nationalgrid

Thomas R. Teehan
Senior Counsel

December 23, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

Rhode Island Public Utilities Commission
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2012 Electric Infrastructure, Safety, and Reliability Plan

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 2012 [2]. In consultation with the Rhode Island Division of Public Utilities and Carriers ("Division"), 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 Electric ISR Plan is designed to protect and improve the electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, sustaining system viability through targeted investments, 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 describes the general categories of work the Company proposes to perform in fiscal year 2012, distinguishing work that is required to meet statutory and regulatory obligations from other targeted electric infrastructure-related work that is also necessary to provide system safety and reliability. The Plan also includes 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 five witnesses. Ms. Catherine McDonough, Mr. Robert Sheridan, and Mr. Daniel Glenning testify jointly to introduce the Plan and describe the Plan's program components. Mr. David Tufts provides the calculation of the Company's fiscal year 2012 revenue requirement under the Plan. Ms. Jeanne Lloyd testifies regarding rate design, typical bill impacts, and the terms of an illustrative tariff. The proposed Plan would account for a total net incremental increase in revenues of approximately $3.7 million. For the average residential customer using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly rate increase of $0.30, or 0.4 percent.

As the first annual electric capital spending plan to be developed under Rhode Island's new law promoting a safe and reliable electric distribution system, this Plan presents a unique opportunity to

[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.

facilitate and encourage investment in our electric utility infrastructure and enhance its ability to provide safe, reliable, and efficient electric service to customers. The Company has worked with the Division to reach agreement on this Plan. Having completed this collaborative work with the Division, the Company now submits the Plan to the Rhode Island Public Utilities Commission for review and approval.

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

PRE-FILED DIRECT TESTIMONY

OF

CATHERINE MCDONOUGH

ROBERT D. SHERIDAN

AND

DANIEL GLENNING

December 23, 2010

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I. INTRODUCTION

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

A. My name is Catherine T. McDonough and my business address is 40 Sylvan Road, Waltham, Massachusetts, 02451.

Q. Ms. McDonough, please state your position with the Company.

A. I am employed as the Director of Economic Analysis, Asset Strategy and Policy, Electric Distribution Asset Management for National Grid USA Service Company, Inc. ("Service Company") which provides engineering, financial, administrative and other technical support to subsidiary companies of National Grid USA. In my capacity as Director, I am charged with ensuring that the infrastructure and vegetation management programs conducted by The Narragansett Electric Company d/b/a National Grid (the "Company") are consistent with federal and state policies and assist in meeting the Company's regulatory obligation to provide safe, reliable, and efficient electric service to customers at reasonable cost. I am also responsible for communicating the Company's infrastructure program and investment plans to regulators and other stakeholders.

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

A. I have a Bachelor of Arts degree from the University of Massachusetts, as well as a Master of Arts degree and Ph.D. in Financial Economics from New York University. I joined Niagara Mohawk Power Corporation ("Niagara Mohawk" d/b/a National Grid) approximately 11 years ago. Before being named to my current position in April 2008, I was a project manager directing research to support a variety of strategic decisions related to electric distribution operations, dynamic pricing programs, customer satisfaction, and electric pricing. Prior to joining Niagara Mohawk, I served as an Assistant Professor of Finance at SUNY Binghamton and Babson College following several years as a Vice President, Senior Economist with Merrill Lynch Capital Markets in New York City.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (the "Commission") or any other regulatory agency?

A. I have testified before the New York Public Service Commission, Massachusetts Department of Public Utilities, and the New Hampshire Public Utilities Commission.

Q. Mr. Sheridan, please state your full name and business address.

A. My name is Robert D. Sheridan and my business address is 40 Sylvan Road, Waltham, Massachusetts, 02451.

Q. Mr. Sheridan, please state your position with the Company.

A. I am employed as the Director of Distribution Planning for Service Company. In my capacity as Director of Distribution Planning, I am charged with conducting distribution system and asset reviews each year for National Grid's electric distribution companies in Rhode Island, Massachusetts, New Hampshire and upstate New York. My responsibilities include developing recommended system improvement projects in support of the objectives of each electric distribution company concerning capacity, reliability, and sustainability of the distribution network.

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

A. I graduated from the University of South Florida in 1986, earning a Bachelor of Science in Electrical Engineering, and from Bentley College in 1995, earning a Masters of Business Administration. I am a registered professional engineer in the Commonwealth of Massachusetts. In 1987, I began my engineering career as an Associate Engineer at General Dynamics, Electric Boat Division in Groton, Connecticut, working with the power systems on nuclear submarines. In 1988, I took a position with Massachusetts Electric Company in North Andover, Massachusetts. Since that time, I have held various engineering and management positions within National Grid, all focusing on the electric distribution system. In 1995, I was promoted to District Engineering Manager. I then became District Engineering Manager for the Company in 1998. In 2002, I was promoted to Vice President of Distribution Planning and Engineering for New England. In 2005, I became Vice President of Distribution Engineering and Asset Management for both New England and upstate New York. In 2008, I assumed my current position as Director of Network Asset Planning.

Q. Have you previously testified before the Commission or any other regulatory agency?

A. I have testified before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

Q. Mr. Glenning, please state your full name and business address.

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

Q. Mr. Glenning, please state your position with the Company.

A. I am employed as the Director of Project Management for Electricity Operations for Service Company. In my capacity as Director, I am responsible for approximately 50 project managers at National Grid USA. I work with these project managers and their managers to fully develop the scope, schedule, and cost estimates for projects across the electric distribution companies and transmission companies. I also work with other functional managers and Portfolio Management Office ("PMO") to ensure all projects are in compliance with all National Grid processes and procedures. Additionally, I am responsible for the development of National Grid project management processes and performance metrics for all companies to ensure projects are executed on schedule and within cost.

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

A. I have a Bachelor of Science in Engineering from Clarkson University and have completed the Naval Postgraduate School Certificate in Project Management/Program Management. I am also certified as a Project Management Professional ("PMP") by the Project Management Institute. I have been managing projects for National Grid for the past two and one-half years. I am responsible for management of the Project Management Department within Electricity Operations. I am responsible for ensuring that the Project Manager effectively initiates, plans, executes, controls, and closes capital projects for each electric distribution and transmission company. As part of this process, we proactively address schedule, technical, and cost risks so the projects can be successfully completed. Typically at National Grid there are over 1,000 electric distribution and transmission projects in various project lifecycle states. Prior to National Grid, I managed projects as a civilian project manager for the United States Navy. During my career, I held a number of different positions as Program Manager, Project Manager, Engineering Manager, and various engineering positions. I managed new weapon and sonar system development projects for the Navy. I was responsible for developing project acquisition strategies that focused on cost and risk reductions to ensure projects could achieve objectives be completed on time and within budget.

Q. Have you previously testified before the Commission or any other regulatory agency?

A. Yes. I have testified before the Commission in R.I.P.U.C. Docket No. 4111.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present the consensus plan developed by the Company and the Rhode Island Division of Public Utilities and Carriers (the "Division") regarding the Company's proposed fiscal year ("FY") 2012 electric infrastructure, safety, and reliability plan (the "Electric ISR Plan" or the "Plan")[1]. As we will describe below, implementation of the Electric ISR Plan is necessary for 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 and reliability spending covered by the Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for the twelve month fiscal year ending March 31, 2012 ("FY 2012"): 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")

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

program. The Division and the Company have agreed that these expenses are necessary in FY 2012 in order for the Company to provide safe, reliable service to customers in Rhode Island.

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

A. The consensus-based Electric ISR Plan, which is provided as Exhibit 1 to our testimony, encompasses the electric infrastructure, safety, and reliability spending plan for FY 2012, as well as a proposed 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. As envisioned in the new law, 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. The FY 2012 levels of incremental net capital investment, vegetation management O&M expense, and I&M O&M expense related to inspections, feeder hardening and porcelain cutout activities in the Company's proposed plan are $16.5 million, $8.1 million, and $1.1 million, respectively.

Q. Please explain how your testimony is organized.

A. Below, our testimony discusses the Company's plan for the capital investment, VM O&M, and I&M O&M categories of spending and describes any particular considerations that were taken into account by the Company and the Division in arriving at the agreed upon budget amounts. With regard to the specific categories of spending, Section 3 of this testimony discusses the Company's proposed capital investment plan for FY 2012, Section 4 discusses the Company's proposed VM program, and Section 5 of our testimony discusses the Company's proposed I&M program. Mr. David Tufts provides pre-filed direct testimony concerning the revenue requirement calculation associated with these investments, while Ms. Jeanne Lloyd addresses the tariff provision, proposed ISR factors, rate design, and typical bill impacts in her pre-filed direct testimony.

III. CAPITAL INVESTMENT PLAN

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

A. In this filing, the Company is putting forth a capital spending plan for FY 2012 in the amount of $58.4 million, including $1.2 million of flood mitigation expenses to be discussed below, encompassing a range of project work that is needed in order 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 order to facilitate review by the Division and, ultimately, by the Commission, the Company developed the Electric ISR Plan provided as Exhibit 1 to our testimony. In the Plan, 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. In presenting specific projects and goals, and in collaborating with the Division to review those specific projects and goals, the Company's objective is to demonstrate to the Commission that there is a very real need to undertake the projects encompassed in the Capital Investment Plan and that completion of these projects is in the interests of Rhode Island customers.

Q. Please describe the categories of work activities that are included in the Electric ISR 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 2012 capital investment levels that have been identified by the Company and the Division as appropriate to maintain safe and reliable electric distribution service.

A. As described in detail in Exhibit 1, the investment levels proposed for recovery through the Electric ISR Plan for FY 2012 are associated with five key driver work categories: Statutory/Regulatory, Damage Failure, System Capacity and Performance, Asset Condition, and Non-infrastructure. Chart 1 summarizes the planned spending level for each of these key driver categories proposed for FY 2012, as follows:

Chart 1: Proposed FY 2012 Capital Outlays by Key Driver Category

SPENDING RATIONALE	**FY 2012 PROPOSED BUDGET**	**%**
Statutory/Regulatory	$ 21,636,500	38%
Damage/Failure	9,705,000	17%
Subtotal	*$ 31,341,500*	*55%*
Asset Condition	$ 9,737,050	17%
Non-Infrastructure	278,000	0%
System Capacity and Performance	15,821,100	28%
Subtotal	*$ 25,836,150*	*45%*
Grand Total	$ 57,177,650	
Flood Damage Avoidance Engineering Studies[1]	$ 1,200,000	
Grand Total including Flood-Related Studies	$ 58,377,650	

As shown in Chart 1, a significant portion of the outlays for capital projects in FY 2012 are necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates (i.e., $21.6 million, or 38 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 $9.7 million, or 17 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 account for approximately $31.3 million, or 55 percent, of proposed capital outlays in FY 2012. 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, the Company and the Division have agreed that these categories of spending are subject to necessary and unavoidable deviations. As such, mandatory, or non-discretionary, capital investments are proposed 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. This is described in greater detail in the testimony of David Tufts.

The system capacity, asset condition, and non-infrastructure projects that the Company will pursue in FY 2012 have been chosen in order to maintain the overall reliability of the system. 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 in order to comply with the Company's system and capacity loading policy. These projects are designed to reduce the 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.

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 $15.8 million, or 28 percent, of the proposed capital investment in FY 2012.

Projects necessary due to the poor condition of infrastructure assets account for about $9.7 million, or 17 percent, of the proposed capital outlays in FY 2012. 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 in order to avoid the prospect that a large number of similar assets will fail at the same time or within short windows of time.

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 outlays for non-infrastructure projects will account for about $280,000 and less than one percent of capital outlays in FY 2012.

Finally, an additional aim of the Company's proposed plan is to reduce the risk of widespread customer interruptions due to flood conditions similar to those experienced in Rhode Island in March 2010. To that end, the Company proposes to spend $1.2 million in FY 2012 to complete the required engineering studies for construction projects that will reduce the vulnerability of nine substations to flood conditions so that the Company can begin construction on these projects 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 Exhibit 1, the Company has provided detail on the specific projects within each work category that would be undertaken in FY 2012 as part of the Electric ISR Plan. The Company and the Division have reviewed each of these planned projects, as well as overall spending levels and have come to consensus as to the appropriate investment levels for FY 2012. The Company is also prepared to provide additional documentation to the Commission to support the establishment of the Electric ISR Plan, as necessary.

Q. Please quantify the amounts to be included for recovery in the Company's revenue requirement calculation.

A. As discussed in more detail in the testimony of David Tufts and in the Capital Investment Plan section of Exhibit 1, the Company's FY 2012 revenue requirement is calculated based on the Company's projected capital amounts to be placed into service in FY 2012 plus associated cost of removal, as shown in Chart 2 below.

Chart 2: Proposed FY 2012 Capital Outlays, Plant In Service, and Cost of Removal

Spending Rationale	Proposed Capital Outlays FY 2012	Capital Placed Into Service FY 2012	Estimated Cost of Removal (COR)	Capital Placed Into Service Plus COR
Statutory/Regulatory	$21,636,500	$20,612,500	$2,432,000	$23,044,500
Damage/Failure	9,705,000	9,475,200	1,524,000	10,999,200
Subtotal	*$31,341,500*	*$30,087,700*	*$3,956,000*	*$34,043,700*
Asset Condition	$9,737,050	$5,805,000	$1,006,000	$ 6,811,000
Non-Infrastructure	278,000	278,000	-	278,000
System Capacity & Performance	15,821,100	12,631,500	1,518,000	14,149,500
Subtotal	*$25,836,150*	*$18,714,500*	*$2,524,000*	*$21,238,500*
Grand Total	$57,177,650	$48,802,000	$6,480,000	$55,282,000
Flood Damage Avoidance Engineering Studies[1]	$1,200,000	-	$99,000	$ 99,000
Grand Total including Flood-Related Studies	$58,377,650	$48,802,000	$6,579,000	$55,381,000

[1] Flood-related engineering studies are considered 'discretionary' for recovery purposes

Q. How were the above plant in-service amounts determined?

A. The Company has used estimated timing of in-service dates for capital spending being placed into service during FY 2012 to develop its Capital Placed In-Service figure, shown above, and used in the revenue requirement calculation. Due to the multi-year nature of certain projects, current and prior year(s) capital spending may be included in the FY 2012 plant in-service amount when a project is placed into service during FY 2012. Similarly, the capital portion of a project included in the FY 2012 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.

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. What are the reliability benefits associated with the Vegetation Management Program?

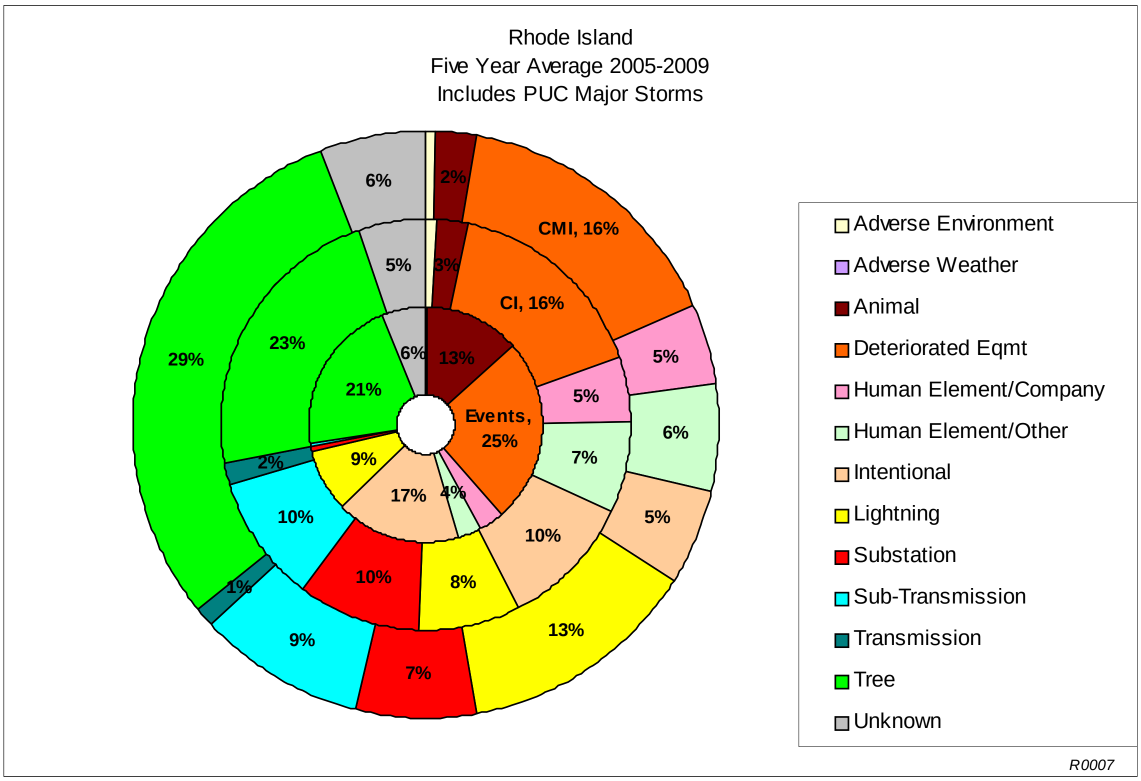
A. The Vegetation Management ("VM") Program is designed to achieve two goals: first, to reduce the frequency and magnitude of vegetation-related interruptions occurring on distribution circuits, and second to improve public safety by minimizing the potential for public contact with energized conductors or for electrical fires in trees and bordering vegetation. The program is structured to create and maintain clearance between energized distribution conductors and vegetation, especially tree limbs. In addition, the hazard tree program is intended to minimize the frequency and damaging effect of tree and large tree limb failures adjacent to but often outside the right-of-way along the Company's overhead primary distribution assets.

For FY 2012, the Company is planning to spend almost two-thirds of its VM Program budget on Cycle Pruning because of the direct correlation between cycle pruning and system reliability. As a result, the Company has formulated a strategic plan for dealing with vegetation management, which includes systematic trimming across the distribution system on a four-year cycle. A stable and consistent circuit pruning program maintains reliability and is important in safeguarding the public's safety because it minimizes tree/wire contact issues and improves crew accessibility. Cycle Pruning also facilitates the Company's line inspection process.

Q. Why is vegetation management important?

A. Especially in adverse weather, the proximity of tree limbs and vegetation to the overhead circuits is a significant cause of outages. First, the Company's overhead facilities cannot sustain the damage that occurs when trees or significant limbs fall on or interfere with the wires and poles without adversely affecting reliability. Trees adversely impact reliability because a tree or tree limb contact with the distribution system during windy/stormy conditions can trip circuit breakers and cause feeder lockouts thus leaving customers without power. Secondly, when it is rainy and windy, vegetation that has not been properly managed and has grown close to the conductor can contact the conductor, creating safety and reliability concerns. The risk of electric shock to the public/workforce and the risk of fire during these periods is significant. Accordingly, the Company's VM Program is an essential component of the Company's plan to maintain the safety and the reliability of its electric distribution network. As shown in Chart 3, trees were responsible for almost 30 percent of customer minutes interrupted over the past five years.

Chart 3: Customer Interruptions by Cause



Q. How does the VM Program work?

A. The Company has prepared a detailed overview of the VM Program, which is set forth in Exhibit 1. The description provided in Exhibit 1 is geared toward providing the Commission with insight into the significance of VM in terms of reducing safety concerns to the public/workforce, minimizing the potential damage to electric assets from fallen trees and limbs, and for maintaining reliability. Further, the description highlights the technical approach that the Company employs to determine the appropriate level of VM that is necessary. These activities, including cycle pruning and hazard tree removal, have been significantly enhanced since 2006/2007.

Q. How has the Cycle Pruning program changed in recent years?

A. The Company has made two notable changes to the Cycle Pruning Program in recent years to boost the efficiency and cost-effectiveness of the program. First, beginning in 2003, the Company converted to a circuit-based approach rather than targeting specific communities. Circuits are used to serve customers across municipal boundaries. As a result, when a tree-related outage occurs on a circuit, customers along the entire circuit have the potential to experience an outage. The advantage of a circuit-based approach is that pruning occurs along the entirety of the circuit at a single point in time, rather than being completed in segments through tree-trimming activities in particular municipalities that may occur at different times. Therefore, a circuit-based approach increases reliability by lessening the potential for tree-related outages along the entire circuit. With this approach, and as described below, the Company aims to maintain a four-year cycle for circuit trimming.

Second, in order to target the correct work at the optimal frequency, the Company began using a reliability ranking model, called the Tree Model, based on historic tree-related interruption data. The results from this model help to generate prioritized annual work plans for cycle pruning to make sure that the pruning budget is deployed on the highest priority circuits. The circuit rankings are used to guide field assessment audits to determine which circuits may need to be added or removed to balance the annual schedule while maintaining a reasonable level of tree-related reliability. The field assessment is a necessary step to ensure that actual vegetation grow-in conditions are acceptable when the Company considers delaying the pruning of a circuit by one more year. The Tree Model and field assessments are also key in identifying circuits that need to be pulled ahead of the full cycle time to address reliability concerns or because the vegetation grow-in conditions make it risky to allow the circuit to go to full cycle.

Q. If the program is more efficient, please explain why the costs of the program are higher in recent years versus the early part of the decade?

A. To further abet its safety and reliability goals, the Company has made two other enhancements to the Cycle Pruning Program that have increased the required spending on cycle trimming in recent years.

