Because the Electric ISR was effective April 1, 2011, and appropriately includes capital additions rather than capital spend in the calculation of the revenue requirement on such capital additions, the amount of capital additions ultimately allowable in the ISR is limited to amounts no greater than the actual cumulative amount of capital spending on 'nondiscretionary' projects and no greater than the cumulative amount of 'discretionary' project spend as agreed to by the Division and as approved by the Commission. The calculation of this cumulative limitation on vintage year capital investments allowable in the Electric ISR Plan can be found on Page 4 of Attachment 1. The amounts reflected on Lines 9 and 18 of Page 4 for allowable capital additions for 'nondiscretionary' and 'discretionary', respectively, by vintage year are brought forward to the respective vintage year revenue requirement calculations on

Lines 1 and 2 of Pages 2 and 3. As indicated earlier, these proposed spending and capital addition estimates will be trued-up to actual when known.

Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in rate base in determining depreciation expense. Retirements however, do not affect rate base as both ‘plant in service’ and the ‘depreciation reserve’ are reduced by the installed value of the plant being retired and therefore have no impact on net plant, as calculated on Line 9 on Pages 2 and 3 of the Attachment. For purposes of calculating the revenue requirement, plant retirements have been estimated based on the percentage of retirements to additions during calendar years 2010 and 2009 for the FY 2013 and FY 2012 revenue requirement calculations, respectively, and have been deducted from the total depreciable capital amount as shown on lines 4 through 6. Incremental book depreciation expense on Line 18 is computed based on the net depreciable additions, from Line 6 at the 3.40 percent composite depreciation rate as approved in R.I.P.U.C. Docket No. 4065, and as shown on Line 14. 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 12, is combined with the incremental depreciable amount from Line 9 (vintage year ISR allowable capital additions less non-general plant depreciation expense included in base distribution rates) to arrive at the incremental investment on Line 13 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 13, and accumulated depreciation and accumulated deferred tax reserves as shown on Lines 19 and 22, respectively.

The deferred tax amount arising from the capital investment, as calculated on Lines 14 through 22, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate. The calculation of tax depreciation is described below. The average change in rate base, shown on Line 27, equals the average year-end cumulative change in rate base on Line 26. This amount is multiplied by the pre-tax rate of return in the most recent rate case (in this example, the one approved by the Commission in R.I.P.U.C. Docket No. 4065), as shown on Line 28, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 29. To this, incremental depreciation expense is added on Line 30, as are property taxes on Line 31, which are computed on net capital investment in the year following the investment to coincide with the timing in which property taxes are assessed. The sum of these three 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, Lines 8 and 9, as part of the total Electric ISR Plan revenue requirement. This capital investment revenue requirement amount is added to the total O&M expenses on Line 3, Page 1, to derive the total FY 2013 Electric ISR Plan revenue requirement of $14,429,525, as shown on Line 13, and represents and incremental $4,499,500 from the FY 2012 Electric ISR Plan revenue requirement, as shown on Line 17.

Tax Depreciation Calculation

The tax depreciation calculations for FY 2013 and FY 2012 are provided on Pages 5 and 6 of Attachment 1, respectively. The tax depreciation amount assumes that a portion of the capital investment, as shown on Line 1 of those pages, will be eligible for immediate deduction on the Company's corresponding FY federal income tax return. This immediate deductibility is referred to as the capital repairs deduction.[11] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Lines 4 through 12. During 2010, Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 ("Act") which provided for an extension of bonus depreciation. Specifically, the Act provided for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 2012. In accordance with the Act, capital investments made from April 2012 through December 2012 are eligible for 50 percent bonus depreciation, as shown on Line 9.[12]

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate as shown on Line 17. The amount of depreciation deducted for MACRS on Line 18 is added to the amount of capital repairs deduction plus the bonus depreciation deduction and cost of removal to

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

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

arrive at total tax depreciation as shown on Line 20. These annual total tax depreciation amounts are carried forward to Line 16 of Attachment 1, Pages 2 and 3, for the respective years, and incorporated in the deferred tax calculation.

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

Line No.		Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
1	**Operation and Maintenance (O&M) Expenses**			
2				
3	Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$9,207,845	$10,526,900	
4				
5				
6	**Capital Investment**			
7	Forecasted Revenue Requirement Related to Electric Capital Investment:			
8	Annual Revenue Requirement on FY 2012 Capital Included in Rate Base	$722,180	$2,775,419	$2,623,941
9	Annual Revenue Requirement on FY 2013 Capital Included in Rate Base	$0	$1,127,207	$3,631,272
10				
11	**Capital Investment Component of Revenue Requirement**	**$722,180**	**$3,902,625**	**$6,255,213**
12				
13	**Total Fiscal Year Revenue Requirement**	**$9,930,025**	**$14,429,525**	
14				
15	Less: Adjustment to Base Rates to reflect recovery of VM and I&M O&M expense in the ISR Factor	($6,549,368)		
16				
17	**Total Incremental Fiscal Year Rate Adjustment**	**$3,380,657**	**$4,499,500**	

Line Notes:

3 Projected Vegetation Management and Inspection & Maintenance expense for FY 2012 and FY 2013
8 From Page 3, Line 32
9 From Page 2, Line 32
11 Line 8 + Line 9
13 Line 3 + Line 11
15 Per Docket No. 4065
17 Column (a) equals Line 13 plus Line 15; Column (b) equals Line 13 minus Line 13, Column (a)

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

Line No.				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)
	Capital Additions Allowance				
	Non-Discretionary Capital				
1	Actual Non-Discretionary Capital Additions	Page 4 Line 9, Column (b)	1/	$28,619,000	$0
	Discretionary Capital				
2	Approved Discretionary Capital Spending	Page 4 Line 18, Column (a)	1/	$22,747,000	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 2		$51,366,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$51,366,000	$0
5	Retirements	Line 4 * Retirements Rate	2/	$8,416,779	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$42,949,221	$42,949,221
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$51,366,000	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$38,875,088	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$12,490,912	$12,490,912
	Cost of Removal				
10	Cost of Removal - Non-Discretionary			$3,365,680	$0
11	Cost of Removal - Discretionary			$3,709,320	$0
12	Total Cost of Removal	Column (a) = Line 10 + Line 11; Column (b) = Prior Year Line 12		$7,075,000	$7,075,000
13	**Total Net Plant in Service**	**Line 9 + Line 12**		**$19,565,912**	**$19,565,912**
	Deferred Tax Calculation:				
14	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%
15	Vintage Year Tax Depreciation:				
16	2013 Spend	Page 5 Line 20		$30,149,089	$2,121,967
17	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		$30,149,089	$32,271,056
18	Book Depreciation	Column (a) = Line 6 * Line 14 * 50%; Column (b) = Line 6 * Line 14		$730,137	$1,460,274
19	Cumulative Book Depreciation	Prior Year Line 19 + Current Year Line 18		$730,137	$2,190,410
20	Cumulative Book / Tax Timer	Line 17 - Line 18		$29,418,952	$30,080,646
21	Effective Tax Rate			35.00%	35.00%
22	Deferred Tax Reserve	Line 20 * Line 21		$10,296,633	$10,528,226
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 13		$19,565,912	$19,565,912
24	Accumulated Depreciation	- Line 19		($730,137)	($2,190,410)
25	Deferred Tax Reserve	- Line 22		($10,296,633)	($10,528,226)
26	Year End Rate Base	Sum of Lines 23 through 25		$8,539,142	$6,847,276
	Revenue Requirement Calculation:				
27	Average Rate Base	(Prior Year Line 26 + Current Year Line 26) ÷2		$4,269,571	$7,693,209
28	Pre-Tax ROR		3/	9.30%	9.30%
29	Return and Taxes	Line 27 * Line 28		$397,070	$715,468
30	Book Depreciation	Line 19		$730,137	$1,460,274
31	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 12 - Line 19) * Property Tax Rate	4/	$0	$1,455,530
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**		**$1,127,207**	**$3,631,272**

1/ Reflects projected capital additions (plant-in-service); to be replaced with actual capital additions for annual reconciliation
2/ Assumes 16.39% based on 2010 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	52.08%	5.30%	2.76%		2.76%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	42.75%	9.80%	4.19%	2.26%	6.45%
	100.00%		7.04%	2.26%	9.30%

4/ Property Tax Rate Calculation based on 2010 actual net plant in service and property tax expense applicable to distribution

Plant in Service	$1,235,201,285
Accumulated Depreciation	$529,716,452
Distribution-Related Net Plant in Service	$705,484,833
Distribution-Related Rate Year Property Tax Expense	$20,831,185
Distribution-Related Property Tax Rate	2.95%

