nationalgrid

Thomas R. Teehan
Senior Counsel

August 1, 2013

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4307 - Electric Infrastructure, Safety, and Reliability Plan Fiscal Year 2013 Annual Report and Reconciliation Filing

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's Electric Infrastructure, Safety, and Reliability ("ISR") Plan Fiscal Year ("FY") 2013 Annual Report and Reconciliation filing. Pursuant to the provisions of the approved ISR Plan and implementing tariffs found at R.I.P.U.C. No. 2118, 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 Operations and Maintenance ("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. Similarly, the annual O&M Reconciling Factor is to reconcile actual Inspection and Maintenance ("I&M") program expense and actual Vegetation Management program expense to actual billed revenue from the O&M Reconciling Factor for the plan year. Additionally, on August 1, the Company is to submit an annual report on the prior FY's ISR activities describing certain deviations from the original plans approved by the Commission.

The enclosed Annual Report and Reconciliation filing contains the pre-filed direct testimony of Jennifer Grimsley, William R. Richer, and Nancy Ribot. Ms. Grimsley presents the Company's annual report on its ISR activities for FY 2013. She provides the actual spending for the period April 1, 2012 through March 31, 2013 as well as detailed explanations for variations from the approved plan. In addition, Ms. Grimsley provides information on the Company's plant in service during that time period. Mr. Richer calculates an updated FY 2013 ISR revenue requirement associated with actual FY 2013 O&M programs, the actual cumulative FY 2013 and FY 2012 plant additions, and actual tax deductibility percentages for FY 2012 capital additions. Mr. Richer's calculation of the updated revenue requirement takes into consideration that the forecasted ISR Plan investment was put into rate base and is now being recovered in base rates as a

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

result of the 2012 rate case, Docket 4323. Finally, Ms. Ribot provides the results of the annual reconciliations of the updated FY 2013 capital investment revenue requirement and the O&M expense to the actual revenue billed, the status of the FY 2012 CapEx and O&M reconciliations, the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2013, and the proposed tariff rate summary reflecting the new reconciling factors. Ms. Ribot also provides the bill impacts of the proposed reconciling 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 a decrease of $0.08, from $78.97 to $78.89.

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

Enclosures

cc: Docket 4307 Service List
LeoWold, Esq.
Steve Scialabba, Division
James Lanni, Division
Al Contente, Division

National Grid

The Narragansett Electric Company

FY 2013 Electric Infrastructure, Safety, and Reliability Plan
Reconciliation Filing

August 1, 2013

Submitted to:
Rhode Island Public Utilities Commission
R.I.P.U.C. Docket No. 4307

Submitted by:

nationalgrid

Filing Letter

Testimony of
Jennifer L. Grimsley

PRE-FILED DIRECT TESTIMONY

OF

JENNIFER L. GRIMSLEY

August 1, 2013

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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, Inc. ("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 and No. 4382 in support of the Company’s fiscal year 2013 (“FY13”) and fiscal year 2014 (“FY14”) Infrastructure, Safety and Reliability (“ISR”) Plans, in Docket No. 4218 in support of the Company’s fiscal year 2012 (“FY12”) Infrastructure, Safety and Reliability (“ISR”) Plan Reconciliation and in Docket No. 4237 in support of the Company’s Contact Voltage Program,

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

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 FY13 Electric ISR Plan approved by the Commission in this docket on March 29, 2012. This filing includes the actual Discretionary and Non-Discretionary Capital investment spending and the actual Vegetation Management and Inspection and Maintenance (I&M) expenses for the period April 1, 2012 through March 31, 2013 with explanations for variations from the approved plan. In addition, I also present detailed information on the Company's plant in service and cost of removal during that time period. This information is then utilized by Mr. William Richer, as discussed in his testimony, for his reconciliation of the FY13 Electric ISR revenue requirement with the budgeted amounts for the categories approved by the Commission. The specific FY13 Electric ISR spending, plant in service additions and cost of removal by categories is set forth in Attachment JLG-1 attached to this testimony.

III. <u>ACTUAL CAPITAL SPENDING</u>

Q. Please summarize the Company's actual capital spending for FY13 for the Electric ISR Plan.

A. As set forth in Table 1 in Attachment JLG-1, overall, for FY13, the Company spent $49.5 million for capital investment under the Electric ISR Plan. This amount was $7.0 million under budget against an annual approved budget of $56.5 million. The $7.0 million variance was comprised of $2.5 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 $4.5 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 both the asset condition and system capacity and performance category which were delayed or came in under budget.

As discussed in the FY12 ISR docket, 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, through the second quarter of FY13, the Company has kept the Rhode Island Division of Public Utilities and Carriers ("Division") and the Commission apprised of these deviations and variances and provided explanations for them in its quarterly report filings. In FY13, the Company consolidated its financial systems, implementing the SAP financial reporting system in November of 2012. As a result of this major system conversion, the Company was unable to file its third and fourth quarterly ISR reports due to the unavailability of certain financial information ordinarily included in those reports. The financial data required to support the capital spending amounts of the full fiscal year is now available from the SAP system and is included in this annual report for all quarters of FY13. The spending results for the FY13 ISR plan have been reviewed and several adjustments were made based on a review of capital, expense and cost of removal cost trends both pre- and post-SAP. As with any system conversion of this magnitude, continued review of financial data is ongoing until such time as the Company determines the systems are adequately stabilized and operating in an expected fashion. If the Company should discover any inaccuracies with the data recorded in its general ledger and submitted with this filing, appropriate adjustments to this filing will be submitted to ensure that customers are insulated from any unintended economic harm.

Q. Will the Company resume quarterly reporting for FY14?

A. Yes, the Company does plan to resume quarterly reporting for FY14. The Company plans to file its first quarterly report for FY14 in September 2013, and will keep the Division and Commission apprised of any delays.

Q. What were the primary drivers for the Electric ISR Plan capital variance below budget in FY13?

A. The major drivers for the Electric ISR Plan capital variance for FY13 were in the Non-Discretionary Statutory/Regulatory category and the Discretionary Asset Condition and 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 FY13 as well as an increase in the amount of contributions and reimbursements received on Distributed Generation and Public Requirements projects. These reductions resulted in a variance below budget of $9.6 million.

As shown on Table 6 in Attachment JLG-1, there was a $3.8 million variance below budget for the Discretionary Asset Condition category, a result of the delay of a number of projects for FY13. These delays were primarily in the asset replacement and flood mitigation avoidance categories, and are discussed in Section 2 of Attachment JLG-1. In addition, as shown on Table 6 in Attachment JLG-1, there was a $2.6 million variance below budget for the Discretionary System Capacity and Performance category, again a result of the delay of a number of projects for FY13. These delays were primarily driven by permitting and land acquisition issues for substation projects.

Q. Were there any capital budget categories where spending exceeded the budget in the FY13 Electric ISR Plan and what were the primary drivers?

A. The Non-Discretionary Damage/Failure budget category exceeded its budget by $7.0 million in FY13. This variance was for major storms, as shown on Table 3 in Attachment JLG-1 and was primarily driven by Hurricane Sandy in October 2012 and the February 7, 2013 winter storm. In addition, the Discretionary Non-Infrastructure Category exceeded its budget by $1.9 million in FY13. This variance was for telecommunications as well as administrative accounting items as shown on Table 5 in Attachment JLG-1. The Telecommunications variance was driven by a radio improvement project which was inadvertently not budgeted in FY13. This project will upgrade the radio system for Rhode Island from UHF Logic Trunk Radio to PassPort networked trunking, and replace the electric mobile radio fleet, which is not PassPort trunking compliant. The Non-Infrastructure category also contains several administrative accounting items which contribute to the variance above budget, as discussed in Attachment JLG-1.

