Thomas R. Teehan
Senior Counsel

August 1, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4218 - Electric Infrastructure, Safety, and Reliability ("ISR") Plan FY 2012 <u>Annual Report and Reconciliation Filing</u>

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's Annual Report and Reconciliation filing relative to the Fiscal Year ("FY") 2012 Electric Infrastructure, Safety, and Reliability ("ISR") Plan. Pursuant to the provisions of the approved ISR plan and implementing tariffs found at R.I.P.U.C. No. 2044, after the conclusion of the ISR plan year, which runs from April 1 through March 31, the Company is to annually file, by August 1 of each year, the proposed CapEx Reconciling Factors and O&M Reconciling Factor to become effective for the twelve months beginning October 1. The CapEx Reconciling Factors are to reconcile the actual Cumulative Revenue Requirement to the actual billed revenue generated from the CapEx Factors for the applicable plan year. The annual Operations and Maintenance ("O&M") Reconciling Factor is to reconcile actual Inspection & Maintenance ("I&M") program expense and actual Vegetation Management program expense to actual billed revenue from the O&M Factor for the plan year. Additionally, on August 1, the Company is to submit an annual report on the prior fiscal year's ISR activities describing deviations from the original plans approved by the Commission.

This Annual Report and Reconciliation Filing contains the pre-filed testimony of Company witnesses Jennifer Grimsley, William R. Richer, and the direct testimony of Nancy Ribot. Ms. Grimsley testifies regarding the Company's annual report on its ISR activities for FY 2012. She provides the actual spending for the period April 1, 2011 through March 31, 2012 as well as detailed explanations for variations from the approved plan. In addition, Ms Grimsley provides detailed information on the Company's plant in service during that time period. Mr. Richer calculates the reconciliation of the projected revenue requirement to the actual revenue requirement associated with actual FY 2012 capital investments and O&M expense levels. Finally, Ms. Ribot provides the difference between the actual revenues collected through the approved CapEx Factors and O&M Factors and the results of the reconciliations of the actual FY 2012 capital investment

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

revenue requirement and the Operations and Maintenance ("O&M") expense. The CapEx reconciliation is a net over recovery of $65,588 and the O&M reconciliation is a net under recovery of $159,045. Ms. Ribot provides proposed CapEx and O&M Reconciling Factors, for effect October 1, 2012, and presents the proposed tariffs reflecting the new reconciling factors. She also provides the bill impacts associated with those factors.

The impact of the proposed CapEx Reconciling Factors and the proposed O&M Reconciling Factor on a typical residential customer, receiving Standard Offer Service and using 500 kWhs per month, is an increase of $0.01, from $73.41 to $73.42.

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: Docket 4218 Service List
LeoWold, Esq.
Steve Scialabba
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Al Contente

National Grid

The Narragansett Electric Company

FY 2012 Electric Infrastructure, Safety, and
Reliability Plan Reconciliation Filing

August 1, 2012

Submitted to:
Rhode Island Public Utilities Commission
R.I.P.U.C. Docket No. 4218

Submitted by:
nationalgrid

Testimony of
Jennifer L. Grimsley

PRE-FILED DIRECT TESTIMONY

OF

JENNIFER L. GRIMSLEY

August 1, 2012

Table of Contents

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Please describe your educational background and professional experience.

A. I graduated from Washington University in 1986, earning a bachelor's degree in electrical engineering and from Rivier College in 1991, earning a master's degree in business administration. In 1986, I began my engineering career as an associate engineer with Massachusetts Electric Company ("Mass. Electric") in North Andover. In 1993, I was promoted to district engineering manager for Massachusetts Electric in Northampton, and have held various engineering and management positions since that time, including Project Manager for the Reliability Enhancement Program in 2006. In 2007, I became Manager Asset Strategy and Policy and was responsible for developing the strategies to replace distribution assets. I was promoted to Director, Asset Strategy & Policy in 2008. In 2009, I became Executive Advisor to the Chief Operating Officer of Electricity Operations for National Grid. In 2011, I assumed my current role as Director, New England Electric Network Strategy.

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

A. Yes. I testified before this Commission in Docket No. 4307 in support of the Company's fiscal year 2013 ("FY13") Infrastructure, Safety and Reliability ("ISR") Plan.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present the annual report and reconciliation filing related to the fiscal year 2012 ("FY12") Electric ISR Plan approved by the Commission in this docket on March 23, 2011. This filing includes the actual Discretionary and Non-Discretionary Capital investment spending and the actual Vegetation Management (V&M) and Inspection and Maintenance (I&M) expenses for the period April 1, 2011 to March 31, 2012 with explanations for variations from the approved plan. In addition, I also present detailed information on the Company's plant in service during that time period. This information is then utilized by Mr. William Richer, as discussed in his testimony, for his reconciliation of the FY12 Electric ISR revenue requirement with the budgeted amounts for the categories approved by the Commission. The specific FY12

Electric ISR spending and plant in service additions by categories is set forth in Attachment-JLG-1 attached to this testimony.

III. ACTUAL CAPITAL SPENDING

Q. Please summarize the Company's actual capital spending for FY12 for the Electric ISR Plan.

A. As set forth in Table 1 in Attachment-JLG-1, overall, for FY12, the Company spent $50.5 million for capital investment under the Electric ISR Plan. This amount was $7.9 million under budget against an annual approved budget of $58.4 million. The $7.9 million variance was comprised of $5.2 million in the non-discretionary capital category (statutory/regulatory and damage/failure) primarily driven by economic conditions leading to a reduction in the amount of new business and public requirement projects in comparison to historical projections. The additional $2.6 million variance below budget was in the discretionary capital category (asset condition, non-infrastructure and system capacity and performance) and was primarily driven by projects in the system capacity and performance category which were delayed or came in under budget.

As noted previously in this docket, the Company stated that while implementing the ISR Plan in any fiscal year, the Company will encounter circumstances during the year that will require reasonable deviations from the original ISR Plan approved by the Commission. This has been the case and throughout the year, the Company has kept the Division and Commission apprised of these deviations and variances and provided explanations for them in its quarterly report filings. For example, as discussed in more detail below, delays in acquiring land, permitting and licensing for substation projects required the Company to reallocate resources and delay budgeted projects, which contributed to a portion of the variance below budget for the FY12 Electric ISR program.

Q. What were the primary drivers for the Electric ISR capital variance below budget in FY12?

A. The major drivers for the Electric ISR capital variance for FY12 were in the Non-Discretionary Statutory/Regulatory category and the Discretionary System Capacity and Performance category. As shown on Table 2 in Attachment-JLG-1, the major variances for the Statutory/Regulatory category were the result of a significant reduction in the amount of new business and public requirement projects due primarily to the economy in Rhode Island in FY12. These reductions resulted in a variance below budget of $8.6 million.

In addition, as shown on Table 6 in Attachment-JLG-1, the $1.9 million variance below budget for the Discretionary System Capacity and Performance category was the result of the delay of a number of projects for FY12. Among those projects were variances below budget of $1.2 million for substation work for Coventry and Hopkinton that were delayed due to permitting; a variance below budget of $500,000 due to a delay in purchasing land in West Warwick; an additional engineering review that was necessary for the Johnston substation which resulted in a variance below budget of $578,000; and a $600,000 delay in the engineering and design of the Energy Management System/Remote terminal Unit program. Offsetting a portion of the variances below budget from the projects listed above was the purchase of land for the Newport Substation project which was accelerated and purchased in FY12.

Q. Were there any capital budget categories where spending exceeded the budget in the FY12 Electric ISR and what were the primary drivers?

A. The Non-Discretionary Damage/Failure budget category exceeded its budget by $3.2 million in FY12. This variance was for major storms, as shown on Table 3 in Attachment-JLG-1 and was primarily driven by Tropical Storm Irene in August and September of 2011 and the October 2011 Snow Event.

IV. PLANT IN SERVICE

Q. Please provide an overview of the plant in service for FY12.

A. As shown on Table 8 in Attachment-JLG-1, the Company placed $51.6 million of plant in service, which was $2.8 million above the forecast for plant in service of approximately $49 million for FY12. As explained in the testimony of Mr. Richer, it is Plant in Service amounts rather than capital spending amounts that are used to calculate the revenue requirement included in the ISR factor.

V. O&M SPENDING

Q. Please summarize the Company's actual O & M spending for the FY12 Electric ISR Plan.

A. As shown on Table 9 in Attachment-JLG-1, the total Vegetation Management spending for FY12 was $7.8 million against an approved budget of $8.1 million. In addition, as shown on Table 10, the overall I&M spending was approximately $1.5 million, approximately $300,000 or 29% higher than the original FY12 Electric ISR Plan budget. This variance was primarily due to advancing a portion of the feeder hardening work from FY13 to FY12. While this work was managed within the overall capital budget, as discussed in Section II of Attachment-JLG-1, it did exceed the O&M budget, as discussed in Section V of Attachment-JLG-1.

VI. RELIABILITY

Q. Please summarize the results of the Company's reliability performance for FY12, as previously provided in the annual Distribution System Performance Report.

A. Table 11 in Attachment-JLG-1 presents the Company's Reliability Performance for calendar year 2011 ("CY11"). As shown, the Company met both its SAIFI and SAIDI performance metrics in CY11, with SAIFI of 0.86, against a target of 1.05, and SAIDI of 60.7 minutes, against a target of 71.9 minutes. Overall, the Company's performance has shown a downward (improving) trend over the past several years with major event days excluded. For CY11, the Company had five events, comprised of 10 days, which were characterized as major event days, the most significant being Tropical Storm Irene which led to the interruption of over 300,000 customers starting on August 28, 2011. Table 12 and Table 13 provide specific detail of customers interrupted and daily SAIDI for each of the five events, as well as overall reliability performance measures.

Q. Does this conclude this testimony?

A. Yes, it does.

List of Attachments

Attachment JLG-1

ATTACHMENT-JLG-1

FY12 ELECTRIC

INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN

ANNUAL REPORT AND RECONCILIATION

Electric Infrastructure, Safety and Reliability Plan

FY12 Annual Report and Reconciliation

Executive Summary

In accordance with tariff, R.I.P.U.C. No. 2044, Sheets 1- 4, The Narragansett Electric Company d/b/a/ National Grid ("the Company") submits this annual report and reconciliation filing for the fiscal year 2012 ("FY12") Infrastructure, Safety and Reliability ("ISR") Plan approved by the Commission in this docket. This filing also provides the actual discretionary and non-discretionary capital investment spending and the actual Vegetation Management (V&M) and Inspection and Maintenance (I&M) expenses for the period April 1, 2011 to March 31, 2012 and compares them to the budgeted amounts for these categories approved by the Commission. Also included are details on the Company's plant in service during that time period. Finally, this filing also includes the specific information that was originally to be provided on June 30, 2012 in the Distribution System Performance Report. However, after discussions with the Division, it was mutually agreed that since the information underlying the Distribution System Performance Report and this ISR Annual Reconciliation filing was duplicative, the Company would provide the information from the Distribution System Performance update as part of its ISR reconciliation annually.

For FY12, the Company's capital Electric ISR spending was $50.5 million. Section I below provides a summary overview of the actual non-discretionary and discretionary capital investment. Section II provides an explanation of any capital investment variance by category to the budget approved in Docket No. 4218. A summary overview of the plant placed in service in FY12 compared to the FY12 ISR budget is set forth in Section III. Section IV provides a breakdown of the $7.9 million of Vegetation Management expenses and an explanation of the variance for these expenses with the approved budget of $8.1 million. Section V provides a similar breakdown for the $1.5 million of I&M expenses and an explanation of the variance for these expenses with the approved budget of $1.1M. The reliability performance metrics that previously had been reported in the Distribution System Performance Report are addressed in Section VI of this filing.

I FY12 ACTUAL RESULTS

1. Capital Spending Overview

As set forth in Table 1 below, overall, for FY12, the Company spent $50.5 million for capital investment under the Electric ISR Plan. This amount was $7.9 million under budget against an annual approved budget of $58.4 million. This $7.9 million variance is comprised of $5.2 million of non-discretionary capital (statutory/regulatory and damage/failure) spending which was primarily driven by economic conditions leading to a reduction in the amount of new business and public requirement projects in comparison to historical projections. An additional variance of $2.6 million of discretionary capital (asset condition, non-infrastructure and system capacity and performance) spending was primarily driven by projects in the system capacity and performance spending categories which were delayed or came in under budget. The key drivers and variances by category of capital are as discussed in greater detail in Section 2 below.

Table 1

US Electricity Distribution - Rhode Island
Capital Spending by Spending Rationale
FY 12 thru March 31, 2012

		FY12 Total	
in $000's	**Budget**	**Actual**	**Variance**
NON-DISCRETIONARY INVESTMENT			
Statutory/Regulatory	21,637	13,075	(8,562)
Damage/Failure	9,705	12,993	3,288
Subtotal	*31,342*	*26,068*	(5,273)
DISCRETIONARY INVESTMENT			
Asset Condition	10,937	10,320	(617)
Non-Infrastructure	278	149	(129)
System Capacity & Performance	15,821	13,995	(1,826)
Subtotal	*27,036*	*24,424*	(2,612)
Total Capital Investment in Systems[1]	**58,378**	**50,492**	**(7,885)**

[1] For consistency, "Variances" in this Attachment shown in parentheses ( ) reflect an under spend.

II. ACTUAL SPENDING BY CATEGORY

1. Non- Discretionary Capital Expenditures Compared to Budget for FY12

The key drivers for the variances by major categories for non-discretionary capital spending compared to the budget for FY12 are listed below.

a. *Statutory/Regulatory - $8.6 million under budget for FY12*

The major variance for the Statutory/Regulatory category was the result of a significant reduction in the amount of new business and public requirement projects in comparison to historical projections due primarily to the economy in Rhode Island in FY12. As shown in Table 2 below new business and public requirements capital spending were the major contributors to this category's variance below budget of $8.6 million. Detailed budget and actual spending by budget classification for the Statutory/Regulatory category is shown in Table 2.

Table 2

Spending Rationale	Budget Classification	FY12 Budget ($)	FY12 Actual Spending ($)	Variance (Budget – Actual)/ Budget %
Statutory/Regulatory	3rd Party Attachments	641,000	463,848	(28%)
	Land and Land Rights - Distribution	321,000	185,520	(42%)
	Meters – Distribution	1,803,000	1,496,949	(17%)
	New Business - Commercial	6,157,500	3,390,872	(45%)
	New Business - Residential	3,917,000	2,833,259	(28%)
	Outdoor Lighting - Capital	1,018,000	495,328	(51%)
	Public Requirements	3,968,000	1,134,582	(71%)
	Transformers and Related Equipment	3,811,000	3,074,796	(19%)
	Statutory/Regulatory Subtotal	**21,636,500**	**13,075,155**	**(40%)**

b. ***Damage/Failure - $3.3 million over budget for FY12***

In contrast, the Damage/Failure capital spend for FY12 was significantly higher than budget due primarily to the storm activity associated with the costs[2] of restoration following Tropical Storm Irene in August and September of 2011 and the October 2011 Snow Event. Detailed budget and actual spending by budget classification for the Damage/Failure category is shown in Table 3.

Table 3

Spending Rationale	**Budget Classification**	**FY12 Budget ($)**	**FY12 Actual Spending ($)**	**Variance (Budget – Actual)/ Budget %**
Damage/Failure	Damage/Failure	9,365,000	9,573,923	4%
	Major Storms - Dist	460,000	3,418,936	643%
	Damage/Failure Subtotal	**9,705,000**	**12,992,859**	**34%**

2. Discretionary Capital Expenditures Compared to Budget for FY12

a. ***Asset Condition - $0.6 million under budget for FY12***

Overall spending was less than budget in the Asset Condition category for FY12 primarily driven by the variance on the flood damage and avoidance mitigation projects. The dollars budgeted in the FY12 ISR for the flood damage avoidance engineering studies were to study the flood potential, to evaluate alternative solutions for those substations that were impacted by the flooding in Rhode Island in 2010, and to begin to progress any mitigation work that resulted from these engineering reviews. Where the studies concern flood potential and flood mitigation for numerous stations, that work is charged to the appropriate O&M accounts and those costs are not included in the ISR. On the other hand, where the studies are specific to a capital solution at a specific substation, such as for engineering and design, those costs will be included in the ISR. There is typically

[2] Capital replacement work during major storm events is not recovered through the storm fund.

a lag in when these costs appear in the specific project accounts, as they are initially charged to a Preliminary Survey & Investigation (PS&I) account and later transferred to the capital project. The bulk of the costs included in the FY12 ISR were to progress mitigation measures to retire the Westerly substation with the installation of new facilities in Hopkinton. The FY12 proposal for $1.2 million included aggressive assumptions on permitting and licensing for the work required to retire the Westerly substation, and delays have been experienced. Requests from local municipalities to review additional alternatives for Hopkinton were received and have been resolved. Siting and permitting activities required for the construction of the new substation and the retirement of Westerly are well underway, and the Company expects to close on the required property for the new substation in February of 2013.