First, with safety and reliability benefits in mind, the Company shortened the cycle frequency to four years beginning in 2006 to better reflect the length of the growing season and the growth characteristics of the predominant tree species in Rhode Island as reflected in the Hardiness Zones delineated by the U.S. Agricultural and Markets Department. This contrasts sharply to the Company's Cycle Pruning program prior to 2006, when the frequency of cycle pruning was variable year-to-year and the effective cycle frequency could be close to nine years.

Second, the Company enhanced its pruning specifications in 2007 to create additional clearance between conductors and trees or tree limbs, especially overhead clearance, and to remove additional interruption hazards at the time of the pruning operation. The additional clearance specifications were implemented partly in response to research that showed that over 75 percent of tree interruptions came from outside the existing pruning clearance zone. The expanded pruning specifications increased the removal of overhanging dead, dying, and defective branches that create an imminent risk to the network or public.

Q. Why did the Company expand its Enhanced Hazard Tree Mitigation program in recent years?

A. Even with the enhanced pruning specification described above, full tree and large limb failures have been shown to account for a significant portion of customer interruptions, not only in Rhode Island but also in other states. Indeed, fallen trees account for almost

60 percent of tree-related customer interruptions in Rhode Island and other New England states.

To address this issue, the Enhanced Hazard Tree Mitigation ("EHTM") program was implemented in 2007 to identify and remove dying or structurally weakened trees and branches along the sections of the network where the ratio of customers served per mile is highest and the associated benefit of removing hazard trees is therefore greatest. Even though the impact of the EHTM program on system-wide reliability statistics is muted due to the targeted nature of the program, EHTM has been shown to improve the reliability performance of the mainline portion of the targeted circuits in Rhode Island by over 60 percent. The EHTM program can, therefore, markedly improve the satisfaction and reduce the complaint rate of customers who experience frequent interruptions related to those targeted circuits.

Q. How does the Enhanced Hazard Tree Program help to contain the operating and maintenance expense and capital budgets to address damaged equipment?

A. Hazard trees are designated as such because they have a high probability of failing and causing damage to Company equipment. The direct costs to repair the damage to the network caused by a fallen tree or limb can range from $200 to $13,500 depending upon the nature of the specific work that needs to be done. Even if it is conservatively assumed that 60 percent of the damage from hazard trees is at the low end, 20 percent is at middle the part, and 20 percent is at the high-end of this range, the expected cost to restore the system to its normal configuration following each event caused by a hazard tree would be approximately $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 EHTM program is therefore an important program to contain the O&M and capital budgets for damage/failure.

Q. Do any other utilities perform Enhanced Hazard Tree Mitigation?

A. Hazard tree mitigation programs are common place on major utility distribution systems. In a 2008 benchmarking study conducted by Pennsylvania Power and Light ("PPL") Utilities, 14 of 15 major utilities indicated that that they had a Hazard Tree Program. The Company has also been involved in best practice sharing sessions with many other utilities including Northeast Utilities, Duke, Hydro One, and Hydro-Quebec.

Q. Could you briefly review the FY 2012 spending levels for the 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 plan that the Company has worked out 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 considerable discussion with the Division, the Electric ISR Plan allows for approximately $8.1 million in program spending for FY 2012, comparable to what the

Company spent for its vegetation management program in FY 2009. This includes $5.3 million for cycle trimming and $750,000 for EHTM, as shown in Chart 4 below.

Chart 4: Vegetation Management Spending

Distribution Vegetation Management Outlays ($000)					
				Expected	Proposed
	FY2008*	FY2009*	FY2010**	FY2011**	FY2012***
Cycle Trimming	$4,141	$5,574	$4,552	$2,881	$5,300
Hazard Tree	$721	$757	$709	$283	$750
Sub-T (off & on road)	$294	$436	$302	$475	$267
Police/Flagman Detail	$340	$187	$241	$105	$491
All Other Activities (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$1,134	$903	$1,078	$1,085	$1,261
Total	**$6,630**	**$7,858**	**$6,882**	**$4,829**	**$8,069**

* Reflects 4 year Cycle Pruning Program
** Includes Downward Adjustments in Response to Commission Order
*** Return to 100% base funding for Cycle Pruning and 63% of base funding for Hazard Tree

V. INSPECTION AND MAINTENANCE PROGRAM

Q. What are the reliability benefits associated with the Inspection and Maintenance Program?

A. The Electric ISR Plan incorporates the implementation of an inspection program for overhead and underground distribution infrastructure in order to achieve the objective of maintaining safe and reliable service to customers in the short and long term. The Inspection and Maintenance ("I&M") Program is designed to provide the Company with comprehensive system-wide information on the condition of overhead and underground system components. Through the I&M Program, the Company will inspect overhead and sub-transmission infrastructure on a six-year cycle and underground distribution infrastructure on a five-year cycle. Under this approach, the Company will collect inspection results on approximately 17 percent of its overhead distribution system and 20 percent of its underground electric distribution system every year so that it will have comprehensive system-wide information on the condition of all overhead components within six years and all underground system components within five years.

Q. Could you briefly review the FY 2012 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. As shown in Chart 5 below, the Company proposes an I&M Program O&M expense budget of approximately $1.1 million for FY 2012. In agreement with the Division, the Company has opted to defer the capital work associated with the proactive I&M Program (shown in Columns (a) and (b) of Chart 5) until FY 2013, following the outcome of the FY 2012 inspection work itself, quantified at $145,000 for FY 2012. This enables the Company to complete the required work already identified in the feeder hardening program in FY 2012 before transitioning fully to the I&M Program in FY 2013. The I&M Program expense budget also includes approximately $994,000 for O&M expenses related to the capital costs of approximately $4.1 million relative to feeder hardening and the replacement of potted porcelain cutouts, which are included in the asset condition portion of the proposed capital budget discussed in the Capital Investment portion of Exhibit 1.

Chart 5: Inspection and Maintenance Program Costs

Calculation of Inspection and Maintenance (I&M) Program Costs for FY2012 1

	Overhead I&M	Undergound I&M	Subtotal I&M	Potted Porcelain Cutout	Feeder Hardening	Total
	(a)	(b)	(c)	(d)	(e)	(f)
Capex	$0	$0	$0	$1,714,000	$2,350,000	$4,064,000
Operation and Maintenance Expenses:						
Opex Related to Capex	$0	$0	$0	$171,400	$822,500	$993,900
Repair - Related Costs	-	-	-	-	-	-
Inspections - Related Costs 2\	144,945	-	144,945	-	-	144,945
Total Operation and Maintenance Expenses	$144,945	$0	$144,945	$171,400	$822,500	$1,138,845
Total O&M Costs	$144,945	$0	$144,945	$1,885,400	$3,172,500	$5,202,845

1\ Derivation of I&M categories is consistent with those included in rate allowance per RIPUC Docket No. 4065
2\ Includes incremental inspection FTE and incremental contractor costs for inspection and QA/QC

Q. What are the objectives of the Feeder Hardening work contained in the ISR Plan?

A. The intent of the Feeder Hardening program, as quantified above in Column (e) of Chart 5, is to identify overhead feeders with the most potential for reliability performance improvement related to deteriorated equipment and lightning interruptions. The Company uses a feeder hardening ranking model to determine which feeders meet the criteria for hardening. To date, the Company has completed 1,372 miles of feeder hardening in Rhode Island, or 26 percent of the system. Under the proposed Electric ISR Plan, the Company would continue the Feeder Hardening program through the end of FY 2012. The Company will harden an additional 209 miles so that when the program ends at the end of FY 2012, 1,581 miles, or 30 percent, of the system will have been hardened.

The proposed Electric ISR Plan includes approximately $823,000 in associated feeder hardening O&M expense during FY 2012 and approximately $2.4 million of capital costs, which are included in the overall $58.4 million Capital Investment Plan budget identified in the Capital Investment portion of Exhibit 1.

Q. Please describe the work to replace potted porcelain cutouts scheduled for FY 2012 and provide a projection of when the Company believes it will have replaced all the potted porcelain cutouts on its Rhode Island system?

A. Fuse cutouts provide over-current protection for the electric distribution system. As was common in the utility industry at the time, the Company installed porcelain cutouts in the early to mid-1980s through early 2001. However, beginning in 2006, the Company adopted a policy of replacing all potted porcelain cutouts on the Company's system, which it expects to have completed by the end of FY 2013. The elimination of potted porcelain cutouts reduces potential safety hazards and will increase the reliability of those replaced cutouts. As identified above in Column (d) of Chart 5, the Electric ISR Plan budget includes approximately $171,000 of O&M expense for this work and approximately $1.7 million in capital charges to remove potted porcelain cutouts that are also included in the overall $58.4 million Capital Investment Plan budget identified in the Capital Investment portion of Exhibit 1.

VI. <u>CONCLUSION</u>

Q. In your opinion, does the 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 2012 is designed to establish the capital investment, VM, and I&M activities in Rhode Island that are necessary to meet the needs of its customers and maintain the overall safety and reliability of the Company's electric distribution system. The Electric ISR Plan was presented to the Division and reviewed in collaboration 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 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 your testimony?

A. Yes, it does.

Exhibit 1

FY 2012 Electric Infrastructure, Safety, and Reliability Plan

Introduction and Summary
FY 2012 Proposal

National Grid[1] in consultation with the Division of Public Utilities and Carriers ("Division") has developed the following proposed fiscal year ("FY") 2012 electric infrastructure, safety, and reliability ("Electric ISR") plan (the "Electric ISR Plan" or "Plan") in compliance with Rhode Island's recently enacted 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 that the Company is submitting for its electric distribution operations is the product of a collaborative effort with the Division. The Plan is designed to maintain and upgrade the Company's electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, sustaining asset viability through targeted investments driven primarily by condition, continuing a level of feeder hardening and cutout replacement, and operating a

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[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.*

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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 2012 Plan for these categories of costs, the resulting FY 2012 revenue requirement associated with the proposed Electric ISR Plan, a proposed tariff provision enabling the rate adjustments and mechanism underlying the proposed Electric ISR Plan, the proposed rate design, and the proposed typical bill impacts resulting from the rate design.

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 2012. 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.

As envisioned in the legislation, after the end of the fiscal year, the Company would 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 and

[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.

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reconcile the revenue requirement to the revenue billed from the rate adjustments implemented at the beginning of each fiscal year.

The Company also proposes 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 described below, an annual report on the prior fiscal 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 2012 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 $16.5 million, $8.1 million, and $1.1 million, respectively. Each of these categories is addressed below.

Section 2 of this proposal contains the Company's proposed capital investment plan for FY 2012. 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, 7, and 8 include an illustrative tariff provision, rate design, and bill impacts, respectively.

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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 2012 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 2012 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 2012 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 2012. This estimated amount would be subject to true-up to actual vegetation management O&M expense.

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Inspection and Maintenance Program

The Company has also estimated the O&M expense associated with the inspection and maintenance program for FY 2012. Section 4 of this proposal provides details of the proposed inspection and maintenance program for FY 2012. 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, 2011, 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 example, 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.

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Electric Infrastructure, Safety, and Reliability Provision

In order to implement the rate mechanisms described in the new legislation for its electric distribution operations, the Company has prepared a proposed new tariff provision entitled "Electric Infrastructure, Safety, and Reliability Provision ("Electric ISR Provision"). This proposed tariff provision is contained in Section 6. The proposed Electric ISR Provision sets out a mechanism for reflecting the Plan's approved amounts in rates charged to customers and for reconciling net capital investment and O&M expense to revenue that was billed based upon the prior year's projections.

Rate Design

Under the proposed Plan, the revenue requirement calculated under the ISR Provision would be appropriately allocated to the Company's rate classes. The Company proposes that the following provisions apply for purposes of rate design:

a. The revenue requirement associated with the incremental net capital investments would 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 would 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 would be divided by estimated billing demand based on a

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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 would be allocated to rate classes based upon the allocation of operations and maintenance 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 would 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 would 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 for the rate class.

The proposed rate design under the Plan is contained in Section 7.

Bill Impacts

The bill impacts associated with the rate design contained in Section 7 are provided in Section 8.

Conclusion

The Company and the Division have worked diligently to arrive at an Electric ISR Plan that meets the goals of the new law to provide a safe and reliable electric delivery system for

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Rhode Island. The creation of the FY 2012 Electric ISR Plan affords the Commission a groundbreaking opportunity to create a system safety and reliability plan that provides safe, reliable, and efficient electric service for customers at reasonable costs.

Section 2

Electric Capital Investment Plan
FY 2012 Electric ISR Plan

Electric Capital Investment Plan
FY 2012 Proposal

Background

The Company developed its proposed Electric Capital Investment Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.[4] 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 (4) sustain asset viability through targeted investments driven primarily by condition. An additional aim of the proposed plan is to reduce the risk of widespread customer interruptions due to flood conditions similar to those experienced in Rhode Island in March 2010.

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 the past four years.

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[4] The Company delivers electricity to 481,994 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 5,650 miles of overhead and 1,231 miles of underground distribution and sub-transmission circuit in a network that includes 107 sub-transmission lines and 378 distribution feeders. The Company relies on 64 substations that house 134 power transformers and 839 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 280,334 distribution poles, 5,151 manholes and 63,785 pole top transformers.

Electric Capital Investment Plan
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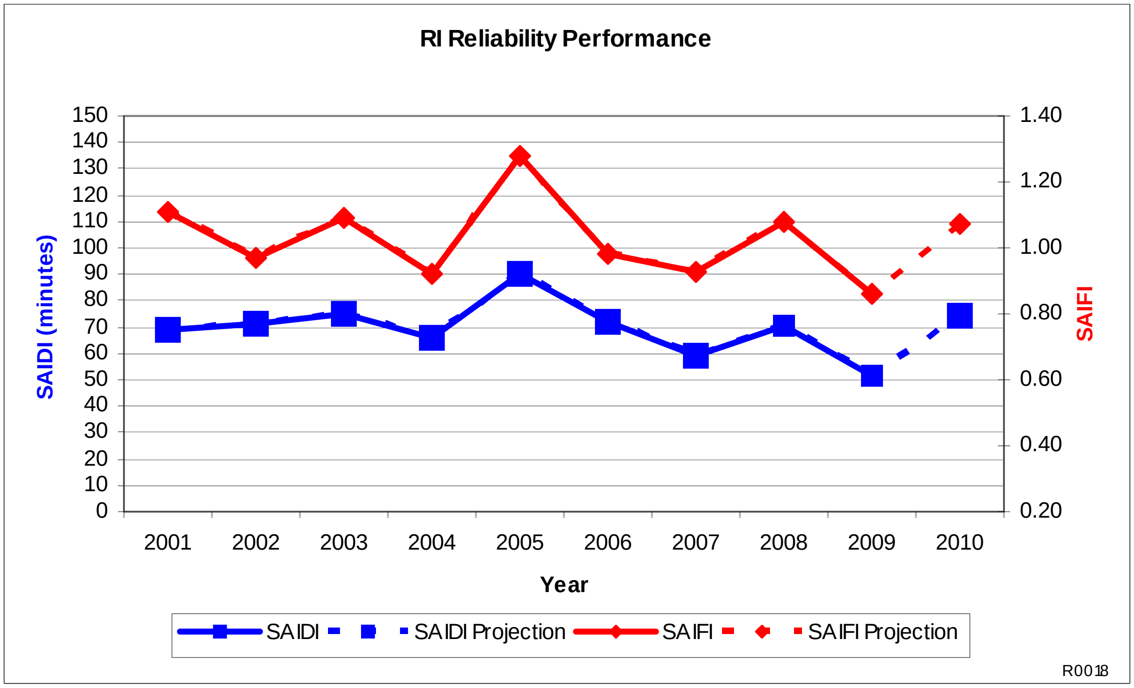
Chart 1: Reliability Performance



Still, reliability performance very much depends on the stresses placed on the network from weather conditions and the ability of the system to tolerate those stresses. The Company is currently at risk of falling short of its reliability targets in 2010. As shown in Chart 2, nearly 75 percent of the customer minutes interrupted result from the following causes: deteriorated equipment (16 percent), lightning (13 percent), trees (29 percent), sub-transmission events (9 percent), and reliability issues with substations (7 percent). These issues continue to be important factors adversely affecting reliability performance in 2010. Indeed, thirteen of the twenty largest individual events in 2010 so far have involved substations, equipment failure or deterioration, or lightning.

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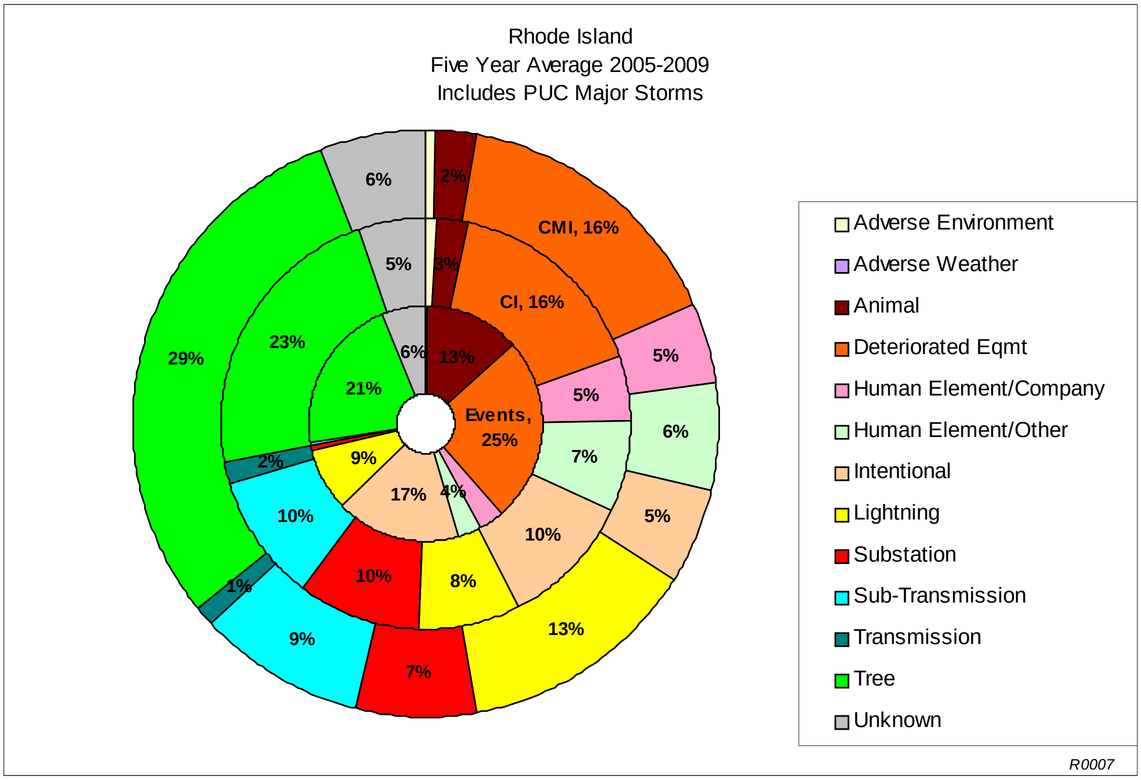
Chart 2: Customer Interruptions by Cause



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 $57.2 million to maintain the safety and reliability of its electric delivery infrastructure in FY 2012, covering the period from April 2011 through March 2012. This spending level is greater than the $48.3 million that it expects to spend in FY 2011, covering the period April 2010 through March 2011, but comparable to the Company's annual level of spending for capital improvements on the Rhode Island network

Electric Capital Investment Plan
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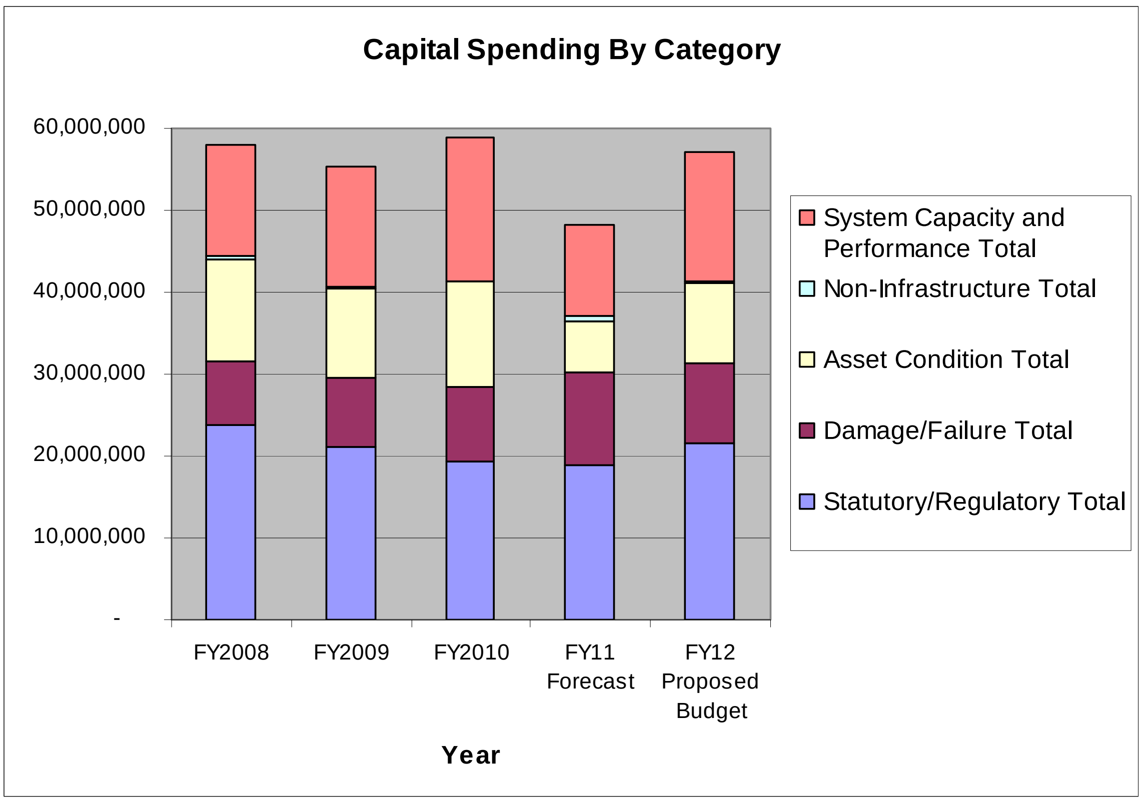
during the FY 2008 through FY 2010 periods. It is important to note that the reduced FY 2011 amount is due to the postponement of some of the Company's essential asset replacement and substation work during CY 2011 in response to the Commission's Order in R.I.P.U.C. Docket No. 4065. The FY 2012 plan includes work to reduce the risk of customer interruptions from failed equipment at the Woonsocket substation and to address some important capacity issues at the substations in Newport and Coventry.