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

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Additions Allowance					
	Non-Discretionary Capital					
1	Actual Non-Discretionary Capital Additions	Page 4 Line 9, Column (a)	1/	$30,087,700	$0	$0
	Discretionary Capital					
2	Actual Discretionary Capital Additions	Page 4 Line 18, Column (a)	1/	$18,714,500	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$48,802,200	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$48,802,200	$0	$0
5	Retirements	Line 4 * Retirements Rate	2/	$7,720,508	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b) and (c) = Prior Year Line 6		$41,081,692	$41,081,692	$41,081,692
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 4		$48,802,200	$0	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$38,875,088	$0	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Columns (b) and (c) = Prior Year Line 9		$9,927,112	$9,927,112	$9,927,112
	Cost of Removal					
10	Cost of Removal - Non-Discretionary			$3,956,000	$0	$0
11	Cost of Removal - Discretionary			$2,623,000	$0	$0
12	Total Cost of Removal	Column (a) = Line 10 + Line 11; Columns (b) and (c) = Prior Year Line 12		$6,579,000	$6,579,000	$6,579,000
13	**Total Net Plant in Service**	**Line 9 + Line 12**		**$16,506,112**	**$16,506,112**	**$16,506,112**
	Deferred Tax Calculation:					
14	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%	3.40%
15	Vintage Year Tax Depreciation:					
16	2012 Spend	Page 6 Line 20 Column (a)		$44,401,468	$823,508	$761,680
17	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		$44,401,468	$45,224,976	$45,986,656
18	Book Depreciation	Column (a) = Line 6 * Line 14 * 50%; Columns (b) and (c) = Line 6 * Line 14		$698,389	$1,396,778	$1,396,778
19	Cumulative Book Depreciation	Prior Year Line 19 + Current Year Line 18		$698,389	$2,095,166	$3,491,944
20	Cumulative Book / Tax Timer	Line 17 - Line 18		$43,703,079	$43,129,810	$42,494,712
21	Effective Tax Rate			35.00%	35.00%	35.000%
22	Deferred Tax Reserve	Line 20 * Line 21		$15,296,078	$15,095,433	$14,873,149
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 13		$16,506,112	$16,506,112	$16,506,112
24	Accumulated Depreciation	- Line 19		($698,389)	($2,095,166)	($3,491,944)
25	Deferred Tax Reserve	- Line 22		($15,296,078)	($15,095,433)	($14,873,149)
26	Year End Rate Base	Sum of Lines 23 through 25		$511,646	($684,488)	($1,858,981)
	Revenue Requirement Calculation:					
27	Average Rate Base	(Prior Year Line 26 + Current Year Line 26) ÷2		$255,823	($86,421)	($1,271,734)
28	Pre-Tax ROR		3/	9.30%	9.30%	9.30%
29	Return and Taxes	Line 27 * Line 28		$23,792	($8,037)	($118,271)
30	Book Depreciation	Line 19		$698,389	$1,396,778	$1,396,778
31	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 12 - Line 19) * Property Tax Rate	4/	$0	$1,386,678	$1,345,435
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**		**$722,180**	**$2,775,419**	**$2,623,941**

1/ Reflects projected capital additions (plant-in-service); to be replaced with actual capital additions for annual reconciliation
2/ Reflects approved capital spending; to be replaced with actual capital spending for annual reconciliation
3/ Assumes 15.82% based on 2009 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
4/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	52.08%	5.30%	2.76%		2.76%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	42.75%	9.80%	4.19%	2.26%	6.45%
	100.00%		7.04%	2.26%	9.30%

5/ Property Tax Rate Calculation based on 2010 actual net plant in service and property tax expense applicable to distribution

Plant in Service	$1,235,201,285
Accumulated Depreciation	$529,716,452
Distribution-Related Net Plant in Service	$705,484,833
Distribution-Related Rate Year Property Tax Expense	$20,831,185
Distribution-Related Property Tax Rate	2.95%

The Narragansett Electric Company
d/b/a National Grid
Electric Capital Investment Summary

			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
	Non Discretionary Capital			
1	FY 2012 Actual Non-Discretionary Capital Additions		$ 30,087,700	$ 30,087,700
2	FY 2013 Actual Non-Discretionary Capital Additions		-	28,619,000
3	Cumulative Actual Non- Discretionary Capital Addtions	Line 3 + Line 4	30,087,700	58,706,700
4	FY 2012 Actual Non-Discretionary Capital Spending		31,341,500	31,341,500
5	FY 2013 Actual Non-Discretionary Capital Spending		-	30,428,000
6	Cumulative Actual Non-Discretionary Capital Spending	Line 4 + Line 5	31,341,500	61,769,500
7	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	Lesser of Line 3 or Line 6	30,087,700	58,706,700
8	Prior Year Cumulative Allowed Non-Discretionary Capital Included in Rate Base	Prior Year Line 9	-	30,087,700
9	**Total Allowed Non-Discretionary Capital Included in Rate Base Current Year**	Line 7 - Line 8	**$ 30,087,700**	**$ 28,619,000**
	Discretionary Capital			
10	FY 2012 Actual Discretionary Capital Additions		$ 18,714,500	$ 18,714,500
11	FY 2013 Actual Discretionary Capital Addtions		-	22,747,000
12	Cumulative Actual Discretionary Capital Addtions	Line 10 + Line 11	18,714,500	41,461,500
13	FY 2012 Approved Discretionary Capital Spending		27,036,150	27,036,150
14	FY 2013 Approved Discretionary Capital Spending		-	26,112,000
15	Cumulative Actual Discretionary Capital Spending	Line 13 + Line 14	27,036,150	53,148,150
16	Cumulative Allowed Discretionary Capital Included in Rate Base	Line 12	18,714,500	41,461,500
17	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base		-	18,714,500
18	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 16 - Line 17	**$ 18,714,500**	**$ 22,747,000**
19	**Total Allowed Capital Included in Rate Base Current Year**	Line 9 + Line 18	**$ 48,802,200**	**$ 51,366,000**

The Narragansett Electric Company
Illustrative Calculation of Tax Depreciation and Repairs Deduction
On FY 2013 Capital Investment

			Fiscal Year 2013 (a)	Fiscal Year 2014 (b)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 Line 3	$51,366,000	
2	Capital Repairs Deduction Rate		16.00%	
3	Capital Repairs Deduction	Line 2 x Line 3	$8,218,560	
	Bonus Depreciation			
4	Plant Additions	Line 1	$51,366,000	
5	Less Capital Repairs Deduction	Line 3	$8,218,560	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$43,147,440	
7	Percent of Plant Eligible for Bonus Depreciation		85.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 x Line 7	$36,675,324	
9	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%	37.50%	
10	Bonus Depreciation Rate (January 2013 - March 2013)		0.00%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10	37.50%	
12	Bonus Depreciation	Line 8 x Line 11	$13,753,247	
	Remaining Tax Depreciation			
13	Plant Additions	Line 1	$51,366,000	
14	Less Capital Repairs Deduction	Line 3	$8,218,560	
15	Less Bonus Depreciation	Line 12	$13,753,247	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$29,394,193	$29,394,193
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 x Line 17	$1,102,282	$2,121,967
19	Cost of Removal		$7,075,000	
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	$30,149,089	$2,121,967

The Narragansett Electric Company
Illustrative Calculation of Tax Depreciation and Repairs Deduction
On FY 2012 Capital Investment

			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Repairs Deduction				
1	Plant Additions	Page 3 Line 3	$48,802,200		
2	Capital Repairs Deduction Rate		32.00%		
3	Capital Repairs Deduction	Line 2 x Line 3	$15,616,704		
	Bonus Depreciation				
4	Plant Additions	Line 1	$48,802,200		
5	Less Capital Repairs Deduction	Line 3	$15,616,704		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$33,185,496		
7	Percent of Plant Eligible for Bonus Depreciation		75.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 x Line 7	$24,889,122		
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 x Line 11	$21,777,982		
	Remaining Tax Depreciation				
13	Plant Additions	Line 1	$48,802,200		
14	Less Capital Repairs Deduction	Line 3	$15,616,704		
15	Less Bonus Depreciation	Line 12	$21,777,982		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$11,407,514	$11,407,514	$11,407,514
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 x Line 17	$427,782	$823,508	$761,680
19	Cost of Removal		$6,579,000		
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	$44,401,468	$823,508	$761,680

Section 6

Rate Design

FY 2013 Electric ISR Plan

The Narragansett Electric Company
Infrastructure, Safety & Reliability Plan Factors Calculations - Summary

Line No.		A16 / A60 (a)	C-06 (b)	G-02 (c)	B32 / G32 (d)	B62 / G62 (e)	S10 / S14 (f)	X-01 (g)
(1)	O&M Factor per kWh	$0.00159	$0.00166	$0.00135	$0.00073	n/a	$0.01047	$0.00201
(2)	O&M Factor per kW	n/a	n/a	n/a	n/a	$0.35	n/a	n/a
(3)	CapEx kWh Charge	$0.00063	$0.00060	n/a	n/a	n/a	$0.00295	$0.00076
(4)	CapEx kW Charge	n/a	n/a	$0.17	$0.16	$0.12	n/a	n/a

(1) Page 2, Line 6
(2) Page 2, Line 8
(3) Page 3, Line 6
(4) Page 3, Line 8

The Narragansett Electric Co.
Proposed Operations & Maintenance Factor

Line No.		Total (a)	Residential A16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B32 / G32 (e)	3000 kW Demand B62 / G62 (f)	Lighting S10 / S14 (g)	Propulsion X-01 (h)
(1)	FY2013 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$10,526,900							
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$44,309	$20,803	$4,116	$7,477	$6,649	$1,901	$3,164	$198
(3)	Percentage of Total	100.00%	46.95%	9.29%	16.88%	15.01%	4.29%	7.14%	0.45%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$10,526,900	$4,942,419	$977,907	$1,776,416	$1,579,699	$451,665	$751,730	$47,065
(5)	Forecasted kWh - April 2012 through March 2013	7,844,725,884	3,105,782,394	588,802,811	1,314,771,168	2,157,466,029	582,827,820	71,763,802	23,311,860
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00159	$0.00166	$0.00135	$0.00073	n/a	$0.01047	$0.00201
(7)	Forecasted kW - April 2012 through March 2013						1,259,092		
(8)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		n/a	n/a	n/a	n/a	$0.35	n/a	n/a