The Asset Replacement Budget Classification had the following deferrals:

- The Remote Terminal Unit (RTU) replacement program ($300,000) was delayed to FY14. The decision to delay this program until FY14 was based on the current condition of the remaining three RTUs in the program. The Company determined these units could be kept in service until FY14.

- Similarly, the Nasonville Metalclad project was also deferred from FY12 ($300,000) after a more detailed Company review indicated that the condition of the switchgear did not warrant replacement at this time.

Offsetting these deferrals in the Asset Replacement Budget Classification was the purchase of a mobile substation replacement (approximately $700,000) which the Company decided to accelerate and purchase in FY12. By acquiring this additional mobile substation, the Company will reduce constraints on this equipment and be able to work more projects in parallel. This in turn, contributes to efficiency and timeliness for staying on schedule with more projects.

In addition, approximately $500,000 was spent in FY12 for engineering and design work for the Inspection and Maintenance Program. This work was not included in the original budget, but needed to be completed to perform the proposed I&M construction in the FY13 plan.

Detailed budget and actual spending by budget classification for the Asset Condition category is shown in Table 4.

Table 4

Spending Rationale	Budget Classification	FY12 Budget ($)	FY12 Actual Spending ($)	Variance (Budget – Actual)/ Budget %
Asset Condition	Woonsocket & Related	5,005,000	4,864,807	(3%)
	Asset Replacement	4,732,050	5,455,292	15%
	Flood Damage Avoidance Engineering Studies	1,200,000	--	(100%)
	Asset Condition Subtotal	**10,937,050**	**10,320,099**	**(6%)**

b. ***Non-Infrastructure - $0.1million under budget for FY12***

As shown in Table 5 overall spending in the non-infrastructure category for FY12 was lower primarily due to a reduced demand for general equipment. It should be noted that the Non-Infrastructure category contains several administrative accounting items. First, this category contains a positive balance of approximately $500,000 for Capital Allocations remaining in the Capital Overhead Clearing Project. This project is used to accumulate capital charges which are then allocated over the course of the year. This method is used for personnel, such as engineers and analysts, who work on many smaller capital projects to charge their time. The intent is to clear this project to zero each year and any under or over clearing will be carried over into the following year and allocated accordingly. Also in the non-infrastructure category there is a negative balance of approximately $400,000 for projects or work orders that were cancelled and transferred to expense and other accounting adjustments.

Table 5

Spending Rationale	**Budget Classification**	**FY12 Budget ($)**	**FY12 Actual Spending ($)**	**Variance (Budget – Actual)/ Budget %**
Non-Infrastructure	General Equipment	278,000	148,707	(47%)
	Non-Infrastructure Subtotal	**278,000**	**148,707**	**(47%)**

c. ***System Capacity and Performance - $1.9 million under budget for FY12***

Overall spending was lower than budget in the System Capacity and Performance category for FY12 primarily driven by the following projects. Detailed budget and actual spending by budget classification for the System Capacity and Performance category is shown in Table 6.

Coventry & Hopkinton & Related

- The variance below budget of approximately $1.2 million for the substation work for the Coventry and Hopkinton projects was driven by the longer than projected permitting timeframe which resulted in delaying both of these projects in FY12.

Newport & Related:

- The purchase of land for the Newport Substation project was accelerated and the land was purchased in FY12, accounting for a variance of approximately $1.2 million greater than budget.

West Warwick & Related

- The variance below budget of approximately $500,000 for West Warwick was due to a delay in purchasing land. The Company is in the process of completing a Purchase and Sale agreement and expects this project to move forward in FY13.

Load Relief

In the Load Relief Budget Classification, the following projects were the primary drivers in the variances below budget:

- Load Relief to the 9J3, Brown Street project was deferred to FY13 to accommodate and coordinate scheduling pole sets with the Telephone Company resulting in a variance below budget of approximately $300,000.

- The schedule for the Johnston Substation 12.47kV expansion required additional review time and only preliminary engineering for this project was started in FY12 resulting a variance below budget of approximately $578,000.

- The Company was able to achieve cost efficiencies for the overloaded distribution transformer work which was completed by the end of the fiscal year with more units replaced than originally forecasted, however, the total cost for this work was under budget by approximately $200,000 due to lower installed unit costs than had been estimated.

- Balancing out a significant portion of the variances below budget on the above projects, the Company spent approximately $500,000 more than the budgeted amount on the project to relocate the 23kV 2227 and 2230 lines. This variance was driven primarily by unexpected foundation costs along the route, due to large boulders and shallow bedrock; the need for additional pole and crossarm replacements; and the need for more complex coordination than anticipated on safety oversight and training as this project was progressing along a corridor with an active transmission project, the RI Reliability Project, a nearby a high pressure gas main. This project is forecasted to exceed the FY13 budget amount of $350,000 by approximately $100,000 for these reasons.

- In addition the Company spent approximately $800,000 on a distribution load relief project for the Newport area which was a carryover from FY11, and not budgeted in FY12.

Reliability

In the Reliability Budget Classification, the following projects accounted for the variance below budget:

- The Energy Management System (EMS)/ Remote Terminal Unit (RTU) project was delayed due to constraints in project management, engineering, and design resources resulting in a variance below budget of $600,000 in FY12.

- The Reliability Blanket project was under budget by approximately $600,000 at the end of the fiscal year driven by a lower volume of blanket work identified and available and storm restoration impact on internal resource availability to perform overhead capital work

- Similar to the overloaded transformer project, the potted porcelain cutout replacements were also completed by the end of the fiscal year with more units replaced than originally forecasted. The total costs were under budget by approximately $600,000 due to lower installed unit costs gained by efficiencies in scheduling work requiring customer outages.

- Offsetting a portion of the variance in the Reliability Blanket project, and keeping within the overall reliability Budget Classification was an additional $200,000 for four additional reclosers installed for reliability benefits on specific feeders.

Reliability – Feeder Hardening

- In the Reliability – Feeder Hardening Budget Classification, the Company completed approximately 225 miles of Feeder Hardening in FY12. In addition, approximately 75 miles out of the 130 miles of the FY13 Feeder Hardening was started in the 4th quarter of FY12, with construction on 56 of these miles completed in FY12. This work was accelerated as external resources were available and able to be efficiently mobilized without exceeding the total discretionary capital budget for System Capacity and Performance. This FY13 Feeder Hardening work was agreed to with the Division in the FY13 ISR filed with the Commission on December 29, 2012. Total capital spending on Feeder Hardening in FY12, including the FY13 miles worked in FY12, was $2.6 million against a FY12 budget of $2.4 million. The Company does not expect to exceed the FY13 capital budget for Feeder Hardening, with total projected capital spending on

Feeder Hardening for FY13 forecasted to be $1.0 million against a budget of $1.5 million.

Table 6

Spending Rationale	**Budget Classification**	**FY12 Budget ($)**	**FY12 Actual Spending ($)**	**Variance (Budget – Actual)/ Budget %**
System Capacity and Performance	Coventry & Related	1,000,000	552,632	(45%)
	Hopkinton & Related	800,000	75,287	(91%)
	Newport & Related	720,000	1,962,765	173%
	West Warwick & Related	520,000	17,094	(97%)
	Load Relief	6,492,920	6,228,961	(4%)
	Reliability	3,938,180	2,554,262	(35%)
	Reliability – Feeder Hardening	2,350,000	2,564,239	9%
	System Capacity and Performance Subtotal	**15,821,100**	**13,955,241**	**(12%)**

d. *FY12 Work Plan Accomplishments*

Table 7 below provides actual work plan accomplishments against the goals of the FY12 work plan.

Table 7

Actual Work Plan Accomplishments for FY12

Program Type	FY12 Goals	FY12 Accomplishments	% Goal Complete
Feeder Hardening mileage	225 miles	281 miles	124%
Recloser installation counts	3	7	233%
Count of feeder load relief efforts	6	6	100%
Distribution transformer upgrades	455	576	120%
Cutouts replaced	3,100	4,617	149%

III FY12 Capital for Plant Investment Placed in Service

In addition to providing the capital spending for FY12, the Company is also required as part of its reconciliation filing to submit the annual capital spending for Plant Additions that were placed in service during the fiscal year. As shown in Table 8 below, for FY12, $51.6 million was placed in service, which was $2.8 million above the forecast for plant in service for FY12.

Table 8

US Electricity Distribution - Rhode Island
Plant Additions by Spending Rationale
FY 12 thru March 31, 2012

		FY12 Total	
in $000's	**FY12 Annual ISR Forecast**	**FY12 Actual in Service**	**% of Forecast Plant in Service**
NON-DISCRETIONARY INVESTMENT			
Statutory/Regulatory	20,612	15,144	73%
Damage/Failure	9,475	13,628	144%
Subtotal	*30,087*	*28,772*	96%
DISCRETIONARY INVESTMENT			
Asset Condition	5,805	13,019	224%
Non-Infrastructure	278	60	22%
System Capacity & Performance	12,632	9,799	78%
Subtotal	*18,715*	*22,878*	122%
Total Capital Investment in Systems	**48,802**	**51,650**	**106%**

IV. FY12 Vegetation Management

As shown below in Table 9, for FY12, overall the total vegetation management spending for FY12 was $7.8 million with an approved budget of $8.1 million. However, the Company did complete 100 percent of the annual distribution mileage cycle trimming goal with an associated spend of 103 percent of the FY12 cycle trimming budget. This increase above the budget was primarily driven by work on the 3302 sub-transmission line from Quonset Point to Narragansett.

Table 9

US Electricity Distribution - Rhode Island
O&M Vegetation Management Expenditures
FY12 thru March 31,2012

in $000	**FY2012 Total**		
	Budget	Actual	Variance
Vegetation Management			
Cycle Trimming	5,300	5,451	151
Hazard Tree	750	806	56
SubT (on and off road)	267	71	(196)
Police Detail	491	461	(30)
Core Crew (all other activities)	1,261	1,031	(230)
Total Veg Management	**8,069**	**7,820**	**(249)**

	FY12 Goal	FYTD Complete	**Annual % Complete vs FY 12** Goal
Distribution Mileage Trimming	1,416	1,416	100%

V. FY12 Inspection and Maintenance

As shown in Table 10 below, for FY12, 73 percent of the annual inspection goal was completed with an associated spend of 103 percent of the FY12 inspection budget. Costs to inspect the overhead distribution system were higher than estimated. Also, as noted above, storm activity in Rhode Island in FY12 had an impact on resource availability to perform this work. Specifically, the need to redeploy resources for the restoration effort for Tropical Storm Irene and the October snow event impacted the level of the inspection work plan. This deferral of inspections is not expected to have an impact on the proposed level of repairs to be performed as there are sufficient inspections completed to support the funding for repairs, both capital and O&M, in the FY13 ISR[3].

With respect to cutout replacements, the number of replacements exceeded the target by 50 percent (4,601 vs. 3,100), and the program was under budget due to lower installed unit costs gained by efficiencies in scheduling work requiring customer outages.

As discussed in the System Capacity and Performance section above, approximately 75 miles out of the 130 miles of the FY13 Feeder Hardening was started in the 4th quarter of FY12. Total expense spending on Feeder Hardening in FY12, including the FY13 miles worked in FY12, was $1.2 million against a FY12 budget of $822,500. While capital costs were within 10 percent of the FY12 capital budget for Feeder Hardening, expense costs for Feeder Hardening were 48 percent higher than budgeted due to this additional work, and a higher than anticipated percentage of expense related repairs. The Company does not expect to exceed the FY13 expense budget for Feeder Hardening, with total projected expense spending on Feeder Hardening for FY13 forecasted for $350,000 against a budget of $530,000.

Overall, the Inspection and Maintenance program cost was $1.5 million, approximately $300,000 higher than the original ISR budget.

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[3] The FY 2013 funding level for repairs resulting from inspections was reduced by half in the negotiations with the Division, as a result of Greg Booth’s recommendation.

Table 10

US Electricity Distribution - Rhode Island
Inspection and Maintenance Program Progress Update
FY12 thru March 31,2012

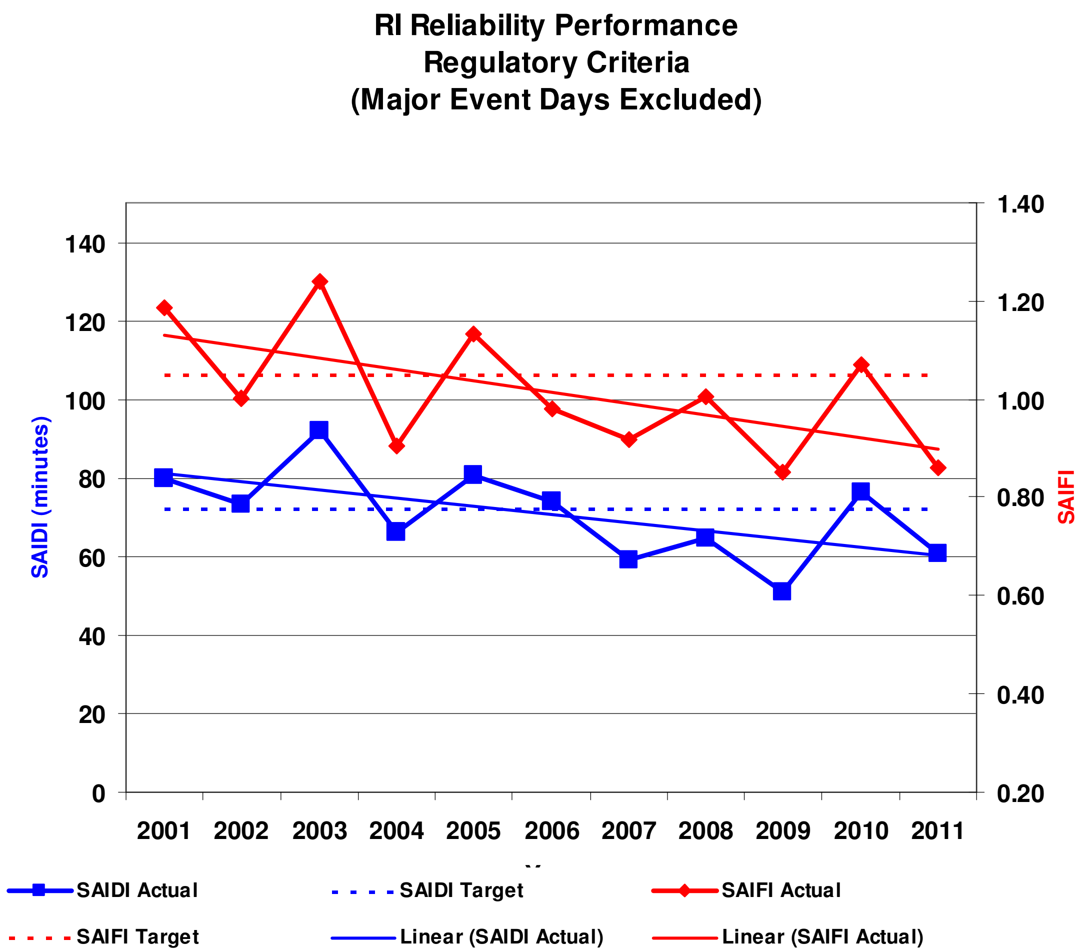
in $000	**FY2012 Total**		
	Budget	**Actual**	**Variance**
Potted Porcelain Cutouts	171	99	(58%)
Feeder Hardening	823	1,217	148%
Subtotal	994	1,316	132%
Inspections - Related Costs	145	150	103%
Total O&M Expenses	**1,139**	**1,466**	**129%**

	FY12 Goal	**FYTD Complete**	**Annual % Complete vs FY 12 Goal**
RI Distribution Overhead Structures Inspected	48,567	35,677	73%

VI. Reliability Performance

The Company met both its SAIFI and SAIDI performance metrics in Calendar year 2011, with SAIFI of 0.86, against a target of 1.05, and SAIDI of 60.7 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days[4]. A comparison of reliability performance in calendar year 2011 ("CY11") relative to that of previous years is shown in Table 11. The Company's performance has shown a downward (improving) trend over the past several years with major event days excluded.