IV. <u>PLANT IN SERVICE</u>

Q. Please provide an overview of the plant in service for FY13.

A. As shown on Table 8 in Attachment JLG-1, the Company placed $44.3 million of plant in service, which was $7.0 million below the forecast for plant in service of approximately $51.3 million for FY13. 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. <u>O&M SPENDING</u>

Q. Please summarize the Company's actual O & M spending for the FY13 Electric ISR Plan.

A. As shown on Table 10 in Attachment JLG-1, the total Vegetation Management spending for FY13 was $8.248 million against an approved budget of $8.256 million. In addition, as shown on Table 11, the overall I&M spending was approximately $1.2 million, against an approved budget of $2.3 million. While this work had a significant variance below budget, the majority of the work was completed. Detailed information regarding the variance below budget and the work completed is discussed in Section V of Attachment JLG-1.

VI. <u>RELIABILITY</u>

Q. Please summarize the results of the Company's reliability performance for FY13.

A. Table 12 in Attachment JLG-1 presents the Company's Reliability Performance for calendar year 2012 ("CY12"). As shown, the Company met both its SAIFI and SAIDI performance metrics in CY12, with SAIFI of 0.90, against a target of 1.05, and SAIDI of 65.99 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 CY12, the Company had two events, comprised of four days, which were characterized as major event days, the most significant being Hurricane Sandy, which led to the interruption of over 150,000 customers starting on October 29, 2012. Tables 13 and 14 provide specific detail of customers interrupted and daily SAIDI for each of the two events, as well as overall reliability performance measures including major event days.

Q. Does this conclude this testimony?

A. Yes, it does.

ATTACHMENT-JLG-1

FY13 ELECTRIC

INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN

ANNUAL REPORT AND RECONCILIATION

Attachment JLG-1

Electric Infrastructure, Safety and Reliability Plan

FY13 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 2013 ("FY13") 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 and Inspection and Maintenance (I&M) expenses for the period April 1, 2012 to March 31, 2013. The actual spending is compared to the budgeted amounts for these categories as approved by the Commission. Also included are details on the Company's plant in service during that time period. Finally, this filing also includes a summary of the Company's Reliability Performance through December 31, 2012.

For FY13, the Company's capital Electric ISR spending was $49.5 million, which was $7.0 million less than the annual approved budget of $56.5 million. Section I, below provides a summary overview of the actual non-discretionary and discretionary capital investment. Section II provides an explanation of capital investment variances by category to the budget approved in Docket No. 4307. A summary overview of the plant placed in service in FY13 compared to the FY13 ISR budget is set forth in Section III. Section IV provides a breakdown of Vegetation Management expenses and an explanation of the variance for these expenses within the categories of the approved budget of $8.3 million. Section V provides a similar breakdown for I&M expenses and an explanation of the variance with the approved budget of $2.3 million. Finally, the Company's reliability performance metrics are addressed in Section VI of this filing.

In FY13, the Company consolidated its financial systems, implementing the SAP financial reporting system in November of 2012. As a result of this major system conversion, the Company was unable to file its third and fourth quarterly ISR reports due to the unavailability of certain financial information ordinarily included in those reports. The financial data required to support the capital spending amounts of the full fiscal year is now available from the SAP system and is included in this annual report for all quarters of FY13. The spending results for the FY13 ISR plan have been reviewed and several adjustments were made based on a review of capital, expense and cost of removal cost trends both pre- and post-SAP. As with any system conversion of this magnitude, continued review of financial data is ongoing until such time as the Company determines the systems are adequately stabilized and operating in an expected fashion. If the

Company should discover any inaccuracies with the data recorded in its general ledger and submitted with this filing, appropriate adjustments to this filing will be submitted to ensure that customers are insulated from any unintended economic harm.

I FY13 Actual Results

1. Capital Spending Overview

As set forth in Table 1 below[1], overall, for FY13, the Company spent $49.5 million for capital investment under the Electric ISR Plan. This amount was $7.0 million under budget against an annual approved budget of $56.5 million. This $7.0 million variance is comprised of $2.5 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, as well as an increase in contributions and reimbursements in comparison to historical projections. An additional variance of $4.5 million of discretionary capital (asset condition, non-infrastructure and system capacity and performance) spending was primarily driven by projects in the asset condition and 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

	FY13 Annual ISR Budget ($)	FY13 Actual ($)	Variance ($)
NON-DISCRETIONARY CAPITAL SPENDING			
Statutory/Regulatory	20,006,000	10,410,223	(9,595,777)
Damage/Failure	10,422,000	17,515,452	7,093,452
Subtotal	**30,428,000**	**27,925,675**	**(2,502,325)**
DISCRETIONARY CAPITAL SPENDING			
Asset Condition	11,863,000	8,070,832	(3,792,168)
Non-Infrastructure	336,000	2,269,065	1,933,065
System Capacity & Performance	13,913,000	11,249,212	(2,663,788)
Subtotal	**26,112,000**	**21,589,109**	**(4,522,891)**
TOTAL CAPITAL SPENDING	**56,540,000**	**49,514,784**	**(7,025,216)**

[1] For consistency, in this Attachment, “Variances” shown in parentheses ( ) reflect an under spending.

II. Actual Spending by Category

1. Non- Discretionary Capital Expenditures Compared to Budget for FY13

The key drivers for the variances by major categories for non-discretionary capital spending compared to the budget for FY13 are listed below.

a. ***Statutory/Regulatory - $9.6 million under budget for FY13***

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 FY13. Furthermore, Contributions in Aid of Construction (CIACs) and reimbursements for distributed generation and public requirements projects exceeded historical projections, with $1.2M more in reimbursements than FY12. The credit balances for distributed generation and public requirements are due to timing, where the construction and the reimbursements are not occurring in the same fiscal year. As shown in Table 2 below, new business commercial, meters, public requirements and distributed generation capital spending were the major contributors to this category's variance below budget of $9.6 million. Detailed budget and actual spending by budget classification for the Statutory/Regulatory category is shown in Table 2 below.

Table 2

Spending Rationale	**Budget Classification**	**FY13 Budget ($)**	**FY13 Actual Spending ($)**	**Variance**
Statutory/Regulatory	3rd Party Attachments	705,000	223,335	(481,665)
	Land and Land Rights - Distribution	297,000	127,922	(169,078)
	Meters – Distribution	1,815,000	1,454,793	(360,207)
	Distributed Generation		(675,256)	(675,256)
	New Business - Commercial	5,950,000	3,721,667	(2,228,333)
	New Business - Residential	3,304,000	2,885,908	(418,092)
	Outdoor Lighting - Capital	571,000	487,545	(83,455)
	Public Requirements	3,709,000	(1,230,546)	(4,939,546)
	Transformers and Related Equipment	3,655,000	3,414,855	(240,145)
	Statutory/Regulatory Subtotal	**20,006,000**	**10,410,223**	**(9,595,777)**

b. ***Damage/Failure - $7.1 million over budget for FY13***

In contrast, the Damage/Failure capital spending for FY13 was higher than budget due primarily to the storm activity associated with the costs[2] of restoration following Hurricane Sandy and the February 7 Winter Storm. Detailed budget and actual spending by budget classification for the Damage/Failure category is shown in Table 3.

Table 3

Spending Rationale	Budget Classification	FY13 Budget ($)	FY13 Actual Spending ($)	Variance
Damage/Failure	Damage/Failure	9,772,000	7,795,002	(1,976,998)
	Major Storms - Dist	650,000	9,720,450	9,070,450
	Damage/Failure Subtotal	**10,422,000**	**17,525,452**	**7,093,452**

2. Discretionary Capital Expenditures Compared to Budget for FY13

a. ***Asset Condition - $3.8 million under budget for FY13***

Overall spending was less than budget in the Asset Condition category for FY13 primarily driven by the variance on asset replacement projects, the flood damage and avoidance mitigation projects, and the Woonsocket project.

As discussed in the Company's second quarterly report[3], the following projects are the primary drivers for the variance below budget in the asset replacement projects:

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

3 Electric Infrastructure, Safety ad Reliability Plan, FY13 Quarterly Update, Second Quarter Ending September 30, 2012, filed November 30, 2012.

- The Eddy St. Cable installation was completed in FY12 ahead of schedule, with some carryover of costs into FY13, resulting in a variance below budget of approximately $430,000.