Chart 3: Capital Outlays by Key Driver Category



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Separately, with the support of the Rhode Island Division of Public Utilities and Carriers, the Company also plans to begin work to reduce the potential reliability issues associated with future flooding events similar to those that took place in March 2010. The Company proposes to spend an additional $1.2 million (not included in the $57.2 million discussed above) in FY 2012 to complete the required engineering studies for construction projects that will reduce the vulnerability of nine substations to flood conditions so that the Company can begin construction on these projects in FY 2013.

Because a portion of the proposed capital outlays in FY 2012 is for projects (mainly substation projects) that are completed over multiple years, the Company expects that only a portion of those outlays will be placed into service in FY 2012. Likewise, a portion of the capital to be placed in service in FY 2012 will also reflect the capital outlays for similar multi-year projects that were begun in previous years.

A. Summary of Investment Plan by Key Driver

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 2008 through FY 2010 period, expected outlays in FY 2011, and the proposed spending level in FY 2012 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 2012.

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Chart 4: Proposed FY 2012 Capital Outlays by Key Driver Category

SPENDING RATIONALE	FY12 PROPOSED BUDGET	%
Statutory/Regulatory	$ 21,636,500	38%
Damage/Failure	9,705,000	17%
Subtotal	*$ 31,341,500*	*55%*
Asset Condition	$ 9,737,050	17%
Non-Infrastructure	278,000	0%
System Capacity and Performance	15,821,100	28%
Subtotal	*$ 25,836,150*	*45%*
Grand Total	$ 57,177,650	
Flood Damage Avoidance Engineering Studies[1]	$ 1,200,000	
Grand Total including Flood-Related Studies	$ 58,377,650	

[1] Flood-related engineering studies are considered 'discretionary' for recovery purposes.

As shown in Chart 4, much of the outlays for capital projects in FY 2012 are 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 $21.6 million, or 38 percent, of the proposed capital budget in FY 2012.

The need to repair failed and damaged equipment equates to approximately $9.7 million, or 17 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.

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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 $31.3 million, or 55 percent, of proposed capital outlays in FY 2012.

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 60 percent of the investment dollars categorized as system capacity and performance, or 17 percent of the proposed capital budget in FY 2012. 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 in order 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 2012 have been chosen to minimize the likelihood of reliability issues and other problems due to under-investment in the overall system.

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Investments that are required to maintain reliable service to customers accounted for 40 percent of the system capacity and performance total or 11 percent of the total FY 2012 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 $15.8 million, or 28 percent, of network investment.

Projects necessary due to the poor condition of infrastructure assets account for about $9.7 million, or 17 percent, of the proposed capital outlays in FY 2012. 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 requires the Company to develop strategies to replace assets if their condition impairs reliable, safe service to customers. Also, Company and industry-wide experience with assets that have poor operating characteristics in the field requires the Company to develop strategies to remove equipment that operates poorly while in service. These strategies are developed in order 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

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based on their failure consequences and probability of providing safe and reliable service to customers.

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 $280,000 and less than one percent of capital outlays in FY 2012.

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

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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 an optimized 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 2012 presented herein represents the Company's best information regarding the investments it will need to make in order 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

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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.

Projects with projected scope and costs above established thresholds must be approved by management. 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

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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 the variance range identified in the project spending plan. The reauthorization request must include presentation of the original authorization, 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 reauthorizations above established thresholds require re-approval. 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. Significant projects also require re-sanctioning if the project completion date is delayed more than three months beyond the approved date.

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 some project detail 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 $21.6 million to meet its Statutory/Regulatory requirements in FY 2012. This is $2 million more than what the Company expects to spend in FY 2011 but comparable to what the Company spent for this purpose on average from FY 2008 through FY 2010.

The expected increase in required spending for statutory/regulatory purposes relative to FY 2011 is based on an expected recovery for economic activity as the impact of the current debt overhang and the credit climate becomes more favorable. Approximately half of the Statutory/Regulatory budget is required to establish electric delivery service to new customers.

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The Company currently expects to spend about $10 million dollars for this purpose in FY 2012, approximating the historic three-year average spending for this purpose during the FY 2008-to-FY 2010 period and up from the approximately $9 million amount that the Company expects will be required in FY 2011. 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.

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

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.

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The expected increases in spending in the categories noted above are offset to some extent by a projected decline in required spending for meters in FY 2012 based on the favorable purchase agreements that the Company has struck with vendors.

The Company also expects that it will need to spend less to facilitate third-party attachments compared to recent years. 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.

The Company also expects an increase in spending to replace mercury vapor outdoor lights. Due to environmental concerns with mercury, the Federal Policy Act of 2005, banned as of 2008 the manufacturing and import of mercury vapor ballasts. As a result, the Company has begun a program to replace all remaining mercury vapor lighting on its system over the next few years.

ii. Damage/Failure

The Company is proposing a $9.7 million budget for FY 2012 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 2008-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

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final restoration of the plant in-service will not be complete until FY 2012 (e.g. failed substation transformer). The budget set for FY 2012 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 2012 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.

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iii. Asset Condition

The Company is proposing to spend $9.7 million in FY 2012 to replace assets that need to be replaced in order to maintain reliability performance, up from the expected $6.1 million that the Company expects to spend for this purpose in FY 2011 but less than the $12.1 average level of spending during the FY 2008 through FY 2010 period. Almost 80 percent of the proposed spending to address asset condition issues in FY 2012 will be used to construct new substations or to replace deteriorated equipment in several existing substations.

The construction of a new substation in Woonsocket accounts for $5 million (approximately 51 percent) of the proposed spending to address asset condition issues in FY 2012. 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. This project includes $805,000 to perform work on three feeders that will connect to the new substation.

Under Ground Cable Strategy - The goal of this strategy is to replace primary underground cable that is in poor condition or has a poor operating history. Replacing these

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cables on a planned basis is highly desirable since the work involved often requires civil work including duct work and manholes. Customers are directly affected by these extended repairs which create contingency situations where alternate feeds are not possible or available. Examples of distribution cables currently being planned for replacement include the 1102A&B, 1158, and 1168 cables in downtown Providence. The Company expects to spend approximately $770,000 on underground cable replacements in FY 2012.

The Substation Circuit Breaker Strategy and Program targets obsolete and unreliable breaker families. The Company has approximately 839 distribution substation circuit breakers including 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 expects to spend approximately $1.4 million to implement this strategy in FY 2012.

The Substation Metalclad Switchgear Replacement Strategy and Program is another important strategy to improve the reliability of substations. This strategy replaces switchgear installed prior to 1970 beginning with those metalclad switchgears that have sustained a failure or are of a manufacturer type on which a failure has occurred. There are approximately 36 metalclads in service operating at 13.2 kV and 4.16 kV voltage level. Of these, approximately 70 were installed in the 1960s and 1970s. Several design factors with older vintage metalclad substations contribute to bus failures or component failures. These factors include:

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- 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.

As part of this program the Company will strive to replace one metalclad substation per year using assessments based on age, manufacturer, and conditions as determined by visual and electro-acoustic test results. The distribution strategy is funded at $300,000 in FY 2012 to perform the engineering work at the Nasonville substation so that construction can begin in FY 2013 and FY 2014.

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

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ensure that battery systems meet the current operating requirements and perform their designed function. The Company proposes to spend $500,000 in FY 2012 to implement this strategy.

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 extend over many years. Replacement candidates for the next two years are in the engineering phase and construction plans are being prepared. This project is budgeted at $300,000 for FY 2012.

iv. System Capacity and Reliability

The Company has set a budget of $15.8 million for system capacity and reliability projects in FY 2012. This is up from the $11.2 million that the Company expects to spend in FY 2011 and is comparable to the average level of spending during the FY 2008 through FY 2010 period. Planning Criteria (Load Relief) projects account for about $9.5 million, or approximately 60 percent of the proposed spending in FY 2012, up from the $6.3 million that the Company expects to spend in FY 2011. Substation projects account for about one-third of that required investment.

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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.

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

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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 2009 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 2009 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.

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

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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 is developing 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. 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. Provide contingency relief at Wood River substation, contingency relief at Westerly substation, and support the retirement of 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

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and 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 three new 13.8 kV feeders to provide load relief to City of Newport. The completion of this project will provide thermal relief to overloaded feeders and supply lines in Newport. 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 system during contingencies.
- **Staples Substation** - Addition of 13.8 kV Circuit Breaker - Install new breaker at Staples to supply new feeder which will relieve the Riverside 108W55 and Staples 112W43 and 112W41 due to spot load at the CVS Park.
- **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 to 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.

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- **Kilvert St – Install TB2** - TB#1 at Kilvert St is a 1-33/44/55 MVA 115/12.47 kV transformer loaded to 21.6 MVA, or 32 percent of its summer normal rating (67 MVA) and 26 percent of its summer emergency rating (84 MVA), during the summer peak of 2009. A failure of the existing Kilvert TB#1 will result in outages, yielding approximately 17.5 MVA of unserved load. The installation of a new feeder 87F3 at Kilvert St in 2010 further supports the need for contingency relief. Furthermore, a recommendation has been made within the 15-year planning horizon to install an additional feeder (87F5) in 2022. The Mobile Installation estimate in the event of a failure of TB1 is twenty-four hours. A failure of Kilvert St TB#1 would result in outage exposure of 420 MWh.

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 63,800 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

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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 $1.2 million in FY 2012.

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 $340,000 in FY 2012.

In addition to the Load Relief Projects identified above, the Company is also proposing to spend approximately $6.3 million in FY 2012 on several programs designed to maintain system reliability, which is comparable to the Company's spending level for these programs over the past few years. Such programs include:

Pockets of Poor Performance Strategy - The intent of this strategy is to identify subsections of feeders (typically at the line fuse level) experiencing measurably more frequent

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customer interruptions than the remainder of the feeder. Typically, these identified areas are known as "pockets of poor performance." The reliability levels targeted by Pockets of Poor Performance Strategy are:

- **Customer Level Reliability -** Reliability at the customer level is the main driver of this strategy. Identifying and correcting repeat device interruption locations will improve customer service.
- **Reliability "Hot-spots" -** This strategy will help identify future reliability "hot-spots" and support the timely correction of localized problems before they become larger issues.

Once the specific locations have been identified, a reliability review of the area will be conducted by Network Asset Planning to determine the source(s) of the problem(s). The range of potential work could be as simple as solving a coordination problem to performing preventive maintenance (e.g., tree trimming, repairing equipment, grounding and bonding) and/or line reconductoring. The Company is planning to spend approximately $500,000 to execute this strategy in FY 2012.

Feeder Hardening Strategy - The Feeder Hardening strategy and program identifies feeders with characteristics indicating the potential for significant reliability performance improvements related to overhead deteriorated 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. FY 2012 is the last year

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feeder hardening will be utilized in Rhode Island, at which time much of the work performed under the feeder hardening program will be subsumed by the Company's inspection and maintenance program. The Feeder Hardening strategy is funded at approximately $2.4 million in FY 2012.

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 $164,000 in FY 2012.

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

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incorporates the components of the potted porcelain cutout replacement strategy after FY 2012. The potted porcelain cutout strategy is funded at $1.7 million in FY 2012.

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 $1.2 million in FY 2012.

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. This data is essential

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to capture the full benefits of energy efficiency programs. The Company has set a $600,000 budget for this program in FY 2012.

D. Flood Mitigation Projects

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 Extension – Woonsocket	115kV-13.8kV	Blackstone

Water levels reached between three feet and eight feet in these locations. Flood waters from the Pawtuxet, Blackstone, and Pawcatuck Rivers were brackish, contained raw sewage and other contaminants such as oil and gasoline which are detrimental to the safety of personnel, as well as the many mechanical components which comprise circuit breaker operating mechanisms, electro-mechanical relays, circuit switcher operators, and transformers controls. Most of these

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devices also utilize microprocessor and solid state relays and circuitry. Substation control houses containing substation batteries, relays (electro-mechanical and microprocessor based), remote terminal units, and AC and DC circuit breaker panels were also exposed to flood waters.

In order to maintain service to those customers normally supplied from these substations, the following activities were necessary until repairs or replacement of substation equipment affected by the flood waters were complete and the substations could be re-energized.

- Transfer of load to area substations not affected by the flood waters.
- Installation of temporary equipment such as mobile substations and padmounted transformers.
- Increased loading levels on area distribution equipment.

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 restore these locations to service. The other locations have been fully restored to service.

Following the floods, mitigation measures at the affected substations were developed including installation of watertight enclosures of equipment, raising of equipment, and in some cases relocation of the substation. The Company proposes to spend $1.2 million in FY 2012 to perform engineering studies so that construction on the flood mitigation projects described below can begin in FY 2013.

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The proposed solutions that are 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. The possible solutions include relocating existing substations to alternate locations or rebuilding sections of existing substations that are in areas susceptible to flood conditions with elevated equipment. The Company will also consider retiring certain substations by changing supply configurations. Any equipment that needs to be raised will be raised at least 12 inches above the peak flood elevation. Each location was also evaluated for installation of flood protection barriers; however, none of the substations were determined to be suitable candidates. Major substation projects to be considered to address flooding concerns include:

- Retirement of Westerly substation at its present location with substation expansions of the new Hopkinton substation and Langworthy substation to supply the load which the Westerly substation currently supplies.
- Installation of an elevated 23 kV metalclad and control house on existing property at the Sockanosett substation.

E. Recovery of Electric ISR Plan Capital Investment

As discussed in Section 5 of the Electric ISR Plan, the Company's FY 2012 revenue requirement is calculated based on the Company's projected capital amounts to be placed into service in FY 2012 plus associated cost of removal. The Company has used estimated timing of

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in-service dates for capital spending being placed into service during FY 2012 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 non-discretionary 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. 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. Due to the multi-year nature of certain projects, current and prior year(s) capital spending may be included in the FY 2012 plant in-service amount when a project is placed into service during FY 2012. Similarly, the capital portion of a project included in the FY 2012 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 2012 amounts used in the development of the revenue requirement.

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Chart 6: Proposed FY 2012 Capital Outlays, Plant In Service, and Cost of Removal

Spending Rationale	Proposed Capital Outlays FY 2012	Capital Placed Into Service FY 2012	Estimated Cost of Removal (COR)	Capital Placed Into Service Plus COR
Statutory/Regulatory	$21,636,500	$20,612,500	$2,432,000	$23,044,500
Damage/Failure	9,705,000	9,475,200	1,524,000	10,999,200
Subtotal	*$31,341,500*	*$30,087,700*	*$3,956,000*	*$34,043,700*
Asset Condition	$9,737,050	$5,805,000	$1,006,000	$ 6,811,000
Non-Infrastructure	278,000	278,000	-	278,000
System Capacity & Performance	15,821,100	12,631,500	1,518,000	14,149,500
Subtotal	*$25,836,150*	*$18,714,500*	*$2,524,000*	*$21,238,500*
Grand Total	$57,177,650	$48,802,200	$6,480,000	$55,282,000
Flood Damage Avoidance Engineering Studies[1]	$1,200,000	-	$99,000	$ 99,000
Grand Total including Flood-Related Studies	$58,377,650	$48,802,200	$6,579,000	$55,381,200

[1] Flood-related engineering studies are considered ‘discretionary’ for recovery purposes

Capital Outlays by Key Driver Category and Budget Classification, Excluding FY 2012 Flood-Related Studies

SPENDING RATIONALE	BUDGET CLASS	FY08	FY09	FY10	FY11 Forecast	FY12 Proposed Budget
Statutory/ Regulatory	3rd Party Attachments	(123,199)	873,018	780,847	795,000	641,000
	Land and Land Rights - Dist	313,141	310,128	274,560	292,000	321,000
	Meters – Dist	2,194,959	2,135,191	2,042,048	2,150,000	1,803,000
	New Business - Commercial	7,602,534	6,993,422	4,705,078	5,100,000	6,157,500
	New Business - Residential	4,951,161	2,856,774	3,256,239	3,560,000	3,917,000
	Outdoor Lighting - Capital	712,535	1,236,779	941,164	700,000	718,000
	Outdoor Lighting - Capital MV	-	-	61,933	23,000	300,000
	Public Requirements	1,640,703	1,465,029	3,121,260	3,130,000	3,968,000
	Transformers & Related Equipment	6,595,658	5,301,415	4,128,756	3,100,000	3,811,000
Statutory/Regulatory Total		**23,887,490**	**21,171,755**	**19,311,884**	**18,850,000**	**21,636,500**
Damage/ Failure	Damage/ Failure	7,266,897	7,488,952	9,143,559	8,000,000	9,245,000
	Major Storms – Dist	375,380	856,490	(112,426)	3,400,000	460,000
Damage/Failure Total		**7,642,276**	**8,345,442**	**9,031,133**	**11,400,000**	**9,705,000**
Asset Condition	--Woonsocket & Related	80,639	57,883	1,043,789	2,400,000	5,005,000
	Asset Replacement	12,381,390	10,793,745	11,530,572	3,500,000	4,732,050
	Asset Replacement - I&M (NE)	20,727	112,553	490,942	200,000	-
	Safety	76,680	(22,943)	-	-	-
Asset Condition Total		**12,559,436**	**10,941,238**	**13,065,303**	**6,100,000**	**9,737,050**
Non-Infrastructure	Corporate/Admin/General	(60,904)	(3,464)	(1,238,810)	-	
	Facilities	121,166	134,036	256,800	200,000	-
	General Equipment	324,847	154,236	391,872	250,000	278,000
	Telecommunications Capital - Dist	-	-	-	350,000	-
Non-Infrastructure Total		**385,109**	**284,809**	**(590,139)**	**800,000**	**278,000**
System Capacity and Performance	--Coventry & Related	4,345	89,324	558,222	100,000	1,000,000
	--Hopkinton & Related	372	96,615	547,535	125,000	800,000
	--Newport & Related	305,411	715,163	2,926,839	1,750,000	720,000
	--West Warwick & Related	-	-	114,900	100,000	520,000
	Load Relief	3,486,228	5,988,143	4,650,580	4,225,000	6,492,920
	Reliability	5,446,383	3,878,186	5,768,069	3,750,000	3,938,180
	Reliability - FEEDER HARDENING	4,315,685	3,828,491	2,888,145	1,100,000	2,350,000
System Capacity and Performance Total		**13,558,425**	**14,595,921**	**17,454,289**	**11,150,000**	**15,821,100**
Grand Total		**58,032,737**	**55,339,166**	**58,272,470**	**48,300,000**	**57,177,650**