Table 11



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[4] Major Event Days ("MED") is defined as a day in which the daily system System Average Interruption Duration Index ("SAIDI") exceeds a MED threshold value (4.43 minutes for 2011). For purposes of calculating daily system SAIDI any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.

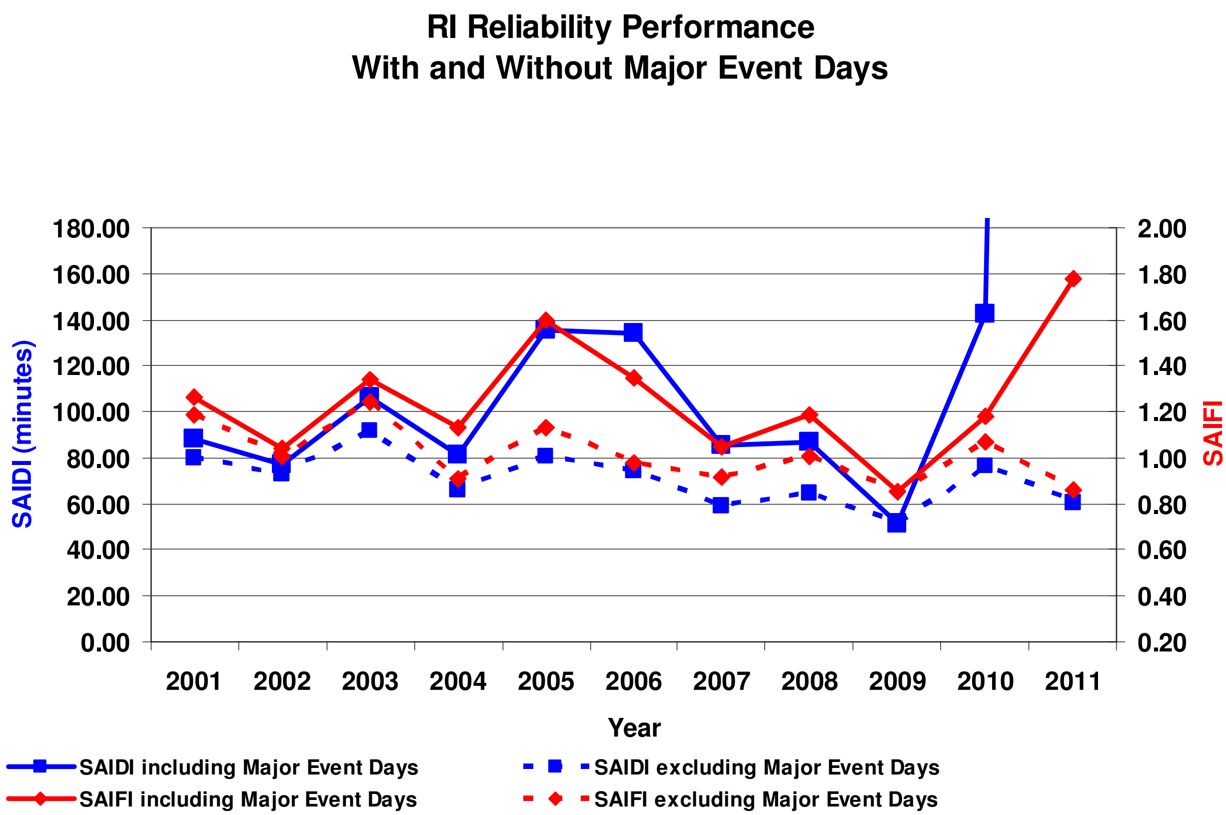
CY11 had 10 days that were characterized as major event days. The most significant single event was Tropical Storm Irene, which started on August 28, and led to 360,000 customer interruptions through September 4th, when all customers were restored. August 28th through September 1st are excluded as major event days. All events in 2011 characterized as major event days are shown in Table 12.

Table 12

Event	Dates Excluded	Total Customers Interrupted/Daily SAIDI
January 12, 2011 Snowstorm	Jan 12, 2011	16,904 / 4.71 (min)
June 9, 2011 – Rain and thunderstorm	June 9, 2011	19,060 / 9.92 (min)
Tropical Storm Irene	August 28 – September 1, 2011 (5 days)	317,370 / 1,752.60 (min) 9,105 / 32.45 (min) 6,758 / 26.99 (min) 5,272 / 15.69 (min) 4,119 / 5.04 (min)
October 23, 2011– Transformer and bus lockout at Drumrock Substation	October 23, 2011	27,238 / 6.80 (min)
October Snowstorm	October 29 – 30, 2011 (2 days)	7,856 / 7.65 (min) 23,790 / 19.29 (min)

Reliability performance, both including and excluding major event days, is shown in Table 13 for 2001 to 2011. SAIDI for 2011 including major event days exceeds the scale of the chart, at 1,947 minutes (32.5 hours), driven by Tropical Storm Irene. As shown in the graph, 2005, 2006, 2010 and 2011 showed the greatest differences between performance with and without major event days. The major event day exclusions in 2005 were for the July 19, 2005 lightning storm, the October 25, 2005 severe wind storm and the December 9, 2005 snow and wind storm. The major event days in 2006 were the July 18, 2006 lightning storm, the August 2, 2006 lightning storm, the August 3, 2006 lightning storm, and the October 28, 2006 wind storm. In 2010, major event days were on March 14th, March 30th and March 31st from storms with high winds and heavy rains. The March 30th event led to flooding across the state, impacting 8 substations.

Table 13



Testimony of
William R. Richer

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM R. RICHER

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I. INTRODUCTION

Q. Please state your full name and business address.

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

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

A. I am the Director of Revenue Requirements - Rhode Island for National Grid USA Service Company, Inc. ("Service Company"). Service Company provides engineering, financial, administrative, and other technical support to subsidiary companies of National Grid USA. My current duties include revenue requirements oversight for National Grid's electric and gas distribution activities in the US, including the electric division of The Narragansett Electric Company, d/b/a National Grid ("Narragansett" or "Company").

Q. Please describe your education and professional experience.

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

Company) as a supervisor of Plant Accounting. Since that time I have held various positions within the Service Company including Manager of Financial Reporting, Principal Rate Department Analyst, Manager of General Accounting, Director of Accounting Services, and Assistant Controller.

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

A. Yes. I have testified before the Commission on numerous occasions. This testimony is intended to supplement previous testimony provided in this docket by David E. Tufts on revenue requirements matters in this proceeding.

Q. What is the purpose of your testimony?

A. The Commission approved in this docket new Electric Infrastructure, Safety and Reliability ("ISR") factors which went into effect on April 1, 2011. Those factors were based on a projected revenue requirement of $9,930,025 (including $6,549,368 of expenses embedded in base rates that are now being recovered through the ISR factors) associated with estimated ISR capital investment and O&M spending during the Company's Fiscal Year ("FY") ended March 31, 2012. The purpose of my testimony is to describe the reconciliation of this projected revenue requirement to the actual revenue requirement associated with actual FY 2012 capital and O&M expense levels. This actual revenue requirement for FY 2012 is $9,971,953 resulting in a net difference from the originally proposed revenue requirement of $41,928.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following Attachment:

- Attachment WRR-1: Electric ISR Plan Revenue Requirement Reconciliation.

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

Q. How does the actual FY 2012 ISR revenue requirement differ from the projected FY 2012 ISR revenue requirement?

A. The actual FY 2012 ISR revenue requirement calculation is nearly identical to the projected ISR revenue requirement used for purposes of developing the approved ISR factors that were in place from April 1, 2011 to March 31, 2012, and as described previously in the testimony of Mr. Tufts in this proceeding. As a result, I will rely on that testimony for the detailed description of the revenue requirement calculation and will limit this testimony to: (1) summarize the revenue requirements reconciliation shown on Page 1 of Attachment WRR-1, (2) describe how the ‘non-discretionary’ and ‘discretionary’ capital investment amounts used in the revenue requirement were determined, and (3) discuss the change in the calculation of tax depreciation to coincide with tax depreciation to be taken on the Company’s FY 2012 federal income tax return.

Q. Please summarize the revenue requirement reconciliation associated with the

Company's FY 2012 Electric ISR Program.

A. As shown on Page 1, Column (b) of WRR-1, the Company's FY 2012 Electric ISR Program 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. The description of these elements and the related amounts are supported by the direct testimony and supporting attachments of Ms. Jennifer L. Grimsley. Line 6 of Column (b) reflects the actual FY 2012 revenue requirement related to O&M expenses, or $9,285,345. This amount is compared to the forecasted FY 2012 revenue requirement related to O&M expense of $9,207,845 from Column (a), resulting in a difference of the O&M related expense component of the revenue requirement of $77,590 as shown in Column (c).

The revenue requirement associated with the Company's actual FY 2012 capital investment in electric utility infrastructure, or $686,518, is shown on Line 10, Column (b) and is detailed on Page 2 of Attachment WRR-1. Column (a) reflects the forecasted FY 2012 capital investment component of the revenue requirement, or $722,180, resulting in a difference of ($35,662) as shown in Column (c).

The total actual FY 2012 ISR Plan revenue requirement for both O&M expenses and capital investment is $9,971,953 compared to the forecasted FY 2012 ISR Plan of $9,930,025 as shown in Line 15, Column (b) and Column (a), respectively, resulting in a net difference of $41,928.

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 Attachment WRR-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. The ultimate revenue requirement on the incremental net capital investment equals the return on the investment (i.e. average rate base at the weighted average cost of capital), plus depreciation expense and property taxes associated with the investment. Incremental 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 ISR Mechanism effective April 1, 2011, and is defined as the 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.

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. The amounts of ‘non-discretionary’ and ‘discretionary’ investment allowed to be included in the revenue requirement calculation are subject to certain limitations as shown on Page 3 of Attachment WRR-1. For ‘non-discretionary’ investments, the revenue requirement is based on the lesser of the actual ‘non-discretionary’ capital investments placed into service and actual ‘non-discretionary’ spending levels on a cumulative fiscal year to date basis. The ‘non-discretionary’ capital used in the FY 2012 revenue requirement calculation has been limited to the actual ‘non-discretionary’ capital spending amount of $ 26,068,014 as compared to $30,087,700 of ‘non-discretionary’ investment assumed in the FY 2012 forecasted revenue requirement. The amount of ‘discretionary’ capital investment to be used in the revenue requirement must be no greater than the cumulative amount of ‘discretionary’ project spend as approved by the Commission in this proceeding. This means that the ‘discretionary’ investment is limited to the lesser of actual cumulative ‘discretionary’ capital additions or spending, or ‘discretionary’ spending approved by the Commission in this docket. For purposes of the FY 2012 revenue requirement, the lesser of these items was actual ‘discretionary’ capital additions of $22,878,442 as shown on Attachment WRR-1, Page 3.

The Company forecasted $27,036,150 of 'discretionary' spending in the approved FY 2012 Electric ISR Plan.

Q. Please describe how tax depreciation was determined in the revenue requirement calculation and how it differs from the tax depreciation calculation in the FY 2012 projected revenue requirement.

A. The tax depreciation calculation for FY 2012 is provided on Page 4 of Attachment WRR-1. Based on the Company's FY 2011 tax return and anticipated treatment in the Company's FY 2012 tax return that is expected to be filed by December 2012, changes were made to the calculation of tax depreciation specifically as it relates to the percent of plant additions eligible for the 100 percent capital repairs deduction, and the percent of all remaining plant additions that are expected to be eligible for bonus depreciation. In the projected FY 2012 ISR revenue requirement, the percent of plant additions eligible for the 100 percent capital repairs deduction and the percent eligible for bonus depreciation were based on the best information available when the FY 2012 ISR proposal was filed in December 2010 and subsequently revised in February 2011 (The purpose for the February 2011 revision was due to tax law changes that affected bonus depreciation implemented by Congress in December 2010). In 2011, the IRS issued final rules for electric utilities regarding eligibility for capital repairs deductibility, which is the basis for the rate that will be used on the FY 2012 tax return and is being reflected on Page 4 of Attachment WRR-1. Tax depreciable plant additions eligible for the capital repairs deduction has been revised to 18.60 percent from 32 percent used in the projected FY 2012 ISR revenue requirement. For purposes of calculating bonus depreciation, the Company assumed that 85 percent of the plant additions under the ISR Plan not eligible for the capital repairs deduction would qualify for the bonus depreciation deduction, whereas the projected revenue requirement assumed 75 percent would be eligible. The Company used a bonus depreciation rate of 100 percent for the April 2011 through December 2011 period and 50 percent for the January 2012 through March 2012 period, consistent with Internal Revenue Service (“IRS”) rules for bonus depreciation for those periods.

The remaining plant additions not eligible for bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate. There was no change to the MACRS component of the tax depreciation calculation from FY 2012 projected revenue requirement except for the resulting amounts. The amount of depreciation deducted for MACRS is added to the amount of capital repairs deduction plus the bonus depreciation deduction and cost of removal to arrive at total tax depreciation. The total tax depreciation amount is carried forward to Line 30 of Attachment WRR-1, Page 2, and incorporated in the deferred tax calculation.

Q. What is the updated revenue requirement associated with actual capital investment?

A. The revenue requirement associated with the actual capital investment portion of the

Company's electric ISR Plan is $686,518 as shown on Page 2, Line 53 which is carried forward to the revenue requirement summary on Line 10, Column (b) of Page 1.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Index of Attachment

Attachment WRR-1

Electric Infrastructure, Safety, and Reliability Plan Revenue Requirement Calculation

The Narragansett Electric Company
d/b/a National Grid
FY 2012 Electric ISR Revenue Requirement Reconciliation
Summary

Line No.			As Approved in Docket No. 4218 (a)	Actuals FY 2012 (b)	Under/(Over) Recover (c)=(b)-(a)
1	**Operation and Maintenance (O&M) Expenses:**				
2					
3	Current Year Vegetation Management (VM)		$ 8,069,000	$ 7,819,551	$ (249,449)
4	Current Year Inspection & Maintenance (I&M)		1,138,845	1,465,884	327,039
5					
6	**O&M Expense Component of Revenue Requirement Subtotal**	Line 3 + Line 4	$ 9,207,845	$ 9,285,435	$ 77,590
7					
8	**Capital Investment:**				
9					
10	Annual Revenue Requirement on FY 2012 Capital included in Rate Base	(a) - R.I.P.U.C. Docket No. 4218, Section 5: Attachment 1, Page 1 of 3, Line 15(a) (b) - Page 2 of 4, Line 53(a)	$ 722,180	$ 686,518	($35,662)
11					
12					
13	**Capital Investment Component of Revenue Requirement Subtotal**	Line 10	$ 722,180	$ 686,518	($35,662)
14					
15	**Total Fiscal Year Revenue Requirement**	Line 6 + Line 13	$ 9,930,025	$ 9,971,953	$ 41,928