- Governor St. Providence spending was below budget because the project schedule was adjusted to best coordinate with a gas project on the same street. This resulted in a variance below budget of approximately $980.000.

- Fdr 1111 Install Cable Weybosset/Union Streets, Providence is under budget due to the acceleration of the project into FY12, ahead of schedule. This resulted in a variance below budget of approximately $200,000.

- Fdr 1127 install Cable Dyer/Dorrance Sts Providence is under budget due to the acceleration of the project into FY12, ahead of schedule. This resulted in a variance below budget of approximately $260,000.

- Relay Replacement Project spending is under budget in FY13 due to spending at Riverside Substation being delayed into FY14 in order to advance higher priority work at the Riverside Substation. This resulted in a variance below budget of approximately $700,000.

In addition, the Spare Transformer project in the asset condition category was reflected in the system capacity and performance category, resulting in a variance below budget of $350,000 in the asset condition category.

Offsetting a portion of this variance below budget were emergent projects that were not budgeted in FY13, the most significant of which are the following:

- Final payments were made on a Mobile Substation Replacement Project which was an emergent project in FY12. The mobile substation will reduce constraints on this equipment and allow work on more projects in parallel. This resulted in a variance above budget of approximately $575,000.

- Additional cable replacement projects were undertaken to replace the cable work which was accelerated into FY12, such as Feeder 1107, Chapel Street and Mathewson Street and Merton Sub Cable 37K22. This resulted in a variance above budget of approximately $580,000.

For the Asset Replacement – Inspection and Maintenance project, the variance below budget was approximately $300,000. For FY13, 93% of the planned I&M work was completed. Twelve of the sixteen feeders in the I&M program were completed, and 4 feeders were partially completed. Three of the feeders which were partially completed were delayed due to Telephone Company pole sets. (Currently only one feeder is still awaiting Telephone Company pole sets.)

The amounts budgeted in the FY13 ISR for the flood damage avoidance were to begin mitigation work resulting from engineering reviews. The bulk of the costs included in the FY13 ISR were to start mitigation measures to retire the Westerly substation with the installation of new facilities in Hopkinton and at the Langworthy substation. The Company has consolidated capacity-related and flood-mitigation-related projects for Hopkinton in the system capacity and performance category going forward. For the FY13 ISR, the Hopkinton and Langworthy projects in the asset condition category were approximately $700,000 under budget due to the transfer of approximately $175,000 out of the asset condition project to consolidate with the Hopkinton system capacity project and due to delays experienced with the Hopkinton project. The delays were primarily driven by extended Town negotiations regarding the proposed property requiring a zoning amendment approval and delays in the environmental due diligence process for purchasing the land. Originally the Company expected to close on the land in February of 2013, but currently the date scheduled for closing on the property is October 2013. The Company is currently assessing the overall schedule impacts, but does expect the schedule for construction to be delayed by several months. The Langworthy variance below budget is approximately $200,000 (of the ($700,000 total variance mentioned above). This variance is due to final design being deferred to FY14 primarily driven by delays in obtaining transformer information from the manufacturer. It is expected that Langworthy will be complete by May 2014.

Engineering is progressing for solutions at Pontiac, Pawtuxet, and Warwick Mall substations, and solutions for these substations account for more than half of the funds spent in this category. Spending for the Pontiac station was approximately $160,000 under budget as a result of refined scope definition that occurred during this fiscal year to include other asset condition work at this station.

Spending for the Sockanosett Substation had a variance $200,000 under budget. As discussed in the FY 14 ISR Plan[4], spending for Sockanosett has been deferred pending an area capacity study that may affect the need for this substation. The study is expected to be completed by October 2013.

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4 Electric Infrastructure, Safety, and Reliability Plan FY 2014 Proposal, filed December 28, 2012, Docket No. 4382.

The variance of approximately $640,000 below budget for Woonsocket is due to completion of this project ahead of schedule, and with lower than estimated costs. This project was placed in service in February of 2013, ahead of the original schedule, with minimal work carrying over into FY13. In addition, one less recloser was installed than had been included in the project estimate, and less repaving was required at the site than originally anticipated. Overall this project was budgeted for $1.7 million and the actual cost was $1.4 million.

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

Table 4

Spending Rationale	Budget Classification	FY13 Budget ($)	FY13 Actual Spending ($)	Variance
Asset Condition	Woonsocket & Related	825,000	188,356	(636,644)
	Asset Replacement	8,583,000	6,611,918	(1,971,082)
	Asset Replacement – I&M	1,250,000	1,086,377	(163,623)
	Flood Damage Avoidance Engineering Studies	1,205,000	184,181	(1,020,819)
	Asset Condition Subtotal	**11,863,000**	**8,070,832**	**(3,792,168)**

b. *Non-Infrastructure - $1.9 million over budget for FY13*

As shown in Table 5 overall spending in the non-infrastructure category for FY13 is higher than budget due to a radio improvement project, which was inadvertently not budgeted in FY13. This project will upgrade the radio system for Rhode Island from UHF Logic Trunk Radio to PassPort networked trunking, and replace the electric mobile radio fleet, which is not PassPort trunking compliant. PassPort trunking is a two-way radio system technology that networks multiple transmitter sites together simplifying radio operation for the end user. This will also maintain compatibility with radio systems between Rhode Island and Massachusetts for emergency restoration. The spending on this project in FY13 was approximately $1 million.

It should be noted that the Non-Infrastructure category contains several administrative accounting items. In the non-infrastructure category there is a positive balance of approximately $500,000 for other accounting adjustments. This includes a reclassification adjustment associated with a $400,000 credit described in the Company's FY 12 Electric ISR reconciliation filing. In FY 13, this credit was reclassified resulting in an increase in the non-infrastructure category offset by smaller decreases to other ISR categories. The net impact on total FY 13 ISR spending as a result of this particular adjustment is zero. Also in the Non-Infrastructure Administrative/General category is approximately $390,000 which is a transmission charge inadvertently included in the distribution costs. This charge was post-SAP and will be corrected in FY14. It should be noted that this charge is not included in plant in service costs included in Table 8, and will have no customer impact.

Table 5

Spending Rationale	**Budget Classification**	**FY13 Budget ($)**	**FY13 Actual Spending ($)**	**Variance**
Non-Infrastructure	Administrative/General	--	889,752	889,752
	General Equipment	$186,000	191,193	5,193
	Telecommunications	$150,000	1,188,120	1,038,120
	Non-Infrastructure Subtotal	**336,000**	**2,269,065**	**1,933,065**

c. ***System Capacity and Performance - $2.7 million under budget for FY13***

Overall spending was lower than budget in the System Capacity and Performance category for FY13 primarily driven by the projects listed below. Detailed budget and actual spending by budget classification for the System Capacity and Performance category is shown in Table 6.

Hopkinton & Related

- The variance below budget of approximately $760,000 for the substation work for the Hopkinton projects was primarily driven by extended Town negotiations regarding the proposed property, requiring a zoning amendment approval and delays in the environmental due diligence process for purchasing the land, as discussed previously in the asset condition category. Originally the Company expected to close on the land in February of 2013, but currently the date scheduled for closing on the property is October 2013. The Company is currently assessing the overall schedule impacts, but does expect the schedule for construction to be delayed by several months. Furthermore, the $175,000 from the asset condition category which was to be transferred to the system capacity and performance category was mistakenly transferred to expense. This will be corrected and transferred into the capital project in FY14.

Newport & Related:

- The variance below budget for the Newport projects is approximately $225,000. The budget for FY13 assumed award of the engineering design to an external vendor as well as some spending for long lead materials. However this project is still in the permitting phase as the Company continues to work with the City for a zoning amendment. Work for engineering design is on hold until the Company can be reasonably confident that zoning amendment will be approved.

West Warwick & Related

- The variance below budget of approximately $275,000 for West Warwick was due to continued delays in purchasing land. The Company currently expects the land purchase to be finalized by September 2013, with milestones for engineering design to be completed by September 2014.

Construction is scheduled to start in March 2015 and be completed by June 2016.