Project Detail for Proposed FY 2012 Capital Outlays

SPENDING RATIONALE	RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY12 PROPOSED BUDGET
Statutory/ Regulatory	3rd Party Attachments	COS022	Ocean St-Dist-3rd Party Attch Blnkt	50	641,000
	3rd Party Attachments Total				**641,000**
	Land and Land Rights - Dist	COS009	Ocean St-Dist-Land/Rights Blanket	50	321,000
	Land and Land Rights - Dist Total				**321,000**
	Meters - Dist	CN4904	Narragansett Meter Purchases	50	1,072,000
		COS004	Ocean St-Dist-Meter Blanket	50	731,000
	Meters - Dist Total				**1,803,000**
	New Business - Commercial	C31790	CVS Distribution Improvements	50	427,500
		COS011	Ocean St-Dist-New Bus-Comm Blanket	50	3,910,000
		RESERVE 049_011 LINE	Reserve for New Business Commercial Unidentified Specifics & Schedule Changes	50	1,820,000
	New Business - Commercial Total				**6,157,500**
	New Business - Residential	COS010	Ocean St-Dist-New Bus-Resid Blanket	50	3,807,000
		RESERVE 049_010 LINE	Reserve for New Business Residential Unidentified Specifics & Schedule Changes	50	110,000
	New Business - Residential Total				**3,917,000**
	Outdoor Lighting - Capital	COS012	Ocean St-Dist-St Light Blanket	50	718,000
	Outdoor Lighting - Capital Total				**718,000**
	Outdoor Lighting - Capital MV	C26837	Mercury Vapor Replacement	50	300,000
	Outdoor Lighting - Capital MV Total				**300,000**
	Public Requirements	C01286	DOTR-Wyoming Bridges No. 43/44	50	161,000
		C09885	DOTR-Stillwater Viaduct Bridge #278	50	60,000
		C10126	DOTR-Reconst. Branch Av Bridge Prov	50	57,000
		C10284	HWY-Recon Rt 4 W Allenton Rd Int NK	50	69,000
		C11278	DOTR-Industrial Drive Bridge No.882	50	80,000
		C29043	DOTR- Recon Pawtucket Brdge 550	50	37,000
		C34605	DOTR-NK-Reloc P.11-2 Boston Neck Rd	50	69,000
		C35087	DOTR-Apponaug Circulator Imprv Warw	50	460,000
		C35145	DOTR-Cranston Hi Haz Intersect Imp	50	23,000
		COS013	Ocean St-Dist-Public Require Blankt	50	1,302,000
		RESERVE 049_013 LINE	Reserve for Public Requirements Unidentified Specifics & Schedule Changes	50	1,650,000
	Public Requirements Total				**3,968,000**
	Transformers & Related Equipment	CN4920	Narragansett Transformer Purchases	50	3,811,000
	Transformers & Related Equipment Total				**3,811,000**
Statutory/Regulatory Total					**21,636,500**
Damage/ Failure	Damage/Failure	C18593	DxT Substation Dmg/Fail Reserve C49	50	175,000
		COS002	Ocean St-Dist-Subs Blanket	50	616,000
		COS014	Ocean St-Dist-Damage & Failure Blankt	50	7,305,000
		RESERVE 049_014 LINE	Reserve for Damage/Failure Unidentified Specifics & Schedule Changes	50	1,149,000
	Damage/Failure Total				**9,245,000**
	Major Storms - Dist	C22433	OSD Storm Cap Confirm Proj	50	460,000
	Major Storms - Dist Total				**460,000**
Damage/ Failure Total					**9,705,000**
Asset Condition	__Woonsocket & Related	C03693	Woonsocket Sub New 115/13 kV Sub	41	2,800,000

SPENDING RATIONALE	RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY12 PROPOSED BUDGET
		C15200	Woonscket Sub - 3 Dist. fdrs	41	805,000
		C24279	Woonsocket Sub New 13 kV S/gear	41	1,400,000
	__Woonsocket & Related Total				**5,005,000**
	Asset Replacement	C06140	RTU Rplcmnt Program - NECo	50	300,000
		C23852	Inst Ductline Governor St. Prov.	30	250,000
		C26062	OS ARP Relay & related	34	250,000
		C26763	RI Small Capital	50	100,000
		C27950	Kent County 22F2 Love Ln SPCA Rplc.	31	400,000
		C31777	OS IE UG Cable Replacement Program	36	275,000
		C31859	IE - OS Replace open wire primary	27	287,500
		C32019	Batts/Chargers NE South OS RI	39	250,000
		C32278	OS ARP Breakers & Reclosers	34	1,350,000
		C33843	BatteryRplStrategyCo49DxT	39	499,000
		C36111	Replace the metalclad at Nasonville	39	300,000
		C36112	Removal of Crossman St. Sub	39	200,000
		C36113	Line work for Crossman Conversion	39	225,000
		C36414	1102A & 1102B PILC Replacement	36	77,400
		C36415	Village Grn Drt Brd Cable Rplcmnt	37	78,000
		C36416	1158 PILC replacement	39	90,150
		COS017	Ocean St-Dist-Asset Replace Blanket	50	1,100,000
		RESERVE 049_017 LINE	Reserve for Asset Replacement Unidentified Specifics & Schedule Changes	34	(350,000)
		RESERVE 049_017 SUB	Reserve for Asset Replacement Unidentified Specifics & Schedule Changes (substation)	34	(950,000)
	Asset Replacement Total				**4,732,050**
Asset Condition Total					**9,737,050**
Non-Infrastructure	General Equipment	COS006	Ocean St-Dist-Genl Equip Blanket	50	278,000
	General Equipment Total				**278,000**
Non-Infrastructure Total					**278,000**
System Capacity & Performance	__Coventry & Related	C24179	Coventry MITS (Dist Sub)	41	500,000
		C24180	Coventry MITS (Dist Line)	41	500,000
	__Coventry & Related Total				**1,000,000**
	__Hopkinton & Related	C24176	Hopkinton Substation (Dist Sub)	36	300,000
		C33050	New Hopkinton RI Substation	36	500,000
	__Hopkinton & Related Total				**800,000**
	__Newport & Related	C11578	Newport, R.I. Land Purchase	41	300,000
		C15158	Newport Mall Substation	41	200,000
		C24159	Newport Sub Transmission Line Tap	41	120,000
		C32401	Construct Newport Mall Substation	41	100,000
	__Newport & Related Total				**720,000**
	__West Warwick & Related	C28920	Install Distr. Sub - West Warwick	39	300,000
		C28921	Install 4 dist. Fdrs West Warwick	39	100,000
		C32002	W. Warwick 115/12.5kV Sub	39	120,000
	__West Warwick & Related Total				**520,000**
	Load Relief	004484	Fdr 1131 Mars Plastics - Olneyville	50	237,500
		C05505	IE - OS Dist Transformer Upgrades	30	1,192,000
		C13967	PS&I Activity - Rhode Island	36	150,000
		C23012	63F6 Ext 2 PH down Ten Rod Rd	48	400,000
		C24221	Load Relief to 9J3 - Brown Street	36	300,000
		C27245	Relocate 23kV 2227 & 22230 NEEWS	34	700,000

SPENDING RATIONALE	RATE CASE CATEGORY	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY12 PROPOSED BUDGET
		C28615	BRISTOL 51F1 Load Relief	36	175,000
		C28627	WAMPANOAG 48F3 Load Relief	36	200,000
		C28851	Recon. 38F5 and 2227 Greenville Ave	27	89,250
		C28900	Recond. 2228 Johnston sub - Randall	36	1,400,000
		C28932	Recon. 0.5 Miles Segment of 2232	21	474,000
		C32256	Replace Getaways 107W53 and 107W65	50	70,000
		C32363	Inst. Mainline Cond. 6J6 and Conv.	30	156,750
		C32450	Nasonville 127W43	31	157,500
		C33535	Johnston Sub 12.47 kV Expansion	35	585,000
		C35870	Staples New Breaker	34	210,920
		C36522	Kilvert St 87 - Install TB2	39	150,000
		COS016	Ocean St-Dist-Load Relief Blanket	50	340,000
		RESERVE 049_016 LINE	Reserve for Load Relief Unidentified Specifics & Schedule Changes	34	(70,000)
		RESERVE 049_016 SUB	Reserve for Load Relief Unidentified Specifics & Schedule Changes (substation)	34	(425,000)
	Load Relief Total				**6,492,920**
	Reliability - Dist	C05485	IE - OS Recloser Installations	41	164,250
		C05524	IE - OS Cutout Replacements	41	1,714,000
		C32575	Pockets of Poor Performance - OS	41	497,000
		C33762	Ocean State _Electric Fence FY10		150,000
		C35726	EMS/RTU Addition - Narragansett Electric		600,000
		COS015	Ocean St-Dist-Reliability Blanket	50	1,200,000
		RESERVE 049_015 LINE	Reserve for Reliability Unidentified Specifics & Schedule Changes	34	(387,070)
	Reliability - Dist Total				**3,938,180**
	Reliability - FEEDER HARDENING	C05461	FH - OS Feeder Hardening	45	2,350,000
	Reliability - FEEDER HARDENING Total				**2,350,000**
System Capacity & Performance Total					**15,821,100**
Grand Total					**57,177,650**
Flood Damage Avoidance Engineering Studies					**1,200,000**
Grand Total including Flood-Related Studies					**58,377,650**

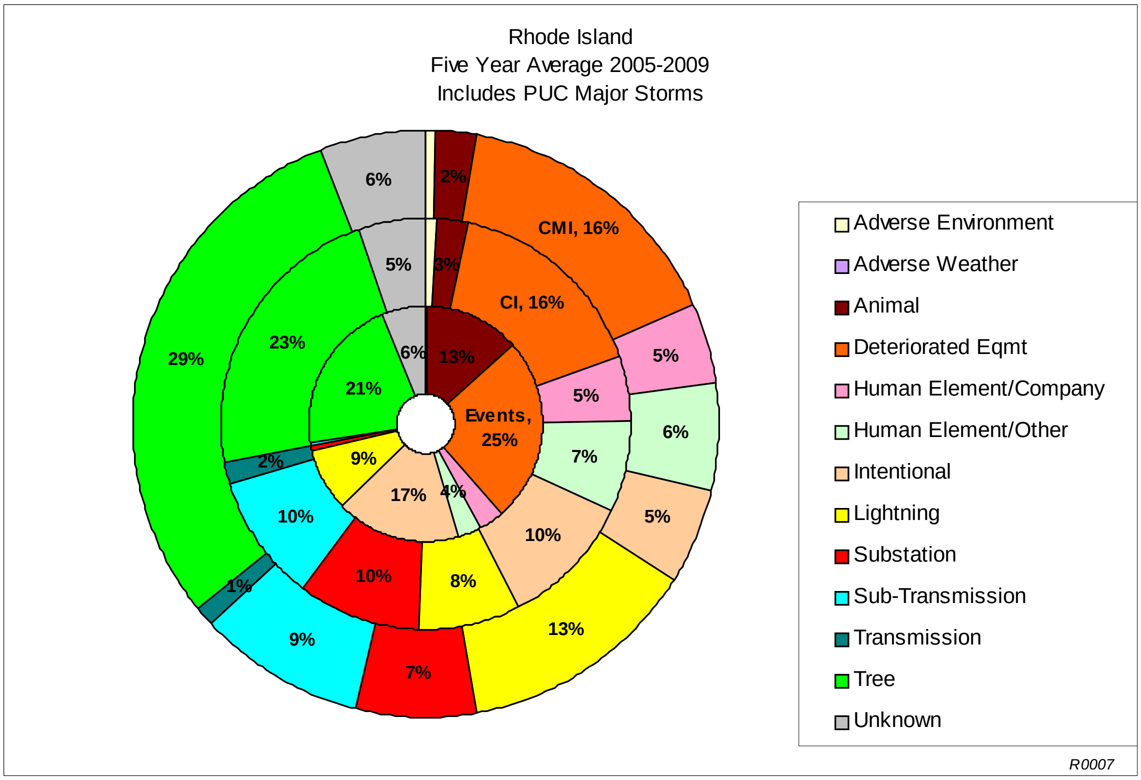
Section 3

Vegetation Management Program
FY 2012 Electric ISR Plan

Vegetation Management Program
FY 2012 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 because tree contact with the electric distribution system increases the risk of electric shock to the public/workforce and the risk of fire. Trees can also be an important hindrance to reliability since tree contact with the distribution system during windy/stormy conditions can trip circuit breakers and cause feeder lockouts. As shown in Chart 1, trees were responsible for almost 30 percent of customer minutes interrupted over the past five years.

Chart 1: Customer Interruptions by Cause



Vegetation Management Program
FY 2012 Proposal

The Company has developed a proactive VM program to provide a measure of safety of the public/workforce, to increase operational efficiency, and to reduce the number of customer interruptions due to trees. The Company's VM program consists of several different activities that aim to address different tree-related issues. As described below, many of these activities, including Cycle Pruning and hazard tree removal, were significantly enhanced in 2006/2007.

Cycle Pruning: The Company spends almost 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.

The importance of Cycle Pruning to ensure the safety of the public and workforce cannot be overstated. A stable and consistent circuit pruning program is essential to ensure that vegetation does not come in contact with distribution conductor since such contact would increase the exposure of the public to electric shock and fires.

Consistent circuit pruning also helps to prevent the deterioration of network reliability and abets the efficient management of the network. Managing the vegetation along the network helps to avoid interruptions due to tree contact and makes the network more accessible to line crews so that they can restore power to customers quickly following an outage. Timely Cycle Pruning also enables crews to efficiently inspect circuits and to perform the required maintenance necessary to avoid outages.

Vegetation Management Program
FY 2012 Proposal

The basis for the Cycle Pruning program is the schedule or length of time determined to be optimal between pruning events on a circuit. This optimal pruning cycle, or interval between which the Company trims trees along an entire circuit, 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 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 acceptability, and overall impact to customers. This growth rate is weighted against acceptable levels of pruning clearance and cost/efficiency to implement. For example, tree growth rate of 1.5 feet a year could yield a cycle of six feet cut every four years, or 1.5 feet cut every year; however, cutting all lines on a one-year cycle would not be cost-effective or efficient to implement. The balance between growth, clearance, and cost is what determines the optimal pruning cycle.

The Company has made two notable changes to the Cycle Pruning Program in recent years to boost the efficiency and cost-effectiveness of the program. First, beginning in 2003, the Company converted to a circuit-based approach rather than targeting specific communities. Circuits are used to serve customers across municipal boundaries. As a result, when a tree-related outage occurs on a circuit, customers along the entire circuit have the potential to experience an outage. The advantage of a circuit-based approach is that pruning occurs along the entirety of the circuit at a single point in time, rather than being completed in segments through tree-trimming activities in particular municipalities that may occur at different times.

Vegetation Management Program
FY 2012 Proposal

Thus a circuit-based approach increases reliability by lessening the potential for tree-related outages along the entire circuit.

Second, in order to target the correct work at the optimal frequency, the Company began to use a reliability ranking model, called the Tree Model, based on historic tree-related interruption data. The results from this model help to generate prioritized annual work plans for cycle pruning to make sure that the pruning budget is deployed on the highest priority circuits. The circuit rankings are used to guide field assessment audits to determine which circuits may need to be added or removed to balance the annual schedule while maintaining a reasonable level of tree-related reliability. The field assessment is a necessary step to ensure that actual vegetation grow-in conditions are acceptable when the Company considers delaying the pruning of a circuit by one more year. The Tree Model and field assessments are also key in identifying circuits that need to be pulled ahead of the full cycle time to address reliability concerns or because the vegetation grow-in conditions make it risky to allow the circuit to go to full cycle.

To further abet its safety and reliability goals, the Company has made two other enhancements to the Cycle Pruning Program that has increased the required spending on cycle trimming in recent years.

First, with safety and reliability benefits in mind, the Company shortened the cycle frequency to four years beginning in 2006 to better reflect the length of the growing season and the growth characteristics of the predominant tree species in Rhode Island as reflected in the Hardiness Zones delineated by the U.S. Agricultural and Markets Department. This contrasts

Vegetation Management Program
FY 2012 Proposal

sharply to the Company's Cycle Pruning program prior to 2006, when the frequency of cycle pruning was variable year-to-year and the effective cycle frequency could be close to nine years.

Second, the Company enhanced its pruning specifications in 2007 to create additional clearance between conductors and trees or tree limbs, especially overhead clearance, and to remove additional interruption hazards at the time of the pruning operation. The additional clearance specifications were implemented partly in response to research that showed that over 75 percent of tree interruptions came from outside the existing pruning clearance zone. The expanded pruning specifications increased the removal of overhanging dead, dying, and defective branches that create an imminent risk to the network or public.

Enhanced Hazard Tree Mitigation ("EHTM"): Even with the enhanced pruning specification described above, full tree and large limb failures have been shown to account for a significant portion of customer interruptions, not only in Rhode Island but also in other states. Indeed, fallen trees account for almost 60 percent of tree-related customer interruptions in Rhode Island and other New England states.

To address this issue, the EHTM program was implemented in 2007 to identify and remove dying or structurally weakened trees and branches along the three phase sections. This is the portion of the network where the ratio of customers served per mile is highest and the associated benefit of removing hazard trees is therefore greatest. EHTM uses an industry leading tree risk assessment protocol to target and identify the removal of trees that are deemed hazardous to the network. National Grid now performs EHTM in all four states that comprise its

Vegetation Management Program
FY 2012 Proposal

U.S. footprint. The EHTM work generally accounts for approximately 10 percent of the overall VM budget.

The EHTM program has two important yet often overlooked benefits. First, the hazard tree mitigation program targets the mainline portion of the Company's worst performing circuits where many customers have experienced multiple interruptions related to trees. Even though the impact of the EHTM program on system-wide reliability statistics is muted due to the targeted nature of the program, EHTM has been shown to improve the reliability performance of the mainline portion of the targeted circuits in Rhode Island by over 60 percent. The EHTM program can, therefore, markedly improve the satisfaction and reduce the complaint rate of customers who experience frequent interruptions related to those targeted circuits.

Second, the hazard tree mitigation program generates significant savings with regard to the Company's operation and maintenance ("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. 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)

Vegetation Management Program
FY 2012 Proposal

- $13,450 (multiple line crews to replace transformer, pole and cleanup spillage 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 each event caused by a hazard tree would be approximately $3,200 (i.e. (0.6*$200) + (0.2*$1,950) + (0.2*$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*$820) and removing these trees has saved an expected $8.7 million (2,727*$3,200). In this way, hazard tree mitigation therefore sharply mitigates increased O&M and capital costs.

Hazard tree mitigation programs are common place on major utility distribution systems. In a 2008 benchmarking study conducted by Pennsylvania Power and Light (“PPL”) Utilities, 14 of 15 major utilities that responded to the survey indicated that they had a Hazard Tree Program and a method to prioritize the removal of Distribution Danger/Hazard Trees.

The Company has also done significant benchmarking and participated in information sharing meetings with other utilities to compare best management practices and to stay connected with industry practices.

Vegetation Management Program
FY 2012 Proposal

- The Company has participated in the Utility Arborist Association's System Forester's Summit since 2008. This group is currently drafting papers to identify best management practices, one of which is hazard tree removal on Transmission and Distribution systems. Northeast Utilities, which has a specialized hazard tree mitigation program on their distribution system, is helping to facilitate this effort.

- Through informational sharing meetings in September 2008, the Company learned that Duke Energy also uses a similar distribution hazard tree mitigation program in all the states it serves. At an informational sharing session in 2008, Hydro One indicated that a large component of their distribution vegetation management program includes and will continue to include hazard tree removals.

- More recently at a best management practice sharing session hosted by the Company in July 2010, Hydro-Quebec indicated that it, and other North American utilities included in its benchmarking studies, have distribution hazard tree mitigation programs. Hydro-Quebec also indicated that more than 30 percent of its distribution vegetation maintenance spending is allocated to its hazard tree mitigation program.

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

Vegetation Management Program
FY 2012 Proposal

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 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 2012 Vegetation Management Budget

The Electric ISR Plan proposes to spend approximately $8.1 million for VM in FY 2012. This includes $5.3 million for cycle trimming and $750,000 for EHTM. As shown in Chart 2 below, this budget is comparable to what the Company spent to implement its VM program in FY 2009 but up considerably from the suppressed level of spending dedicated to VM in FY 2010 and FY 2011.

Vegetation Management Program
FY 2012 Proposal

Chart 2: Vegetation Management Outlays

Distribution Vegetation Management Outlays ($000)					
				Expected	Proposed
	FY2008*	FY2009*	FY2010**	FY2011**	FY2012***
Cycle Trimming	$4,141	$5,574	$4,552	$2,881	$5,300
Hazard Tree	$721	$757	$709	$283	$750
Sub-T (off & on road)	$294	$436	$302	$475	$267
Police/Flagman Detail	$340	$187	$241	$105	$491
All Other Activities (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$1,134	$903	$1,078	$1,085	$1,261
Total	**$6,630**	**$7,858**	**$6,882**	**$4,829**	**$8,069**

* Reflects 4 year Cycle Pruning Program
** Includes Downward Adjustments in Response to Commission Order
*** Return to 100% base funding for Cycle Pruning and 63% of base funding for Hazard Tree

In response to the Rhode Island Public Utilities Commission's ruling in the Company's latest electric distribution general rate case, which set the level of total VM spending recovery in base distribution rates in calendar year 2010 at $5.1 million, the Company reduced its FY 2011 VM budget to $4.8 million.[6] With this VM budget reduction, the Company significantly reduced its EHTM budget to $283,000, a fraction of the spending devoted to this purpose in prior recent years. The Company also reduced the mileage in its Cycle Pruning program for FY 2011 to 828

[6] Please note that level of $5.1 million, which is for the calendar year 2010, produces the $4.8 million VM budget, which is for the fiscal year 2011.

Vegetation Management Program
FY 2012 Proposal

miles compared to the 1,300 miles required for the optimal four year cycle. The Company, however, maintained its budget for core activities in FY 2011 because, as previously noted, the Company has very little discretion with regard to those activities.

The Company is very concerned about the impact of these budget reductions on the safety and reliability of the electric service that it provides to customers and on the capital budget required to address damaged equipment due to tree failures. With the FY 2011 level of funding, crews cannot remove hazard trees that would normally be removed under the risk tree assessment protocol. In fact, the Company is able to mitigate only the most imminent tree hazards in FY 2011, and the amount of risk related to hazard tree failure has increased to unacceptable levels.

The Company is also concerned about the forced reduction in the work plan for Cycle Pruning because, if sustained at this level, this mileage amount is equivalent to setting a six-year pruning cycle -- a frequency that is not sufficient to prevent vegetation from reaching conductors and causing safety and reliability issues. Based on the cost/benefit analysis presented above, spending at these reduced levels can be expected to boost the Company's capital budget required to repair failed and damaged equipment in the years ahead.