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

Line No.				Fiscal Year 2012 (a)
1	Capital Investment Allowance			
2	*Non-Discretionary Capital*			
3	Lesser of Actual Cumulative Non-Discretionary Additions or Spending	Page 3 of 4, Line 6(b)		$ 26,068,014
4				
5	*Discretionary Capital*			
6	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Page 3 of 4, Line 17(b)		22,878,442
7				
8	Total Allowed Capital Included in Rate Base	Line 3 + Line 6		48,946,456
9				
10	Depreciable Net Capital Included in Rate Base			
11	Total Allowed Capital Included in Rate Base in Current Year	Line 8		48,946,456
12	Retirements		1/	7,740,446
13	Net Depreciable Capital Included in Rate Base	Column(a) = Line 11 - Line 12		41,206,009
14				
15	Change in Net Capital Included in Rate Base			
16	Capital Included in Rate Base	Line 8		48,946,456
17	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		38,875,088
18	Incremental Depreciable Amount	Column(a) = Line 16 - Line 17		10,071,368
19				
20	Cost of Removal			
21	Cost of Removal - Non-Discretionary		2/	2,998,483
22	Cost of Removal - Discretionary	From Company Books	2/	2,809,385
23	Total Cost of Removal	Column(a) = Line 21 + Line 22		5,807,869
24				
25	**Total Net Plant in Service**	**Line 18 + Line 23**		**$ 15,879,236**
26				
27	Deferred Tax Calculation:			
28	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%
29	Vintage Year Tax Depreciation:			
30	2012 Spend	Page 4 of 4, Line 27		44,927,567
31	Cumulative Tax Depreciation	Prior Year Line 31 + Current Year Line 30		44,927,567
32				
33	Book Depreciation	Column(a) = Line 13 * Line 28 * 50%		700,502
34	Cumulative Book Depreciation	Current Year Line 33		700,502
35				
36	Cumulative Book / Tax Timer	Line 31 - Line 34		$ 44,227,064
37	Effective Tax Rate			35.00%
38	Deferred Tax Reserve	Line 36 * Line 37		$ 15,479,473
39				
40	Rate Base Calculation:			
41	Cumulative Incremental Capital Included in Rate Base	Line 25		$ 15,879,236
42	Accumulated Depreciation	-Line 34		(700,502)
43	Deferred Tax Reserve	-Line 38		(15,479,473)
44	Year End Rate Base	Sum of Lines 41 through 43		$ (300,739)
45				
46	Revenue Requirement Calculation:			
47	Average Rate Base	Current Year Line 44 ÷ 2		$ (150,369)
48	Pre-Tax ROR		3/	9.30%
49	Return and Taxes	Line 47 * Line 48		(13,984)
50	Book Depreciation	Line 33		700,502
51	Property Taxes	$0 in Year 1, then Prior Year (Line 13 + Line 23 + Line 34) * Property Tax Rate		-
52				
53	**Annual Revenue Requirement**	**Sum of Lines 49 through 51**		**$ 686,518**

1/ Actual Retirements
2/ Cost of Removal - Nondiscretionray and Discretionary was allocated as a percentage of Total Nondiscretionary and Discretionary Capital Spending.
3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065

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

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

Line No.			As Approved in Docket No. 4218 (a)	Actuals FY 2012 (b)
	Non Discretionary Capital			
1	FY 2012 Non-Discretionary Capital **ADDITIONS**		$ 30,087,700	$ 28,771,217
2				
3	FY 2012 Non-Discretionary Capital **SPENDING**		31,341,500	26,068,014
4				
5	**Non Discretionary Reconciliation Test:**			
6	***Non Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Non-Discretionary Capital ADDITIONS or SPENDING*** 1/		**$ 30,087,700**	**$ 26,068,014**
7				
8				
9	**Discretionary Capital**			
10	FY 2012 Discretionary Capital **ADDITIONS**		$ 18,714,500	$ 22,878,442
11				
12	FY 2012 Discretionary Capital **SPENDING**		-	24,424,047
13				
14	FY 2012 Approved Discretionary Capital **SPENDING**		27,036,150	27,036,150
15				
16	**Discretionary Reconciliation Test:**			
17	***Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Discretionary Capital ADDITIONS or SPENDING or APPROVED SPENDING*** 1/		**$ 18,714,500**	**$ 22,878,442**
18				
19				
20	**Total Allowed Capital Included in Rate Base Current Year**	Line 6 + Line 17	**$ 48,802,200**	**$ 48,946,456**

1/ For FY 2012, cumulative capital additions and capital spending is equal to current year capital additions and capital spending.

The Narragansett Electric Company
d/b/a National Grid
FY 2012 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction

Line No.			Fiscal Year 2012 (a)	
1	Capital Repairs Deduction			
2	Plant Additions	Page 2 of 4, Line 8	$ 48,946,456	
3	Capital Repairs Deduction Rate	Per Tax Department	18.60%	1/
4	Capital Repairs Deduction	Line 2 * Line 3	9,104,041	
5				
6	Bonus Depreciation			
7	Plant Additions	Line 1	48,946,456	
8	Less Capital Repairs Deduction	Line 4	9,104,041	
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8	39,842,415	
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	85.00%	2/
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10	33,866,052	
12	Bonus Depreciation Rate (April 2011 - December 2011)	1 * 75% * 100%	75.00%	
13	Bonus Depreciation Rate (January 2012 - March 2012)	1 * 25% * 50%	12.50%	
14	Total Bonus Depreciation Rate	Line 12 + Line 13	87.50%	
15	Bonus Depreciation	Line 11 * Line 14	$ 29,632,796	
16				
17	Remaining Tax Depreciation			
18	Plant Additions	Line 2	48,946,456	
19	Less Capital Repairs Deduction	Line 4	9,104,041	
20	Less Bonus Depreciation	Line 15	29,632,796	
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20	10,209,619	
22	20 YR MACRS Tax Depreciation Rates		3.750%	
23	Remaining Tax Depreciation	Line 21 * Line 22	$ 382,861	
24				
25	Cost of Removal	Page 2 of 4, Line 23	5,807,869	
26				
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 4, 15, 23 and 25	$ 44,927,567	

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

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

Testimony of
Nancy Ribot

PRE-FILED DIRECT TESTIMONY

OF

NANCY RIBOT

August 1, 2012

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I. Introduction and Qualifications

Q. Please state your full name and business address.

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

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

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

Q. Please describe your educational background and training.

A. In 2000, I graduated from Fitchburg State University in Fitchburg, MA with a Bachelor of Science Degree in Accounting.

Q. Please describe your professional experience?

A. From 1995 to 1998, I was employed by National Quality Assurance, USA as Junior Accountant. From 1999 to 2000, I held a position as a Cost Accountant at Avery Dennison Corporation. In 2001, I was employed by PriceWaterhouseCoopers as an Associate Auditor. From 2002 to 2007, I was employed as a Senior Accountant at the DCU Center in Worcester, MA. In 2007, I obtained a position at National Grid as an accounting analyst for Niagara Mohawk Power Corporation. In 2008, I transferred to the Company's New England Electric Pricing Department; in which capacity I provide rate related support to The Narragansett Electric Company. In 2011, I was promoted to Senior Analyst. My responsibilities include providing support for The Narragansett Electric Company's filings for its electric service. More specifically, I have prepared the electric pricing schedules pertaining to The Narragansett Electric Company's 2010, 2011, and 2012 annual retail rate filings, the electric pricing schedules for the FY2012 and FY2013 Infrastructure Safety and Reliability Plan filings, the Standard Offer Service Quarterly Filings, and the FY2012 Electric Revenue Decoupling Mechanism Reconciliation filing. In addition, I have provided rate related support for the Narragansett Electric Company's two most recent base distribution rate cases, Docket No. 4065 and 4323.

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

A. No.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the following information regarding the Fiscal Year 2012 ("FY 2012") Electric Infrastructure, Safety and Reliability ("ISR") Plan:

- the results of the annual reconciliations of the actual fiscal year 2012 ("FY 2012") capital investment revenue requirement and the Operations and Maintenance ("O&M") expense to the actual revenue billed;
- the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2012; and
- the proposed tariff reflecting the new reconciling factors.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section III presents the Summary of Annual CapEx and O&M Reconciliations;
- Section IV presents the current and the proposed R.I.P.U.C. Tariff No. 2095, Summary of Retail Delivery Rates, reflecting the proposed CapEx Reconciling Factors and the proposed O&M Reconciling Factor;
- Section V describes the ISR Provision, R.I.P.U.C. No. 2044;
- Section VI presents the results of the CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation and the calculation of the proposed CapEx Reconciling Factors;
- Section VII presents the results of the O&M Revenue and Expense Reconciliation and the calculation of the proposed O&M Reconciling Factor; and
- Section VIII presents the rate class bill impact analysis.

III. Summary of Annual CapEx and O&M Reconciliations

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

A. A summary of the results of the annual CapEx and O&M reconciliations is presented in Attachment NR-1. The annual reconciliations required pursuant to the ISR Provision include both a reconciliation of the actual revenue billed during the plan year through the approved CapEx and O&M Factors to the revenue approved for recovery in the ISR Plan (the forecasted revenue requirement), as well as a reconciliation of the forecasted CapEx revenue requirement and O&M expense to the actual revenue requirement. The reconciliation of forecasted to actual revenue requirement is presented in the testimony of Company Witness William R. Richer.

Attachment NR-1 presents the results of the reconciliations for both CapEx and O&M expense. The CapEx reconciliation is a net over recovery of $65,588. This includes an over collection of $29,926 of actual billed revenue compared to the forecasted revenue requirement and a difference of $35,662 attributable to an actual revenue requirement that was lower than the forecasted, as discussed in the testimony of Mr. Richer.

The O&M reconciliation is a net under recovery of $159,045. This includes an under collection of $81,455 of actual billed revenue compared to the forecasted expense and a difference of $77,590 attributable to an actual expense that was higher than forecasted.

IV. Summary of Retail Delivery Rates, Tariff No. 2095

Q. Is the Company providing a proposed Summary of Retail Delivery Rates, Tariff No. 2095?

A. Yes. The current and proposed Summary of Retail Delivery Rates, Tariff No. 2095, are attached as Attachment NR-2. Please note that in addition to the rate changes proposed in this filing, the proposed Summary of Retail Delivery Rates tariff reflects the corrected Distribution Backup Demand charges applicable to rate classes B-32 and B-62, which were filed on July 16, 2012 and are pending Commission approval.

V. ISR Provision

Q. Please describe the ISR Provision.

A. Pursuant to the provisions of R.I.G.L. §39-1-27.7.1, the Commission approved the Company's ISR Provision, R.I.P.U.C. No. 2044, and the Company's fiscal year 2012 ISR Plan in Docket No. 4218, effective April, 1, 2011. In accordance with the ISR Provision, the Company is allowed to recover the revenue requirement related to capital investments through CapEx Factors and to recover the revenue requirement related to certain expenditures for Inspection and Maintenance and Vegetation Management activities through O&M Factors.

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

Q. Is the Company proposing revisions to the ISR Provision?

A. Not at this time. However, the Company has proposed revisions to the ISR Provision in Docket No. 4323 that are necessary to implement certain proposals in that docket. A copy of the current ISR Provision is included in Attachment NR-3 for reference.

VI. <u>CapEx Reconciliation & Proposed CapEx Reconciling Factors</u>

Q. What is the result of the CapEx Reconciliation for FY 2012?

A. The FY 2012 CapEx Reconciliation is presented in Attachment NR-4, page 1. Line 1, shows that CapEx Revenue billed during the period April 1, 2011 through March 31, 2012 totaled $752,106. Line 2 shows the actual CapEx Revenue Requirement of $686,518, which is supported in the testimony of Company Witness William R. Richer. Line 3 shows the difference of $65,588, representing an over recovery. Page 2 of

Attachment NR-4 presents the results of the CapEx reconciliation for each of the Company's rate classes.

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

A. The ISR Provision requires that the CapEx Reconciling Factors be calculated as per-kWh factors designed to recover or refund the under or over recovery of the actual Cumulative Revenue Requirement, as allocated to each rate class by the Rate Base Allocator, for the prior fiscal year. The Rate Base Allocator is the percentage of total rate base allocated to each rate class in the most recently approved allocated cost of service study. Page 2, Line 4 of Attachment NR-4 shows the allocation of the actual CapEx revenue requirement to each rate class based upon the Rate Base Allocator approved in the Company's last general rate case, Docket No. 4065. The forecasted fiscal year 2012 capital investment revenue requirement approved for recovery through the CapEx Factors effective April 1, 2011 was allocated to each class using the same Rate Base Allocator.

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

A. As shown on Attachment NR-4, page 2, the CapEx Factor revenue for each rate class, as shown on Line 5, is subtracted from the allocated actual fiscal year 2012 capital investment revenue requirement, on Line 4, resulting in an over or under recovery from each rate class, as shown on Line 6, which nets to a total over recovery of $65,588. The detail of each rate class' CapEx revenue billed is presented on Attachment NR-4, page 3.

Q. Attachment NR-4, page 3 presents kilowatt-hour and/or demand (kW) billing units only from April 2011 through September 2011. Why are the billing units from October 2011 through March 2012 omitted?

A. The FY 2012 CapEx Factors were implemented on April 1, 2011. At that time, the Company's Information Technology (IT) Department had not made the necessary changes to the Company's billing system to separately track the CapEx Factor Revenue. Therefore, the CapEx Factor Revenue for the period prior to October 1, 2011 is calculated by multiplying the kilowatt-hour or kW billing units by the appropriate CapEx Factor for each rate class. Billing system modifications were completed by October 2011; at which time, the calculation of the CapEx Factor Revenue was no longer necessary.

Q. How is the Company proposing to refund the net FY 2012 CapEx over recovery?

A. The Company is proposing to implement a CapEx Reconciling charge or credit factor for each rate class that is consistent with the results of the rate class reconciliation. The calculation of the proposed CapEx Reconciling Factors is presented in Attachment NR-4, page 2. The over or under collection on Line 6 is divided by each class' forecasted kWh deliveries for the period October 1, 2012 through September 30, 2013. The class specific CapEx reconciling factors, as shown on Line 8, are as follows:

Rate Class	Charge/(Credit) per kWh
A-16 & A-60	0.000¢
C-06	0.000¢
G-02	(0.003)¢
G-32 & B-32	0.000¢
G-62 & B-62	0.000¢
Streetlights	(0.002)¢
X-01	0.001¢

Q. How will the Company collect or refund the under or over recovery from rate classes that have no proposed reconciling factor?

A. The Company will roll forward the ending balance of each rate class' CapEx reconciliation into the next reconciliation period and it will be either a charge or credit, as appropriate, in the fiscal year 2013 ISR Plan Reconciliation.

VII. Operation & Maintenance Reconciliation & Proposed O&M Reconciling Factor

Q. What is the result of the O&M Reconciliation for FY 2012?

A. The O&M Reconciliation for FY 2012 is presented in Attachment NR-5, page 1. Line 1, shows O&M Revenue billed through the O&M Factors from April 1, 2011 through March 31, 2012 which totaled $9,126,390. Line 2 shows the actual O&M expense for fiscal year 2012 of $9,285,435, which is supported in the testimony of Company Witness

William R. Richer. Line 3 shows the difference of \$159,045, representing an under recovery.

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

A. The proposed O&M Reconciling Factor is calculated on Lines 4 and 5 of page 1. The under recovery of \$159,045 divided by the forecasted kWhs during the recovery period, October 1, 2012 through September 30, 2013, of 7,838,280,122 results in a charge of 0.002¢ per kWh.

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

A. Yes. Attachment NR-5, page 2 presents the O&M Factor Revenue billings by rate class and by month.

Q. Attachment NR-5, Page 2 presents kilowatt-hour and/or demand (kW) billing units only for the period April 2011 through September 2011. Why are the billing units from October 2011 through March 2012 omitted?

A. As was the case with the CapEx Factors, previously mentioned, the billing system modification necessary to track the O&M Charges separately was completed in October 2011, therefore, O&M Factor revenue for the period April 2011 through September 2011 was calculated by multiplying the approved charges by the billing units for each rate class as demonstrated on Attachment NR-5, page 2.

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

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

VIII. Typical Bill Analysis

Q. Has the Company provided a typical bill analysis to illustrate the impact of the proposed rate changes on each of the Company's rate classes?

A. Yes. The typical bill analysis illustrating the monthly bill impact of the proposed rate changes for each rate class is contained in Attachment NR-6. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer, receiving Standard Offer Service and using 500 kWhs per month, is an increase of $0.01, or approximately 0.0%, from $73.41 to $73.42.