Load Relief

The primary drivers for the variance below budget for the Load Relief Budget Classification were the following projects.

- The Reconductoring of the 2232 was delayed into the first and second quarters of FY14, due to resource impacts from Hurricane Sandy resulting in a variance below budget of $700,000.

- The Nasonville 127W43 feeder project was delayed due to customer related delays, and no spending occurred on this project in FY13 resulting in a variance below budget of $600,000.

- The Harrison Feeder Upgrade project had a variance below budget of $400,000 due to the delay in construction to FY14 to accommodate additional permitting and licensing for a new manhole and duct system, after a detailed manhole survey of the existing infrastructure revealed it inadequate to support additional cable installation.

- The Highland Drive substation project had a variance below budget of $630,000. This project had an aggressive schedule however, delays were encountered in land rights/acquisition to access the substation parcel. These issues have been resolved and the Company expects to complete the land purchase by August 2013.

Offsetting a portion of this variance below budget was an allowance for schedule changes of a negative $1.6 million in the load relief category. In addition, further offsetting a portion of the variance in the Reliability budget classification, and keeping within the overall Reliability budget classification were the overloaded transformer project which had a variance above budget of approximately $425,000. This was primarily due to additional efforts to limit the reliability impact of individual transformer outages, including increased labor to tie secondaries together to reduce the number of customers affected.

Reliability

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

- The Energy Management System (EMS)/ Remote Terminal Unit (RTU) projects were delayed due to constraints in project management, engineering, and design resources in FY12. Although these projects are now progressing, they show a variance below budget of approximately $400,000 in FY13 due to those earlier delays.

- The Reliability Blanket project was under budget by approximately $590,000 at the end of FY13 driven by a lower volume of blanket work identified and available and by the impact of storm restoration on internal resource availability to perform overhead capital work

- The potted porcelain cutout replacements were completed by the end of the fiscal year with one percent more units replaced than originally forecasted. The total costs were under budget by approximately $460,000 due to lower installed unit costs gained by efficiencies in scheduling work requiring customer outages.

Offsetting a portion of the variance in the Reliability budget classification, and keeping spending within the overall Reliability budget classification were the following projects:

- Wood River Differential Scheme: The installation of a differential scheme for protection of the No. 10 and No. 20 transformers, and scheme enhancements, at Wood River Substation were necessary to limit exposure to substations and customers upstream of Wood River. This project was an action item resulting from a review of the February 2012 outage at Wood River. The FY13 costs for this project were approximately $465,000.

- Spare transformer purchase: This transformer will be a system spare for nine transformers in RI that presently do not have a spare. It will provide coverage for the following transformers: Peacedale T1 and T2, Hopkins Hill T1 and T2, Division Street T1 and T2, Quonsett T1, Westerly T1 and T4. The FY13 costs for this project were approximately $430,000. This project was originally budgeted in the asset condition category for $350,000.

Reliability – Feeder Hardening

- In the Reliability – Feeder Hardening budget classification, the Company completed the remaining 76 miles of the Feeder Hardening program in

FY13. The Company had accelerated some of the FY13 Feeder Hardening work into FY12. 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. In the 4th quarterly report for FY12, the Company projected capital spending on Feeder Hardening for FY13 to be $1.0 million against a budget of $1.5 million. The Feeder Hardening work was completed in FY13 with a variance of approximately $100,000 below the revised forecast, and a variance of $600,000 below the original approved budget.

Table 6

Spending Rationale	**Budget Classification**	**FY13 Budget ($)**	**FY13 Actual Spending ($)**	**Variance**
System Capacity and Performance	Coventry & Related	975,000	1,006,010	31,010
	Hopkinton & Related	800,000	37,468	(762,532)
	Newport & Related	450,000	226,213	(223,787)
	West Warwick & Related	325,000	50,970	(274,030)
	Load Relief	5,576,000	5,297,879	(278,121)
	Reliability	4,287,000	3,723,651	(563,349)
	Reliability – Feeder Hardening	1,500,000	907,019	(592,981)
	System Capacity and Performance Subtotal	**13,913,000**	**11,249,212**	**(2,663,788)**

d. *FY13 Work Plan Accomplishments*

Table 7 below provides actual work plan accomplishments against the goals of the FY13 work plan.

Table 7

Actual Work Plan Accomplishments for FY13

Program Type	FY13 Goals	FY13 Accomplishments	% Goal Complete
Feeder Hardening mileage	3 Feeders/ Goal was to complete all remaining Feeder Hardening	76.21 Miles	100% of Feeder Hardening is complete in RI
Recloser installation counts	4	4	100%
Distribution transformer upgrades	550	573	104%
Cutouts replaced	4,000	4,067	101%
I&M Program	16,323 Hours (on 16 Feeders)	15,229 Hours (12 feeders 100% complete, 4 feeders partially complete)	93%

III FY13 Capital for Plant Investment Placed in Service

In addition to providing the capital spending for FY13, 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 FY13, $44.2 million was placed in service, which was $7.0 million below the forecast for plant in service for FY13. Table 9 provides the total Cost of Removal (COR) for FY13, which was $5.2 million, or $1.9 million below the forecast for Cost of Removal.

Table 8

	FY13 Annual ISR Forecast	FY13 Actual In Service	Variance
NON-DISCRETIONARY INVESTMENT			
Statutory/Regulatory	18,406,000	11,261,897	(7,144,103)
Damage/Failure	10,213,000	12,172,707	1,959,707
Subtotal	**28,619,000**	**23,434,604**	(5,184,396)
DISCRETIONARY INVESTMENT			
Asset Condition	10,120,000	6,638,163	(3,481,837)
Non-Infrastructure	336,000	112,879	(223,121)
System Capacity & Performance	12,291,000	14,145,495	1,854,495
Subtotal	22,747,000	20,896,537	(1,850,463)
Total Capital Investment in Systems	**51,366,000**	**44,331,141**	**(7,034,859)**

Table 9

	FY13 Annual ISR COR Forecast	FY13 Actual COR	Variance
NON-DISCRETIONARY COST OF REMOVAL (COR)			
Statutory/Regulatory	1,693,400	1,363,678	(329,722)
Damage/Failure	1,672,280	2,982,593	1,310,313
Subtotal	**3,365,680**	**4,346,271**	**980,591**
DISCRETIONARY COST OF REMOVAL (COR)			
Asset Condition	2,256,490	913,715	(1,342,775)
Non-Infrastructure	27,900	(427,536)	(455,436)
System Capacity & Performance	1,424,930	347,491	(1,077,439)
Subtotal	**3,709,320**	**833,671**	(2,875,649)
Total Cost of Removal	**7,075,000**	**5,179,942**	**(1,895,058)**

IV. <u>FY13 Vegetation Management</u>

As shown below in Table 10, overall the total vegetation management spending for FY13 was \$8.249 million with an approved budget of \$8.256 million. The Company completed 104 percent of the annual distribution mileage cycle trimming goal with an associated spend of 93 percent of the FY13 cycle trimming budget. Variances within categories were due to an aggressive approach by our procurement team, which allowed the Company to command lower prices for its cycle pruning program, and increased police detail requirements throughout the state. Also as shown in Table 10, the Company is including \$356,000 of Sub-T and Core costs that were spent in FY12 but inadvertently excluded from the FY12 filing. The Company discussed this matter with the Division and indicated that it would include these costs in the FY13 reconciliation filing.

The vegetation management costs do not include costs for major storms, such as Hurricane Sandy or the Winter Storm on February 7, 2013. Those costs will be included in the Company's cost recovery filing(s) in Docket 2509.

Finally, with respect to the issues with Verizon, the Company began discussions with Verizon in March of 2013 to attempt to negotiate a new arrangement designed to specifically identify the responsibilities of both parties for the payment of both routine and storm trimming cost. At this time, the parties have traded proposals, but have reached no resolution.