Line No.
(1) per Section 5: Attachment 1, page 1, line 3, column (b)
(2) per R.I.P.U.C. 4065 Schedule NG-HSG-1 (C) - 2nd Amended, page 4, line 74
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column * 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 Co.
Proposed CapEx Factor

Line No.		Total (a)	Residential A16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B32 / G32 (e)	3000 kW Demand B62 / G62 (f)	Lighting S10 / S14 (g)	Propulsion X-01 (h)
(1)	Proposed FY2013 Capital Investment under ISR Plan	$3,902,625							
(2)	Total Rate Base ($000s)	$550,864	$278,750	$50,517	$90,429	$76,427	$22,285	$29,950	$2,505
(3)	Percentage of Total	100.00%	50.60%	9.17%	16.42%	13.87%	4.05%	5.44%	0.45%
(4)	Allocated Proposed Costs to be Recovered	$3,902,625	$1,974,821	$357,891	$640,650	$541,452	$157,880	$212,183	$17,747
(5)	Forecasted kWh - April 2012 through March 2013	7,844,725,884	3,105,782,394	588,802,811	1,314,771,168	2,157,466,029	582,827,820	71,763,802	23,311,860
(6)	Proposed CapEx Factor - kWh charge		$0.00063	$0.00060	n/a	n/a	n/a	$0.00295	$0.00076
(7)	Forecasted kW - April 2012 through March 2013				3,597,512	3,247,042	1,259,092		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$0.17	$0.16	$0.12	n/a	n/a

Line No.
(1) per Section 5: Attachment 1, page 1, line 11, column (b)
(2) per R.I.P.U.C. 4065 Schedule NG-HSG-1 (C) - 2nd Amended, page 4, line 51
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column * 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

Section 7
Bill Impacts
FY 2013 Electric ISR Plan

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-16 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
120	$21.38	$9.45	$11.93	$21.47	$9.45	$12.02	$0.09	0.4%	9.0%
240	$37.99	$18.90	$19.09	$38.16	$18.90	$19.26	$0.17	0.4%	15.7%
500	$73.96	$39.36	$34.60	$74.32	$39.36	$34.96	$0.36	0.5%	38.2%
700	$101.64	$55.11	$46.53	$102.15	$55.11	$47.04	$0.51	0.5%	20.2%
950	$136.23	$74.79	$61.44	$136.93	$74.79	$62.14	$0.70	0.5%	14.6%
1,000	$143.16	$78.73	$64.43	$143.89	$78.73	$65.16	$0.73	0.5%	2.3%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates			Proposed Rates		
Customer Charge		$3.75	Customer Charge		$3.75
Transmission Energy Charge (1)	kWh x	$0.01623	Transmission Energy Charge (1)	kWh x	$0.01623
Distribution Energy Charge (2)	kWh x	$0.03516	Distribution Energy Charge (3)	kWh x	$0.03586
Transition Energy Charge	kWh x	($0.00031)	Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619	Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83	LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07558	Standard Offer Charge (4)	kWh x	$0.07558

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes O&M Factor of $0.00141/kWh, and CapEx Factor of $0.00011/kWh
Note (3): Includes Proposed O&M Factor of $0.00159/kWh, and Proposed CapEx Factor of $0.00063/kWh
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes Standard Offer Service Charge of $0.07492/kWh, Standard Offer Adjustment Factor of $(.00041)/kWh, Standard Offer Service Administrative Cost Factor of $0.00138/kWh, and Renewable Energy Standard Credit of $(.00031)/kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
100	$13.28	$7.87	$5.41	$13.35	$7.87	$5.48	$0.07	0.5%
200	$25.70	$15.75	$9.95	$25.84	$15.75	$10.09	$0.14	0.5%
300	$38.11	$23.62	$14.49	$38.33	$23.62	$14.71	$0.22	0.6%
500	$62.93	$39.36	$23.57	$63.29	$39.36	$23.93	$0.36	0.6%
750	$93.97	$59.05	$34.92	$94.52	$59.05	$35.47	$0.55	0.6%
1000	$125.00	$78.73	$46.27	$125.73	$78.73	$47.00	$0.73	0.6%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$0.00
Transmission Energy Charge (1)	kWh x	$0.01623
Distribution Energy Charge (2)	kWh x	$0.02148
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07558

Proposed Rates

Customer Charge		$0.00
Transmission Energy Charge (1)	kWh x	$0.01623
Distribution Energy Charge (3)	kWh x	$0.02218
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07558

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes O&M Factor of $0.00141/kWh, and CapEx Factor of $0.00011/kWh
Note (3): Includes Proposed O&M Factor of $0.00159/kWh, and Proposed CapEx Factor of $0.00063/kWh
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes Standard Offer Service Charge of $0.07492/kWh, Standard Offer Adjustment Factor of $(.00041)/kWh, Standard Offer Service Administrative Cost Factor of $0.00138/kWh, and Renewable Energy Standard Credit of $(.00031)/kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on C-06 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
250	$43.29	$19.22	$24.07	$43.45	$19.22	$24.23	$0.16	0.4%	35.2%
500	$77.37	$38.44	$38.93	$77.71	$38.44	$39.27	$0.34	0.4%	17.0%
1,000	$145.56	$76.89	$68.67	$146.23	$76.89	$69.34	$0.67	0.5%	19.0%
1,500	$213.73	$115.33	$98.40	$214.75	$115.33	$99.42	$1.02	0.5%	9.8%
2,000	$281.91	$153.77	$128.14	$283.26	$153.77	$129.49	$1.35	0.5%	19.1%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

<u>Present Rates</u>

Customer Charge		$8.00
Transmission Energy Charge (1)	kWh x	$0.01755
Distribution Energy Charge (2)	kWh x	$0.03366
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07381

<u>Proposed Rates</u>

Customer Charge		$8.00
Transmission Energy Charge (1)	kWh x	$0.01755
Distribution Energy Charge (3)	kWh x	$0.03431
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07381

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00016/kWh
Note (2): Includes O&M Factor of $0.0015/kWh, and CapEx Factor of $0.00011/kWh
Note (3): Includes Proposed O&M Factor of $0.00166/kWh, and Proposed CapEx Factor of $0.0006/kWh
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes Standard Offer Service Charge of $0.07257/kWh Standard Offer Adjustment Factor of $0.00027/kWh, Standard Offer Service Administrative Cost Factor of $0.00128/kWh, and Renewable Energy Standard Credit of $(.00031)/kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$630.78	$307.54	$323.24	$632.76	$307.54	$325.22	$1.98	0.3%
50	10,000	$1,451.28	$768.85	$682.43	$1,458.26	$768.85	$689.41	$6.98	0.5%
100	20,000	$2,818.78	$1,537.71	$1,281.07	$2,834.10	$1,537.71	$1,296.39	$15.32	0.5%
150	30,000	$4,186.28	$2,306.56	$1,879.72	$4,209.92	$2,306.56	$1,903.36	$23.64	0.6%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.54
Distribution Energy Charge (4)	kWh x	$0.00744
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Proposed Rates

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (3)	kW x	$4.67
Distribution Energy Charge (5)	kWh x	$0.00759
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes CapEx kW Charge of $0.04 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.17 per kW
Note (4): Includes O&M Factor of $0.0012/kWh
Note (5): Includes Proposed O&M Factor of $0.00135/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes Standard Offer Fixed Price Option Charge of $0.07257/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00027/kWh, and Standard Offer Service Administrative Cost Factor of $0.00128 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$829.49	$461.31	$368.18	$831.78	$461.31	$370.47	$2.29	0.3%
50	15,000	$1,948.05	$1,153.28	$794.77	$1,955.81	$1,153.28	$802.53	$7.76	0.4%
100	30,000	$3,812.32	$2,306.56	$1,505.76	$3,829.20	$2,306.56	$1,522.64	$16.88	0.4%
150	45,000	$5,676.59	$3,459.84	$2,216.75	$5,702.58	$3,459.84	$2,242.74	$25.99	0.5%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

<u>Present Rates</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.54
Distribution Energy Charge (4)	kWh x	$0.00744
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

<u>Proposed Rates</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (3)	kW x	$4.67
Distribution Energy Charge (5)	kWh x	$0.00759
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes CapEx kW Charge of $0.04 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.17 per kW
Note (4): Includes O&M Factor of $0.0012/kWh
Note (5): Includes Proposed O&M Factor of $0.00135/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes Standard Offer Fixed Price Option Charge of $0.07257/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00027/kWh, and Standard Offer Service Administrative Cost Factor of $0.00128 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$1,028.19	$615.08	$413.11	$1,030.80	$615.08	$415.72	$2.61	0.3%
50	20,000	$2,444.82	$1,537.71	$907.11	$2,453.37	$1,537.71	$915.66	$8.55	0.3%
100	40,000	$4,805.87	$3,075.42	$1,730.45	$4,824.31	$3,075.42	$1,748.89	$18.44	0.4%
150	60,000	$7,166.91	$4,613.13	$2,553.78	$7,195.24	$4,613.13	$2,582.11	$28.33	0.4%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.54
Distribution Energy Charge (4)	kWh x	$0.00744
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Proposed Rates