IX. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

Attachment NR-1

Attachment NR-1

FY2012 ISR Plan Annual Reconciliation Summary

FY 2012 ISR Plan Annual Reconciliation Summary

		CapEx (a)	O&M (b)
(1)	Actual Revenue Requirement	$ 686,518	$ 9,285,435
(2)	Forecasted Revenue Requirement	$ 722,180	$ 9,207,845
(3)	(Over)Under Spend	$ 35,662	$ (77,590)
(4)	Actual Revenue Billed	$ 752,106	$ 9,126,390
(5)	Forecasted Revenue Requirement	$ 722,180	$ 9,207,845
(6)	Over(Under)	$ 29,926	$ (81,455)
(7)	Total Over(Under) Recovery	$ 65,588	$ (159,045)

Line Descriptions:

(1) column (a) per Attachment NR-4, Page 1, Line (2)
column (b) per Attachment NR-5, Page 1, Line (2)

(2) column (a) per FY2012 ISR Plan, Docket No. 4218, Schedule DET-1 Revised, Page 1, Line 15, Column (a)
column (b) per FY2012 ISR Plan, Docket No. 4218, Schedule DET-1 Revised, Page 1, Line 3, Column (a)

(3) Line (2) - Line (1); also see Attachment WRR-1, Page 1, Column (c)

(4) column (a) per Attachment NR-4, Page 1, Line (1)
column (b) per Attachment NR-5, Page 1 , Line (1)

(5) per Line (2)

(6) Line (4) - Line (5)

(7) Line (3) + Line (6); see also Attachment NR-4, Page 1, Line (3), and Attachment NR-5, Page 1, Line (3)

Attachment NR-2

Attachment NR-2

Current and Proposed Summary of Retail Delivery Rates, R.I.P.U.C. Tariff No. 2095

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate	Charge Description	Distribution Charge	Operating & Maintenance Exp Charge	CapEx Factor Charge	RDM Adj Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting Charge	Renewable Energy Distribution Charge	LIHEAP Enhancement Charge	Base Transmission Charge	Transmission Adjustment	Transmission Uncollectible Factor	Total Transmission Charge	Base Transition Charge	Transition Charge Adj	Total Transition Charge	Energy Efficiency Program Charge	Total Delivery Charges
A	B	C	D	E	F	G=C+D+E+F	H	I	J=H + I	K	L	M	N	O=L+M+N	P	Q	R=P+Q	S	T=G+J+K+O+R+S
A-16																			
Basic Residential																			
Rate	Customer Charge	$3.75				$3.75				$0.83									$4.58
R.I.P.U.C.No. 2082	kWh Charge	$0.03416	$0.00159	$0.00056	($0.00014)	$0.03617	$0.00000	$0.00007	$0.00007		$0.01950	($0.00026)	$0.00018	$0.01942	$0.00081	($0.00018)	$0.00063	$0.00622	$0.06251
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
A-60																			
Low Income Rate	Customer Charge	$0.00				$0.00				$0.83									$0.83
R.I.P.U.C.No. 2083	kWh Charges																		
	kWh Charge	$0.02048	$0.00159	$0.00056	($0.00014)	$0.02249	$0.00000	$0.00007	$0.00007		$0.01950	($0.00026)	$0.00018	$0.01942	$0.00081	($0.00018)	$0.00063	$0.00622	$0.04883
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
B-32																			
C&I Back-up Service																			
Rate	Customer Charge	$750.00				$750.00				$0.83									$750.83
R.I.P.U.C.No. 2084	Backup Demand Charge - in excess of 200 kW	$0.41		$0.14		$0.55													$0.55
	kW Charge - in excess of 200 kW	$2.15		$0.14		$2.29													$2.29
	kW Charge					$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00818	$0.00073	$0.00000	($0.00014)	$0.00877	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02215
	High Voltage Delivery Discount	($0.42)				($0.42)													($0.42)
	Second Feeder Service	$2.42				$2.42													$2.42
	High Voltage Metering Discount (115kV)	($2.00)				($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%																	
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
B-62																			
3,000 kW Back-up																			
Service Rate	Customer Charge	$17,000.00				$17,000.00				$0.83									$17,000.83
R.I.P.U.C.No. 2085	Backup Demand Charge	-$0.10	$0.35	$0.11		$0.36													$0.36
	kW Charge	$2.57	$0.35	$0.11		$3.03													$3.03
	kW Charge					$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00009	$0.00000	$0.00000	($0.00014)	-$0.00005	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.01333
	High Voltage Delivery Discount	($0.42)				($0.42)													($0.42)
	Second Feeder Service	$2.42				$2.42													$2.42
	High Voltage Metering Discount (115kV)	($2.00)				($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%																	
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
C-06																			
Small C&I Rate	Customer Charge	$8.00				$8.00				$0.83									$8.83
R.I.P.U.C.No. 2086	Unmetered Charge	$5.00				$5.00				$0.83									$5.83
	kWh Charge	$0.03257	$0.00166	$0.00053	($0.00014)	$0.03462	$0.00000	$0.00007	$0.00007		$0.01847	($0.00026)	$0.00017	$0.01838	$0.00081	($0.00018)	$0.00063	$0.00622	$0.05992
	Additional Minimum Charge (per kVA in excess of 25 kVA)	$1.85				$1.85													$1.85
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
G-02																			
General C&I Rate	Customer Charge	$125.00				$125.00				$0.83									$125.83
R.I.P.U.C.No. 2087	kW > 10 Charge	$4.63		$0.15		$4.78													$4.78
	kW Charge					$0.00					$2.70			$2.70					$2.70
	kWh Charge	$0.00623	$0.00135	$0.00000	($0.00014)	$0.00744	$0.00000	$0.00007	$0.00007		$0.00846	($0.00026)	$0.00015	$0.00835	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02271
	High Voltage Delivery Discount	($0.42)				($0.42)													($0.42)
	High Voltage Metering Discount	-1.0%																	
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	

Taxes and other rate clauses apply as usual and will appear on customer bills as applicable.

Effective: 07/01/2012
(Replacing R.I.P.U.C No. 2095 effective 04/23/12)
Issued: 05/15/2012

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate	Charge Description	Distribution Charge	Operating & Maintenance Exp Charge	CapEx Factor Charge	RDM Adj Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting Charge	Renewable Energy Distribution Charge	LIHEAP Enhancement Charge	Base Transmission Charge	Transmission Adjustment	Transmission Uncollectible Factor	Total Transmission Charge	Base Transition Charge	Transition Charge Adj	Total Transition Charge	Energy Efficiency Program Charge	Total Delivery Charges
A	B	C	D	E	F	G=C+D+E+F	H	I	J=H + I	K	L	M	N	O=L+M+N	P	Q	R=P+Q	S	T=G+J+K+O+R+S
G-32																			
200 kW Demand																			
Rate	Customer Charge	$750.00				$750.00				$0.83									$750.83
R.I.P.U.C.No. 2088	kW Charge - in excess of 200 kW	$2.15		$0.14		$2.29													$2.29
	kW Charge					$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00818	$0.00073	$0.00000	($0.00014)	$0.00877	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02215
	High Voltage Delivery Discount	($0.42)				($0.42)													($0.42)
	Second Feeder Service	$2.42				$2.42													$2.42
	High Voltage Metering Discount (115kV)	($2.00)				($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%	$0.00000	$0.00000															
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*04/01/12*	*04/01/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
G-62																			
3,000 kW Demand																			
Rate	Customer Charge	$17,000.00				$17,000.00				$0.83									$17,000.83
R.I.P.U.C.No. 2089	kW Charge	$2.57	$0.35	$0.11		$3.03													$3.03
	kW Charge					$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00009	$0.00000	$0.00000	($0.00014)	-$0.00005	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.01333
	Second Feeder Service	$2.42				$2.42													$2.42
	High Voltage Delivery Discount	($0.42)				($0.42)													($0.42)
	High Voltage Metering Discount (115kV)	($2.00)				($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%																	
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*04/01/12*	*04/01/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
X-01																			
Electric Propulsion																			
Rate	Customer Charge	$16,500.00				$16,500.00				$0.83									$16,500.83
R.I.P.U.C.No. 2090	kW Charge	$0.00				$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.01240	$0.00201	$0.00067	($0.00014)	$0.01494	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02832
	Effective Date	*4/23/12*	*4/1/12*	*4/1/12*	*7/1/12*		*04/01/12*	*04/01/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
M-1																			
Station Power																			
Delivery &																			
Reliability Service																			
Rate	Option A:																		
R.I.P.U.C.No. 2091	fixed charges	$3,640.42	$0.00	$0.00		$3,640.42				$0.83	$0.00	$0.00	$0.00	$0.00	$3,500.00	$0.00	$3,500.00	$800.00	$7,941.25
	variable charges	$0.00	$0.00	$0.00		$0.00					$0.00	$0.00	$0.00	$0.00	$0.00081	($0.00018)	$0.00063	$0.00622	$0.00685
	(transition and conservation charges																		
	billed on higher of fixed charges																		
	or kWhs times variable charges)																		
	Option B:																		
	fixed charge	$3,640.42	$0.00	$0.00		$3,640.42				$0.83									$3,641.25
	kWh charge										$0.00000	$0.00000	$0.00000	$0.00000	$0.00081	($0.00018)	$0.00063	$0.00622	$0.00685
	Effective Date	*4/1/11*	*4/1/12*	*4/1/12*						*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	

Taxes and other rate clauses apply as usual and will appear on customer bills as applicable.

Effective: 07/01/2012
(Replacing R.I.P.U.C No. 2095 effective 04/23/12)
Issued: 05/15/2012

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2082 through 2091
D. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044
E. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044
F. Per RDM Filing, R.I.P.U.C. Docket No. ____, filed May 2012
G. Col C + Col D + Col E + Col F
H. per Net Metering Provision, R.I.P.U.C. No. 2099

I. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2081
J. Col H + Col I
K. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
L. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
M. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
N. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
O. Col L + Col M +Col N

P. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
Q. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
R. Col P + Col Q
S. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2042, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
T. Col G + Col J + Col K + Col O + Col R + Col S

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate	Charge Description	Distribution Charge			
A	B	C			
RateS-06	Fixture Charges				
Decorative Street					
and					
Area Lighting Service		Full Service S-06	Full Service S-10	Full Service S-14	Temp-off S-14
R.I.P.U.C.No. 2092					
	Luminaires				
Rate S-10					
Limited Service -	Incandescent				
Private Lighting	Roadway LUM INC RWY 105W	n/a	$69.46	$69.46	$41.68
R.I.P.U.C.No. 2093	LUM INC RWY 205W (S-14 Only)	n/a	n/a	$69.46	$41.68
	Mercury Vapor				
Rate S-14	Roadway LUM MV RWY 100W	n/a	$69.46	$69.46	$41.68
General Street and	LUM MV RWY 175W	n/a	$72.63	$72.63	$43.58
Area Lighting					
Service	LUM MV RWY 250W (S-14 Only)	n/a	n/a	$72.63	$43.58
R.I.P.U.C.No. 2094	LUM MV RWY 400W	n/a	$120.39	$120.39	$72.23
	LUM MV RWY 1000W	n/a	$163.46	$163.46	$98.08
	Post-top LUM MV POST 175W (S-14 Only)	n/a	n/a	$156.80	$94.08
	Flood LUM MV FLD 400W	n/a	$143.14	$143.14	$85.88
	LUM MV FLD 1000W	n/a	$181.37	$181.37	$108.82
	Sodium Vapor				
	Roadway LUM HPS RWY 50W	n/a	$69.46	$69.46	$41.68
	LUM HPS RWY 70W	n/a	$69.72	$69.72	$41.83
	LUM HPS RWY 100W	n/a	$72.63	$72.63	$43.58
	LUM HPS RWY 150W	n/a	$72.63	$72.63	$43.58
	LUM HPS RWY 250W	n/a	$120.39	$120.39	$72.23
	LUM HPS RWY 400W	n/a	$163.46	$163.46	$98.08
	Flood LUM HPS FLD 250W	n/a	$143.14	$143.14	$85.88
	LUM HPS FLD 400W	n/a	$181.37	$181.37	$108.82
	Post-top LUM HPS POST 50W	n/a	$155.49	$155.49	$93.29
	LUM HPS POST 100W	n/a	$156.80	$156.80	$94.08
	WALL HPS 250W 24HR	n/a	$172.21	$172.21	$103.33
	SHOEBOX - LUM HPS REC 100W-C1	n/a	$92.30	n/a	n/a
	Metal Halide				
	Flood LUM MH FLD 400W	n/a	$181.37	$181.37	$108.82
	LUM MH FLD 1000W	n/a	$181.37	$181.37	$108.82
	Decorative DEC HPS TR 50W	$155.49	n/a	n/a	n/a
	DEC HPS TR 100W	$156.80	n/a	n/a	n/a
	DEC HPS AG 50W	$239.39	n/a	n/a	n/a
	DEC HPS AG 100W	$241.52	n/a	n/a	n/a
	DEC HPS WL 50W	$269.63	n/a	n/a	n/a
	DEC HPS WL 100W	$273.09	n/a	n/a	n/a
	DEC HPS TR-TW 50W	$334.84	n/a	n/a	n/a
	DEC HPS TR-TW 100W	$337.49	n/a	n/a	n/a
	DEC HPS AG-TW 50W	$502.64	n/a	n/a	n/a
	DEC HPS AG-TW 100W	$506.93	n/a	n/a	n/a
	DEC HPS WL-TW 50W	$563.13	n/a	n/a	n/a
	DEC HPS WL-TW 100W	$570.08	n/a	n/a	n/a
	Standards				
	POLE-WOOD	n/a	$77.81	$77.81	$77.81
	POLE FIBER PTEMB <25' w/out foundatio	n/a	$105.72	$105.72	$105.72
	POLE FIBER RWY <25 w/ foundation	n/a	$162.86	$162.86	$162.86
	POLE FIBER RWY => 25 w/ foundation	n/a	$185.67	$185.67	$185.67
	POLE METAL EMBEDDED (S-14 Only)	n/a	$253.37	$253.37	$253.37
	POLE METAL=>25FT (with foundation)	n/a	$304.55	$304.55	$304.55
	DEC VILL PT/FDN	$607.38	n/a	n/a	n/a
	DEC WASH PT/FDN	$631.69	n/a	n/a	n/a
	Effective Date	*06/01/2010*	*06/01/2010*	*06/01/2010*	*06/01/2010*
	Customer Charge				
	kWh Charge	($0.00429)	($0.00429)	($0.00429)	
	Effective Date	*4/23/12*	*4/23/12*	*4/23/12*	

Charge Description	Operating & Maintenance Exp Charge	CapEx Factor Charge	RDM Adj Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting Charge	Renewable Energy Distribution Charge	LIHEAP Enhancement Charge	Base Transmission Charge	Transmission Adjustment	Transmission Uncollectible Factor	Total Transmission Charge	Base Transition Charge	Transition Charge Adj	Total Transition Charge	Energy Efficiency Program Charge	Total Delivery Charges
B	D	E	F	G=C+D+E+F	H	I	J=H + I	K	L	M	N	O=L+M+N	P	Q	R=P+Q	S	T=G+J+K+O+R +S
Customer Charge								$0.83									$0.83
kWh Charge	$0.01047	$0.00262	($0.00014)	$0.00866	$0.00000	$0.00007	$0.00007		$0.01168	($0.00026)	$0.00010	$0.01152	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02710
Effective Date	*4/1/12*	*4/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	

Taxes and other rate clauses apply as usual and will appear on customer bills as applicable.