Table 10

US Electricity Distribution - Rhode Island
O&M Vegetation Management Expenditures
FY13 thru March 31, 2013

	FY2013 Total		
	Budget	Actual	Variance
Vegetation Management			
Cycle Trimming	$5,150,000	$4,764,244	($385,756)
Hazard Tree	$1,117,000	$1,198,336	$81,336
SubT (on & off road)	$290,000	$243,307	($46,693)
Police Detail	$488,000	$766,382	$278,382
Core Crew (all other Act.)	$1,211,000	$1,276,480	$65,480
Total FY 13 Vegetation Management	**$8,256,000**	**$8,248,749**	**($7,251)**
FY 12 Sub T Correction		$321,623	
FY 12 Core Crew Correction		$34,322	
Total FY 12 Correction		**$355,945**	
Total Vegetation Management		**$8,604,694**	

	FY13 Goal	FY13 Complete	**Annual % Complete vs FY13** Goal
Distribution Mileage Trimming	1,300	1,348	104%

V. FY13 Inspection and Maintenance

As shown in Table 11 below, for FY13, 100% of the annual inspection goal was completed with an associated spend of 108 percent of the FY13 inspection budget. Costs to inspect the overhead distribution system were higher than estimated due to both underestimating the costs for the inspections and to a large number of storms that impacted Rhode Island during the fiscal year. As such, additional overtime was needed to complete the target of twenty percent and to compensate for the shifting of resources to storm restoration. These factors contributed approximately equally to the increased costs of the inspection program for the year.

With respect to cutout replacements, the number of replacements exceeded the target number by one percent (4,000 v. 4,067), 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 76 miles of Feeder Hardening was completed in FY13. As shown in Table 11, total expense spending on Feeder Hardening in FY13 was under budget in FY13 as some of the work had been advanced to FY12.

Also, as shown in Table 11, both expense related to capital spending for the I&M program and repair related spending for the I&M program were under budget. For FY13, 93% of the planned I&M work was completed. Twelve of the sixteen feeders in the I&M program were completed, and 4 feeders were partially completed. Three of the feeders which were partially completed were delayed due to Telephone Company pole sets. (Currently only one feeder is still awaiting Telephone Company pole sets.) However, the primary driver for the under spend was due to modification in the work order management system to more appropriately capture grounding as a capital item when performed separately from pole or other equipment installation. Grounding always has been an available Unit of Property but was not tied as a compatible unit in the work management system to the Retirement Unit in the Unit of Plant catalog. This was not a significant issue in the past as grounding was typically capitalized as a part of other capital work that was being performed. With the inception of the Inspection and Maintenance program, grounding assets are more frequently installed as stand-alone assets. The Company has modified the work management system to properly reflect the grounding assets being created in the Fixed Asset Repository as stand-alone assets. The capital spending for I&M was under budget even with this change in the work order management system.

Overall, the Inspection and Maintenance program cost was $1.25 million, approximately $1.0 million lower than the original ISR budget.

Table 11

US Electricity Distribution - Rhode Island
Inspection and Maintenance Program Progress Update
FY13 thru March 31, 2013

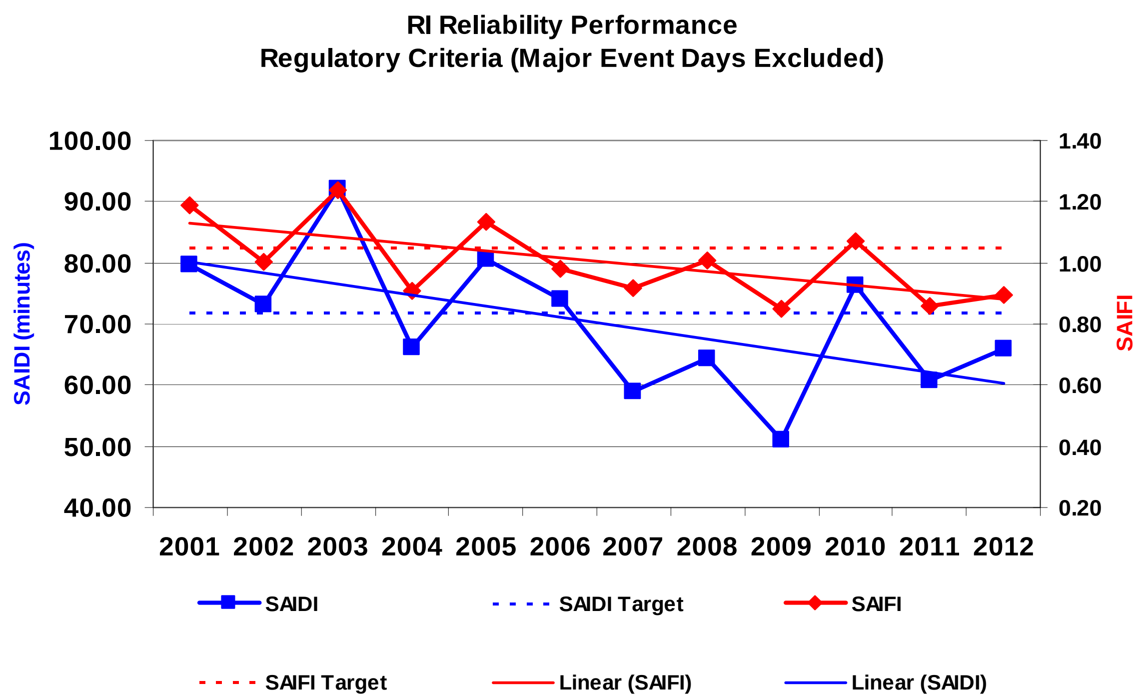
	FY2013 Total		
	Budget	**Actual**	**Variance**
Opex Related to Capex			
Potted Porcelain Cutouts	$176,500	$112,085	($64,415)
Feeder Hardening	$530,000	$493,513	($36,487)
Overhead I&M	$770,000	$231,884	($538,116)
Subtotal Opex Related to Capex	**$1,476,500**	**$605,598**	($870,902)
Repair Related Costs- Overhead I&M	**$609,000**	**$442,865**	($166,135)
Inspections - Related Costs	**$185,400**	**$199,858**	$14,458
Total O&M Expenses	**$2,270,900**	**$1,248,321**	**($1,022,579)**

	FY13 Goal	**FYTD Complete**	**Annual % Complete vs FY 13 Goal**
RI Distribution Overhead Structures Inspected	52,504	52,504	100%

VI. Reliability Performance

The Company met both its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance metrics in calendar year 2012 ("CY12"), with SAIFI of 0.90 against a target of 1.05, and SAIDI of 65.99 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[5] A comparison of reliability performance in CY12 relative to that of previous years is shown in Table 12. The Company's performance has shown a downward (improving) trend over the past several years with major event days excluded.

Table 12



CY12 had 4 days that were characterized as major event days. The most significant single event was Hurricane Sandy, which started on October 29, and led to 158,516 customer interruptions through November 5th, when all customers were restored. October 29th through October 31st are excluded as major event days. All events in 2012 characterized as major event days are shown in Table 13.