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (3)	kW x	$4.67
Distribution Energy Charge (5)	kWh x	$0.00759
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes CapEx kW Charge of $0.04 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.17 per kW
Note (4): Includes O&M Factor of $0.0012/kWh
Note (5): Includes Proposed O&M Factor of $0.00135/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes Standard Offer Fixed Price Option Charge of $0.07257/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00027/kWh, and Standard Offer Service Administrative Cost Factor of $0.00128 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,226.90	$768.85	$458.05	$1,229.82	$768.85	$460.97	$2.92	0.2%
50	25,000	$2,941.60	$1,922.14	$1,019.46	$2,950.92	$1,922.14	$1,028.78	$9.32	0.3%
100	50,000	$5,799.41	$3,844.27	$1,955.14	$5,819.41	$3,844.27	$1,975.14	$20.00	0.3%
150	75,000	$8,657.22	$5,766.41	$2,890.81	$8,687.90	$5,766.41	$2,921.49	$30.68	0.4%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.54
Distribution Energy Charge (4)	kWh x	$0.00744
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Proposed Rates

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (3)	kW x	$4.67
Distribution Energy Charge (5)	kWh x	$0.00759
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes CapEx kW Charge of $0.04 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.17 per kW
Note (4): Includes O&M Factor of $0.0012/kWh
Note (5): Includes Proposed O&M Factor of $0.00135/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes Standard Offer Fixed Price Option Charge of $0.07257/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00027/kWh, and Standard Offer Service Administrative Cost Factor of $0.00128 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,425.62	$922.63	$502.99	$1,428.85	$922.63	$506.22	$3.23	0.2%
50	30,000	$3,438.36	$2,306.56	$1,131.80	$3,448.47	$2,306.56	$1,141.91	$10.11	0.3%
100	60,000	$6,792.95	$4,613.13	$2,179.82	$6,814.52	$4,613.13	$2,201.39	$21.57	0.3%
150	90,000	$10,147.53	$6,919.69	$3,227.84	$10,180.55	$6,919.69	$3,260.86	$33.02	0.3%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

<u>Present Rates</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.54
Distribution Energy Charge (4)	kWh x	$0.00744
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

<u>Proposed Rates</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.64
Transmission Energy Charge (1)	kWh x	$0.00825
Distribution Demand Charge-xcs 10 kW (3)	kW x	$4.67
Distribution Energy Charge (5)	kWh x	$0.00759
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4.00%
Standard Offer Charge (7)	kWh x	$0.07381

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00015/kWh
Note (2): Includes CapEx kW Charge of $0.04 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.17 per kW
Note (4): Includes O&M Factor of $0.0012/kWh
Note (5): Includes Proposed O&M Factor of $0.00135/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes Standard Offer Fixed Price Option Charge of $0.07257/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00027/kWh, and Standard Offer Service Administrative Cost Factor of $0.00128 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,437.81	$3,172.36	$2,265.45	$5,441.56	$3,172.36	$2,269.20	$3.75	0.1%
750	150,000	$19,403.99	$11,896.35	$7,507.64	$19,492.53	$11,896.35	$7,596.18	$88.54	0.5%
1,000	200,000	$25,752.26	$15,861.81	$9,890.45	$25,879.34	$15,861.81	$10,017.53	$127.08	0.5%
1,500	300,000	$38,448.78	$23,792.71	$14,656.07	$38,652.95	$23,792.71	$14,860.24	$204.17	0.5%
2,500	500,000	$63,841.83	$39,654.51	$24,187.32	$64,200.17	$39,654.51	$24,545.66	$358.34	0.6%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (2)	kW x	$2.03
Distribution Energy Charge (4)	kWh x	$0.00874
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Proposed Rates

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (3)	kW x	$2.16
Distribution Energy Charge (5)	kWh x	$0.00883
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes CapEx kW Charge of $0.03 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.16 per kW
Note (4): Includes O&M Factor of $0.00064/kWh
Note (5): Includes Proposed O&M Factor of $0.00073/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes the average January 2012, February 2012 and March 2012 Standard Offer Service Charge of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh, and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$7,469.82	$4,758.54	$2,711.28	$7,475.45	$4,758.54	$2,716.91	$5.63	0.1%
750	225,000	$27,024.04	$17,844.53	$9,179.51	$27,119.61	$17,844.53	$9,275.08	$95.57	0.4%
1,000	300,000	$35,912.32	$23,792.71	$12,119.61	$36,048.78	$23,792.71	$12,256.07	$136.46	0.4%
1,500	450,000	$53,688.88	$35,689.06	$17,999.82	$53,907.11	$35,689.06	$18,218.05	$218.23	0.4%
2,500	750,000	$89,242.01	$59,481.77	$29,760.24	$89,623.78	$59,481.77	$30,142.01	$381.77	0.4%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates			Proposed Rates		
Customer Charge		$750.00	Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84	Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678	Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (2)	kW x	$2.03	Distribution Demand Charge - > 200 kW (3)	kW x	$2.16
Distribution Energy Charge (4)	kWh x	$0.00874	Distribution Energy Charge (5)	kWh x	$0.00883
Transition Energy Charge	kWh x	($0.00031)	Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619	Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83	LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614	Standard Offer Charge (7)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes CapEx kW Charge of $0.03 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.16 per kW
Note (4): Includes O&M Factor of $0.00064/kWh
Note (5): Includes Proposed O&M Factor of $0.00073/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes the average January 2012, February 2012 and March 2012 Standard Offer Service Charge of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh, and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$9,501.83	$6,344.72	$3,157.11	$9,509.33	$6,344.72	$3,164.61	$7.50	0.1%
750	300,000	$34,644.10	$23,792.71	$10,851.39	$34,746.70	$23,792.71	$10,953.99	$102.60	0.3%
1,000	400,000	$46,072.39	$31,723.61	$14,348.78	$46,218.22	$31,723.61	$14,494.61	$145.83	0.3%
1,500	600,000	$68,928.99	$47,585.42	$21,343.57	$69,161.28	$47,585.42	$21,575.86	$232.29	0.3%
2,500	1,000,000	$114,642.19	$79,309.03	$35,333.16	$115,047.39	$79,309.03	$35,738.36	$405.20	0.4%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

<u>Present Rates</u>

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (2)	kW x	$2.03
Distribution Energy Charge (4)	kWh x	$0.00874
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

<u>Proposed Rates</u>

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (3)	kW x	$2.16
Distribution Energy Charge (5)	kWh x	$0.00883
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes CapEx kW Charge of $0.03 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.16 per kW
Note (4): Includes O&M Factor of $0.00064/kWh
Note (5): Includes Proposed O&M Factor of $0.00073/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes the average January 2012, February 2012 and March 2012 Standard Offer Service Charge of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh, and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh

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Date: 28-Dec-11
Time: 09:08 AM

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$11,533.85	$7,930.90	$3,602.95	$11,543.22	$7,930.90	$3,612.32	$9.37	0.1%
750	375,000	$42,264.15	$29,740.89	$12,523.26	$42,373.79	$29,740.89	$12,632.90	$109.64	0.3%
1,000	500,000	$56,232.46	$39,654.51	$16,577.95	$56,387.67	$39,654.51	$16,733.16	$155.21	0.3%
1,500	750,000	$84,169.09	$59,481.77	$24,687.32	$84,415.45	$59,481.77	$24,933.68	$246.36	0.3%
2,500	1,250,000	$140,042.35	$99,136.28	$40,906.07	$140,471.00	$99,136.28	$41,334.72	$428.65	0.3%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (2)	kW x	$2.03
Distribution Energy Charge (4)	kWh x	$0.00874
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Proposed Rates

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (3)	kW x	$2.16
Distribution Energy Charge (5)	kWh x	$0.00883
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes CapEx kW Charge of $0.03 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.16 per kW
Note (4): Includes O&M Factor of $0.00064/kWh
Note (5): Includes Proposed O&M Factor of $0.00073/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes the average January 2012, February 2012 and March 2012 Standard Offer Service Charge of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh, and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh

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Date: 28-Dec-11
Time: 09:08 AM

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$13,565.86	$9,517.08	$4,048.78	$13,577.11	$9,517.08	$4,060.03	$11.25	0.1%
750	450,000	$49,884.20	$35,689.06	$14,195.14	$50,000.86	$35,689.06	$14,311.80	$116.66	0.2%
1,000	600,000	$66,392.53	$47,585.42	$18,807.11	$66,557.12	$47,585.42	$18,971.70	$164.59	0.2%
1,500	900,000	$99,409.20	$71,378.13	$28,031.07	$99,669.62	$71,378.13	$28,291.49	$260.42	0.3%
2,500	1,500,000	$165,442.53	$118,963.54	$46,478.99	$165,894.61	$118,963.54	$46,931.07	$452.08	0.3%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (2)	kW x	$2.03
Distribution Energy Charge (4)	kWh x	$0.00874
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Proposed Rates