Effective: 07/01/2012
(Replacing R.I.P.U.C No. 2095 effective 04/23/12)
Issued: 05/15/2012

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2082 through 2091
D. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044
E. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044
F. Per RDM Filing, R.I.P.U.C. Docket No. ____, filed May 2012
G. Col C + Col D + Col E + Col F
H. per Net Metering Provision, R.I.P.U.C. No. 2099
I. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2081
J. Col H + Col I
K. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
L. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
M. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
N. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
O. Col L + Col M +Col N
P. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
Q. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
R. Col P + Col Q
S. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2042, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
T. Col G + Col J + Col K + Col O + Col R + Col S

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate	Charge Description	Distribution Charge	Operating & Maintenance Exp Charge	O&M Reconciliation Factor	CapEx Factor Charge	CapEx Reconciliation Factor	RDM Adj Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting Charge	Renewable Energy Distribution Charge	LIHEAP Enhancement Charge	Base Transmission Charge	Transmission Adjustment	Transmission Uncollectible Factor	Total Transmission Charge	Base Transition Charge	Transition Charge Adj	Total Transition Charge	Energy Efficiency Program Charge	Total Delivery Charges
A	B	C	D	E	F	G	H	I=C+D+E+F +G+H	J	K	L=J + K	M	N	O	P	Q=N+O+P	R	S	T=R+S	U	V=I+L+M+Q +T+U
A-16																					
Basic Residential																					
Rate	Customer Charge	$3.75						$3.75				$0.83									$4.58
R.I.P.U.C.No. 2082	kWh Charge	$0.03416	$0.00159	$0.00002	$0.00056	$0.00000	($0.00014)	$0.03619	$0.00000	$0.00007	$0.00007		$0.01950	($0.00026)	$0.00018	$0.01942	$0.00081	($0.00018)	$0.00063	$0.00622	$0.06253
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
A-60																					
Low Income Rate	Customer Charge	$0.00						$0.00				$0.83									$0.83
R.I.P.U.C.No. 2083	kWh Charges																				
	kWh Charge	$0.02048	$0.00159	$0.00002	$0.00056	$0.00000	($0.00014)	$0.02251	$0.00000	$0.00007	$0.00007		$0.01950	($0.00026)	$0.00018	$0.01942	$0.00081	($0.00018)	$0.00063	$0.00622	$0.04885
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
B-32																					
C&I Back-up Service																					
Rate	Customer Charge	$750.00						$750.00				$0.83									$750.83
R.I.P.U.C.No. 2084	Backup Demand Charge - in excess of 200 kW	$0.10	$0.30		$0.14			$0.54													$0.54
	kW Charge - in excess of 200 kW	$2.15			$0.14			$2.29													$2.29
	kW Charge							$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00818	$0.00073	$0.00002	$0.00000	$0.00000	($0.00014)	$0.00879	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02217
	High Voltage Delivery Discount	($0.42)						($0.42)													($0.42)
	Second Feeder Service	$2.42						$2.42													$2.42
	High Voltage Metering Discount (115kV)	($2.00)						($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%																			
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
B-62																					
3,000 kW Back-up																					
Service Rate	Customer Charge	$17,000.00						$17,000.00				$0.83									$17,000.83
R.I.P.U.C.No. 2085	Backup Demand Charge	($0.16)	$0.35		$0.11			$0.30													$0.30
	kW Charge	$2.57	$0.35		$0.11			$3.03													$3.03
	kW Charge							$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00009	$0.00000	$0.00002	$0.00000	$0.00000	($0.00014)	($0.00003)	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.01335
	High Voltage Delivery Discount	($0.42)						($0.42)													($0.42)
	Second Feeder Service	$2.42						$2.42													$2.42
	High Voltage Metering Discount (115kV)	($2.00)						($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%																			
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
C-06																					
Small C&I Rate	Customer Charge	$8.00						$8.00				$0.83									$8.83
R.I.P.U.C.No. 2086	Unmetered Charge	$5.00						$5.00				$0.83									$5.83
	kWh Charge	$0.03257	$0.00166	$0.00002	$0.00053	$0.00000	($0.00014)	$0.03464	$0.00000	$0.00007	$0.00007		$0.01847	($0.00026)	$0.00017	$0.01838	$0.00081	($0.00018)	$0.00063	$0.00622	$0.05994
	Additional Minimum Charge (per kVA in excess of 25 kVA)	$1.85						$1.85													$1.85
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
G-02																					
General C&I Rate	Customer Charge	$125.00						$125.00				$0.83									$125.83
R.I.P.U.C.No. 2087	kW > 10 Charge	$4.63			$0.15			$4.78													$4.78
	kW Charge							$0.00					$2.70			$2.70					$2.70
	kWh Charge	$0.00623	$0.00135	$0.00002	$0.00000	($0.00003)	($0.00014)	$0.00743	$0.00000	$0.00007	$0.00007		$0.00846	($0.00026)	$0.00015	$0.00835	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02270
	High Voltage Delivery Discount	($0.42)						($0.42)													($0.42)
	High Voltage Metering Discount	-1.0%																			
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	

Taxes and other rate clauses apply as usual and will appear on customer bills as applicable.

Effective: 10/01/2012
(Replacing R.I.P.U.C No. 2095 effective 7/1/12)
Issued: 08/01/2012

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate	Charge Description	Distribution Charge	Operating & Maintenance Exp Charge	O&M Reconciliation Factor	CapEx Factor Charge	CapEx Reconciliation Factor	RDM Adj Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting Charge	Renewable Energy Distribution Charge	LIHEAP Enhancement Charge	Base Transmission Charge	Transmission Adjustment	Transmission Uncollectible Factor	Total Transmission Charge	Base Transition Charge	Transition Charge Adj	Total Transition Charge	Energy Efficiency Program Charge	Total Delivery Charges
A	B	C	D	E	F	G	H	I=C+D+E+F +G+H	J	K	L=J + K	M	N	O	P	Q=N+O+P	R	S	T=R+S	U	V=I+L+M+Q +T+U
G-32																					
200 kW Demand																					
Rate	Customer Charge	$750.00						$750.00				$0.83									$750.83
R.I.P.U.C.No. 2088	kW Charge - in excess of 200 kW	$2.15			$0.14			$2.29													$2.29
	kW Charge							$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00818	$0.00073	$0.00002	$0.00000	$0.00000	($0.00014)	$0.00879	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02217
	High Voltage Delivery Discount	($0.42)						($0.42)													($0.42)
	Second Feeder Service	$2.42						$2.42													$2.42
	High Voltage Metering Discount (115kV)	($2.00)						($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%	$0.00000		$0.00000																
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*04/01/12*	*04/01/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
G-62																					
3,000 kW Demand																					
Rate	Customer Charge	$17,000.00						$17,000.00				$0.83									$17,000.83
R.I.P.U.C.No. 2089	kW Charge	$2.57	$0.35		$0.11			$3.03													$3.03
	kW Charge							$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.00009	$0.00000	$0.00002	$0.00000	$0.00000	($0.00014)	($0.00003)	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.01335
	Second Feeder Service	$2.42						$2.42													$2.42
	High Voltage Delivery Discount	($0.42)						($0.42)													($0.42)
	High Voltage Metering Discount (115kV)	($2.00)						($2.00)													($2.00)
	High Voltage Metering Discount	-1.0%																			
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*04/01/12*	*04/01/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
X-01																					
Electric Propulsion																					
Rate	Customer Charge	$16,500.00						$16,500.00				$0.83									$16,500.83
R.I.P.U.C.No. 2090	kW Charge	$0.00						$0.00					$2.92			$2.92					$2.92
	kWh Charge	$0.01240	$0.00201	$0.00002	$0.00067	$0.00001	($0.00014)	$0.01497	$0.00000	$0.00007	$0.00007		$0.00659	($0.00026)	$0.00013	$0.00646	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02835
	Effective Date	*4/23/12*	*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*04/01/12*	*04/01/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	
M-1																					
Station Power																					
Delivery &																					
Reliability Service																					
Rate	Option A:																				
R.I.P.U.C.No. 2091	fixed charges	$3,640.42	$0.00		$0.00			$3,640.42				$0.83	$0.00	$0.00	$0.00	$0.00	$3,500.00	$0.00	$3,500.00	$800.00	$7,941.25
	variable charges	$0.00	$0.00		$0.00			$0.00					$0.00	$0.00	$0.00	$0.00	$0.00081	($0.00018)	$0.00063	$0.00622	$0.00685
	(transition and conservation charges																				
	billed on higher of fixed charges																				
	or kWhs times variable charges)																				
	Option B:																				
	fixed charge	$3,640.42	$0.00		$0.00			$3,640.42				$0.83									$3,641.25
	kWh charge												$0.00000	$0.00000	$0.00000	$0.00000	$0.00081	($0.00018)	$0.00063	$0.00622	$0.00685
	Effective Date	*4/1/11*	*4/1/12*		*4/1/12*							*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	

Taxes and other rate clauses apply as usual and will appear on customer bills as applicable.

Effective: 10/01/2012
(Replacing R.I.P.U.C No. 2095 effective 7/1/12)
Issued: 08/01/2012

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2082 through 2091
D. - G. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044
H. Per RDM Filing, R.I.P.U.C. Docket No. ____, filed May 2012
I. Col C + Col D + Col E + Col F
J. per Net Metering Provision, R.I.P.U.C. No. 2099
K. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2081
L. Col H + Col I
M. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
N. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
O. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
P. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
Q. Col L + Col M +Col N
R. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
S. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
T. Col P + Col Q
U. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2042, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
V. Col G + Col J + Col K + Col O + Col R + Col S

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate	Charge Description	Distribution Charge			
A	B	C			
RateS-06	Fixture Charges				
Decorative Street and					
Area Lighting Service		Full Service S-06	Full Service S-10	Full Service S-14	Temp-off S-14
R.I.P.U.C.No. 2092					
	Luminaires				
Rate S-10					
Limited Service -	Incandescent				
Private Lighting	Roadway LUM INC RWY 105W	n/a	$69.46	$69.46	$41.68
R.I.P.U.C.No. 2093	LUM INC RWY 205W (S-14 Only)	n/a	n/a	$69.46	$41.68
	Mercury Vapor				
Rate S-14	Roadway LUM MV RWY 100W	n/a	$69.46	$69.46	$41.68
General Street and	LUM MV RWY 175W	n/a	$72.63	$72.63	$43.58
Area Lighting Service	LUM MV RWY 250W (S-14 Only)	n/a	n/a	$72.63	$43.58
R.I.P.U.C.No. 2094	LUM MV RWY 400W	n/a	$120.39	$120.39	$72.23
	LUM MV RWY 1000W	n/a	$163.46	$163.46	$98.08
	Post-top LUM MV POST 175W (S-14 Only)	n/a	n/a	$156.80	$94.08
	Flood LUM MV FLD 400W	n/a	$143.14	$143.14	$85.88
	LUM MV FLD 1000W	n/a	$181.37	$181.37	$108.82
	Sodium Vapor				
	Roadway LUM HPS RWY 50W	n/a	$69.46	$69.46	$41.68
	LUM HPS RWY 70W	n/a	$69.72	$69.72	$41.83
	LUM HPS RWY 100W	n/a	$72.63	$72.63	$43.58
	LUM HPS RWY 150W	n/a	$72.63	$72.63	$43.58
	LUM HPS RWY 250W	n/a	$120.39	$120.39	$72.23
	LUM HPS RWY 400W	n/a	$163.46	$163.46	$98.08
	Flood LUM HPS FLD 250W	n/a	$143.14	$143.14	$85.88
	LUM HPS FLD 400W	n/a	$181.37	$181.37	$108.82
	Post-top LUM HPS POST 50W	n/a	$155.49	$155.49	$93.29
	LUM HPS POST 100W	n/a	$156.80	$156.80	$94.08
	WALL HPS 250W 24HR	n/a	$172.21	$172.21	$103.33
	SHOEBOX - LUM HPS REC 100W-C1	n/a	$92.30	n/a	n/a
	Metal Halide				
	Flood LUM MH FLD 400W	n/a	$181.37	$181.37	$108.82
	LUM MH FLD 1000W	n/a	$181.37	$181.37	$108.82
	Decorative DEC HPS TR 50W	$155.49	n/a	n/a	n/a
	DEC HPS TR 100W	$156.80	n/a	n/a	n/a
	DEC HPS AG 50W	$239.39	n/a	n/a	n/a
	DEC HPS AG 100W	$241.52	n/a	n/a	n/a
	DEC HPS WL 50W	$269.63	n/a	n/a	n/a
	DEC HPS WL 100W	$273.09	n/a	n/a	n/a
	DEC HPS TR-TW 50W	$334.84	n/a	n/a	n/a
	DEC HPS TR-TW 100W	$337.49	n/a	n/a	n/a
	DEC HPS AG-TW 50W	$502.64	n/a	n/a	n/a
	DEC HPS AG-TW 100W	$506.93	n/a	n/a	n/a
	DEC HPS WL-TW 50W	$563.13	n/a	n/a	n/a
	DEC HPS WL-TW 100W	$570.08	n/a	n/a	n/a
	Standards				
	POLE-WOOD	n/a	$77.81	$77.81	$77.81
	POLE FIBER PTEMB <25' w/out foundation	n/a	$105.72	$105.72	$105.72
	POLE FIBER RWY <25 w/ foundation	n/a	$162.86	$162.86	$162.86
	POLE FIBER RWY => 25 w/ foundation	n/a	$185.67	$185.67	$185.67
	POLE METAL EMBEDDED (S-14 Only)	n/a	$253.37	$253.37	$253.37
	POLE METAL=>25FT (with foundation)	n/a	$304.55	$304.55	$304.55
	DEC VILL PT/FDN	$607.38	n/a	n/a	n/a
	DEC WASH PT/FDN	$631.69	n/a	n/a	n/a
	Effective Date	*06/01/2010*	*06/01/2010*	*06/01/2010*	*06/01/2010*

Rate	Charge Description	Distribution Charge S-06	Distribution Charge S-10	Distribution Charge S-14	Distribution Charge Temp-off S-14	Operating & Maintenance Exp Charge	O&M Reconciliation Factor	CapEx Factor Charge	CapEx Reconciliation Factor	RDM Adj Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting Charge	Renewable Energy Distribution Charge	LIHEAP Enhancement Charge	Base Transmission Charge	Transmission Adjustment	Transmission Uncollectible Factor	Total Transmission Charge	Base Transition Charge	Transition Charge Adj	Total Transition Charge	Energy Efficiency Program Charge	Total Delivery Charges
A	B	C				D	E	F	G	H	I=C+D+E+F+G +H	J	K	L=J + K	M	N	O	P	Q=N+O+P	R	S	T=R+S	U	V=I+L+M+Q+T +U
	Customer Charge														$0.83									$0.83
	kWh Charge	($0.00429)	($0.00429)	($0.00429)		$0.01047	$0.00002	$0.00262	($0.00002)	($0.00014)	$0.00866	$0.00000	$0.00007	$0.00007		$0.01168	($0.00026)	$0.00010	$0.01152	$0.00081	($0.00018)	$0.00063	$0.00622	$0.02710
	Effective Date	*4/23/12*	*4/23/12*	*4/23/12*		*4/1/12*	*10/1/12*	*4/1/12*	*10/1/12*	*7/1/12*		*4/1/12*	*4/1/12*		*1/1/12*	*4/1/12*	*4/1/12*	*4/1/12*		*4/1/12*	*4/1/12*		*3/1/12*	

Taxes and other rate clauses apply as usual and will appear on customer bills as applicable.

Effective: 10/01/2012
(Replacing R.I.P.U.C No. 2095 effective 7/1/12)
Issued: 08/01/2012

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2082 through 2091
D. - G. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044
H. Per RDM Filing, R.I.P.U.C. Docket No. ____, filed May 2012
I. Col C + Col D + Col E + Col F
J. per Net Metering Provision, R.I.P.U.C. No. 2099
K. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2081
L. Col H + Col I
M. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
N. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
O. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
P. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2080
Q. Col L + Col M +Col N
R. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
S. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1191
T. Col P + Col Q
U. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2042, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
V. Col G + Col J + Col K + Col O + Col R + Col S

Attachment NR-3

Attachment NR-3

Infrastructure, Safety, and Reliability Provision

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.

"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

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

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.

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.

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

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.

"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 NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

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.