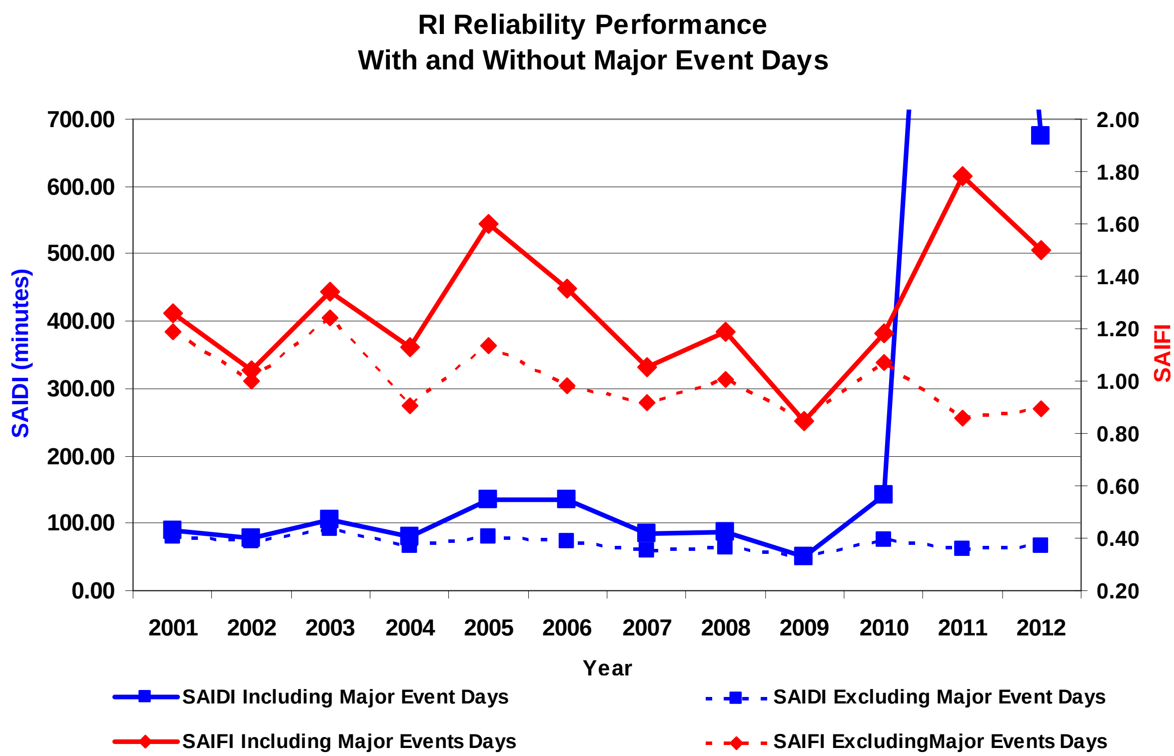
5 Major Event Days ("MED") is defined as a day in which the daily system SAIDI exceeds a MED threshold value (4.97 minutes for 2012). For purposes of calculating daily system SAIDI any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, 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.

Table 13

Event	Dates Excluded	Total Customers Interrupted/Daily SAIDI
July 18 Thunderstorm	July 18, 2012	July 18: 33,151/16.60
Hurricane Sandy	October 29, 2012 to October 31, 2012 (3 days)	October 29: 144,797/545.92 October 30: 4,570/19.14 October 31: 2,838/8.7

Reliability performance, both including and excluding major event days, is shown in Table 14 for 2001 through 2012. 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, 2011 and 2012 show the greatest differences between performance with and without major event days. In 2011, the Company experienced 10 major events days from 5 events, with 7 of the days occurring from Tropical Storm Irene and the October Snowstorm.

Table 14


RI Reliability Performance
With and Without Major Event Days
SAIDI (minutes)
SAIFI
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
SAIDI Including Major Event Days
SAIDI Excluding Major Event Days
SAIFI Including Major Events Days
SAIFI ExcludingMajor Events Days

Testimony of
William R. Richer

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM R. RICHER

August 1, 2013

Table of Contents

I. INTRODUCTION

Q. Please state your full name and business address.

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

Q. 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 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 my previous testimony provided in this docket on revenue requirements matters in this proceeding.

Q. What is the purpose of your testimony?

A. The Commission approved in this docket a new Electric Infrastructure, Safety and Reliability ("ISR") factor which went into effect April 1, 2012. That factor was based on a projected fiscal year ("FY") 2013 ISR revenue requirement of $13,989,525 for the estimated operation and maintenance ("O&M") associated with the Company's vegetation management ("VM") program and inspection and maintenance ("I&M") program for the Company's FY ended March 31, 2013, and the estimated ISR plant additions during the Company's FY ended March 31, 2013 and March 31, 2012. The purpose of my testimony is to present an updated FY 2013 ISR revenue requirement associated with actual FY 2013 O&M programs, the FY 2013 and FY 2012 plant additions, and actual tax deductibility percentages for FY 2012 capital additions. Actual tax deductibility percentages for FY 2013 plant additions will not be known until the Company files its FY 2013 income tax return in December of this year. As shown on Attachment WRR-1, Page 1 at Line 16 in Column (c), the updated FY 2013 ISR revenue requirement collectible through the Company's ISR factor for the FY 2013 period amounts to $12,179,038.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following Attachment:

- Attachment WRR-1: Electric Infrastructure, Safety and Reliability Plan Revenue Requirement Reconciliation

II. ISR PLAN FY 2013 REVENUE REQUIREMENT

Q. Did the Company calculate the updated FY 2013 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the August 2012 ISR factor reconciliation?

A. The updated FY 2013 ISR revenue requirement calculation is identical to the ISR revenue requirement used for purposes of developing the approved ISR factors that were effective April 1, 2012, and as described previously in my testimony in this proceeding, but incorporating updated ISR investment amounts, a newly approved weighted average cost of capital from Docket No. 4323, and known tax deductibility percentages. As a result, I will rely on that testimony for the detailed description of the revenue requirement calculation and will limit this testimony to the following: (1) a description of the impact of Docket No. 4323 to the electric ISR revenue requirement, (2) a summary of the revenue requirement update shown on Page 1 of Attachment WRR-1, and (3) a discussion of the change in the calculation of tax depreciation to coincide with tax depreciation taken on the Company's FY 2012 federal income tax return filed in December of 2012.

Q. Would you describe the impact on the FY 2013 ISR revenue requirement recoverable through the FY 2013 ISR factor as a result of the implementation of new electric base distribution rates that were approved by the Commission in Docket No. 4323 and put into effect on February 1, 2013?

A. The ISR mechanism was established to allow the Company to recover outside of base rates its costs associated with plant additions incurred to expand its electric infrastructure and improve the reliability and safety of its electric facilities. When new base rates are implemented, as was the case in Docket No. 4323, the costs being recovered associated with pre-rate case ISR plant additions cease to be recovered through a separate ISR factor, and are instead recovered through base rates, and the underlying ISR plant additions becomes a component of base distribution rate base from that point forward. In April 2012, the Company filed an application with the

Commission seeking a change in base rates for its electric and gas distribution businesses. The proceeding culminated with the Commission's approval of a settlement agreement with the Division and the U.S. Department of the Navy establishing new base rates for the Company. The Company's rate base reflected in that request reflected projected plant additions through January 31, 2014. In its base rate request, the Company proposed to maintain consistency with the existing ISR mechanism for the FY 2012 and FY 2013 periods. Consequently, the forecast used to develop rate base in the distribution rate case included the ISR approved plant additions levels for FY 2012, FY 2013 and 10 months of FY 2014 (using the FY 2013 ISR approved plant additions level as a proxy for FY 2014). The FY 2014 estimate included in rate base will be factored into the FY 2014 ISR reconciliation filing a year from now and is not a consideration in this filing. The effective date of new rates in that proceeding was February 1, 2013. Therefore, recovery of the approved FY 2013 ISR revenue requirement via the ISR factor stopped on January 31, 2013, and all future recovery of those forecasted FY 2012 and FY 2013 ISR plant additions will be via the Company's base rates.

Q. Please continue.

A. As a result of the implementation of new base rates pursuant to Docket No. 4323 effective February 1, 2013, the cumulative amount of forecasted ISR plant additions were rolled into base rates effective at that date. Consequently, the Company is reflecting only a ten month amount of revenue requirement associated with the ISR plant additions that was rolled into base rates effective February 1, 2013. The Company has prorated the updated FY 2013 ISR revenue requirement for the forecasted FY 2012 and FY 2013 ISR investments rolled into base rates effective February 1, 2013 for ten months (April 1, 2012 through January 31, 2013), or 83.3 percent (ten twelfths). The FY 2013 revenue requirement for incremental FY 2012 and incremental FY 2013 ISR investments reflect a full year of revenue requirement as none of these incremental investments is included in the Company's base rate rate-base. These incremental FY vintage amounts are to remain in the ISR recovery mechanism as provided for in the terms of the approved settlement in Docket No. 4323. Consequently, Attachment WRR-1 presents four separate revenue requirement calculations, a calculation of the updated revenue requirement on the forecasted amount of FY 2013 ISR plant additions rolled into base rates effective February 1, 2013 and a revenue requirement calculation for the incremental FY 2013 ISR plant additions which is not reflected in base rates. These calculations are also presented for the similar FY 2012 vintage year amounts.