To ameliorate the risks to customers and workers, the Company and the Rhode Island Division of Public Utilities and Carriers believe that it is necessary to re-establish a four-year pruning cycle. To that end, the Company proposes to set a $5.3 million budget to prune 1,300 miles, 25 percent of circuit miles, in FY 2012. The Company also believes that it is essential to restore funding for the EHTM program to more normal levels in FY 2012 so as to boost

Vegetation Management Program
FY 2012 Proposal

customer satisfaction and contain O&M and capital expenditures which would otherwise be required to address the damage to the Company's overhead electric assets from fallen trees and limbs.

Section 4

Inspection and Maintenance Plan
FY 2012 Electric ISR Plan

Inspection and Maintenance Program
FY 2012 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 and sub-transmission equipment on a six-year cycle and underground distribution infrastructure on a five-year cycle[7] With this approach the Company

[7] Substations are dealt with separately and using visual and operational checks.

Inspection and Maintenance Program
FY 2012 Proposal

will obtain new inspection results on approximately 17 percent of its overhead distribution system and 20 percent of its underground electric distribution system every year so that it will have comprehensive system-wide information on the condition of all overhead components within six years and all underground system components within five 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 as follows:

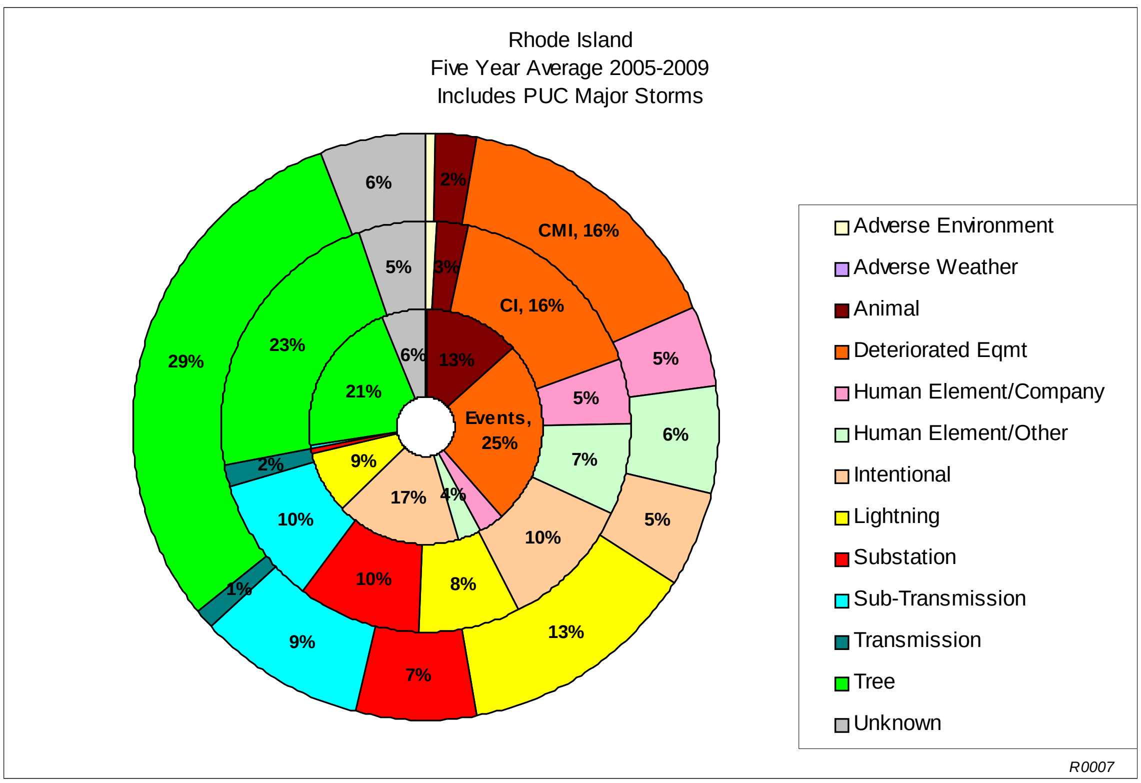
- Level 1: An immediate issue that requires the inspector to stand by until a qualified crew/supervisor arrives to resolve the issues as soon as practical, or an issue that must be repaired within one week.
- Level 2: An issue that, if left unresolved, has a high probability of failure within 12-18 months of the inspection. The identified work will be completed within one year.
- Level 3: An issue that has a high probability of failure within three to five years of the inspection. This information will be used to make reliability investment decisions.
- Level 4: Information is 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 and underground system components generates several benefits for customers.

Inspection and Maintenance Program
FY 2012 Proposal

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 13 percent of customer minutes interrupted. Proactive maintenance also helps to ensure that assets achieve their expected life.

Chart 1: Customer Interruptions by Cause



Inspection and Maintenance Program
FY 2012 Proposal

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.

Inspection and Maintenance Program
FY 2012 Proposal

Fiscal Year 2012 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 $1.1 million for fiscal year ("FY") 2012. In generating the budget, the Company has opted to defer the capital work associated with the proactive I&M Program (shown in Columns (a) and (b) of Chart 2) until FY 2013, following the outcome of the FY 2012 inspection work itself, quantified at $145 thousand for FY 2012. This enables the Company to complete the required work already identified in the feeder hardening program in FY 2012 before transitioning fully to the I&M Program in FY 2013. The I&M Program expense budget also includes approximately $994 thousand for O&M expenses related to the capital costs of approximately $4.1 million relative to feeder hardening and the replacement of potted porcelain cutouts, which are included in the asset condition portion of the proposed capital budget discussed in Section 2 regarding Electric Capital Investment.

Chart 2: Inspection and Maintenance Program Costs

Calculation of Inspection and Maintenance (I&M) Program Costs for FY2012 1

	Overhead I&M (a)	Undergound I&M (b)	Subtotal I&M (c)	Potted Porcelain Cutout (d)	Feeder Hardening (e)	Total (f)
Capex	$0	$0	$0	$1,714,000	$2,350,000	$4,064,000
Operation and Maintenance Expenses:						
Opex Related to Capex	$0	$0	$0	$171,400	$822,500	$993,900
Repair - Related Costs	-	-	-	-	-	-
Inspections - Related Costs 2\	144,945	-	144,945	-	-	144,945
Total Operation and Maintenance Expenses	$144,945	$0	$144,945	$171,400	$822,500	$1,138,845
Total O&M Costs	$144,945	$0	$144,945	$1,885,400	$3,172,500	$5,202,845

1\ Derivation of I&M categories is consistent with those included in rate allowance per RIPUC Docket No. 4065
2\ Includes incremental inspection FTE and incremental contractor costs for inspection and QA/QC

Section 5

Revenue Requirement

FY 2012 Electric ISR Plan

Revenue Requirement
FY 2012 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 Plan ("ISR Plan").

As shown on Page 1, Column (a) of the attachment, the Company's fiscal year ("FY") 2012 electric ISR Plan revenue requirement consists of two 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 2012 revenue requirement related to O&M expenses, or $9,207,845. Subtracted from this is the Company's current base rate allowance attributable to VM and I&M O&M expenses of $6,549,368 on Line 5, for which the Company is proposing a credit to permanently reduce base distribution rates until such time as such rates are reset as part of a general rate case. The resulting incremental O&M-related expense component of the electric ISR Plan revenue requirement is $2,658,477, as shown on Line 7.

The revenue requirement associated with the Company's forecasted FY 2012 capital investment in electric utility infrastructure, or $1,063,326, is shown on Line 11 and is detailed on Page 2 of the attachment. The total annual FY electric ISR Plan revenue requirement for both O&M expenses and capital investment, net of the credit for current base rate recovery of VM and I&M O&M expenses, is reflected on Line 17 and is equal to the sum of lines 7 and 15. Finally, Line 19 reflects the incremental FY revenue requirement required to deliver the

Revenue Requirement
FY 2012 Proposal

Company's electric ISR Plan and is equal to the current year's revenue requirement less the prior year's revenue requirement from Line 17. Each of these components is discussed in more detail below.

For illustration purposes, Column (b) of the attachment provides an illustration of the FY 2013 ISR Plan revenue requirement, which is detailed on Page 3 of the attachment, assuming the same level of capital investment forecasts for FY 2013 as in FY 2012.

<u>Operation and Maintenance Expenses</u>

For FY 2012, the Company's revenue requirement includes $9,207,845 of VM and I&M O&M expenses as shown on Page 1, Line 3 in Column (a) of the attachment. For purposes of illustration, forecasted VM and I&M O&M expenses on Line 3 are assumed to be the same amount for FY 2012 and FY 2013. In accordance with the Company's last general rate case in R.I.P.U.C. Docket No. 4065, the Company is currently recovering $6,549,368 in base distribution rates associated with its VM and I&M O&M expenses. Because the electric ISR Plan revenue requirement represents the Company's total cost associated with its electric ISR Plan, including VM and I&M O&M expenses, the Company is proposing a one-time credit to base distribution rates for the $6,549,368 currently being recovered through base distribution rates, as shown on Line 5, until such time as base distribution rates are reset as part of a general rate increase. Line 7 therefore represents the net O&M amount related to the ISR Plan, or $2,658,477.

Revenue Requirement
FY 2012 Proposal

Electric Infrastructure Investment

As noted above, Page 2 of the attachment calculates the revenue requirement of incremental capital investment associated with the Company's FY 2012 electric 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 Company's base distribution rates 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 44.

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 Page 2, Lines 1 through 20. The Company proposes that the revenue requirement used for establishing rates effective April 1, 2011 be calculated based upon the Company's projection of electric plant investments to be placed into service during FY 2012, which is comprised of $30,087,700 of 'non-discretionary'-related investments and $18,714,500 of 'discretionary'-related investments, as shown on Lines 4 and 12,

Revenue Requirement
FY 2012 Proposal

respectively. Each year's revenue requirement, as part of the annual electric ISR Plan reconciliation, will be trued up as follows:

- 'Non-discretionary' capital investments will be reconciled to the lesser of the actual 'non-discretionary'-related capital investments placed into service and actual 'non-discretionary' spending levels on a cumulative fiscal year-to-date basis, as demonstrated on Lines 2 through 8.
- 'Discretionary' capital investments will be reconciled to the lesser of the actual 'discretionary'-related capital investments placed into service and the level of approved 'discretionary' spending as per this Docket on a cumulative fiscal year-to-date basis, as demonstrated on Lines 10 through 16.

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 cumulative incremental depreciable amount, as calculated on Line 32. For purposes of the revenue requirement, plant retirements have been estimated at 15.82 percent of the annual capital included in rate base (based on the 2009 percentage of retirements to additions) and have been deducted from the total capital amount included in rate base. The cumulative net depreciable capital included in rate base shown on Page 2, Line 26 equals cumulative capital allowed in rate base less cumulative retirements. Incremental book depreciation expense on Line 54 is

Revenue Requirement
FY 2012 Proposal

computed based on the cumulative net depreciable capital included in rate base, described in the preceding paragraph, at the 3.40 percent composite depreciation rate as approved in R.I.P.U.C. Docket No. 4065, as shown on Line 47. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cumulative cost of removal, as shown on Line 42, is combined with the cumulative incremental depreciable amount from Line 32 to derive the cumulative incremental amount on Line 44 used in determining the rate base upon which the annual electric ISR Plan revenue requirement is calculated.

The cumulative incremental change in rate base on Line 65 includes the cumulative incremental rate base amount from Line 44 adjusted for accumulated depreciation and accumulated deferred tax reserves as shown on Lines 55 and 59, respectively. The deferred tax amount arising from the capital investment on Lines 46 through 59 equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate. The tax depreciation amount assumes that 32 percent of the capital investment will be eligible for immediate deduction on the Company's corresponding FY federal income tax return[8].

The average cumulative change in rate base on Line 68 equals the average year-end

[8] 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. 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 in a subsequent reconciliation filing under the ISR Plan.

Revenue Requirement
FY 2012 Proposal

cumulative change in rate base on Line 65. 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 R.I.P.U.C. in Docket No. 4065) on Line 69 to compute the return and tax portion of the incremental revenue requirement on Line 70. To this, incremental depreciation expense is added on Line 71, as are property taxes on Line 72, 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 74, which is carried forward to Page 1, Line 11 as part of the total electric FY 2012 ISR Plan revenue requirement.

Finally, Page 3 of the attachment represents a calculation of the FY 2013 revenue requirement assuming the same level of electric capital investment as in FY 2012. This calculation is presented for illustrative purposes only in order to demonstrate what the total revenue requirement impact would be in FY 2013, were the level of electric ISR Plan investment to be consistent between FY 2012 and FY 2013.

Exhibit 1

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)
1	**Operation and Maintenance (O&M) Expenses:**	
2		
3	Current Year Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$9,207,845
4		
5	Adjustment to Base Rates to Exclude Current Recovery of VM and I&M O&M Expense	($6,549,368)
6		
7	**O&M Expense Component of Revenue Requirement Subtotal**	**$2,658,477**
8		
9	**Capital Investment:**	
10	Forecasted Revenue Requirement Related to Electric Capital Investment:	
11	Annual Revenue Requirement on FY 2012 Capital Included in Rate Base	$1,063,326
12	Annual Revenue Requirement on FY 2013 Capital Included in Rate Base	$0
13	Subtotal Electric Capital Investment Revenue Requirement	$1,063,326
14		
15	**Capital Investment Component of Revenue Requirement Subtotal**	**$1,063,326**
16		
17	**Total Fiscal Year Revenue Requirement**	**$3,721,803**
18		
19	**Total Incremental Fiscal Year Rate Adjustment**	**$3,721,803**

Line Notes:

3 Column (a) reflects projected Vegetation Management and Inspection & Maintenance O&M expense for FY 2012; Column (b) for FY 2013 is assumed a 2012 for illustrative purposes only
5 Represents allowance in base distribution rates for Vegetation Management and Inspection & Maintenance expense per R.I.P.U.C. Docket No. 4065 until distribution rates are reset as part of a general rate case
7 Line 3 + Line 5
11 Column (a) from Page 2, Line 74, Column (a); Column (b) from Page 2, Line 74, Column (a)
12 Column (b) from Page 3, Line 74, Column (b) for illustrative purposes only
13 Line 11 + Line 12
15 + Line 13
17 Line 7 + Line 15
19 Current Year Line 17 - Prior Year Line 17

Exhibit 1

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

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
1	Capital Additions Allowance				
2	*Non-Discretionary Capital*				
3	Actual Non-Discretionary Capital Additions		1/	$30,087,700	$0
4	Cumulative Actual Non-Discretionary Capital Additions	(Prior Year Line 4 + Current Year Line 3)	1/	$30,087,700	$30,087,700
5					
6	Actual Non-Discretionary Capital Spending		2/	$31,341,500	$0
7	Cumulative Actual Non-Discretionary Capital Spending	(Prior Year Line 7 + Current Year Line 6)	2/	$31,341,500	$31,341,500
8	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	(Lesser of Line 4 or Line 7)	3/	$30,087,700	$30,087,700
9					
10	*Discretionary Capital*				
11	Actual Discretionary Capital Additions		1/	$18,714,500	$0
12	Cumulative Actual Discretionary Capital Additions	(Prior Year Line 12 + Current Year Line 11)	1/	$18,714,500	$18,714,500
13					
14	Approved Discretionary Capital Spending		4/	$27,036,150	$0
15	Cumulative Approved Discretionary Capital Spending	(Prior Year Line 15 + Current Year Line 14)	4/	$27,036,150	$27,036,150
16	Cumulative Allowed Discretionary Capital Included in Rate Base	(Lesser of Line 12 or Line 15)	5/	$18,714,500	$18,714,500
17					
18	Total Cumulative Allowed Capital Included in Rate Base	(Line 8 + Line 16)		$48,802,200	$48,802,200
19	Total Prior Year Cumulative Allowed Capital Included in Rate Base	(Line 18 from prior year)		$0	$48,802,200
20	Total Allowed Capital Included in Rate Base in Current Year	(Line 18 - Line 19)		$48,802,200	$0
21					
22	Depreciable Net Capital Included in Rate Base				
23	Total Allowed Capital Included in Rate Base in Current Year	(From Line 20)		$48,802,200	$0
24	Retirements	(Line 23 * Retirements Rate)	6/	$7,720,508	$0
25	Net Depreciable Capital Included in Rate Base	(Line 23 - Line 24)		$41,081,692	$0
26	Cumulative Net Depreciable Capital Included in Rate Base	(Prior Year Line 26 + Current Year Line 25)		$41,081,692	$41,081,692
27					
28	Change in Net Capital Included in Rate Base				
29	Capital Included in Rate Base	(From Line 23)		$48,802,200	$0
30	Depreciation Expense	(As approved per R.I.P.U.C. Docket No. 4065, excluding general plant)		$38,875,088	$0
31	Incremental Depreciable Amount	(Line 29 - Line 30)		$9,927,112	$0
32	Cumulative Incremental Depreciable Amount	(Prior Year Line 32 + Current Year Line 31)		$9,927,112	$9,927,112
33					
34	Cost of Removal				
35	Cost of Removal - Non-Discretionary			$3,956,000	$0
36	Cumulative Cost of Removal - Non-Discretionary	(Prior Year Line 36 + Current Year Line 35)		$3,956,000	$3,956,000
37					
38	Cost of Removal - Discretionary			$2,623,000	$0
39	Cumulative Cost of Removal - Discretionary	(Prior Year Line 39 + Current Year Line 38)		$2,623,000	$2,623,000
40					
41	Total Cost of Removal	(Line 35 + Line 38)		$6,579,000	$0
42	Total Cumulative Cost of Removal	(Line 36 + Line 39)		$6,579,000	$6,579,000
43					
44	**Cumulative Incremental Amount**	**(Line 32 + Line 42)**		**$16,506,112**	**$16,506,112**
45					
46	Deferred Tax Calculation:				
47	Composite Book Depreciation Rate	(As Approved in R.I.P.U.C. Docket No. 4065)		3.40%	3.40%
48	20 YR MACRS Tax Depreciation Rates			3.75%	7.22%
49	Capital Repairs Deduction			32.00%	32.00%
50					
51	Annual Tax Depreciation	(Line 23 * Line 49) + ((Line 23 - (Line 23 * Line 49)) * Line 48 + Line 41		$23,440,160	$2,395,661
52	Cumulative Tax Depreciation	(Prior Year Line 52 + Current Year Line 51)		$23,440,160	$25,835,821
53					
54	Book Depreciation	(Prior Year Line 26 * Line 47 + Current Year Line 25 * Line 47 * 50%)		$698,389	$1,396,778
55	Cumulative Book Depreciation	(Prior Year Line 55 + Current Year Line 54)		$698,389	$2,095,166
56					
57	Cumulative Book / Tax Timer	(Line 52 - Line 55)		$22,741,771	$23,740,655
58	Effective Tax Rate			35.00%	35.00%
59	Deferred Tax Reserve	(Line 57 * Line 58)		$7,959,620	$8,309,229
60					
61	Rate Base Calculation:				
62	Cumulative Incremental Capital Included in Rate Base	(Line 44)		$16,506,112	$16,506,112
63	Accumulated Depreciation	(Line 55 * -1)		($698,389)	($2,095,166)
64	Deferred Tax Reserve	(Line 59 * -1)		($7,959,620)	($8,309,229)
65	Year End Rate Base	(Sum of Lines 62 through 64)		$7,848,103	$6,101,717
66					
67	Revenue Requirement Calculation:				
68	Average Rate Base	(Line 65/2 for 2012 then, (Prior Year Line 65 + Current Year Line 65)/2)		$3,924,052	$6,974,910
69	Pre-Tax ROR		7/	9.30%	9.30%
70	Return and Taxes	(Line 68 * Line 69)		$364,937	$648,667
71	Book Depreciation	(Line 54)		$698,389	$1,396,778
72	Property Taxes	($0 in Year 1, then Line 26 + Line 42 - Line 54 (all Prior Year) * Property Tax Rate)	8/	$0	$1,336,560
73					
74	**Annual Revenue Requirement**	**(Sum of Lines 70 through 72)**		**$1,063,326**	**$3,382,004**
75	**Incremental Revenue Requirement**	**(Line 74 Current Year - Line 73 Current Year)**		**$1,063,326**	**$2,318,678**

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/ Reflects the lesser of actual capital additions or actual capital spending
4/ Reflects approved capital spending
5/ Reflects the lesser of actual capital additions or approved capital spending
6/ Assumes 15.82% based on 2009 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
7/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax 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%

8/ Property Tax Rate Calculation based on 2009 actual net plant in service and property tax expense applicable to distribution

Plant in Service	1,190,817,229
Accumulated Depreciation	505,832,095
Distribution-Related Net Plant in Service	684,985,134
Distribution-Related Rate Year Property Tax Expense	19,494,858
Distribution-Related Property Tax Rate	2.85%