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge - > 200 kW (3)	kW x	$2.16
Distribution Energy Charge (5)	kWh x	$0.00883
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (6)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (7)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes CapEx kW Charge of $0.03 per kW
Note (3): Includes Proposed CapEx kW Charge of $0.16 per kW
Note (4): Includes O&M Factor of $0.00064/kWh
Note (5): Includes Proposed O&M Factor of $0.00073/kWh
Note (6): in accordance with R.I.G.L. § 39-1-27.12
Note (7): Includes the average January 2012, February 2012 and March 2012 Standard Offer Service Charge of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh, and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 200

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	600,000	$91,025.87	$47,585.42	$43,440.45	$91,307.12	$47,585.42	$43,721.70	$281.25	0.3%
5,000	1,000,000	$139,903.64	$79,309.03	$60,594.61	$140,372.39	$79,309.03	$61,063.36	$468.75	0.3%
7,500	1,500,000	$201,000.86	$118,963.54	$82,037.32	$201,703.99	$118,963.54	$82,740.45	$703.13	0.3%
10,000	2,000,000	$262,098.09	$158,618.06	$103,480.03	$263,035.59	$158,618.06	$104,417.53	$937.50	0.4%
20,000	4,000,000	$506,486.97	$317,236.11	$189,250.86	$508,361.97	$317,236.11	$191,125.86	$1,875.00	0.4%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (2)	kW x	$2.86
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

Proposed Rates

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (3)	kW x	$2.95
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes O&M kW Charge of $0.36 per kW, and CapEx kW Charge of $0.02 per kW
Note (3): Includes Proposed O&M kW Charge of $0.35 per kW, and Proposed CapEx kW Charge of $0.12 per kW
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes the average January 2012, February 2012 and March 2012 Standard Offer of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh for Standard Offer Service Admin. Cost Factor

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 300

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	900,000	$118,777.95	$71,378.13	$47,399.82	$119,059.20	$71,378.13	$47,681.07	$281.25	0.2%
5,000	1,500,000	$186,157.11	$118,963.54	$67,193.57	$186,625.86	$118,963.54	$67,662.32	$468.75	0.3%
7,500	2,250,000	$270,381.07	$178,445.31	$91,935.76	$271,084.20	$178,445.31	$92,638.89	$703.13	0.3%
10,000	3,000,000	$354,605.03	$237,927.08	$116,677.95	$355,542.53	$237,927.08	$117,615.45	$937.50	0.3%
20,000	6,000,000	$691,500.87	$475,854.17	$215,646.70	$693,375.87	$475,854.17	$217,521.70	$1,875.00	0.3%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

<u>Present Rates</u>

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (2)	kW x	$2.86
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

<u>Proposed Rates</u>

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (3)	kW x	$2.95
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes O&M kW Charge of $0.36 per kW, and CapEx kW Charge of $0.02 per kW
Note (3): Includes Proposed O&M kW Charge of $0.35 per kW, and Proposed CapEx kW Charge of $0.12 per kW
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes the average January 2012, February 2012 and March 2012 Standard Offer of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh for Standard Offer Service Admin. Cost Factor

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 400

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,200,000	$146,530.03	$95,170.83	$51,359.20	$146,811.28	$95,170.83	$51,640.45	$281.25	0.2%
5,000	2,000,000	$232,410.59	$158,618.06	$73,792.53	$232,879.34	$158,618.06	$74,261.28	$468.75	0.2%
7,500	3,000,000	$339,761.28	$237,927.08	$101,834.20	$340,464.40	$237,927.08	$102,537.32	$703.12	0.2%
10,000	4,000,000	$447,111.97	$317,236.11	$129,875.86	$448,049.47	$317,236.11	$130,813.36	$937.50	0.2%
20,000	8,000,000	$876,514.75	$634,472.22	$242,042.53	$878,389.75	$634,472.22	$243,917.53	$1,875.00	0.2%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

<u>Present Rates</u>

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (2)	kW x	$2.86
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

<u>Proposed Rates</u>

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (3)	kW x	$2.95
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes O&M kW Charge of $0.36 per kW, and CapEx kW Charge of $0.02 per kW
Note (3): Includes Proposed O&M kW Charge of $0.35 per kW, and Proposed CapEx kW Charge of $0.12 per kW
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes the average January 2012, February 2012 and March 2012 Standard Offer of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh for Standard Offer Service Admin. Cost Factor

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 500

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,500,000	$174,282.11	$118,963.54	$55,318.57	$174,563.36	$118,963.54	$55,599.82	$281.25	0.2%
5,000	2,500,000	$278,664.06	$198,272.57	$80,391.49	$279,132.81	$198,272.57	$80,860.24	$468.75	0.2%
7,500	3,750,000	$409,141.49	$297,408.85	$111,732.64	$409,844.61	$297,408.85	$112,435.76	$703.12	0.2%
10,000	5,000,000	$539,618.92	$396,545.14	$143,073.78	$540,556.42	$396,545.14	$144,011.28	$937.50	0.2%
20,000	10,000,000	$1,061,528.64	$793,090.28	$268,438.36	$1,063,403.64	$793,090.28	$270,313.36	$1,875.00	0.2%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (2)	kW x	$2.86
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

Proposed Rates

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (3)	kW x	$2.95
Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes O&M kW Charge of $0.36 per kW, and CapEx kW Charge of $0.02 per kW
Note (3): Includes Proposed O&M kW Charge of $0.35 per kW, and Proposed CapEx kW Charge of $0.12 per kW
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes the average January 2012, February 2012 and March 2012 Standard Offer of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh for Standard Offer Service Admin. Cost Factor

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Date: 28-Dec-11
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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 600

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,800,000	$202,034.20	$142,756.25	$59,277.95	$202,315.45	$142,756.25	$59,559.20	$281.25	0.1%
5,000	3,000,000	$324,917.53	$237,927.08	$86,990.45	$325,386.28	$237,927.08	$87,459.20	$468.75	0.1%
7,500	4,500,000	$478,521.70	$356,890.63	$121,631.07	$479,224.83	$356,890.63	$122,334.20	$703.13	0.1%
10,000	6,000,000	$632,125.87	$475,854.17	$156,271.70	$633,063.37	$475,854.17	$157,209.20	$937.50	0.1%
20,000	12,000,000	$1,246,542.53	$951,708.33	$294,834.20	$1,248,417.53	$951,708.33	$296,709.20	$1,875.00	0.2%

Note: the Present and Proposed Rates reflect the Standard Offer Service, the Energy Efficiency, and the LIHEAP charges approved for January 1, 2012

Present Rates			Proposed Rates		
Customer Charge		$17,000.00	Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.84	Transmission Demand Charge	kW x	$2.84
Transmission Energy Charge (1)	kWh x	$0.00678	Transmission Energy Charge (1)	kWh x	$0.00678
Distribution Demand Charge (2)	kW x	$2.86	Distribution Demand Charge (3)	kW x	$2.95
Distribution Energy Charge	kWh x	$0.00001	Distribution Energy Charge	kWh x	$0.00001
Transition Energy Charge	kWh x	($0.00031)	Transition Energy Charge	kWh x	($0.00031)
Energy Efficiency Program Charge	kWh x	$0.00619	Energy Efficiency Program Charge	kWh x	$0.00619
LIHEAP Enhancement Charge (4)		$0.83	LIHEAP Enhancement Charge (4)		$0.83
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (5)	kWh x	$0.07614	Standard Offer Charge (5)	kWh x	$0.07614

Note (1): Includes Transmission Adjustment Factor of $0.00015/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes O&M kW Charge of $0.36 per kW, and CapEx kW Charge of $0.02 per kW
Note (3): Includes Proposed O&M kW Charge of $0.35 per kW, and Proposed CapEx kW Charge of $0.12 per kW
Note (4): in accordance with R.I.G.L. § 39-1-27.12
Note (5): Includes the average January 2012, February 2012 and March 2012 Standard Offer of $0.07455/kWh, Renewable Energy Standard Credit of $(.00031)/kWh, Standard Offer Adjustment Factor of $0.00075/kWh and Standard Offer Service Administrative Cost Factor of $0.00115 /kWh for Standard Offer Service Admin. Cost Factor

DIRECT TESTIMONY

OF

WILLIAM R. RICHER

Table of Contents

I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is William R. Richer, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am the Director of Revenue Requirements - Rhode Island and New Hampshire for 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. My current duties include revenue requirements oversight for National Grid's electric and gas distribution activities in the US, including the electric division of The Narragansett Electric Company, d/b/a National Grid ("Narragansett" or "Company").

Q. Please describe your education and professional experience.

A. In 1985, I earned a Bachelor of Science degree in Accounting from Northeastern University. During my schooling I interned at the public accounting firm Pannell Kerr Forster in Boston, Massachusetts as a staff auditor and continued with this firm after my graduation. In February 1986, I joined Price Waterhouse in Providence, Rhode Island where I worked as a staff auditor and senior auditor. During this time, I earned my certified public accountants license in the State of Rhode Island. In June 1990, I joined

National Grid in the Service Company (then known as New England Power Service Company) as a supervisor of Plant Accounting. Since that time I have held various positions within the Service Company including Manager of Financial Reporting, Principal Rate Department Analyst, Manager of General Accounting, Director of Accounting Services, and Assistant Controller.