Q. Would you please summarize the updated FY 2013 ISR revenue requirement?

A. Certainly. As shown on Page 1, Column (c) of WRR-1, the Company's FY 2013 Electric ISR Program revenue requirement consists of two elements: (1) O&M expense associated with the Company's VM activities and for system inspection, feeder hardening and potted porcelain cutouts, as encompassed by the Company's 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 5 of Column (c) reflects the actual FY 2013 revenue requirement related to O&M expenses, or $9,853,015.

As shown on Page 1, at Line 15 in Column (c) of Attachment WRR-1, the revenue requirement associated with the Company's actual FY 2013 capital investment amounts to $2,326,023. As previously described, it is comprised of the ten month (April 1, 2012 through January 31, 2013) prorated amount, or 83.3%, of the FY 2013 revenue requirement on vintage FY 2013 and FY 2012 ISR plant additions, which were rolled into the Company's base rates effective February 1, 2013, and the full year revenue requirement on vintage FY 2013 and FY 2012 incremental ISR plant additions above the level of plant additions reflected in base distribution rates. In addition, the FY 2013 revenue requirement reflects the same ten month proration of a property tax-related settlement credit that was included in the approved FY 2013 electric ISR Proposal, and a true up for changes to previously estimated tax depreciation expense to align with tax depreciation rates used on the Company's FY 2012 tax return that was filed in December 2012.

The total actual FY 2013 ISR Plan revenue requirement for both O&M expenses and capital investment of $12,179,038 is shown in Line 16, Column (c), respectively.

Q. Please continue by describing how your attachment is structured.

A. Page 1 of the Attachment summarizes the individual components of the updated FY 2013 ISR revenue requirement. Lines 7 and 9 reflect the approved FY 2013 ISR revenue requirement prorated for the ten month period. Lines 8 and 10 represent the full year 2013 ISR revenue requirements for the incremental FY 2012 and FY 2013 ISR investments, or those investments not included in the Company's base rates, and as supported with detailed calculations on Pages 2 and 4, respectively. Line 12 reflects the ten month proration of a property tax related settlement dated January 30, 2012. Lines 13 and 14 reflect the reconciliation of the approved FY 2012 and FY 2013 ISR revenue requirement for vintage FY 2012 plant additions with the actual vintage FY 2012 and FY 2013 revenue requirement on those investments. This reconciliation is necessary because the actual level of tax deductibility on FY 2012 investments was not known at the time of filing the FY 2012 and FY 2013 ISR Factor proposals. The calculation of the reconciliation amounts is shown on Page 8 and reflects the difference in the approved FY 2012 and FY 2013 ISR revenue requirements on FY 2012 investments and the updated revenue requirement for those fiscal years on FY 2012 ISR investments when incorporating the final tax deductibility levels. As appropriate, the FY 2013 reconciliation amount has been similarly prorated for the ten month period. Detailed calculations of the updated FY 2012 and FY 2013 revenue requirement are presented on pages 9 and 11 of the Attachment, respectively.

Q. Were there other provisions of the approved rate case settlement agreement that are affecting the ISR mechanism?

A. The method used to recover property tax expense under the ISR has been modified by the rate case settlement agreement. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company shall include an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The ISR property tax recovery will also include the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative ISR net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery calculation. This provision of the settlement agreement will only take effect for ISR property tax recovery periods subsequent to the January 31, 2014 end of the rate year.

Q. Has the Company provided support for the actual level of FY 2013 ISR eligible plant investments?

A. Yes. The description of the FY 2013 Electric ISR program and the amount of the incremental plant additions eligible for inclusion in the ISR Mechanism are supported by the direct testimony and supporting attachment of Company Witness Jennifer Grimsley. The ultimate revenue requirement on the ISR eligible plant additions 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 ISR eligible plant additions 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 capital additions plus cost of removal, less annual depreciation expense embedded in the Company's rates, net of depreciation expense attributable to general plant. The actual ISR eligible plant additions for FY 2013 amounts to $44.3 million associated with the Company's FY 2013 ISR Plan (electric infrastructure investment net of general plant) as discussed in the testimony of Ms. Grimsley.

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 7 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 2013 revenue requirement calculation has been limited to the actual 'non-discretionary' capital spending amount of $23,434,604 as compared to $28,619,000 of 'non-discretionary' investment assumed in the FY 2013 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 2013 revenue requirement, the lesser of these items was actual 'discretionary' capital additions of $20,896,537 as shown on Attachment WRR-1, Page 7. The Company forecasted $22,747,000 of 'discretionary' spending in the approved FY 2013 Electric ISR Plan.

Q. What is the updated revenue requirement associated with actual plant additions?

A. The updated FY 2013 revenue requirement associated with the Company's actual FY 2012 and FY 2013 ISR eligible plant investments amounts to $2,326,023 and includes the updated FY 2013 revenue requirement on FY 2012 and FY 2013 investments, reconciliation of the approved FY 2012 and FY 2013 ISR revenue requirement for vintage FY 2012 investments with the actual vintage FY 2012 and FY 2013 revenue requirement on those investments, and the inclusion of a property tax settlement dated January 30, 2012.

III. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.

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 2013 Electric ISR Revenue Requirement Reconciliation
Summary

Line No.			As Approved (a)	Proration (b)		Calculated (c)
1	**Operation and Maintenance (O&M) Expenses:**					
2	Current Year Vegetation Management (VM)	Attachment JLG-1, Page 17 of 22, Table 10	$8,256,000			$8,248,749
3	Prior Year Vegetation Management (VM) Correction	Attachment JLG-1, Page 17 of 22, Table 10				$355,945
4	Current Year Inspection & Maintenance (I&M)	Attachment JLG-1, Page 19 of 22, Table 11	$2,270,900			$1,248,321
5	**Total O&M Expense Component of Revenue Requirement**	Sum of Lines 2 through 4	$10,526,900			$9,853,015
6	**Capital Investment:**					
7	FY2013 Projected Revenue Requirement	Col (a) = R.I.P.U.C. Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 1 of 6, Line 9(b); Col (c) = Col (a) * Col (b)	$1,127,207	* 10/12	=	$939,339
8	FY2013 Incremental Revenue Requirement	Page 2 of 12, Line 51				($546,405)
9	FY2012 Projected Revenue Requirement	Col (a) = R.I.P.U.C. Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 1 of 6, Line 8(b); Col (c) = Col (a) * Col (b)	$2,775,419	* 10/12	=	$2,312,849
10	FY2012 Incremental Revenue Requirement	Page 4 of 12, Line 51, Col (b)				($56,730)
11	Subtotal Capital Investment Component of Revenue Requirement	Sum of Lines 7 through 10	$3,902,625			$2,649,052
12	Less Property Tax Settlement Agreement dated 1/30/12	Col (a) = per Docket No. 4307 Settlement Agreement; Col (c) = Col (a) * Col (b)	($440,000)	* 10/12	=	($366,667)
13	True Up for Capital Repairs Deduction of FY2012 Revenue Requirement Reconciliation R.I.P.U.C. Docket No. 4218	Page 8 of 12, Line 3				($4,814)
14	True Up for Capital Repairs Deduction & Weighted Actual Cost of Capital of FY2013 Revenue Requirement Proposal R.I.P.U.C. Docket No. 4307	Page 8 of 12, Line 6				$48,451
15	**Total Capital Investment Component of Revenue Requirement**	Sum of Lines 11 through 14	$3,462,625			$2,326,023
16	**Total Fiscal Year Revenue Requirement**	Line 5 + Line 15	$13,989,525			$12,179,038

Column (b) - represents the ten month (April 1, 2012 through January 31, 2103) prorated amount of the FY 2013 revenue requirement on vintage FY 2013 and FY 2012 ISR plant additions, which were rolled into the Company's base rates effective February 1, 2013.