Exhibit 1

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

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
1	Capital Additions Allowance				
2	*Non-Discretionary Capital*				
3	Actual Non-Discretionary Capital Additions		1/	$0	$30,087,700
4	Cumulative Actual Non-Discretionary Capital Additions	(Prior Year Line 4 + Current Year Line 3)	1/	$0	$60,175,400
5					
6	Actual Non-Discretionary Capital Spending		2/	$0	$31,341,500
7	Cumulative Actual Non-Discretionary Capital Spending	(Prior Year Line 7 + Current Year Line 6)	2/	$0	$62,683,000
8	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	(Lesser of Line 4 or Line 7)	3/	$0	$60,175,400
9					
10	*Discretionary Capital*				
11	Actual Discretionary Capital Additions		1/		$18,714,500
12	Cumulative Actual Discretionary Capital Additions	(Prior Year Line 12 + Current Year Line 11)	1/		$37,429,000
13					
14	Approved Discretionary Capital Spending		4/		$27,036,150
15	Cumulative Approved Discretionary Capital Spending	(Prior Year Line 15 + Current Year Line 14)	4/		$54,072,300
16	Cumulative Allowed Discretionary Capital Included in Rate Base	(Lesser of Line 12 or Line 15)	5/		$37,429,000
17					
18	Total Cumulative Allowed Capital Included in Rate Base	(Line 8 + Line 16)			$97,604,400
19	Total Prior Year Cumulative Allowed Capital Included in Rate Base	(Line 18 from prior year)			$48,802,200
20	Total Allowed Capital Included in Rate Base in Current Year	(Line 18 - Line 19)			$48,802,200
21					
22	Depreciable Net Capital Included in Rate Base				
23	Total Allowed Capital Included in Rate Base in Current Year	(From Line 20)		$0	$48,802,200
24	Retirements	(Line 23 * Retirements Rate)	6/	$0	$7,720,508
25	Net Depreciable Capital Included in Rate Base	(Line 23 - Line 24)		$0	$41,081,692
26	Cumulative Net Depreciable Capital Included in Rate Base	(Prior Year Line 26 + Current Year Line 25)		$0	$41,081,692
27					
28	Change in Net Capital Included in Rate Base				
29	Capital Included in Rate Base	(From Line 23)		$0	$48,802,200
30	Depreciation Expense	(As approved per R.I.P.U.C. Docket No. 4065, excluding general plant)		$0	$38,875,088
31	Incremental Depreciable Amount	(Line 29 - Line 30)		$0	$9,927,112
32	Cumulative Incremental Depreciable Amount	(Prior Year Line 32 + Current Year Line 31)		$0	$9,927,112
33					
34	Cost of Removal				
35	Cost of Removal - Non-Discretionary			$0	$3,956,000
36	Cumulative Cost of Removal - Non-Discretionary	(Prior Year Line 36 + Current Year Line 35)		$0	$3,956,000
37					
38	Cost of Removal - Discretionary			$0	$2,623,000
39	Cumulative Cost of Removal - Discretionary	(Prior Year Line 39 + Current Year Line 38)		$0	$2,623,000
40					
41	Total Cost of Removal	(Line 35 + Line 38)		$0	$6,579,000
42	Total Cumulative Cost of Removal	(Line 36 + Line 39)		$0	$6,579,000
43					
44	**Cumulative Incremental Amount**	**(Line 32 + Line 42)**		**$0**	**$16,506,112**
45					
46	Deferred Tax Calculation:				
47	Composite Book Depreciation Rate	(As Approved in R.I.P.U.C. Docket No. 4065)		3.40%	3.40%
48	20 YR MACRS Tax Depreciation Rates			3.75%	7.22%
49	Capital Repairs Deduction			32.00%	32.00%
50					
51	Annual Tax Depreciation	(Line 23 * Line 49) + ((Line 23 - (Line 23 * Line 49)) * Line 48 + Line 41		$0	$23,440,160
52	Cumulative Tax Depreciation	(Prior Year Line 52 + Current Year Line 51)		$0	$23,440,160
53					
54	Book Depreciation	(Prior Year Line 26 * Line 47 + Current Year Line 25 * Line 47 * 50%)		$0	$698,389
55	Cumulative Book Depreciation	(Prior Year Line 55 + Current Year Line 54)		$0	$698,389
56					
57	Cumulative Book / Tax Timer	(Line 52 - Line 55)		$0	$22,741,771
58	Effective Tax Rate			35.00%	35.00%
59	Deferred Tax Reserve	(Line 57 * Line 58)		$0	$7,959,620
60					
61	Rate Base Calculation:				
62	Cumulative Incremental Capital Included in Rate Base	(Line 44)		$0	$16,506,112
63	Accumulated Depreciation	(Line 55 * -1)		$0	($698,389)
64	Deferred Tax Reserve	(Line 59 * -1)		$0	($7,959,620)
65	Year End Rate Base	(Sum of Lines 62 through 64)		$0	$7,848,103
66					
67	Revenue Requirement Calculation:				
68	Average Rate Base	(Line 65/2 for 2012 then, (Prior Year Line 65 + Current Year Line 65)/2)		$0	$3,924,052
69	Pre-Tax ROR		7/	9.30%	9.30%
70	Return and Taxes	(Line 68 * Line 69)		$0	$364,937
71	Book Depreciation	(Line 54)		$0	$698,389
72	Property Taxes	($0 in Year 1, then Line 26 + Line 42 - Line 54 (all Prior Year) * Property Tax Rate)	8/	$0	$0
73					
74	**Annual Revenue Requirement**	**(Sum of Lines 70 through 72)**		**$0**	**$1,063,326**
75	**Incremental Revenue Requirement**	**(Line 74 Current Year - Line 73 Current Year)**		**$0**	**$1,063,326**

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/ Reflects the lesser of actual capital additions or actual capital spending
4/ Reflects approved capital spending
5/ Reflects the lesser of actual capital additions or approved capital spending
6/ Assumes 15.82% based on 2009 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
7/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax 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%

8/ Property Tax Rate Calculation based on 2009 actual net plant in service and property tax expense applicable to distribution

Plant in Service	1,190,817,229
Accumulated Depreciation	505,832,095
Distribution-Related Net Plant in Service	684,985,134
Distribution-Related Rate Year Property Tax Expense	19,494,858
Distribution-Related Property Tax Rate	2.85%

Section 6

Electric ISR Provision

FY 2012 Electric ISR Plan

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

In accordance with the provisions of *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for electric distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Electric Infrastructure, Safety, and Reliability ("ISR") Provision.

I. Infrastructure Investment Mechanism

A. Definitions

"Actual Capital Investment" shall mean the sum of i) "Discretionary Capital Investment" and ii) "Non-Discretionary Capital Investment", as defined below, plus cost of removal.

"CapEx Factor" shall mean the per-kWh factor for non-demand rate classes designed to recover the Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, based on Forecasted kWh for the Current Year for each non-demand rate class. For demand-based rate classes Rate G-02, Rates G-32/B-32, and Rates G-62/B-62, the CapEx Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for each demand-based rate class.

"CapEx Reconciling Factor" shall mean the per-kWh factor designed to recover or refund the over or under billing of the actual Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

"Cumulative CapEx" shall mean the cumulative Actual Capital Investment for years prior to the Current Year plus Forecasted Capital Investment for the Current Year, recorded since March 31, 2011.

"Cumulative Revenue Requirement" shall mean the return and taxes on year-end cumulative Incremental Rate Base, at a rate equal to the pre-tax weighted average cost of capital as approved by the Commission in the most recent proceeding before the Commission, plus the annual depreciation on Cumulative CapEx, plus the annual municipal property taxes on Cumulative CapEx, beginning in the year following the in service date of electric plant additions.

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"Current Year" shall mean the fiscal year beginning April 1 of the current year and running through March 31 of the subsequent year during which the proposed CapEx Factor and O&M Factor will be in effect.

"Discretionary Capital Investment" shall mean capital investment, other than 'Non-Discretionary' Capital Investment defined below, approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) actual 'discretionary' electric plant in service or b) approved 'discretionary' capital spending for Discretionary Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Forecasted Capital Investment" shall mean the estimated capital investment and cost of removal anticipated to be incurred/recorded by the Company for a given fiscal year associated with electric distribution infrastructure consistent with its capital forecast.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the twelve month period during which the proposed factors, as defined in this ISR Provision, will be in effect.

"Incremental Rate Base" shall mean the Cumulative CapEx adjusted for accumulated depreciation and calculated accumulated deferred taxes on Cumulative CapEx since March 31, 2011.

"Non-Discretionary Capital Investment" shall mean capital investment related to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) 'non-discretionary' electric plant in service or b) actual 'non-discretionary' capital spending for 'Non-Discretionary' Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Rate Base Allocator" shall mean 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.

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B. Recovery Mechanism

The CapEx Factors shall recover the Cumulative Revenue Requirement on Cumulative CapEx as approved by the Commission in the Company's annual Electric ISR Filings. The CapEx Factors shall be applicable for the twelve-month period commencing April 1.

The Company's electric ISR mechanism shall include an annual CapEx Factor reconciliation which will reconcile actual Cumulative Revenue Requirement to actual billed revenue generated from the CapEx Factors for the applicable Current Year. The recovery or refund of the reconciliation amounts (either positive or negative) shall be reflected in CapEx Reconciling Factors. The Company shall submit a filing by August 1 of each year ("Reconciliation Filing"), in which the Company shall propose the CapEx Reconciling Factors to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the CapEx Reconciling Factors shall be subject to reconciliation with amounts billed through the CapEx Reconciling Factors and any difference reflected in future CapEx Reconciling Factors.

II. Operation and Maintenance Mechanism

A. Definitions

"Actual I&M Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with its I&M Program.

"Actual VM Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with vegetation management.

"Forecasted I&M Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with its I&M Program.

"Forecasted VM Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with vegetation management.

"I&M Program" shall mean the Company's Inspection and Maintenance Program and related inspection and maintenance activities.

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"O&M" shall mean expenses of the Company recorded in FERC regulatory accounts 580 through 598 pursuant to FERC's Code of Federal Regulations.

"O&M Allocator" shall mean the percentage of total O&M allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

"O&M Factor" shall mean the per-kWh factor for all rate classes, except for Rates B62/G-62, designed to recover the Forecasted I&M Expense and Forecasted VM Expense for the Current Year, as allocated by the O&M Allocator, based on Forecasted kWh for the Current Year for each rate class. For Rates G-62/B-62, the O&M Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for the rate class.

"O&M Reconciling Factor" shall mean the uniform per-kWh factor designed to recover or refund the under or over billing of Actual I&M Expense and Actual VM Expense for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

B. Recovery Mechanism

The O&M Factor shall recover the sum of the annual Forecasted I&M Expense and Forecasted VM Expense as approved by the Commission in the Company's annual Electric ISR Filings. The O&M Factor shall be applicable for the twelve-month period commencing April 1.

The Company's Electric ISR mechanism shall include an annual O&M Factor reconciliation which will reconcile Actual I&M Expense and Actual VM Expense to actual billed revenue from the O&M Factor for the Current Year. The recovery or refund of the reconciliation amount (either positive or negative) shall be reflected in the O&M Reconciling Factor. In its Reconciliation Filing, the Company shall propose the O&M Reconciling Factor to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the O&M Reconciling Factor shall be subject to reconciliation with amounts billed through the O&M Reconciling Factor and any difference reflected in a future O&M Reconciling Factor.

THE NARRAGANSETT ELECTRIC COMPANY
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III. Annual Electric Infrastructure, Safety, and Maintenance Plan

By January 1 of each year, the Company shall submit to the Commission for review and approval its proposed Electric Infrastructure, Safety, and Reliability Plan ("Electric ISR Plan") for the upcoming Current Year. The Electric ISR Plan shall consist of Forecasted Capital Investment, Forecasted I&M Expense, Forecasted VM Expense, and, if mutually agreed upon by the Division and the Company, the revenue requirement, whether the result of capital investment or O&M expenditures, of any other cost relating to maintaining safe and reliable electric service.

IV. Annual Report on Electric ISR Plan Activities

The Company's August 1 Reconciliation Filing shall include an annual report on the prior fiscal year's activities. In implementing its Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original plans approved by the Commission. In such cases, in the annual report, the Company would include an explanation of any deviations in excess of ten (10) percent above Forecasted Capital Investment, Forecasted I&M Expense, and Forecasted VM Expense. For cost recovery purposes, the Company has the burden to show that any such deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent.

V. Adjustments to Rates

Modifications to the factors contained in this Electric ISR Provision shall be in accordance with a notice filed with the Commission setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

Effective: April 1, 2011

Section 7

Rate Design

FY 2012 Electric ISR Plan

The Narragansett Electric Company
Infrastructure, Safety & Reliability Plan Adjustment & 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)
	Section 1: Adjustments (*							
(1)	VM and I&M Adjustment per kWh	($0.00101)	($0.00110)	($0.00080)	($0.00048)	n/a	($0.00683)	($0.00112)
(2)	VM and I&M Adjustment per kW	n/a	n/a	n/a	n/a	($0.21)	n/a	n/a
(1)	Page 4, Line 8							
(2)	Page 4, Line 10							
	Section 2: Charges							
(3)	O&M Factor per kWh	$0.00141	$0.00150	$0.00120	$0.00064	n/a	$0.00898	$0.00158
(4)	O&M Factor per kW	n/a	n/a	n/a	n/a	$0.36	n/a	n/a
(5)	CapEx kWh Charge	$0.00017	$0.00017	n/a	n/a	n/a	$0.00079	$0.00018
(6)	CapEx kW Charge	n/a	n/a	$0.06	$0.05	$0.03	n/a	n/a
(3)	Page 3, Line 6							
(4)	Page 3, Line 8							
(5)	Page 2, Line 6							
(6)	Page 2, Line 8							
	Section 3: Net Charges							
(7)	Net kWh Charge[7]	$0.00057	$0.00057	$0.00040	$0.00016	n/a	$0.00294	$0.00064
(8)	Net kW Charge[8]	n/a	n/a	$0.06	$0.05	$0.18	n/a	n/a
(7)	Line (1) + Line (3) + Line (5)							
(8)	Line (2) + Line (4) + Line (6)							

(*) Represents a permanent, one-time reduction to base distribution charges

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 FY Capital Investment under ISR Plan	$1,063,326							
(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	$1,063,326	$538,068	$97,513	$174,554	$147,526	$43,017	$57,812	$4,836
(5)	Forecasted kWh - April 2011 through March 2012	7,744,354,117	3,062,956,771	568,740,502	1,290,932,139	2,151,182,017	571,455,232	73,152,759	25,934,696
(6)	Proposed CapEx Factor - kWh charge		$0.00017	$0.00017	n/a	n/a	n/a	$0.00079	$0.00018
(7)	Forecasted kW - April 2011 through March 2012				2,548,372	2,801,427	1,091,075		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$0.06	$0.05	$0.03	n/a	n/a

Line No.
(1) Section 5, Attachment 1, Page 1, Line 15 of the ISR Plan
(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

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)	Current Year Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$9,207,845							
(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	$9,207,845	$4,323,118	$855,372	$1,553,825	$1,381,758	$395,070	$657,535	$41,167
(5)	Forecasted kWh - April 2011 through March 2012	7,744,354,117	3,062,956,771	568,740,502	1,290,932,139	2,151,182,017	571,455,232	73,152,759	25,934,696
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00141	$0.00150	$0.00120	$0.00064	n/a	$0.00898	$0.00158
(7)	Forecasted kW - April 2011 through March 2012						1,091,075		
(8)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		n/a	n/a	n/a	n/a	$0.36	n/a	n/a

Line No.
(1) Section 5, Attachment 1, Page 1, Line 3 of the ISR Plan
(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

Exhibit 1

The Narragansett Electric Co.
Adjustment to Base Distribution Charges for Vegetation Management O&M Expenses and Inspection & Maintenance O&M Expenses[1]

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)	Vegetation Management (VM) O&M Expenses - Rate Year Allowance	$5,081,368							
(2)	Inspection & Maintenance (I&M) O&M Expense - Rate Year Allowance	$1,468,000							
(3)	Total Expense to be Credited	$6,549,368							
(4)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$44,309	$20,803	$4,116	$7,477	$6,649	$1,901	$3,164	$198
(5)	Percentage of Total	100.00%	46.95%	9.29%	16.88%	15.01%	4.29%	7.14%	0.45%
(6)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$6,549,368	$3,074,953	$608,410	$1,105,207	$982,818	$281,006	$467,693	$29,282
(7)	Billing Units (kWhs)		3,037,613,124	552,428,873	1,371,693,627	2,041,538,285	565,377,847	68,381,640	25,935,238
(8)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Adjustment per kWh		($0.00101)	($0.00110)	($0.00080)	($0.00048)	n/a	($0.00683)	($0.00112)
(9)	Billing Units (kW)						1,301,916		
(10)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Adjustment per kW		n/a	n/a	n/a	n/a	($0.21)	n/a	n/a

Line No.
(1) per R.I.P.U.C. 4065 Schedule NG-RLO-2 (C) - 2nd Amended, page 23, line 11
(2) per R.I.P.U.C. 4065 Schedule NG-RLO-2 (C) - 2nd Amended, page 24, line 13
(3) Line 1 + Line 2
(4) per R.I.P.U.C. 4065 Schedule NG-HSG-1 (C) - 2nd Amended, page 4, line 74
(5) Line 4 ÷ Line 4 Total Column
(6) Line 3 Total Column * Line 5
(7) per R.I.P.U.C. 4065 Schedule NG-HSG-6 (C) - 2nd Amended, page 2, line 18; page 4, line 18; page 5, line 12; page 6, line 11; page 7, line 11;page 12, line 20; page 8, line 8
(8) Line 6 ÷ Line 7, truncated to 5 decimal places
(9) per R.I.P.U.C. 4065 Schedule NG-HSG-6 (C) - 2nd Amended, page 7, line 16
(10) Line 6 ÷ Line 9, truncated to 2 decimal places

[1] *Costs are proposed to be recovered as indicated in the Infrastructure Safety and Reliability Provision Tariff*

Section 8

Bill Impacts

FY 2012 Electric ISR Plan

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	$22.65	$11.86	$10.79	$22.72	$11.86	$10.86	$0.07	0.3%	9.0%
240	$41.40	$23.72	$17.68	$41.54	$23.72	$17.82	$0.14	0.3%	15.7%
500	$82.01	$49.42	$32.59	$82.31	$49.42	$32.89	$0.30	0.4%	38.2%
700	$113.26	$69.19	$44.07	$113.67	$69.19	$44.48	$0.41	0.4%	20.2%
950	$152.31	$93.90	$58.41	$152.88	$93.90	$58.98	$0.57	0.4%	14.6%
1,000	$160.12	$98.84	$61.28	$160.72	$98.84	$61.88	$0.60	0.4%	2.3%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:			Proposed Rates - April 1, 2011:		
Customer Charge		$3.75	Customer Charge		$3.75
Transmission Energy Charge (1)	kWh x	$0.01569	Transmission Energy Charge (1)	kWh x	$0.01569
Distribution Energy Charge	kWh x	$0.03521	Distribution Energy Charge (2)	kWh x	$0.03578
Transition Energy Charge	kWh x	$0.00068	Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09489	Standard Offer Charge (3)	kWh x	$0.09489

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00014/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.00101/kWh, Proposed O&M Factor of $0.00141/kWh, and Proposed CapEx Factor of $0.00017/kWh

Note (3): Includes Standard Offer of $0.09115/kWh Standard Offer Adjustment Factor of $0.00134/kWh, Standard OfferService Administrative Cost Factor of $0.00117/kWh, and Renewable Energy Standard Charge of $0.00123/kWh

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	$13.71	$9.88	$3.83	$13.77	$9.88	$3.89	$0.06	0.4%
200	$27.43	$19.77	$7.66	$27.55	$19.77	$7.78	$0.12	0.4%
300	$41.14	$29.65	$11.49	$41.32	$29.65	$11.67	$0.18	0.4%
500	$68.57	$49.42	$19.15	$68.86	$49.42	$19.44	$0.29	0.4%
750	$102.85	$74.13	$28.72	$103.29	$74.13	$29.16	$0.44	0.4%
1000	$137.13	$98.84	$38.29	$137.73	$98.84	$38.89	$0.60	0.4%

Note: Present Rates are rates in effect as of December 31, 2010

<u>Present Rates:</u>

Customer Charge		$0.00
Transmission Energy Charge (1)	kWh x	$0.01569
Distribution Energy Charge	kWh x	$0.01689
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09489

<u>Proposed Rates - April 1, 2011:</u>

Customer Charge		$0.00
Transmission Energy Charge (1)	kWh x	$0.01569
Distribution Energy Charge (2)	kWh x	$0.01746
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09489

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00014/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.00101/kWh, Proposed O&M Factor of $0.00141/kWh, and Proposed CapEx Factor of $0.00017/kWh

Note (3): Includes Standard Offer of $0.09115/kWh Standard Offer Adjustment Factor of $0.00134/kWh, Standard OfferService Administrative Cost Factor of $0.00117/kWh, and Renewable Energy Standard Charge of $0.00123/kWh

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	$46.88	$24.71	$22.17	$47.03	$24.71	$22.32	$0.15	0.3%	35.2%
500	$85.43	$49.42	$36.01	$85.72	$49.42	$36.30	$0.29	0.3%	17.0%
1,000	$162.52	$98.84	$63.68	$163.11	$98.84	$64.27	$0.59	0.4%	19.0%
1,500	$239.62	$148.27	$91.35	$240.51	$148.27	$92.24	$0.89	0.4%	9.8%
2,000	$316.71	$197.69	$119.02	$317.90	$197.69	$120.21	$1.19	0.4%	19.1%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$8.00
Transmission Energy Charge (1)	kWh x	$0.01579
Distribution Energy Charge	kWh x	$0.03316
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09489