Q. Have you previously filed testimony or testified before the Rhode Island Public Utilities Commission ("R.I.P.U.C." or "Commission")?

A. Yes. I have previously filed testimony with this Commission in Docket No. 4219 on the revenue requirement for the Company's fiscal year ("FY") 2012 Gas Infrastructure, Safety, and Reliability ("ISR") Plan, and testified in Gas Distribution Adjustment Clause proceedings to describe the calculation of the Company's gas earnings subject to the Earnings Sharing Mechanism for the fiscal years ended June 30, 2009, 2010, and 2011. I also testified before this Commission in R.I.P.U.C. Docket No. 2930 on pensions and postretirement benefits other than pensions ("PBOP") for the Company, and in R.I.P.U.C. Docket No. 2090 on revenue requirements in a base rate proceeding for The Narragansett Electric Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's revenue requirement for FY 2013 in support of its Electric Infrastructure, Safety, and Reliability

Plan ("ISR Plan"), as described in the testimony of Ms. Jennifer Grimsley and Mr. Craig Allen.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following schedule:

- Schedule WRR-1: Electric ISR Plan Revenue Requirement Calculation

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

Q. Please describe the components of the revenue requirement associated with the Company's ISR Plan.

A. As shown on Page 1, Column (b) of WRR-1, the Company's FY 2013 Electric ISR Plan revenue requirement amounts to $14,429,525 representing an incremental $4,499,500 from the FY 2012 Electric ISR Plan revenue requirement of $9,930,025. The FY 2013 Electric ISR Plan revenue requirement consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities and for system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's Inspection and Maintenance ("I&M") Program, and (2) the Company's capital investment in electric utility infrastructure. Line 3 of that column reflects the forecasted FY 2013 revenue requirement related to O&M expenses, or $10,526,900, an incremental $1,319,055 from the FY 2012 Electric ISR Plan O&M expense level of $9,207,845.

The FY 2013 revenue requirement associated with the Company's cumulative forecasted capital investment in electric utility infrastructure of $3,902,625 is shown on Line 11, an incremental $3,180,445 from the revenue requirement associated with the Company's cumulative forecasted capital investment in electric utility infrastructure through FY 2012 of $722,180. The FY 2013 revenue requirement associated with the Company's cumulative forecasted capital investment in electric utility infrastructure consists of the $1,127,207 revenue requirement on FY 2013 proposed ISR capital investment, as calculated on Schedule WRR-1, Page 2, plus the $2,775,419 FY 2013 revenue requirement on the FY 2012 ISR capital investment approved in the FY 2012 ISR Plan, as calculated on WRR-1, Page 3. The total annual FY 2013 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $14,429,525, as reflected in Column (b) on Line 13, and is equal to the sum of Lines 3 and 11. Finally, Line 17 reflects the incremental FY revenue requirement of $4,499,500, from the $9,930,025 in the Company's FY 2012 ISR Plan, required to deliver the Company's Electric ISR Plan.

Operation and Maintenance Expenses

Q. Please describe the revenue requirement calculation related to the O&M expenses in more detail.

A. For FY 2013, the Company's revenue requirement includes $10,526,900 of VM and I&M O&M expenses as shown on Schedule WRR-1, Page 1, Line 3 in Column (b).

Q. Is there an amount of O&M expense associated with VM and I&M currently recovered in base rates?

A. No. In accordance with the Company's last general rate case in R.I.P.U.C. Docket No. 4065, the Company was recovering $6,549,368 in base distribution rates associated with its VM and I&M O&M expenses. However, because the ISR Plan revenue requirement represents the Company's total cost associated with its ISR Plan, including VM and I&M O&M expenses, the Company implemented a permanent credit to base distribution rates for the $6,549,368 that was being recovered through base distribution rates, as shown on Schedule WRR-1, Page 1, Line 15 in Column (a). As a result, VM and I&M O&M expenses are being recovered exclusively under the Electric ISR tariff and not through base distribution rates.

<u>**Electric Infrastructure Investment**</u>

Q. Please describe the revenue requirement calculation related to the Company's investment in electric utility infrastructure in more detail.

A. As noted above, Pages 2 and 3 of Schedule WRR-1 calculate the revenue requirement of incremental capital investment associated with the Company's FY 2013 ISR Plan plus the FY 2013 revenue requirement on the capital investment approved in the Company's FY 2012 ISR Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. Incremental electric capital investment for this purpose is intended to represent the net change in rate base for electric infrastructure investments since the establishment of the ISR Mechanism, or April 1, 2011, and is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's rates, net of depreciation expense attributable to general plant. These amounts are shown on Lines 1 through 13.

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

A. For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: 'non-discretionary' capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and 'discretionary' capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined 'non-discretionary' categories. This is shown on Pages 2 and 3, Lines 1 through 3. Because the Electric ISR was effective April 1, 2011, and appropriately includes capital additions rather than capital spend in the calculation of the revenue requirement on such capital additions, the amount of capital additions ultimately allowable in the ISR is limited to amounts no greater than the actual cumulative amount of actual capital spending on 'non-discretionary' projects and no greater than the cumulative amount of 'discretionary' project spend as approved by the Commission. The calculation of this cumulative limitation on vintage year capital investments allowable in the Electric ISR

Plan can be found on Page 4 of Schedule WRR-1. The amounts reflected on Lines 9 and 18 of Page 4 for allowable capital additions for 'non-discretionary' and 'discretionary', respectively, by vintage year are brought forward to the respective vintage year revenue requirement calculations on Lines 1 and 2 of Pages 2 and 3. As indicated earlier, these proposed spending and capital addition estimates will be trued-up to actual when known.

Q. How have plant retirements been handled in the development of the revenue requirement, specifically with regard to their impact on the calculation of depreciation expense and rate base?

A. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total capital included in rate base in determining depreciation expense. Retirements however, do not affect rate base as both 'plant in service' and 'depreciation reserve' are reduced by the installed value of the plant being retired and therefore have no impact on the incremental depreciable amount, as calculated on Line 9 of Schedule WRR-1, Pages 2 and 3 . For purposes of calculating the revenue requirement, plant retirements have been estimated based on the percentage of retirements to additions during calendar years 2010 and 2009 for the FY 2013 and FY 2012 revenue requirement calculations, respectively, and have been deducted from the total depreciable capital amount as shown on Lines 4 through 6 of Schedule WRR-1. Incremental book depreciation expense on Line 18 is computed based on the net depreciable additions, from Line 6 at the 3.40 percent composite depreciation rate as approved in R.I.P.U.C.

Docket No. 4065, as shown on Line 14 of Schedule WRR-1, Pages 2 and 3. The Company has assumed a half year convention for the year of installation.

Q. How has cost of removal been handled in the development of the revenue requirement?

A. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cost of removal, as shown on Line 12 of Schedule WRR-1, Pages 2 and 3, is combined with the incremental depreciable amount from Line 9 (vintage year ISR allowable capital additions less non-general plant depreciation expense included in base distribution rates) to arrive at the incremental investment on Line 13 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

Q. Please describe how tax depreciation was calculated in the revenue requirement calculation.

A. The tax depreciation calculations for FY 2013 and FY 2012 are provided on Pages 5 and 6 of Schedule WRR-1, respectively. The tax depreciation amount assumes that a portion of the capital investment, as shown on Line 1 of those pages, will be eligible for immediate deduction on the Company's corresponding FY federal income tax return.

This immediate deductibility is referred to as the capital repairs deduction.[1] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Lines 4 through 12. During 2010, Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 ("Act") which provided for an extension of bonus depreciation. Specifically, the Act provided for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 2012. In accordance with the Act, capital investments made from April 2012 through December 2012 are eligible for 50 percent bonus depreciation, as shown on Page 5, Line 9.[2]

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate, as shown on Line 17. The amount of depreciation deducted for MACRS on Line 18 is added to the amount of capital repairs deduction plus the bonus depreciation deduction

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

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

and cost of removal to arrive at total tax depreciation as shown on Line 20. These annual total tax depreciation amounts are carried forward to Line 16 of Schedule WRR-1, Pages 2 and 3, for the respective years, and incorporated in the deferred tax calculation.