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

Attachment NR-4

Attachment NR-4

CapEx Reconciliation for the Period April 2011 through March 2012 and Proposed CapEx Reconciling Factors

Fiscal Year 2012 CapEx Reconciliation
Reconciliation of CapEx Revenue and Actual CapEx Revenue Requirement
For the Period April 1, 2011 through March 31, 2012
For the Refund Period October 1, 2012 through September 30, 2013

(1)	CapEx Revenue Billed	$	752,106
(2)	Actual CapEx Revenue Requirement	$	686,518
(3)	Over(Under) Recovery	$	65,588

Line Descriptions:
(1) Per Page 3, column (v)
(2) per Attachment WRR-1, page 1, Column (b), Line 13
(3) Line (1) - Line (2)

Proposed CapEx Reconciling Factors
For Fiscal Year 2012 ISR Plan
For the Recovery (Refund) Period October 1, 2012 through September 30, 2013

Line No.		Total (a)	Residential A-16 / A-60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	3000 kW Demand B-62 / G-62 (f)	Lighting S-10 / S-14 (g)	Propulsion X-01 (h)
(1)	Actual FY2012 Capital Investment Revenue Requirement	$686,518							
(2)	Total Rate Base ($000s)	$550,864	$278,750	$50,517	$90,429	$76,427	$22,285	$29,950	$2,505
(3)	Rate Base as Percentage of Total	100.00%	50.60%	9.17%	16.42%	13.87%	4.05%	5.44%	0.45%
(4)	Allocated Actual FY2012 Capital Investment Revenue Requirement	$686,518	$347,394	$62,957	$112,698	$95,248	$27,773	$37,326	$3,122
(5)	CapEx Revenue Billed	$752,106	$ 357,531.27	$ 65,302.87	$ 154,403.81	$ 106,511.92	$ 26,290.48	$ 39,336.86	$ 2,728.46
(6)	Over(Under) Recovery	$65,588	$10,137	$2,346	$41,706	$11,264	($1,482)	$2,011	($394)
(7)	Forecasted kWhs - October 1, 2012 through September 30, 2013	7,838,280,122	3,121,413,700	594,106,517	1,299,912,565	2,206,753,920	521,512,764	71,732,243	22,848,413
(8)	Proposed Class-specific CapEx Reconciling Factor per kWh	$0.00000	$0.00000	$0.00000	($0.00003)	$0.00000	$0.00000	($0.00002)	$0.00001

Line No.
(1) per Page 1, Line (2)
(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 x Line (3)
(5) per Page 3
(6) Line (4) - Line (5)
(7) per Company forecasts
(8) [Line (6) ÷ Line (7)] x -1, truncated to 5 decimal places

Fiscal Year 2012 CapEx Factor Revenue
For the Period April 1, 2011 through March 31, 2012

CapEx Factor Revenue:

Month	A16/A60 kWhs (a)	A16/A60 CapEx kWh Factor (b)	A16/A60 CapEx Revenue (c)	C06 kWhs (d)	C06 CapEx kWh Factor (e)	C06 CapEx Revenue (f)	Streetlights kWhs (g)	Streetlights CapEx kWh Factor (h)	Streetlights CapEx Revenue (i)	X01 kWhs (j)	X01 CapEx kWh Factor (k)	X01 CapEx Revenue (l)
(1) Apr-11	90,285,025	$ 0.00011	$ 9,931.35	17,510,661	$ 0.00011	$ 1,926.17	2,169,481	$ 0.00053	$ 1,149.82	774,054	$ 0.00012	$ 92.89
May-11	203,607,359	$ 0.00011	$ 22,396.81	40,605,322	$ 0.00011	$ 4,466.59	4,064,070	$ 0.00053	$ 2,153.96	1,955,628	$ 0.00012	$ 234.68
Jun-11	227,044,026	$ 0.00011	$ 24,974.84	44,222,943	$ 0.00011	$ 4,864.52	4,147,407	$ 0.00053	$ 2,198.13	1,801,309	$ 0.00012	$ 216.16
Jul-11	313,118,284	$ 0.00011	$ 34,443.01	53,654,412	$ 0.00011	$ 5,901.99	4,289,372	$ 0.00053	$ 2,273.37	2,098,224	$ 0.00012	$ 251.79
Aug-11	342,832,395	$ 0.00011	$ 37,711.56	56,939,844	$ 0.00011	$ 6,263.38	4,458,235	$ 0.00053	$ 2,362.86	1,891,044	$ 0.00012	$ 226.93
Sep-11	289,507,477	$ 0.00011	$ 31,845.82	51,013,239	$ 0.00011	$ 5,611.46	4,945,013	$ 0.00053	$ 2,620.86	1,907,401	$ 0.00012	$ 228.89
Oct-11		$ 0.00011	$ 25,017.62		$ 0.00011	$ 4,865.30		$ 0.00053	$ 2,954.84		$ 0.00012	$ 204.04
Nov-11		$ 0.00011	$ 24,710.01		$ 0.00011	$ 4,721.45		$ 0.00053	$ 3,591.91		$ 0.00012	$ 234.59
Dec-11		$ 0.00011	$ 26,022.37		$ 0.00011	$ 4,740.20		$ 0.00053	$ 3,556.96		$ 0.00012	$ 219.66
Jan-12		$ 0.00011	$ 29,941.20		$ 0.00011	$ 5,137.48		$ 0.00053	$ 3,913.79		$ 0.00012	$ 225.82
Feb-12		$ 0.00011	$ 27,988.50		$ 0.00011	$ 5,158.01		$ 0.00053	$ 3,129.07		$ 0.00012	$ 240.02
Mar-12		$ 0.00011	$ 27,105.52		$ 0.00011	$ 5,075.22		$ 0.00053	$ 2,967.35		$ 0.00012	$ 220.00
(2) Apr-12		$ 0.00011	$ 35,442.65		$ 0.00011	$ 6,571.10		$ 0.00053	$ 6,463.94		$ 0.00012	$ 133.01
Total			$ 357,531.27			$ 65,302.87			$ 39,336.86			$ 2,728.46

Month	G02 kW (m)	G02 CapEx kW Factor (n)	G02 CapEx Revenue (o)	B32 Suppl/G32 kW (p)	B32/G32 CapEx kW Factor (q)	B32/G32 CapEx Revenue (r)	B62/G62 kW (s)	B62/G62 CapEx kW Factor (t)	B62/G62 CapEx Revenue (u)	Total CapEx Revenue (v)
(1) Apr-11	114,058.3	$ 0.04	$ 4,562.33	91,966.4	$ 0.03	$ 2,758.99	34,357.0	$ 0.02	$ 687.14	$ 21,108.70
May-11	299,218.2	$ 0.04	$ 11,968.73	263,475.1	$ 0.03	$ 7,904.25	114,853.0	$ 0.02	$ 2,297.06	$ 51,422.07
Jun-11	322,619.1	$ 0.04	$ 12,904.76	292,684.9	$ 0.03	$ 8,780.55	101,334.4	$ 0.02	$ 2,026.69	$ 55,965.65
Jul-11	337,481.9	$ 0.04	$ 13,499.28	288,748.5	$ 0.03	$ 8,662.46	98,339.2	$ 0.02	$ 1,966.78	$ 66,998.67
Aug-11	346,668.0	$ 0.04	$ 13,866.72	317,794.8	$ 0.03	$ 9,533.84	129,301.3	$ 0.02	$ 2,586.03	$ 72,551.33
Sep-11	339,725.4	$ 0.04	$ 13,589.02	288,700.8	$ 0.03	$ 8,661.02	115,534.8	$ 0.02	$ 2,310.70	$ 64,867.76
Oct-11		$ 0.04	$ 12,710.01		$ 0.03	$ 8,873.46		$ 0.02	$ 2,185.45	$ 56,810.72
Nov-11		$ 0.04	$ 11,812.19		$ 0.03	$ 8,115.70		$ 0.02	$ 1,995.96	$ 55,181.81
Dec-11		$ 0.04	$ 11,427.93		$ 0.03	$ 7,956.71		$ 0.02	$ 1,830.87	$ 55,754.70
Jan-12		$ 0.04	$ 11,600.98		$ 0.03	$ 7,934.62		$ 0.02	$ 2,379.34	$ 61,133.23
Feb-12		$ 0.04	$ 11,919.19		$ 0.03	$ 7,936.04		$ 0.02	$ 1,772.66	$ 58,143.49
Mar-12		$ 0.04	$ 11,330.13		$ 0.03	$ 8,109.88		$ 0.02	$ 2,015.56	$ 56,823.66
(2) Apr-12		$ 0.04	$ 13,212.54		$ 0.03	$ 11,284.40		$ 0.02	$ 2,236.25	$ 75,343.89
Total			$ 154,403.81			$ 106,511.92			$ 26,290.48	$ 752,105.67

Column Descriptions:
(a) from monthly revenue reports
(b) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (b)
(c) for Apr-11 through Sept-11, column (a) x column (b); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(d) from monthly revenue reports
(e) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (b)
(f) for Apr-11 through Sept-11, column (d) x column (e); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(g) from monthly revenue reports
(h) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (g)
(i) for Apr-11 through Sept-11, column (g) x column (h); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(j) from monthly revenue reports
(k) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (h)
(l) for Apr-11 through Sept-11, column (j) x column (k); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(m) from monthly revenue reports
(n) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 8, Column (d)
(o) for Apr-11 through Sept-11, column (m) x column (n); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(p) from monthly revenue reports
(q) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 8, Column (e)
(r) for Apr-11 through Sept-11, column (p) x column (q); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(s) from monthly revenue reports
(t) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 8, Column (f)
(u) for Apr-11 through Sept-11, column (s) x column (t); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated CapEx revenue)
(v) column (c) + column (f) + column (i) + column (l) + column (o) + column (r) +column (u)

(1) Reflects kWhs consumed after April 1 — 39.04%
(2) Reflects kWhs consumed prior to April 1 — 57.91%

Attachment NR-5

Attachment NR-5

O&M Reconciliation for the Period April 2011 through March 2012 and Proposed O&M Reconciling Factor

Fiscal Year 2012 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For the Period April 1, 2011 through March 31, 2012
For the Recovery Period October 1, 2012 through September 30, 2013

(1)	O&M Revenue Billled	$ 9,126,390
(2)	Actual O&M Revenue Requirement	$ 9,285,435
(3)	Over(Under) Recovery	$ (159,045)
(4)	October 1, 2012 through September 30, 2013 Forecasted kWh Sales	7,838,280,122
(5)	Proposed O&M Reconciling Factor Charge per kWh	$0.00002

Line Descriptions:
(1) per Page 2, column (v)
(2) per Attachment WRR-1, page 1, Column (b), Line 6
(3) Line (1) - Line (2)
(4) per Company forecast
(5) Line (3) ÷ Line (4)

Fiscal Year 2012 Operation & Maintenance Revenue
For the Period April 1, 2011 through March 31, 2012

O&M Factor Revenue:

	Month	A16/A60 kWhs (a)	A16/A60 O&M kWh Factor (b)	A16/A60 O&M Revenue (c)	C06 kWhs (d)	C06 O&M kWh Factor (e)	C06 O&M Revenue (f)	G02 kWhs (g)	G02 O&M kWh Factor (h)	G02 O&M Revenue (i)	B32/G32 kWh (j)	B32/G32 O&M kWh Factor (k)	B32/G32 O&M Revenue (l)
(1)	Apr-11	90,285,025	$ 0.00141	$ 127,301.88	17,510,661	$ 0.00150	$ 26,265.99	39,999,582	$ 0.00120	$ 47,999.50	61,716,120	$ 0.00064	$ 39,498.32
	May-11	203,607,359	$ 0.00141	$ 287,086.38	40,605,322	$ 0.00150	$ 60,907.98	99,824,603	$ 0.00120	$ 119,789.52	163,024,697	$ 0.00064	$ 104,335.81
	Jun-11	227,044,026	$ 0.00141	$ 320,132.08	44,222,943	$ 0.00150	$ 66,334.41	108,127,926	$ 0.00120	$ 129,753.51	176,340,467	$ 0.00064	$ 112,857.90
	Jul-11	313,118,284	$ 0.00141	$ 441,496.78	53,654,412	$ 0.00150	$ 80,481.62	125,995,048	$ 0.00120	$ 151,194.06	181,370,523	$ 0.00064	$ 116,077.13
	Aug-11	342,832,395	$ 0.00141	$ 483,393.68	56,939,844	$ 0.00150	$ 85,409.77	131,869,042	$ 0.00120	$ 158,242.85	195,566,853	$ 0.00064	$ 125,162.79
	Sep-11	289,507,477	$ 0.00141	$ 408,205.54	51,013,239	$ 0.00150	$ 76,519.86	121,574,801	$ 0.00120	$ 145,889.76	177,241,910	$ 0.00064	$ 113,434.82
	Oct-11		$ 0.00141	$ 320,871.70		$ 0.00150	$ 66,447.25		$ 0.00120	$ 129,177.37		$ 0.00064	$ 108,409.24
	Nov-11		$ 0.00141	$ 316,904.74		$ 0.00150	$ 64,490.07		$ 0.00120	$ 123,473.54		$ 0.00064	$ 106,198.20
	Dec-11		$ 0.00141	$ 333,722.34		$ 0.00150	$ 64,719.87		$ 0.00120	$ 120,646.61		$ 0.00064	$ 106,537.05
	Jan-12		$ 0.00141	$ 383,944.03		$ 0.00150	$ 70,127.54		$ 0.00120	$ 124,031.41		$ 0.00064	$ 104,360.18
	Feb-12		$ 0.00141	$ 358,930.00		$ 0.00150	$ 70,435.92		$ 0.00120	$ 124,552.01		$ 0.00064	$ 103,372.82
	Mar-12		$ 0.00141	$ 347,632.22		$ 0.00150	$ 69,297.10		$ 0.00120	$ 122,489.56		$ 0.00064	$ 108,684.14
(2)	Apr-12		$ 0.00141	$ 192,855.98		$ 0.00150	$ 39,893.44		$ 0.00120	$ 75,871.85		$ 0.00064	$ 64,133.25
	Total			$ 4,322,477.35			$ 841,330.82			$ 1,573,111.56			$ 1,313,061.65

	Month	B62/G62 kW (m)	B62/G62 O&M kW Factor (n)	B62/G62 O&M Revenue (o)	Streetlights kWhs (p)	Streetlights O&M kWh Factor (q)	Streetlights O&M Revenue (r)	X01 kWhs (s)	X01 O&M kWh Factor (t)	X01 O&M Revenue (u)	Total Revenue (v)
(1)	Apr-11	34,357.0	$ 0.36	$ 12,368.53	2,169,481	$ 0.00898	$ 19,481.94	774,054	$ 0.00158	$ 1,223.01	$ 274,139.17
	May-11	114,853.0	$ 0.36	$ 41,347.08	4,064,070	$ 0.00898	$ 36,495.35	1,955,628	$ 0.00158	$ 3,089.89	$ 653,052.01
	Jun-11	101,334.4	$ 0.36	$ 36,480.38	4,147,407	$ 0.00898	$ 37,243.71	1,801,309	$ 0.00158	$ 2,846.07	$ 705,648.07
	Jul-11	98,339.2	$ 0.36	$ 35,402.11	4,289,372	$ 0.00898	$ 38,518.56	2,098,224	$ 0.00158	$ 3,315.19	$ 866,485.46
	Aug-11	129,301.3	$ 0.36	$ 46,548.47	4,458,235	$ 0.00898	$ 40,034.95	1,891,044	$ 0.00158	$ 2,987.85	$ 941,780.35
	Sep-11	115,534.8	$ 0.36	$ 41,592.53	4,945,013	$ 0.00898	$ 44,406.22	1,907,401	$ 0.00158	$ 3,013.69	$ 833,062.42
	Oct-11		$ 0.36	$ 39,338.12		$ 0.00898	$ 49,988.51		$ 0.00158	$ 2,686.65	$ 716,918.84
	Nov-11		$ 0.36	$ 35,927.42		$ 0.00898	$ 60,845.32		$ 0.00158	$ 3,088.74	$ 710,928.03
	Dec-11		$ 0.36	$ 32,955.70		$ 0.00898	$ 60,244.00		$ 0.00158	$ 2,892.18	$ 721,717.75
	Jan-12		$ 0.36	$ 42,828.27		$ 0.00898	$ 66,282.73		$ 0.00158	$ 2,973.25	$ 794,547.41
	Feb-12		$ 0.36	$ 31,907.92		$ 0.00898	$ 53,074.26		$ 0.00158	$ 3,160.27	$ 745,433.20
	Mar-12		$ 0.36	$ 36,280.12		$ 0.00898	$ 50,216.70		$ 0.00158	$ 2,896.63	$ 737,496.47
(2)	Apr-12		$ 0.36	$ 19,542.46		$ 0.00898	$ 31,132.12		$ 0.00158	$ 1,751.31	$ 425,180.42
	Total			$ 452,519.11			$ 587,964.37			$ 35,924.74	$ 9,126,389.59

Column Descriptions:
(a) from monthly revenue reports
(b) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 3, Line No 6, Column (b)
(c) for Apr-11 through Sept-11, Column (a) x Column (b); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(d) from monthly revenue reports
(e) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (c)
(f) for Apr-11 through Sept-11, Column (d) x Column (e); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(g) from monthly revenue reports
(h) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (d)
(i) for Apr-11 through Sept-11, Column (g) x Column (h); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(j) from monthly revenue reports
(k) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (e)
(l) for Apr-11 through Sept-11, Column (j) x Column (k); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(m) from monthly revenue reports
(n) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 8, Column (f)
(o) for Apr-11 through Sept-11, Column (m) x Column (n); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(p) from monthly revenue reports
(q) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (g)
(r) for Apr-11 through Sept-11, Column (p) x Column (q); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(s) from monthly revenue reports
(t) from R.I.P.U.C. Docket No. 4218 filed 3-2-2011, Section 7: Rate Design - Revised, Page 2, Line No 6, Column (h)
(u) for Apr-11 through Sept-11, Column (s) x Column (t); for Oct-11 through Apr-12, per Company revenue reports (beginning in Oct-11, Company's revenue reports isolated O&M revenue)
(v) Column (c) + Column (f) + Column (i) + Column (l) + Column (o) + Column (r) + Column (u)