Proposed Rates - April 1, 2011:

Customer Charge		$8.00
Transmission Energy Charge (1)	kWh x	$0.01579
Distribution Energy Charge (2)	kWh x	$0.03373
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09489

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00014/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.0011/kWh, Proposed O&M Factor of $0.0015/kWh, and Proposed CapEx Factor of $0.00017/kWh

Note (3): Includes Standard Offer of $0.09115/kWh Standard Offer Adjustment Factor of $0.00134/kWh, Standard OfferService Administrative Cost Factor of $0.00117/kWh, and Renewable Energy Standard Charge of $0.00123/kWh

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	$622.87	$320.58	$302.29	$625.16	$320.58	$304.58	$2.29	0.4%
50	10,000	$1,432.19	$801.46	$630.73	$1,438.86	$801.46	$637.40	$6.67	0.5%
100	20,000	$2,781.05	$1,602.92	$1,178.13	$2,795.00	$1,602.92	$1,192.08	$13.95	0.5%
150	30,000	$4,129.90	$2,404.38	$1,725.52	$4,151.15	$2,404.38	$1,746.77	$21.25	0.5%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00771
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.56
Distribution Energy Charge (3)	kWh x	$0.00811
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.06 per kW

Note (3): Includes Proposed Base Rate Adjustment of $-0.0008/kWh and Proposed O&M Factor of $0.0012/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$821.92	$480.88	$341.04	$825.05	$480.88	$344.17	$3.13	0.4%
50	15,000	$1,929.79	$1,202.19	$727.60	$1,938.54	$1,202.19	$736.35	$8.75	0.5%
100	30,000	$3,776.26	$2,404.38	$1,371.88	$3,794.38	$2,404.38	$1,390.00	$18.12	0.5%
150	45,000	$5,622.71	$3,606.56	$2,016.15	$5,650.21	$3,606.56	$2,043.65	$27.50	0.5%

Note: Present Rates are rates in effect as of December 31, 2010

<u>Present Rates:</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00771
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

<u>Proposed Rates - April 1, 2011:</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.56
Distribution Energy Charge (3)	kWh x	$0.00811
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.06 per kW

Note (3): Includes Proposed Base Rate Adjustment of $-0.0008/kWh and Proposed O&M Factor of $0.0012/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$1,020.96	$641.17	$379.79	$1,024.92	$641.17	$383.75	$3.96	0.4%
50	20,000	$2,427.40	$1,602.92	$824.48	$2,438.23	$1,602.92	$835.31	$10.83	0.4%
100	40,000	$4,771.46	$3,205.83	$1,565.63	$4,793.75	$3,205.83	$1,587.92	$22.29	0.5%
150	60,000	$7,115.52	$4,808.75	$2,306.77	$7,149.27	$4,808.75	$2,340.52	$33.75	0.5%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00771
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.56
Distribution Energy Charge (3)	kWh x	$0.00811
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.06 per kW

Note (3): Includes Proposed Base Rate Adjustment of $-0.0008/kWh and Proposed O&M Factor of $0.0012/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$1,220.00	$801.46	$418.54	$1,224.79	$801.46	$423.33	$4.79	0.4%
50	25,000	$2,925.00	$2,003.65	$921.35	$2,937.92	$2,003.65	$934.27	$12.92	0.4%
100	50,000	$5,766.67	$4,007.29	$1,759.38	$5,793.12	$4,007.29	$1,785.83	$26.45	0.5%
150	75,000	$8,608.34	$6,010.94	$2,597.40	$8,648.34	$6,010.94	$2,637.40	$40.00	0.5%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00771
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.56
Distribution Energy Charge (3)	kWh x	$0.00811
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.06 per kW

Note (3): Includes Proposed Base Rate Adjustment of $-0.0008/kWh and Proposed O&M Factor of $0.0012/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$1,419.04	$961.75	$457.29	$1,424.67	$961.75	$462.92	$5.63	0.4%
50	30,000	$3,422.61	$2,404.38	$1,018.23	$3,437.61	$2,404.38	$1,033.23	$15.00	0.4%
100	60,000	$6,761.88	$4,808.75	$1,953.13	$6,792.50	$4,808.75	$1,983.75	$30.62	0.5%
150	90,000	$10,101.15	$7,213.13	$2,888.02	$10,147.40	$7,213.13	$2,934.27	$46.25	0.5%

Note: Present Rates are rates in effect as of December 31, 2010

<u>Present Rates:</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00771
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

<u>Proposed Rates - April 1, 2011:</u>

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Energy Charge (1)	kWh x	$0.00671
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.56
Distribution Energy Charge (3)	kWh x	$0.00811
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00013/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.06 per kW

Note (3): Includes Proposed Base Rate Adjustment of $-0.0008/kWh and Proposed O&M Factor of $0.0012/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$5,239.58	$3,205.83	$2,033.75	$5,246.25	$3,205.83	$2,040.42	$6.67	0.1%
750	150,000	$18,645.84	$12,021.88	$6,623.96	$18,699.48	$12,021.88	$6,677.60	$53.64	0.3%
1,000	200,000	$24,739.59	$16,029.17	$8,710.42	$24,814.59	$16,029.17	$8,785.42	$75.00	0.3%
1,500	300,000	$36,927.08	$24,043.75	$12,883.33	$37,044.79	$24,043.75	$13,001.04	$117.71	0.3%
2,500	500,000	$61,302.09	$40,072.92	$21,229.17	$61,505.21	$40,072.92	$21,432.29	$203.12	0.3%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW	kW x	$2.00
Distribution Energy Charge	kWh x	$0.00873
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW (2)	kW x	$2.05
Distribution Energy Charge (3)	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.05 per kW
Note (3): Includes Proposed Base Rate Adjustment of $-0.00048/kWh and Proposed O&M Factor of $0.00064/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$7,231.25	$4,808.75	$2,422.50	$7,241.25	$4,808.75	$2,432.50	$10.00	0.1%
750	225,000	$26,114.58	$18,032.81	$8,081.77	$26,180.73	$18,032.81	$8,147.92	$66.15	0.3%
1,000	300,000	$34,697.92	$24,043.75	$10,654.17	$34,789.58	$24,043.75	$10,745.83	$91.66	0.3%
1,500	450,000	$51,864.59	$36,065.63	$15,798.96	$52,007.30	$36,065.63	$15,941.67	$142.71	0.3%
2,500	750,000	$86,197.92	$60,109.38	$26,088.54	$86,442.71	$60,109.38	$26,333.33	$244.79	0.3%

Note: Present Rates are rates in effect as of December 31, 2010

<u>Present Rates:</u>

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW	kW x	$2.00
Distribution Energy Charge	kWh x	$0.00873
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

<u>Proposed Rates - April 1, 2011:</u>

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW (2)	kW x	$2.05
Distribution Energy Charge (3)	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.05 per kW
Note (3): Includes Proposed Base Rate Adjustment of $-0.00048/kWh and Proposed O&M Factor of $0.00064/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$9,222.92	$6,411.67	$2,811.25	$9,236.25	$6,411.67	$2,824.58	$13.33	0.1%
750	300,000	$33,583.33	$24,043.75	$9,539.58	$33,661.98	$24,043.75	$9,618.23	$78.65	0.2%
1,000	400,000	$44,656.25	$32,058.33	$12,597.92	$44,764.58	$32,058.33	$12,706.25	$108.33	0.2%
1,500	600,000	$66,802.08	$48,087.50	$18,714.58	$66,969.79	$48,087.50	$18,882.29	$167.71	0.3%
2,500	1,000,000	$111,093.75	$80,145.83	$30,947.92	$111,380.21	$80,145.83	$31,234.38	$286.46	0.3%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW	kW x	$2.00
Distribution Energy Charge	kWh x	$0.00873
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW (2)	kW x	$2.05
Distribution Energy Charge (3)	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.05 per kW
Note (3): Includes Proposed Base Rate Adjustment of $-0.00048/kWh and Proposed O&M Factor of $0.00064/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$11,214.58	$8,014.58	$3,200.00	$11,231.25	$8,014.58	$3,216.67	$16.67	0.1%
750	375,000	$41,052.09	$30,054.69	$10,997.40	$41,143.23	$30,054.69	$11,088.54	$91.14	0.2%
1,000	500,000	$54,614.59	$40,072.92	$14,541.67	$54,739.59	$40,072.92	$14,666.67	$125.00	0.2%
1,500	750,000	$81,739.59	$60,109.38	$21,630.21	$81,932.30	$60,109.38	$21,822.92	$192.71	0.2%
2,500	1,250,000	$135,989.58	$100,182.29	$35,807.29	$136,317.71	$100,182.29	$36,135.42	$328.13	0.2%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW	kW x	$2.00
Distribution Energy Charge	kWh x	$0.00873
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW (2)	kW x	$2.05
Distribution Energy Charge (3)	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.05 per kW
Note (3): Includes Proposed Base Rate Adjustment of $-0.00048/kWh and Proposed O&M Factor of $0.00064/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$13,206.25	$9,617.50	$3,588.75	$13,226.25	$9,617.50	$3,608.75	$20.00	0.2%
750	450,000	$48,520.84	$36,065.63	$12,455.21	$48,624.48	$36,065.63	$12,558.85	$103.64	0.2%
1,000	600,000	$64,572.92	$48,087.50	$16,485.42	$64,714.58	$48,087.50	$16,627.08	$141.66	0.2%
1,500	900,000	$96,677.08	$72,131.25	$24,545.83	$96,894.79	$72,131.25	$24,763.54	$217.71	0.2%
2,500	1,500,000	$160,885.42	$120,218.75	$40,666.67	$161,255.21	$120,218.75	$41,036.46	$369.79	0.2%

Note: Present Rates are rates in effect as of December 31, 2010

<u>Present Rates:</u>

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW	kW x	$2.00
Distribution Energy Charge	kWh x	$0.00873
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

<u>Proposed Rates - April 1, 2011:</u>

Customer Charge		$750.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge - > 200 kW (2)	kW x	$2.05
Distribution Energy Charge (3)	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh
Note (2): Includes Proposed CapEx kW Charge of $0.05 per kW
Note (3): Includes Proposed Base Rate Adjustment of $-0.00048/kWh and Proposed O&M Factor of $0.00064/kWh

Note (4): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$87,652.08	$48,087.50	$39,564.58	$88,214.58	$48,087.50	$40,127.08	$562.50	0.6%
5,000	1,000,000	$134,281.25	$80,145.83	$54,135.42	$135,218.75	$80,145.83	$55,072.92	$937.50	0.7%
7,500	1,500,000	$192,567.71	$120,218.75	$72,348.96	$193,973.96	$120,218.75	$73,755.21	$1,406.25	0.7%
10,000	2,000,000	$250,854.17	$160,291.67	$90,562.50	$252,729.17	$160,291.67	$92,437.50	$1,875.00	0.7%
20,000	4,000,000	$484,000.00	$320,583.33	$163,416.67	$487,750.00	$320,583.33	$167,166.67	$3,750.00	0.8%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge	kW x	$2.69
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge (2)	kW x	$2.87
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.21 per kW, Proposed O&M kW Charge of $0.36 per kW, and Proposed CapEx kW Charge of $0.03 per kW

Note (3): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	900,000	$114,858.33	$72,131.25	$42,727.08	$115,420.83	$72,131.25	$43,289.58	$562.50	0.5%
5,000	1,500,000	$179,625.00	$120,218.75	$59,406.25	$180,562.50	$120,218.75	$60,343.75	$937.50	0.5%
7,500	2,250,000	$260,583.34	$180,328.13	$80,255.21	$261,989.59	$180,328.13	$81,661.46	$1,406.25	0.5%
10,000	3,000,000	$341,541.67	$240,437.50	$101,104.17	$343,416.67	$240,437.50	$102,979.17	$1,875.00	0.5%
20,000	6,000,000	$665,375.00	$480,875.00	$184,500.00	$669,125.00	$480,875.00	$188,250.00	$3,750.00	0.6%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:			Proposed Rates - April 1, 2011:		
Customer Charge		$17,000.00	Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28	Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575	Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge	kW x	$2.69	Distribution Demand Charge (2)	kW x	$2.87
Distribution Energy Charge	kWh x	$0.00019	Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068	Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694	Standard Offer Charge (3)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.21 per kW, Proposed O&M kW Charge of $0.36 per kW, and Proposed CapEx kW Charge of $0.03 per kW

Note (3): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$142,064.58	$96,175.00	$45,889.58	$142,627.08	$96,175.00	$46,452.08	$562.50	0.4%
5,000	2,000,000	$224,968.75	$160,291.67	$64,677.08	$225,906.25	$160,291.67	$65,614.58	$937.50	0.4%
7,500	3,000,000	$328,598.96	$240,437.50	$88,161.46	$330,005.21	$240,437.50	$89,567.71	$1,406.25	0.4%
10,000	4,000,000	$432,229.16	$320,583.33	$111,645.83	$434,104.16	$320,583.33	$113,520.83	$1,875.00	0.4%
20,000	8,000,000	$846,750.00	$641,166.67	$205,583.33	$850,500.00	$641,166.67	$209,333.33	$3,750.00	0.4%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge	kW x	$2.69
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge (2)	kW x	$2.87
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.21 per kW, Proposed O&M kW Charge of $0.36 per kW, and Proposed CapEx kW Charge of $0.03 per kW

Note (3): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$169,270.83	$120,218.75	$49,052.08	$169,833.33	$120,218.75	$49,614.58	$562.50	0.3%
5,000	2,500,000	$270,312.50	$200,364.58	$69,947.92	$271,250.00	$200,364.58	$70,885.42	$937.50	0.3%
7,500	3,750,000	$396,614.59	$300,546.88	$96,067.71	$398,020.84	$300,546.88	$97,473.96	$1,406.25	0.4%
10,000	5,000,000	$522,916.67	$400,729.17	$122,187.50	$524,791.67	$400,729.17	$124,062.50	$1,875.00	0.4%
20,000	10,000,000	$1,028,125.00	$801,458.33	$226,666.67	$1,031,875.00	$801,458.33	$230,416.67	$3,750.00	0.4%

Note: Present Rates are rates in effect as of December 31, 2010

Present Rates:

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge	kW x	$2.69
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

Proposed Rates - April 1, 2011:

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge (2)	kW x	$2.87
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.21 per kW, Proposed O&M kW Charge of $0.36 per kW, and Proposed CapEx kW Charge of $0.03 per kW

Note (3): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

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	$196,477.08	$144,262.50	$52,214.58	$197,039.58	$144,262.50	$52,777.08	$562.50	0.3%
5,000	3,000,000	$315,656.25	$240,437.50	$75,218.75	$316,593.75	$240,437.50	$76,156.25	$937.50	0.3%
7,500	4,500,000	$464,630.21	$360,656.25	$103,973.96	$466,036.46	$360,656.25	$105,380.21	$1,406.25	0.3%
10,000	6,000,000	$613,604.17	$480,875.00	$132,729.17	$615,479.17	$480,875.00	$134,604.17	$1,875.00	0.3%
20,000	12,000,000	$1,209,500.00	$961,750.00	$247,750.00	$1,213,250.00	$961,750.00	$251,500.00	$3,750.00	0.3%

Note: Present Rates are rates in effect as of December 31, 2010

<u>Present Rates:</u>

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge	kW x	$2.69
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (4)	kWh x	$0.07694

<u>Proposed Rates - April 1, 2011:</u>

Customer Charge		$17,000.00
Transmission Demand Charge	kW x	$2.28
Transmission Energy Charge (1)	kWh x	$0.00575
Distribution Demand Charge (2)	kW x	$2.87
Distribution Energy Charge	kWh x	$0.00019
Transition Energy Charge	kWh x	$0.00068
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.07694

Note (1): Includes Transmission Adjustment Factor of $0.00001/kWh and Transmission Uncollectible Factor of $0.00011/kWh

Note (2): Includes Proposed Base Rate Adjustment of $-0.21 per kW, Proposed O&M kW Charge of $0.36 per kW, and Proposed CapEx kW Charge of $0.03 per kW

Note (3): Includes Standard Offer of $0.07325/kWh, Renewable Energy Standard Charge of $0.00123/kWh, Standard Offer Adjustment Factor of $0.00144/kWh and Standard Offer Service Administrative Cost Factor of $0.00102 /kWh for Standard Offer Service Admin. Cost Factor

PRE-FILED DIRECT TESTIMONY

OF

DAVID E. TUFTS

December 23, 2010

Table of Contents

I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is David E. Tufts, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am Director, Electric Distribution and Generation Revenue Requirements 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 distribution and generation activities in the US, including The Narragansett Electric Company, d/b/a National Grid ("Narragansett" or "Company").

Q. Please describe your educational background and training.

A. In 1983, I earned a Bachelor of Science degree in Accounting, from Stonehill College in Easton, Massachusetts.

Q. Please describe your professional experience?

A. From 1981 through April 2000, I was employed by various subsidiary companies of Eastern Utilities Associates ("EUA"), including EUA Service Corporation which provided accounting, financial, engineering, planning, data processing, and other services to all EUA System companies. I joined EUA's accounting department in 1983. I held positions of increasing responsibility in accounting and was promoted to the position of

Manager of Accounting Services in 1991. The EUA System was acquired by National Grid USA in early 2000, at which time I joined the Service Company. In January 2009, I became Director, Electric Distribution and Generation Revenue Requirements.

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

A. No, I have not previously testified before the Commission, but I have testified before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

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 fiscal year ("FY") 2012 in support of the Company's electric Infrastructure, Safety and Reliability Plan ("ISR Plan"), as described in the testimony of Ms. Catherine McDonough, Mr. Robert Sheridan, and Mr. Daniel Glenning.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following schedule:

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

II. ELECTRIC ISR PLAN REVENUE REQUIREMENT SUMMARY

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

A. As shown in Schedule DET-1, Column (a), the Company's FY 2012 electric ISR Plan revenue requirement consists of two 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 2012 revenue requirement related to O&M expenses, or $9,207,845. Subtracted from this is the Company's current base rate allowance attributable to VM and I&M O&M expenses of $6,549,368 on Line 5, for which the Company is proposing a credit, as described in the testimony of Jeanne A. Lloyd, to permanently reduce base distribution rates until such time as such rates are reset as part of a general rate case. The resulting incremental O&M-related expense component of the electric ISR Plan revenue requirement is $2,658,477, as shown on Line 7.

The revenue requirement associated with the Company's forecasted FY 2012 capital investment in electric utility infrastructure, or $1,063,326, is shown on Line 11 and is detailed on Page 2 of Schedule DET-1. The total annual FY ISR Plan revenue requirement for both O&M expenses and capital investment, net of the credit for current base rate recovery of VM and I&M O&M expenses, is reflected on Line 17 and is equal to the sum of lines 7 and 15. Finally, Line 19 reflects the incremental FY revenue requirement required to deliver the Company's electric ISR Plan and is equal to the current year's revenue requirement less the prior year's revenue requirement from Line 17. Each of these components is discussed in more detail below.

For illustration purposes, Schedule DET-1, Column (b) also provides an illustration of the FY 2013 electric ISR Plan revenue requirement, assuming the same level of capital and O&M investment forecasts for FY 2013 as in FY 2012.

A. Operation and Maintenance Expenses

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

A. For FY 2012, the Company's revenue requirement includes $9,207,845 of VM and I&M O&M expenses as shown on Schedule DET-1, Page 1, Line 3 in Column (a). For purposes of illustration, forecasted VM and I&M O&M expenses on Line 3 are assumed to be the same amount for FY 2012 and FY 2013.

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

A. Yes. In accordance with the Company's last general rate case in R.I.P.U.C. Docket No. 4065, the Company is currently recovering $6,549,368 in base distribution rates associated with its VM and I&M O&M expenses.

Q. How does the Company propose to avoid double recovery of the VM and I&M expenses?

A. Because the electric 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 is proposing a one-time credit to base distribution rates for the $6,549,368 currently being recovered through base distribution rates, as shown on Line 5, until such time as base distribution rates are reset as part of a general rate increase.

Q. What is the incremental revenue requirement associated with the O&M portion of the electric ISR Plan, after taking into consideration the amount reflected in base distribution rates?

A. The incremental revenue requirement related to the VM and I&M O&M expense portion of the electric ISR Plan, after considering the amount currently being recovered in base distribution rates discussed above, is $2,658,477, as shown on Line 7.

B. <u>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, Page 2 of Schedule DET-1 calculates the revenue requirement of incremental net capital investment associated with 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 Company's base distribution rates 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 44.

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 Page 2, Lines 1 through 20. The Company proposes that the revenue requirement used for establishing rates effective April 1, 2011 be calculated based upon the Company's projection of electric plant investments to be placed into service during FY 2012, which is comprised of $30,087,700 of 'non-discretionary'-related investments and $18,714,500 of 'discretionary'-related investments, as shown on Lines 4 and 12, respectively. Each year's revenue requirement, as part of the annual electric ISR Plan reconciliation, will be trued up as follows:

- 'Non-discretionary' capital investments will be reconciled to the lesser of the actual 'non-discretionary'-related capital investments placed into service and actual ‘non-discretionary’ spending levels on a cumulative fiscal year-to-date basis, as demonstrated on Lines 2 through 8.

- ‘Discretionary’ capital investments will be reconciled to the lesser of the actual ‘discretionary’-related capital investments placed into service and the level of approved ‘discretionary’ spending as per this Docket on a cumulative fiscal year-to-date basis, as demonstrated on Lines 10 through 16.