Q. Please describe the final steps in the calculation of the ISR Plan revenue requirement.

A. The average change in rate base on Line 27 equals the average year-end cumulative change in rate base on Line 26. This amount is multiplied by the pre-tax rate of return in the most recent rate case (in this example, the one approved by the Commission in R.I.P.U.C. Docket No. 4065) on Line 28 to compute the return and tax portion of the incremental revenue requirement on Line 29. To this, incremental depreciation expense is added on Line 30, as are property taxes on Line 31, which are computed on net capital investment in the year following the investment to coincide with the timing in which property taxes are assessed. The sum of these three amounts reflects the annual revenue requirement associated with the capital investment portion of the Company's ISR Plan as shown on Line 32 of Schedule WRR-1, pages 2 and 3, which are carried forward to Page 1, Lines 8 and 9, and summarized on Line 11. This capital investment revenue requirement amount is added to the total O&M expenses on Line 3 of Schedule WRR-1, Page 1 to derive the total FY 2013 ISR Plan revenue requirement of $14,429,525 as shown on Line 13, and, represents an incremental $4,499,500 from the FY 2012 ISR Plan revenue requirement, as shown on Line 17.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Index of Schedules

Schedule WRR-1

Schedule WRR-1

Electric Infrastructure, Safety, and Reliability Plan Revenue Requirement Calculation

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

Line No.		Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
1	**Operation and Maintenance (O&M) Expenses**			
2				
3	Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$9,207,845	$10,526,900	
4				
5				
6	**Capital Investment**			
7	Forecasted Revenue Requirement Related to Electric Capital Investment:			
8	Annual Revenue Requirement on FY 2012 Capital Included in Rate Base	$722,180	$2,775,419	$2,623,941
9	Annual Revenue Requirement on FY 2013 Capital Included in Rate Base	$0	$1,127,207	$3,631,272
10				
11	**Capital Investment Component of Revenue Requirement**	**$722,180**	**$3,902,625**	**$6,255,213**
12				
13	**Total Fiscal Year Revenue Requirement**	**$9,930,025**	**$14,429,525**	
14				
15	Less: Adjustment to Base Rates to reflect recovery of VM and I&M O&M expense in the ISR Factor	($6,549,368)		
16				
17	**Total Incremental Fiscal Year Rate Adjustment**	**$3,380,657**	**$4,499,500**	

Line Notes:
3 Projected Vegetation Management and Inspection & Maintenance expense for FY 2012 and FY 2013
8 From Page 3, Line 32
9 From Page 2, Line 32
11 Line 8 + Line 9
13 Line 3 + Line 11
15 Per Docket No. 4065
17 Column (a) equals Line 13 plus Line 15; Column (b) equals Line 13 minus Line 13, Column (a)

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

Line No.				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)
	Capital Additions Allowance				
	Non-Discretionary Capital				
1	Actual Non-Discretionary Capital Additions	Page 4 Line 9, Column (b)	1/	$28,619,000	$0
	Discretionary Capital				
2	Approved Discretionary Capital Spending	Page 4 Line 18, Column (a)	1/	$22,747,000	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 2		$51,366,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$51,366,000	$0
5	Retirements	Line 4 * Retirements Rate	2/	$8,416,779	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$42,949,221	$42,949,221
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$51,366,000	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$38,875,088	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$12,490,912	$12,490,912
	Cost of Removal				
10	Cost of Removal - Non-Discretionary			$3,365,680	$0
11	Cost of Removal - Discretionary			$3,709,320	$0
12	Total Cost of Removal	Column (a) = Line 10 + Line 11; Column (b) = Prior Year Line 12		$7,075,000	$7,075,000
13	**Total Net Plant in Service**	**Line 9 + Line 12**		**$19,565,912**	**$19,565,912**
	Deferred Tax Calculation:				
14	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%
15	Vintage Year Tax Depreciation:				
16	2013 Spend	Page 5 Line 20		$30,149,089	$2,121,967
17	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		$30,149,089	$32,271,056
18	Book Depreciation	Column (a) = Line 6 * Line 14 * 50%; Column (b) = Line 6 * Line 14		$730,137	$1,460,274
19	Cumulative Book Depreciation	Prior Year Line 19 + Current Year Line 18		$730,137	$2,190,410
20	Cumulative Book / Tax Timer	Line 17 - Line 18		$29,418,952	$30,080,646
21	Effective Tax Rate			35.00%	35.00%
22	Deferred Tax Reserve	Line 20 * Line 21		$10,296,633	$10,528,226
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 13		$19,565,912	$19,565,912
24	Accumulated Depreciation	- Line 19		($730,137)	($2,190,410)
25	Deferred Tax Reserve	- Line 22		($10,296,633)	($10,528,226)
26	Year End Rate Base	Sum of Lines 23 through 25		$8,539,142	$6,847,276
	Revenue Requirement Calculation:				
27	Average Rate Base	(Prior Year Line 26 + Current Year Line 26) ÷2		$4,269,571	$7,693,209
28	Pre-Tax ROR		3/	9.30%	9.30%
29	Return and Taxes	Line 27 * Line 28		$397,070	$715,468
30	Book Depreciation	Line 19		$730,137	$1,460,274
31	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 12 - Line 19) * Property Tax Rate	4/	$0	$1,455,530
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**		**$1,127,207**	**$3,631,272**

1/ Reflects projected capital additions (plant-in-service); to be replaced with actual capital additions for annual reconciliation
2/ Assumes 16.39% based on 2010 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	52.08%	5.30%	2.76%		2.76%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	42.75%	9.80%	4.19%	2.26%	6.45%
	100.00%		7.04%	2.26%	9.30%

4/ Property Tax Rate Calculation based on 2010 actual net plant in service and property tax expense applicable to distribution

Plant in Service	$1,235,201,285
Accumulated Depreciation	$529,716,452
Distribution-Related Net Plant in Service	$705,484,833
Distribution-Related Rate Year Property Tax Expense	$20,831,185
Distribution-Related Property Tax Rate	2.95%

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

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Additions Allowance					
	Non-Discretionary Capital					
1	Actual Non-Discretionary Capital Additions	Page 4 Line 9, Column (a)	1/	$30,087,700	$0	$0
	Discretionary Capital					
2	Actual Discretionary Capital Additions	Page 4 Line 18, Column (a)	1/	$18,714,500	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$48,802,200	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$48,802,200	$0	$0
5	Retirements	Line 4 * Retirements Rate	2/	$7,720,508	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b) and (c) = Prior Year Line 6		$41,081,692	$41,081,692	$41,081,692
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 4		$48,802,200	$0	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$38,875,088	$0	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Columns (b) and (c) = Prior Year Line 9		$9,927,112	$9,927,112	$9,927,112
	Cost of Removal					
10	Cost of Removal - Non-Discretionary			$3,956,000	$0	$0
11	Cost of Removal - Discretionary			$2,623,000	$0	$0
12	Total Cost of Removal	Column (a) = Line 10 + Line 11; Columns (b) and (c) = Prior Year Line 12		$6,579,000	$6,579,000	$6,579,000
13	**Total Net Plant in Service**	**Line 9 + Line 12**		**$16,506,112**	**$16,506,112**	**$16,506,112**
	Deferred Tax Calculation:					
14	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%	3.40%
15	Vintage Year Tax Depreciation:					
16	2012 Spend	Page 6 Line 20 Column (a)		$44,401,468	$823,508	$761,680
17	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		$44,401,468	$45,224,976	$45,986,656
18	Book Depreciation	Column (a) = Line 6 * Line 14 * 50%; Columns (b) and (c) = Line 6 * Line 14		$698,389	$1,396,778	$1,396,778
19	Cumulative Book Depreciation	Prior Year Line 19 + Current Year Line 18		$698,389	$2,095,166	$3,491,944
20	Cumulative Book / Tax Timer	Line 17 - Line 18		$43,703,079	$43,129,810	$42,494,712
21	Effective Tax Rate			35.00%	35.00%	35.000%
22	Deferred Tax Reserve	Line 20 * Line 21		$15,296,078	$15,095,433	$14,873,149
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 13		$16,506,112	$16,506,112	$16,506,112
24	Accumulated Depreciation	- Line 19		($698,389)	($2,095,166)	($3,491,944)
25	Deferred Tax Reserve	- Line 22		($15,296,078)	($15,095,433)	($14,873,149)
26	Year End Rate Base	Sum of Lines 23 through 25		$511,646	($684,488)	($1,858,981)
	Revenue Requirement Calculation:					
27	Average Rate Base	(Prior Year Line 26 + Current Year Line 26) ÷2		$255,823	($86,421)	($1,271,734)
28	Pre-Tax ROR		3/	9.30%	9.30%	9.30%
29	Return and Taxes	Line 27 * Line 28		$23,792	($8,037)	($118,271)
30	Book Depreciation	Line 19		$698,389	$1,396,778	$1,396,778
31	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 12 - Line 19) * Property Tax Rate	4/	$0	$1,386,678	$1,345,435
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**		**$722,180**	**$2,775,419**	**$2,623,941**

1/ Reflects projected capital additions (plant-in-service); to be replaced with actual capital additions for annual reconciliation
2/ Reflects approved capital spending; to be replaced with actual capital spending for annual reconciliation
3/ Assumes 15.82% based on 2009 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
4/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	52.08%	5.30%	2.76%		2.76%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	42.75%	9.80%	4.19%	2.26%	6.45%
	100.00%		7.04%	2.26%	9.30%

5/ Property Tax Rate Calculation based on 2010 actual net plant in service and property tax expense applicable to distribution

Plant in Service	$1,235,201,285
Accumulated Depreciation	$529,716,452
Distribution-Related Net Plant in Service	$705,484,833
Distribution-Related Rate Year Property Tax Expense	$20,831,185
Distribution-Related Property Tax Rate	2.95%

The Narragansett Electric Company
d/b/a National Grid
Electric Capital Investment Summary