(1) Reflects kWhs consumed after April 1 39.04%
(2) Reflects kWhs consumed prior to April 1 57.91%

Attachment NR-6

Attachment NR-6

Typical Bill Analysis

Date: 31-Jul-12
Time: 11:00 AM

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

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
150	$25.36	$10.82	$14.54	$25.36	$10.82	$14.54	$0.00	0.0%	13.7%
300	$45.96	$21.65	$24.31	$45.96	$21.65	$24.31	$0.00	0.0%	17.5%
400	$59.68	$28.86	$30.82	$59.68	$28.86	$30.82	$0.00	0.0%	11.8%
500	$73.41	$36.08	$37.33	$73.42	$36.08	$37.34	$0.01	0.0%	10.8%
600	$87.13	$43.29	$43.84	$87.14	$43.29	$43.85	$0.01	0.0%	9.4%
700	$100.86	$50.51	$50.35	$100.87	$50.51	$50.36	$0.01	0.0%	7.7%
1,000	$142.05	$72.16	$69.89	$142.07	$72.16	$69.91	$0.02	0.0%	15.0%
2,000	$279.31	$144.31	$135.00	$279.35	$144.31	$135.04	$0.04	0.0%	14.1%

Present Rates (as of 7/1/2012)

Customer Charge		$3.75
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge	kWh x	$0.03617
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06927

Proposed Rates

Customer Charge		$3.75
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge (1)	kWh x	$0.03619
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06927

Note (1): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
150	$19.31	$10.82	$8.49	$19.32	$10.82	$8.50	$0.01	0.1%	10.7%
300	$37.77	$21.65	$16.12	$37.78	$21.65	$16.13	$0.01	0.0%	23.2%
400	$50.07	$28.86	$21.21	$50.08	$28.86	$21.22	$0.01	0.0%	14.9%
500	$62.38	$36.08	$26.30	$62.39	$36.08	$26.31	$0.01	0.0%	12.2%
600	$74.67	$43.29	$31.38	$74.69	$43.29	$31.40	$0.02	0.0%	9.6%
700	$86.98	$50.51	$36.47	$87.00	$50.51	$36.49	$0.02	0.0%	7.3%
1,000	$123.89	$72.16	$51.73	$123.91	$72.16	$51.75	$0.02	0.0%	12.3%
2000	$246.90	$144.31	$102.59	$246.95	$144.31	$102.64	$0.05	0.0%	9.8%

Present Rates (as of 7/1/2012)

Customer Charge		$0.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge	kWh x	$0.02249
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06927

Proposed Rates

Customer Charge		$0.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge (1)	kWh x	$0.02251
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06927

Note (1): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
250	$41.00	$16.20	$24.80	$41.01	$16.20	$24.81	$0.01	0.0%	35.2%
500	$72.82	$32.41	$40.41	$72.83	$32.41	$40.42	$0.01	0.0%	17.0%
1,000	$136.42	$64.81	$71.61	$136.45	$64.81	$71.64	$0.03	0.0%	19.0%
1,500	$200.04	$97.22	$102.82	$200.07	$97.22	$102.85	$0.03	0.0%	9.8%
2,000	$263.66	$129.63	$134.03	$263.70	$129.63	$134.07	$0.04	0.0%	19.1%

Present Rates (as of 7/1/2012)

Customer Charge		$8.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01838
Distribution Energy Charge	kWh x	$0.03462
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Proposed Rates

Customer Charge		$8.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01838
Distribution Energy Charge (1)	kWh x	$0.03464
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Note (1): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$590.99	$259.25	$331.74	$590.95	$259.25	$331.70	($0.04)	0.0%
50	10,000	$1,355.56	$648.13	$707.43	$1,355.45	$648.13	$707.32	($0.11)	0.0%
100	20,000	$2,629.82	$1,296.25	$1,333.57	$2,629.61	$1,296.25	$1,333.36	($0.21)	0.0%
150	30,000	$3,904.10	$1,944.38	$1,959.72	$3,903.79	$1,944.38	$1,959.41	($0.31)	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge	kWh x	$0.00744
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Proposed Rates

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge (1)	kWh x	$0.00743
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Note (1): includes the Proposed CapEx Reconciling Factor of (0.003¢)/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$767.93	$388.88	$379.05	$767.87	$388.88	$378.99	($0.06)	0.0%
50	15,000	$1,797.90	$972.19	$825.71	$1,797.74	$972.19	$825.55	($0.16)	0.0%
100	30,000	$3,514.52	$1,944.38	$1,570.14	$3,514.20	$1,944.38	$1,569.82	($0.32)	0.0%
150	45,000	$5,231.12	$2,916.56	$2,314.56	$5,230.65	$2,916.56	$2,314.09	($0.47)	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge	kWh x	$0.00744
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Proposed Rates

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge (1)	kWh x	$0.00743
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Note (1): includes the Proposed CapEx Reconciling Factor of (0.003¢)/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$944.86	$518.50	$426.36	$944.78	$518.50	$426.28	($0.08)	0.0%
50	20,000	$2,240.24	$1,296.25	$943.99	$2,240.03	$1,296.25	$943.78	($0.21)	0.0%
100	40,000	$4,399.20	$2,592.50	$1,806.70	$4,398.78	$2,592.50	$1,806.28	($0.42)	0.0%
150	60,000	$6,558.16	$3,888.75	$2,669.41	$6,557.53	$3,888.75	$2,668.78	($0.63)	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge	kWh x	$0.00744
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Proposed Rates

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge (1)	kWh x	$0.00743
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Note (1): includes the Proposed CapEx Reconciling Factor of (0.003¢)/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,121.81	$648.13	$473.68	$1,121.70	$648.13	$473.57	($0.11)	0.0%
50	25,000	$2,682.58	$1,620.31	$1,062.27	$2,682.32	$1,620.31	$1,062.01	($0.26)	0.0%
100	50,000	$5,283.89	$3,240.63	$2,043.26	$5,283.37	$3,240.63	$2,042.74	($0.52)	0.0%
150	75,000	$7,885.19	$4,860.94	$3,024.25	$7,884.41	$4,860.94	$3,023.47	($0.78)	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge	kWh x	$0.00744
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Proposed Rates

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge (1)	kWh x	$0.00743
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Note (1): includes the Proposed CapEx Reconciling Factor of (0.003¢)/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,298.74	$777.75	$520.99	$1,298.61	$777.75	$520.86	($0.13)	0.0%
50	30,000	$3,124.93	$1,944.38	$1,180.55	$3,124.62	$1,944.38	$1,180.24	($0.31)	0.0%
100	60,000	$6,168.57	$3,888.75	$2,279.82	$6,167.95	$3,888.75	$2,279.20	($0.62)	0.0%
150	90,000	$9,212.22	$5,833.13	$3,379.09	$9,211.29	$5,833.13	$3,378.16	($0.93)	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge	kWh x	$0.00744
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Proposed Rates

Customer Charge		$125.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW	kW x	$4.78
Distribution Energy Charge (1)	kWh x	$0.00743
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06222

Note (1): includes the Proposed CapEx Reconciling Factor of (0.003¢)/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$4,279.61	$1,966.25	$2,313.36	$4,280.45	$1,966.25	$2,314.20	$0.84	0.0%
750	150,000	$15,209.72	$7,373.44	$7,836.28	$15,212.85	$7,373.44	$7,839.41	$3.13	0.0%
1,000	200,000	$20,177.95	$9,831.25	$10,346.70	$20,182.11	$9,831.25	$10,350.86	$4.16	0.0%
1,500	300,000	$30,114.41	$14,746.88	$15,367.53	$30,120.66	$14,746.88	$15,373.78	$6.25	0.0%
2,500	500,000	$49,987.33	$24,578.13	$25,409.20	$49,997.74	$24,578.13	$25,419.61	$10.41	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge	kWh x	$0.00877
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge (2)	kWh x	$0.00879
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$5,724.20	$2,949.38	$2,774.82	$5,725.45	$2,949.38	$2,776.07	$1.25	0.0%
750	225,000	$20,626.91	$11,060.16	$9,566.75	$20,631.60	$11,060.16	$9,571.44	$4.69	0.0%
1,000	300,000	$27,400.87	$14,746.88	$12,653.99	$27,407.12	$14,746.88	$12,660.24	$6.25	0.0%
1,500	450,000	$40,948.78	$22,120.31	$18,828.47	$40,958.15	$22,120.31	$18,837.84	$9.37	0.0%
2,500	750,000	$68,044.62	$36,867.19	$31,177.43	$68,060.24	$36,867.19	$31,193.05	$15.62	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge	kWh x	$0.00877
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge (2)	kWh x	$0.00879
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$7,168.78	$3,932.50	$3,236.28	$7,170.45	$3,932.50	$3,237.95	$1.67	0.0%
							$305.03		
750	300,000	$26,044.10	$14,746.88	$11,297.22	$26,050.35	$14,746.88	$11,303.47	$6.25	0.0%
							$305.03		
1,000	400,000	$34,623.78	$19,662.50	$14,961.28	$34,632.11	$19,662.50	$14,969.61	$8.33	0.0%
							$305.03		
1,500	600,000	$51,783.16	$29,493.75	$22,289.41	$51,795.66	$29,493.75	$22,301.91	$12.50	0.0%
							$305.03		
2,500	1,000,000	$86,101.91	$49,156.25	$36,945.66	$86,122.74	$49,156.25	$36,966.49	$20.83	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge	kWh x	$0.00877
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge (2)	kWh x	$0.00879
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

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Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$8,613.37	$4,915.63	$3,697.74	$8,615.45	$4,915.63	$3,699.82	$2.08	0.0%
750	375,000	$31,461.28	$18,433.59	$13,027.69	$31,469.09	$18,433.59	$13,035.50	$7.81	0.0%
1,000	500,000	$41,846.70	$24,578.13	$17,268.57	$41,857.12	$24,578.13	$17,278.99	$10.42	0.0%
1,500	750,000	$62,617.53	$36,867.19	$25,750.34	$62,633.16	$36,867.19	$25,765.97	$15.63	0.0%
2,500	1,250,000	$104,159.20	$61,445.31	$42,713.89	$104,185.24	$61,445.31	$42,739.93	$26.04	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge	kWh x	$0.00877
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge (2)	kWh x	$0.00879
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$10,057.95	$5,898.75	$4,159.20	$10,060.45	$5,898.75	$4,161.70	$2.50	0.0%
750	450,000	$36,878.47	$22,120.31	$14,758.16	$36,887.84	$22,120.31	$14,767.53	$9.37	0.0%
1,000	600,000	$49,069.61	$29,493.75	$19,575.86	$49,082.11	$29,493.75	$19,588.36	$12.50	0.0%
1,500	900,000	$73,451.91	$44,240.63	$29,211.28	$73,470.66	$44,240.63	$29,230.03	$18.75	0.0%
2,500	1,500,000	$122,216.49	$73,734.38	$48,482.11	$122,247.74	$73,734.38	$48,513.36	$31.25	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge	kWh x	$0.00877
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$750.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW	kW x	$2.29
Distribution Energy Charge (2)	kWh x	$0.00879
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	600,000	$74,127.95	$29,493.75	$44,634.20	$74,140.51	$29,493.75	$44,646.76	$12.56	0.0%
5,000	1,000,000	$111,740.45	$49,156.25	$62,584.20	$111,761.39	$49,156.25	$62,605.14	$20.94	0.0%
7,500	1,500,000	$158,756.08	$73,734.38	$85,021.70	$158,787.48	$73,734.38	$85,053.10	$31.40	0.0%
10,000	2,000,000	$205,771.70	$98,312.50	$107,459.20	$205,813.57	$98,312.50	$107,501.07	$41.87	0.0%
20,000	4,000,000	$393,834.20	$196,625.00	$197,209.20	$393,917.95	$196,625.00	$197,292.95	$83.75	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00005)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00003)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

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

Hours Use: 300

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	900,000	$93,040.45	$44,240.63	$48,799.82	$93,059.27	$44,240.63	48,819	$18.82	0.0%
5,000	1,500,000	$143,261.29	$73,734.38	$69,526.91	$143,292.64	$73,734.38	69,558	$31.35	0.0%
7,500	2,250,000	$206,037.32	$110,601.56	$95,435.76	$206,084.35	$110,601.56	95,483	$47.03	0.0%
10,000	3,000,000	$268,813.36	$147,468.75	$121,344.61	$268,876.07	$147,468.75	121,407	$62.71	0.0%
20,000	6,000,000	$519,917.53	$294,937.50	$224,980.03	$520,042.95	$294,937.50	225,105	$125.42	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00005)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00003)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to 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	$111,952.95	$58,987.50	$52,965.45	$111,978.01	$58,987.50	$52,990.51	$25.06	0.0%
5,000	2,000,000	$174,782.11	$98,312.50	$76,469.61	$174,823.89	$98,312.50	$76,511.39	$41.78	0.0%
7,500	3,000,000	$253,318.57	$147,468.75	$105,849.82	$253,381.23	$147,468.75	$105,912.48	$62.66	0.0%
10,000	4,000,000	$331,855.03	$196,625.00	$135,230.03	$331,938.57	$196,625.00	$135,313.57	$83.54	0.0%
20,000	8,000,000	$646,000.86	$393,250.00	$252,750.86	$646,167.95	$393,250.00	$252,917.95	$167.09	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00005)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00003)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to 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	$130,865.45	$73,734.38	$57,131.07	$130,896.77	$73,734.38	$57,162.39	$31.32	0.0%
5,000	2,500,000	$206,302.95	$122,890.63	$83,412.32	$206,355.14	$122,890.63	$83,464.51	$52.19	0.0%
7,500	3,750,000	$300,599.83	$184,335.94	$116,263.89	$300,678.11	$184,335.94	$116,342.17	$78.28	0.0%
10,000	5,000,000	$394,896.70	$245,781.25	$149,115.45	$395,001.07	$245,781.25	$149,219.82	$104.37	0.0%
20,000	10,000,000	$772,084.20	$491,562.50	$280,521.70	$772,292.95	$491,562.50	$280,730.45	$208.75	0.0%

Present Rates (as of 7/1/2012)

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00005)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00003)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh

Date: 31-Jul-12
Time: 11:00 AM

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to 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	$149,777.95	$88,481.25	$61,296.70	$149,815.51	$88,481.25	$61,334.26	$37.56	0.0%
5,000	3,000,000	$237,823.78	$147,468.75	$90,355.03	$237,886.39	$147,468.75	$90,417.64	$62.61	0.0%
7,500	4,500,000	$347,881.08	$221,203.13	$126,677.95	$347,974.98	$221,203.13	$126,771.85	$93.90	0.0%
10,000	6,000,000	$457,938.36	$294,937.50	$163,000.86	$458,063.57	$294,937.50	$163,126.07	$125.21	0.0%
20,000	12,000,000	$898,167.53	$589,875.00	$308,292.53	$898,417.95	$589,875.00	$308,542.95	$250.42	0.0%

<u>Present Rates (as of 7/1/2012)</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00005)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kWh x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.03
Distribution Energy Charge	kWh x	($0.00003)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00622
Renewable Energy Distribution Charge	kW x	$0.00007
Gross Earnings Tax		4%
Standard Offer Charge (1)	kWh x	$0.04719

Note (1): Includes a simple average of the Jul-2012 through Sept-2012 Standard Offer Service Charge of 4.698¢/kWh, Renewable Energy Standard Charge of 0.253¢/kWh, Standard Offer Adjustment Factor of (0.332¢)/kWh, and Standard Offer Service Administrative Cost Factor of 0.100¢/kWh

Note (2): includes the Proposed CapEx Reconciling Factor of 0.000¢/kWh and the Proposed O&M Reconciling Factor of 0.002¢/kWh