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 cumulative incremental depreciable amount, as calculated on Line 32. Plant retirements have been estimated at 15.82 percent of the annual capital included in rate base (based on the 2009 percentage of retirements to additions) and deducted from the total capital amount included in rate base. The cumulative net depreciable capital included in rate base shown on Schedule DET-1, Page 2, Line 26 equals cumulative capital allowed in rate base less cumulative retirements.

Q. Please describe the calculation of depreciation expense?

A. Incremental book depreciation expense on Line 54 is computed based on the cumulative net depreciable capital included in rate base, described in the preceding paragraph, at the 3.40 percent composite depreciation rate as approved in R.I.P.U.C. Docket No. 4065 on Line 47.

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 cumulative cost of removal, as shown on Line 42, is combined with the cumulative incremental depreciable amount from Line 32 to derive the cumulative incremental amount on Line 44 used in determining the rate base upon which the annual electric ISR Plan revenue requirement is calculated.

Q. Please describe the calculation of deferred tax expense?

A. The cumulative incremental change in rate base on Line 65 includes the cumulative incremental rate base amount from Line 44 adjusted for accumulated depreciation and accumulated deferred tax reserves as shown on Lines 55 and 59, respectively. The deferred tax amount arising from the capital investment on Lines 46 through 59 equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate. The tax depreciation amount assumes that 32 percent of the capital investment will be eligible for immediate deduction on the Company's corresponding FY federal income tax return[1].

Q. Please describe the final steps in the calculation of the FY 2012 electric ISR Plan revenue requirement.

A. The average cumulative change in rate base on Line 68 equals the average year-end cumulative change in rate base on Line 65. 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 R.I.P.U.C. in Docket No. 4065) on Line 69 to compute the return and tax portion of the incremental revenue requirement on Line 70. To this, incremental depreciation expense is added on Line 71, as are property taxes on Line 72, 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 74, which is carried forward to Page 1, Line 11 as part of the total electric FY 2012 ISR Plan revenue requirement.

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[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. 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 post-FY 2011 IRS disallowances in a subsequent reconciliation filing under the ISR Plan.

Q. Please explain Page 3 of Schedule DET-1.

A. Page 3 of Schedule DET-1 represents a calculation of the FY 2013 revenue requirement assuming the same level of electric capital investment as in FY 2012. This calculation is presented for illustrative purposes only in order to demonstrate what the total revenue requirement impact would be in FY 2013, were the level of electric ISR Plan investment to be consistent between FY 2012 and FY 2013.

III. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.

Index of Schedules

Schedule DET-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)
1	**Operation and Maintenance (O&M) Expenses:**	
2		
3	Current Year Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$9,207,845
4		
5	Adjustment to Base Rates to Exclude Current Recovery of VM and I&M O&M Expense	($6,549,368)
6		
7	**O&M Expense Component of Revenue Requirement Subtotal**	**$2,658,477**
8		
9	**Capital Investment:**	
10	Forecasted Revenue Requirement Related to Electric Capital Investment:	
11	Annual Revenue Requirement on FY 2012 Capital Included in Rate Base	$1,063,326
12	Annual Revenue Requirement on FY 2013 Capital Included in Rate Base	$0
13	Subtotal Electric Capital Investment Revenue Requirement	$1,063,326
14		
15	**Capital Investment Component of Revenue Requirement Subtotal**	**$1,063,326**
16		
17	**Total Fiscal Year Revenue Requirement**	**$3,721,803**
18		
19	**Total Incremental Fiscal Year Rate Adjustment**	**$3,721,803**

Line Notes:

3	Column (a) reflects projected Vegetation Management and Inspection & Maintenance O&M expense for FY 2012; Column (b) for FY 2013 is assumed a 2012 for illustrative purposes only
5	Represents allowance in base distribution rates for Vegetation Management and Inspection & Maintenance expense per R.I.P.U.C. Docket No. 4065 until distribution rates are reset as part of a general rate case
7	Line 3 + Line 5
11	Column (a) from Page 2, Line 74, Column (a); Column (b) from Page 2, Line 74, Column (a)
12	Column (b) from Page 3, Line 74, Column (b) for illustrative purposes only
13	Line 11 + Line 12
15	+ Line 13
17	Line 7 + Line 15
19	Current Year Line 17 - Prior Year Line 17

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

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
1	Capital Additions Allowance				
2	*Non-Discretionary Capital*				
3	Actual Non-Discretionary Capital Additions		1/	$30,087,700	$0
4	Cumulative Actual Non-Discretionary Capital Additions	(Prior Year Line 4 + Current Year Line 3)	1/	$30,087,700	$30,087,700
5					
6	Actual Non-Discretionary Capital Spending		2/	$31,341,500	$0
7	Cumulative Actual Non-Discretionary Capital Spending	(Prior Year Line 7 + Current Year Line 6)	2/	$31,341,500	$31,341,500
8	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	(Lesser of Line 4 or Line 7)	3/	$30,087,700	$30,087,700
9					
10	*Discretionary Capital*				
11	Actual Discretionary Capital Additions		1/	$18,714,500	$0
12	Cumulative Actual Discretionary Capital Additions	(Prior Year Line 12 + Current Year Line 11)	1/	$18,714,500	$18,714,500
13					
14	Approved Discretionary Capital Spending		4/	$27,036,150	$0
15	Cumulative Approved Discretionary Capital Spending	(Prior Year Line 15 + Current Year Line 14)	4/	$27,036,150	$27,036,150
16	Cumulative Allowed Discretionary Capital Included in Rate Base	(Lesser of Line 12 or Line 15)	5/	$18,714,500	$18,714,500
17					
18	Total Cumulative Allowed Capital Included in Rate Base	(Line 8 + Line 16)		$48,802,200	$48,802,200
19	Total Prior Year Cumulative Allowed Capital Included in Rate Base	(Line 18 from prior year)		$0	$48,802,200
20	Total Allowed Capital Included in Rate Base in Current Year	(Line 18 - Line 19)		$48,802,200	$0
21					
22	Depreciable Net Capital Included in Rate Base				
23	Total Allowed Capital Included in Rate Base in Current Year	(From Line 20)		$48,802,200	$0
24	Retirements	(Line 23 * Retirements Rate)	6/	$7,720,508	$0
25	Net Depreciable Capital Included in Rate Base	(Line 23 - Line 24)		$41,081,692	$0
26	Cumulative Net Depreciable Capital Included in Rate Base	(Prior Year Line 26 + Current Year Line 25)		$41,081,692	$41,081,692
27					
28	Change in Net Capital Included in Rate Base				
29	Capital Included in Rate Base	(From Line 23)		$48,802,200	$0
30	Depreciation Expense	(As approved per R.I.P.U.C. Docket No. 4065, excluding general plant)		$38,875,088	$0
31	Incremental Depreciable Amount	(Line 29 - Line 30)		$9,927,112	$0
32	Cumulative Incremental Depreciable Amount	(Prior Year Line 32 + Current Year Line 31)		$9,927,112	$9,927,112
33					
34	Cost of Removal				
35	Cost of Removal - Non-Discretionary			$3,956,000	$0
36	Cumulative Cost of Removal - Non-Discretionary	(Prior Year Line 36 + Current Year Line 35)		$3,956,000	$3,956,000
37					
38	Cost of Removal - Discretionary			$2,623,000	$0
39	Cumulative Cost of Removal - Discretionary	(Prior Year Line 39 + Current Year Line 38)		$2,623,000	$2,623,000
40					
41	Total Cost of Removal	(Line 35 + Line 38)		$6,579,000	$0
42	Total Cumulative Cost of Removal	(Line 36 + Line 39)		$6,579,000	$6,579,000
43					
44	**Cumulative Incremental Amount**	**(Line 32 + Line 42)**		**$16,506,112**	**$16,506,112**
45					
46	Deferred Tax Calculation:				
47	Composite Book Depreciation Rate	(As Approved in R.I.P.U.C. Docket No. 4065)		3.40%	3.40%
48	20 YR MACRS Tax Depreciation Rates			3.75%	7.22%
49	Capital Repairs Deduction			32.00%	32.00%
50					
51	Annual Tax Depreciation	(Line 23 * Line 49) + ((Line 23 - (Line 23 * Line 49)) * Line 48 + Line 41		$23,440,160	$2,395,661
52	Cumulative Tax Depreciation	(Prior Year Line 52 + Current Year Line 51)		$23,440,160	$25,835,821
53					
54	Book Depreciation	(Prior Year Line 26 * Line 47 + Current Year Line 25 * Line 47 * 50%)		$698,389	$1,396,778
55	Cumulative Book Depreciation	(Prior Year Line 55 + Current Year Line 54)		$698,389	$2,095,166
56					
57	Cumulative Book / Tax Timer	(Line 52 - Line 55)		$22,741,771	$23,740,655
58	Effective Tax Rate			35.00%	35.00%
59	Deferred Tax Reserve	(Line 57 * Line 58)		$7,959,620	$8,309,229
60					
61	Rate Base Calculation:				
62	Cumulative Incremental Capital Included in Rate Base	(Line 44)		$16,506,112	$16,506,112
63	Accumulated Depreciation	(Line 55 * -1)		($698,389)	($2,095,166)
64	Deferred Tax Reserve	(Line 59 * -1)		($7,959,620)	($8,309,229)
65	Year End Rate Base	(Sum of Lines 62 through 64)		$7,848,103	$6,101,717
66					
67	Revenue Requirement Calculation:				
68	Average Rate Base	(Line 65/2 for 2012 then, (Prior Year Line 65 + Current Year Line 65)/2)		$3,924,052	$6,974,910
69	Pre-Tax ROR		7/	9.30%	9.30%
70	Return and Taxes	(Line 68 * Line 69)		$364,937	$648,667
71	Book Depreciation	(Line 54)		$698,389	$1,396,778
72	Property Taxes	($0 in Year 1, then Line 26 + Line 42 - Line 54 (all Prior Year) * Property Tax Rate)	8/	$0	$1,336,560
73					
74	**Annual Revenue Requirement**	**(Sum of Lines 70 through 72)**		**$1,063,326**	**$3,382,004**
75	**Incremental Revenue Requirement**	**(Line 74 Current Year - Line 73 Current Year)**		**$1,063,326**	**$2,318,678**

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/ Reflects the lesser of actual capital additions or actual capital spending
4/ Reflects approved capital spending
5/ Reflects the lesser of actual capital additions or approved capital spending
6/ Assumes 15.82% based on 2009 retirements as a percent of capital additions; to be replaced with actual retirements for annual reconciliation
7/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

	Ratio	Rate	Weighted Rate	Taxes	Pre-tax 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%

8/ Property Tax Rate Calculation based on 2009 actual net plant in service and property tax expense applicable to distribution

Plant in Service	1,190,817,229
Accumulated Depreciation	505,832,095
Distribution-Related Net Plant in Service	684,985,134
Distribution-Related Rate Year Property Tax Expense	19,494,858
Distribution-Related Property Tax Rate	2.85%

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

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
1	Capital Additions Allowance				
2	*Non-Discretionary Capital*				
3	Actual Non-Discretionary Capital Additions		1/	$0	$30,087,700
4	Cumulative Actual Non-Discretionary Capital Additions	(Prior Year Line 4 + Current Year Line 3)	1/	$0	$60,175,400
5					
6	Actual Non-Discretionary Capital Spending		2/	$0	$31,341,500
7	Cumulative Actual Non-Discretionary Capital Spending	(Prior Year Line 7 + Current Year Line 6)	2/	$0	$62,683,000
8	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	(Lesser of Line 4 or Line 7)	3/	$0	$60,175,400
9					
10	*Discretionary Capital*				
11	Actual Discretionary Capital Additions		1/		$18,714,500
12	Cumulative Actual Discretionary Capital Additions	(Prior Year Line 12 + Current Year Line 11)	1/		$37,429,000
13					
14	Approved Discretionary Capital Spending		4/		$27,036,150
15	Cumulative Approved Discretionary Capital Spending	(Prior Year Line 15 + Current Year Line 14)	4/		$54,072,300
16	Cumulative Allowed Discretionary Capital Included in Rate Base	(Lesser of Line 12 or Line 15)	5/		$37,429,000
17					
18	Total Cumulative Allowed Capital Included in Rate Base	(Line 8 + Line 16)			$97,604,400
19	Total Prior Year Cumulative Allowed Capital Included in Rate Base	(Line 18 from prior year)			$48,802,200
20	Total Allowed Capital Included in Rate Base in Current Year	(Line 18 - Line 19)			$48,802,200
21					
22	Depreciable Net Capital Included in Rate Base				
23	Total Allowed Capital Included in Rate Base in Current Year	(From Line 20)		$0	$48,802,200
24	Retirements	(Line 23 * Retirements Rate)	6/	$0	$7,720,508
25	Net Depreciable Capital Included in Rate Base	(Line 23 - Line 24)		$0	$41,081,692
26	Cumulative Net Depreciable Capital Included in Rate Base	(Prior Year Line 26 + Current Year Line 25)		$0	$41,081,692
27					
28	Change in Net Capital Included in Rate Base				
29	Capital Included in Rate Base	(From Line 23)		$0	$48,802,200
30	Depreciation Expense	(As approved per R.I.P.U.C. Docket No. 4065, excluding general plant)		$0	$38,875,088
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32	Cumulative Incremental Depreciable Amount	(Prior Year Line 32 + Current Year Line 31)		$0	$9,927,112
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34	Cost of Removal				
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42	Total Cumulative Cost of Removal	(Line 36 + Line 39)		$0	$6,579,000
43					
44	**Cumulative Incremental Amount**	**(Line 32 + Line 42)**		**$0**	**$16,506,112**
45					
46	Deferred Tax Calculation:				
47	Composite Book Depreciation Rate	(As Approved in R.I.P.U.C. Docket No. 4065)		3.40%	3.40%
48	20 YR MACRS Tax Depreciation Rates			3.75%	7.22%
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50					
51	Annual Tax Depreciation	(Line 23 * Line 49) + ((Line 23 - (Line 23 * Line 49)) * Line 48 + Line 41		$0	$23,440,160
52	Cumulative Tax Depreciation	(Prior Year Line 52 + Current Year Line 51)		$0	$23,440,160
53					
54	Book Depreciation	(Prior Year Line 26 * Line 47 + Current Year Line 25 * Line 47 * 50%)		$0	$698,389
55	Cumulative Book Depreciation	(Prior Year Line 55 + Current Year Line 54)		$0	$698,389
56					
57	Cumulative Book / Tax Timer	(Line 52 - Line 55)		$0	$22,741,771
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71	Book Depreciation	(Line 54)		$0	$698,389
72	Property Taxes	($0 in Year 1, then Line 26 + Line 42 - Line 54 (all Prior Year) * Property Tax Rate)	8/	$0	$0
73					
74	**Annual Revenue Requirement**	**(Sum of Lines 70 through 72)**		**$0**	**$1,063,326**
75	**Incremental Revenue Requirement**	**(Line 74 Current Year - Line 73 Current Year)**		**$0**	**$1,063,326**

1/ Reflects projected capital additions (plant-in-service); to be replaced with actual capital additions for annual reconciliation
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	100.00%		7.04%	2.26%	9.30%

8/ Property Tax Rate Calculation based on 2009 actual net plant in service and property tax expense applicable to distribution

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Accumulated Depreciation	505,832,095
Distribution-Related Net Plant in Service	684,985,134
Distribution-Related Rate Year Property Tax Expense	19,494,858
Distribution-Related Property Tax Rate	2.85%

PRE-FILED DIRECT TESTIMONY

OF

JEANNE A. LLOYD

December 23, 2010

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's Electricity Distribution and Generation group 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 (1) present a new tariff provision, R.I.P.U.C. No. 2044, Infrastructure, Safety and Reliability ("ISR") Provision; (2) describe the calculation of the ISR factors proposed in this filing; and (3) provide the customer bill impacts of the proposed rate changes.

II. INFRASTRUCTURE, SAFETY AND RELIABILITY PROVISION

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

A. Section 6 of the electric ISR Plan contains the Company's proposed ISR Provision R.I.P.U.C. No. 2044, which describes the process to establish and implement annual rate adjustments designed to recover the costs associated with the Plan. The tariff establishes 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 will propose 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, 2012 ("FY 2012"). The proposed CapEx Factors will be effective for consumption on and after April 1 of each year.

Q. How will the CapEx Factors be designed?

A. First, the cumulative revenue requirement approved by the Commission, which will reflect both an estimate of incremental capital investment for the upcoming fiscal year plus the cumulative prior years' actual incremental capital investment, will be allocated to each of the Company's rate classes based upon a rate base allocator. The rate base allocator will be 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 will be developed from the allocated revenue requirement. For non-demand rate classes, a per kWh charge will be 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 will be per kW charges and will be calculated by dividing the allocated cumulative revenue requirement for each rate class by the forecasted kW billing demand.

Q. Why is the Company proposing to allocate the cumulative revenue requirement using a rate base allocator?

A. The Company is proposing to allocate the cumulative revenue requirement associated with incremental capital investment 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. Will the cumulative revenue requirement, which contains, in part, an estimate of incremental capital investment, and revenue generated from the CapEx Factors be 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 Company will propose O&M Factors for each rate class that will be 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 will the O&M Factors be 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 will be 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 will be the percentage

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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 will be developed for each rate class. For Rates G-62/B-62, the O&M Factor will be in the form of a demand, or per kW, charge and will be 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 will be 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 Company proposing to allocate the I&M and VM expense using a distribution O&M allocator?

A. As with the allocation of the revenue requirement on capital investment, the Company is proposing to allocate O&M expense 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 Company is proposing to use the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last base rate proceeding to spread these costs to each of the rate classes.

Q. For Rates G-02 and B-32/G-32, why is the Company proposing to design the CapEx Factors 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 proposed 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 is the Company proposing to design both the CapEx Factor and the O&M Factor as demand (per kW) charges?

A. Presently, the distribution charges for Rate B-62/G-62 consist only of a demand charge and the Company is proposing to maintain that design with the implementation of the CapEx and O&M Factors.

Q. Will the O&M Factors be subject to reconciliation?

A. Yes. In the Company's annual 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 how the Company has developed the proposed ISR Factors.

A. The proposed ISR factors consist of three separate rate components: CapEx Factors, O&M Factors, and, for implementation on April 1, 2011 only, permanent O&M Credit Factors. Section 7, page 1 of the ISR Plan is a summary of the ISR Factors proposed for April 1, 2011.

<u>CapEx Factors</u>

Q. Please describe the calculation of the CapEx Factors.

A. The CapEx Factors are designed to collect the cumulative revenue requirement related to incremental capital investments through the end of FY 2012. The cumulative revenue requirement of $1,063,326[1] is developed in the testimony of Mr. Tufts. 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 I've described above using forecasted billing units for the period April 1, 2011 through March 31, 2012. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 7, page 2.

<u>O&M Factors</u>

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 2012. As developed in the testimony of Mr. Tufts, these

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[1] See Section 5, Attachment 1, Page 1, Line 15 of the ISR Plan

expenses total $9,207,845[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 I describe above.

<u>O&M Credit Factors</u>

Q. Why is the Company proposing O&M Credit Factors?

A. Distribution rates approved in Docket No. 4065 include rate year allowances for VM and I&M expenses of $5,081,368 and $1,468,000, respectively[3]. The purpose of the proposed O&M Credit Factors is to remove these allowances from distribution rates because they will be entirely recovered through the O&M Factors discussed above. These credit factors represent a permanent one-time reduction to base rates.

Q. Why is the Company proposing to remove the rate year allowances from distribution rates?

A. The Company is proposing to collect all O&M expenses related to I&M and VM activities through the O&M Factors beginning April 1, 2011. Therefore, in order to avoid double recovery of these expenses, it is necessary to decrease base distribution rates to remove the amount of I&M and VM expenses currently reflected in base distribution rates. The Company believes that removing these allowances from base rates will make the ratemaking and reconciliation of these expenses simpler.

[2] See Section 5, Attachment 1, Page 1, Line 3 of the ISR Plan
[3] R.I.P.U.C. Docket No. 4065, Schedule NG -RLO-2 (C) 2nd Amended, Page 23, Line 11 and Page 24, Line 13.

Q. How are the O&M Credit Factors calculated?

A. The Company allocated the Docket No. 4065 rate year I&M and VM expenses to rate classes based on the distribution O&M allocator discussed above.

Next, the Company developed a per kWh credit for each class by dividing the allocated expense by the forecasted kWh as reported in Docket No. 4065[4]. The calculation of the O&M Credit Factors is set forth in the ISR Plan, Section 7, page 4.

Q. In designing the O&M Credit Factors, why did the Company use the kilowatt-hours reported in Docket No. 4065 as opposed to forecasted kilowatt-hours?

A. The Company believes in order to properly remove costs embedded in current distribution rates, the costs must be removed in the same fashion in which they were originally reflected in base distribution rates of the various rate classes, representing the rates. To base the credit factors on current kWh forecasts could result in shifting of costs from one customer class to another.

IV. <u>BILL IMPACTS</u>

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

A. Yes. The monthly bill impacts for each rate class are shown on Section 8 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 $0.30 or 0.4% based upon rates currently in effect.

[4] Schedule NG-HSG-6 (C) - 2nd Amended

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 2011 proposing additional rate changes for April 1, 2011. 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, 2011.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.