			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
	Non Discretionary Capital			
1	FY 2012 Actual Non-Discretionary Capital Additions		$ 30,087,700	$ 30,087,700
2	FY 2013 Actual Non-Discretionary Capital Additions		-	28,619,000
3	Cumulative Actual Non- Discretionary Capital Addtions	Line 3 + Line 4	30,087,700	58,706,700
4	FY 2012 Actual Non-Discretionary Capital Spending		31,341,500	31,341,500
5	FY 2013 Actual Non-Discretionary Capital Spending		-	30,428,000
6	Cumulative Actual Non-Discretionary Capital Spending	Line 4 + Line 5	31,341,500	61,769,500
7	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	Lesser of Line 3 or Line 6	30,087,700	58,706,700
8	Prior Year Cumulative Allowed Non-Discretionary Capital Included in Rate Base	Prior Year Line 9	-	30,087,700
9	**Total Allowed Non-Discretionary Capital Included in Rate Base Current Year**	Line 7 - Line 8	**$ 30,087,700**	**$ 28,619,000**
	Discretionary Capital			
10	FY 2012 Actual Discretionary Capital Additions		$ 18,714,500	$ 18,714,500
11	FY 2013 Actual Discretionary Capital Addtions		-	22,747,000
12	Cumulative Actual Discretionary Capital Addtions	Line 10 + Line 11	18,714,500	41,461,500
13	FY 2012 Approved Discretionary Capital Spending		27,036,150	27,036,150
14	FY 2013 Approved Discretionary Capital Spending		-	26,112,000
15	Cumulative Actual Discretionary Capital Spending	Line 13 + Line 14	27,036,150	53,148,150
16	Cumulative Allowed Discretionary Capital Included in Rate Base	Line 12	18,714,500	41,461,500
17	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base		-	18,714,500
18	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 16 - Line 17	**$ 18,714,500**	**$ 22,747,000**
19	**Total Allowed Capital Included in Rate Base Current Year**	Line 9 + Line 18	**$ 48,802,200**	**$ 51,366,000**

The Narragansett Electric Company
Illustrative Calculation of Tax Depreciation and Repairs Deduction
On FY 2013 Capital Investment

			Fiscal Year 2013 (a)	Fiscal Year 2014 (b)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 Line 3	$51,366,000	
2	Capital Repairs Deduction Rate		16.00%	
3	Capital Repairs Deduction	Line 2 x Line 3	$8,218,560	
	Bonus Depreciation			
4	Plant Additions	Line 1	$51,366,000	
5	Less Capital Repairs Deduction	Line 3	$8,218,560	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$43,147,440	
7	Percent of Plant Eligible for Bonus Depreciation		85.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 x Line 7	$36,675,324	
9	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%	37.50%	
10	Bonus Depreciation Rate (January 2013 - March 2013)		0.00%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10	37.50%	
12	Bonus Depreciation	Line 8 x Line 11	$13,753,247	
	Remaining Tax Depreciation			
13	Plant Additions	Line 1	$51,366,000	
14	Less Capital Repairs Deduction	Line 3	$8,218,560	
15	Less Bonus Depreciation	Line 12	$13,753,247	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$29,394,193	$29,394,193
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 x Line 17	$1,102,282	$2,121,967
19	Cost of Removal		$7,075,000	
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	$30,149,089	$2,121,967

The Narragansett Electric Company
Illustrative Calculation of Tax Depreciation and Repairs Deduction
On FY 2012 Capital Investment

			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Repairs Deduction				
1	Plant Additions	Page 3 Line 3	$48,802,200		
2	Capital Repairs Deduction Rate		32.00%		
3	Capital Repairs Deduction	Line 2 x Line 3	$15,616,704		
	Bonus Depreciation				
4	Plant Additions	Line 1	$48,802,200		
5	Less Capital Repairs Deduction	Line 3	$15,616,704		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$33,185,496		
7	Percent of Plant Eligible for Bonus Depreciation		75.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 x Line 7	$24,889,122		
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 x Line 11	$21,777,982		
	Remaining Tax Depreciation				
13	Plant Additions	Line 1	$48,802,200		
14	Less Capital Repairs Deduction	Line 3	$15,616,704		
15	Less Bonus Depreciation	Line 12	$21,777,982		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$11,407,514	$11,407,514	$11,407,514
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 x Line 17	$427,782	$823,508	$761,680
19	Cost of Removal		$6,579,000		
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	$44,401,468	$823,508	$761,680

Testimony of
Jeanne A. Lloyd

PRE-FILED DIRECT TESTIMONY

OF

JEANNE A. LLOYD

December 29, 2011

Table of Contents

I. INTRODUCTION

Q. Please state your full name and business address.

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

Q. Please state your position.

A. I am the Manager of Electric Pricing, New England in Regulation and Pricing Department of National Grid USA Service Company, Inc. This group provides rate-related support to The Narragansett Electric Company ("Narragansett" or "Company").

Q. Please describe your educational background and training.

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

Q. Please describe your professional experience?

A. I was employed by Eastern Utilities Associates ("EUA") Service Corporation in December 1990 as an Analyst in the Rate Department. I was promoted to Senior Rate Analyst on January 1, 1993. My responsibilities included the study, analysis and design of the retail electric service rates, rate riders and special contracts for the EUA retail companies. After the merger of New England Electric System and EUA in April 2000, I joined the Distribution Regulatory Services Department as a Principal Financial Analyst. I assumed my present position October 1, 2006. Prior to my employment at EUA, I was on the staff of the Missouri Public Service Commission in Jefferson City, Missouri in the position of research economist. My responsibilities included presenting both written and oral testimony before the Missouri Public Service Commission in the areas of cost of service and rate design for electric and natural gas rate proceedings.

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

A. Yes. I have testified before the Commission on numerous occasions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Infrastructure, Safety and Reliability (“ISR”) factors proposed in this filing and 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 tariff provision.

A. The Company’s ISR Provision, R.I.P.U.C. No. 2044, describes the process to establish and implement 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. Infrastructure Investment Mechanism

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 are effective for consumption on and after April 1 of each year.

Q. How are the CapEx Factors designed?

A. First, the cumulative revenue requirement approved by the Commission, which reflects 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 a 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 Commission 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 rate class allocated cumulative revenue requirement by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect. For demand-based rate classes Rate G-02, Rates G-32/B-32, and Rates G-62/B-62, the CapEx Factors are per kW charges and are calculated by dividing the allocated cumulative revenue requirement for each rate class by the forecasted kW billing demand.

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

A. The cumulative revenue requirement associated with incremental capital investment is allocated in a manner that is similar to the way the revenue requirement on capital investment would be allocated if an allocated cost of service study were to be 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. Is 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 will submit a filing by August 1 of each year ("Reconciliation Filing") in which the Company will propose CapEx Reconciling Factors to become effective for the twelve months beginning October 1. In the Reconciliation Filing, the Company will compare the actual cumulative revenue requirement to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over or under collection of the actual cumulative revenue requirement will be refunded to or collected from customers through the CapEx Reconciling Factors. The amount approved for recovery or refund through the CapEx Reconciling Factors will also be 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 associate 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 Commission 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 580-597). 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 Commission 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 is the I&M and VM expense 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 to be 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. For 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 a per kWh charges?

A. The current distribution charges for Rates G-02 and B-32/G-32 consist of 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. For 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 consist only of 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 will propose an O&M Reconciling Factor to become effective for the twelve months beginning October 1. The Company will compare 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 collection of actual expense will be refunded to or collected from customers through the O&M Reconciling Factor. The O&M Reconciling Factor will be a uniform per kWh charge applicable to all rate classes. The amount approved for recovery or refund through the O&M Reconciling Factor will be subject to reconciliation with actual amounts billed through the O&M Reconciling Factor and any difference reflected in future O&M Reconciling Factors.

III. PROPOSED ISR FACTORS

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

A. The CapEx Factors are designed to collect the cumulative revenue requirement related to incremental capital investments through the end of FY 2013. The cumulative revenue requirement of $3,902,625[1] is developed in the testimony of Mr. Richer. The cumulative revenue requirement is allocated to the rate classes based on the total rate base allocator as approved in the compliance filing in Docket No. 4065, and the factors are designed as described above using forecasted billing units for the period April 1, 2012 through March 31, 2013. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, page 3.

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

O&M Factors

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

A. The O&M Factors are designed to collect forecasted O&M expense associated with I&M and VM activities for FY 2013. As developed in the testimony of Mr. Richer, these expenses total $10,526,900[2]. The Company has allocated these O&M expenses using an allocator based on distribution O&M from the allocated cost of service study that was approved in the compliance filing in Docket No. 4065, which the Company believes maintains consistency in how these costs would be reflected in rates, and O&M Factors are designed as described above.

IV. BILL IMPACTS

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

A. Yes. The monthly bill impacts for each rate class are shown on Section 7 of the ISR Plan. For the average residential customer using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly rate increase of $0.36 or 0.5% based upon rates approved for billing January 1, 2012.

V. TARIFF COVER SHEETS

Q. Is the Company including revised tariff cover sheets in its filing?

A. No, the Company is not revising tariff cover sheets at this time. The Company will be submitting its annual reconciliation filing in February 2012 proposing additional rate

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

changes for April 1, 2012. Therefore, the Company will submit a compliance filing following the Commission's decision in both the reconciliation filing docket and this docket that will include tariff cover sheets reflecting all of the approved rate changes for April 1, 2012.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.