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

Line No.				Fiscal Year 2013 (a)
1	Capital Investment Allowance			
2	*Non-Discretionary Capital*			
3	Lesser of Actual Cumulative Non-Discretionary Additions or Spending	Page 7 of 12, Line 11(b) less Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 2 of 6, Line 1(a)		($5,184,396)
4				
5	*Discretionary Capital*			
6	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Page 7 of 12, Line 29(b) less Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 2 of 6, Line 1(a)		($1,850,463)
7				
8	Total Allowed Capital Included in Rate Base	Line 3 + Line 6		($7,034,859)
9				
10	Depreciable Net Capital Included in Rate Base			
11	Total Allowed Capital Included in Rate Base in Current Year	Line 8		($7,034,859)
12	Retirements	Page 6 of 12, Line 9(b)	1/	$5,838,935
13	Net Depreciable Capital Included in Rate Base	Line 11 - Line 12		($12,873,794)
14				
15	Change in Net Capital Included in Rate Base			
16	Incremental Depreciable Amount	Line 8		($7,034,859)
17				
18	Cost of Removal			
19	Cost of Removal - Non-Discretionary	Attachment JLG-1, Page 15 of 22, Table 9		$980,591
20	Cost of Removal - Discretionary	Attachment JLG-1, Page 15 of 22, Table 9		($2,875,650)
21	Total Cost of Removal	Line 19 + Line 20		($1,895,059)
22				
23	**Total Net Plant in Service**	**Line 16 + Line 21**		**($8,929,918)**
24				
25	Deferred Tax Calculation:			
26	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%
27	Vintage Year Tax Depreciation:			
28	2013 Spend	Page 3 of 12, Line 27		($6,086,076)
29	Cumulative Tax Depreciation	Current Year Line 28		($6,086,076)
30				
31	Book Depreciation	Line 13 * Line 26 * 50%		($218,854)
32	Cumulative Book Depreciation	Current Year Line 31		($218,854)
33				
34	Cumulative Book / Tax Timer	Line 29 - Line 32		($5,867,222)
35	Effective Tax Rate			35.00%
36	Deferred Tax Reserve	Line 34 * Line 35		($2,053,528)
37				
38	Rate Base Calculation:			
39	Cumulative Incremental Capital Included in Rate Base	Line 23		($8,929,918)
40	Accumulated Depreciation	-Line 32		$218,854
41	Deferred Tax Reserve	-Line 36		$2,053,528
42	Year End Rate Base	Sum of Lines 39 through 41		($6,657,536)
43				
44	Revenue Requirement Calculation:			
45	Average Rate Base	Current Year Line 42 ÷ 2		($3,328,768)
46	Pre-Tax ROR		2/	9.84%
47	Return and Taxes	Line 45 * Line 46		($327,551)
48	Book Depreciation	Line 31		($218,854)
49	Property Taxes	$0 in Year 1, then Prior Year (Line 13 + Line 21 + Line 32) * Property Tax Rate		-
50				
51	**Annual Revenue Requirement**	**Sum of Lines 47 through 49**		**($546,405)**

1/ Actual Retirements
2/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065 (Settlement)

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	46.05%	5.30%	2.44%		2.44%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	48.78%	9.80%	4.78%	2.57%	7.35%
	100.00%		7.31%	2.57%	9.88%

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

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

	Tax-Effected Weighted Cost		**Blended Tax-Effected Weighted Cost**
R.I.P.U.C. Docket No. 4065	9.88%	Apr 12 - Jan 13	8.23%
R.I.P.U.C. Docket No. 4323	9.68%	Feb 13 - Mar 13	1.61%
			9.84%

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2013 Incremental Capital Investments

Line No.			Fiscal Year 2013 (a)
1	Capital Repairs Deduction		
2	Plant Additions	Page 2 of 12, Line 8	($7,034,859)
3	Capital Repairs Deduction Rate	Per Tax Department	16.00%
4	Capital Repairs Deduction	Line 2 * Line 3	($1,125,577)
5			
6	Bonus Depreciation		
7	Plant Additions	Line 2	($7,034,859)
8	Less Capital Repairs Deduction	Line 4	($1,125,577)
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8	($5,909,282)
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10	($5,909,282)
12	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%	37.50%
13	Bonus Depreciation Rate (January 2013 - March 2013)	1 * 25% * 50%	12.50%
14	Total Bonus Depreciation Rate	Line 12 + Line 13	50.00%
15	Bonus Depreciation	Line 11 * Line 14	($2,954,641)
16			
17	Remaining Tax Depreciation		
18	Plant Additions	Line 2	($7,034,859)
19	Less Capital Repairs Deduction	Line 4	($1,125,577)
20	Less Bonus Depreciation	Line 15	($2,954,641)
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20	($2,954,641)
22	20 YR MACRS Tax Depreciation Rates		3.750%
23	Remaining Tax Depreciation	Line 21 * Line 22	($110,799)
24			
25	Cost of Removal	Page 2 of 12, Line 21	($1,895,059)
26			
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 4, 15, 23 and 25	($6,086,076)

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
FY 2012 Computation of Electric Capital Investment Incremental Revenue Requirement

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
1	Capital Investment Allowance				
2	*Non-Discretionary Capital*				
3	Lesser of Actual Cumulative Non-Discretionary Additions or Spending	Page 9 of 12, Line 3 less Page 11 of 12, Line 1		($4,019,686)	$0
4					
5	*Discretionary Capital*				
6	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Page 9 of 12, Line 6 less Page 11 of 12, Line 2		$4,163,942	$0
7					
8	Total Allowed Capital Included in Rate Base	Line 3 + Line 6		$144,256	$0
9					
10	Depreciable Net Capital Included in Rate Base				
11	Total Allowed Capital Included in Rate Base in Current Year	Line 8		$144,256	$0
12	Retirements	Page 9 of 12, Line 12 less Page 11 of 12, Line 5	1/	$19,938	$0
13	Net Depreciable Capital Included in Rate Base	Column(a) = Line 11 - Line 12		124,317	124,317
14					
15	Change in Net Capital Included in Rate Base				
16	Incremental Depreciable Amount			$144,256	$144,256
17					
18	Cost of Removal				
19	Cost of Removal - Non-Discretionary	Page 9 of 12, Line 21 less Page 11 of 12, Line 10	2/	($957,517)	-
20	Cost of Removal - Discretionary	From Company Books	2/	$186,385	-
21	Total Cost of Removal	Column(a) = Line 19 + Line 20		($771,131)	($771,131)
22					
23	**Total Net Plant in Service**	**Line 16 + Line 21**		**($626,876)**	**($626,876)**
24					
25	Deferred Tax Calculation:				
26	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%
27	Vintage Year Tax Depreciation:				
28	2012 Spend	Page 5 of 12, Line 27		($654,966)	$2,107
29	Cumulative Tax Depreciation	Prior Year Line 29 + Current Year Line 28		($654,966)	($652,859)
30					
31	Book Depreciation	Column(a) = Line 13 * Line 26 * 50%; Column (b) = Line 13 * Line 26		$2,113	$4,227
32	Cumulative Book Depreciation	Prior Year Line 32 + Current Year Line 31		$2,113	$6,340
33					
34	Cumulative Book / Tax Timer	Line 29 - Line 32		($657,080)	($659,200)
35	Effective Tax Rate			35.00%	35.00%
36	Deferred Tax Reserve	Line 34 * Line 35		($229,978)	($230,720)
37					
38	Rate Base Calculation:				
39	Cumulative Incremental Capital Included in Rate Base	Line 23		-$626,875.78	-$626,875.78
40	Accumulated Depreciation	-Line 32		-$2,113.40	-$6,340.19
41	Deferred Tax Reserve	-Line 36		$229,977.92	$230,719.85
42	Year End Rate Base	Sum of Lines 39 through 41		($399,011)	($402,496)
43					
44	Revenue Requirement Calculation:				
45	Average Rate Base	Column (a) = Line 42 ÷ 2, Column (b) = (Prior Year Line 42 + Current Year Line 42) ÷ 2		($199,506)	($400,754)
46	Pre-Tax ROR		3/	9.30%	9.84%
47	Return and Taxes	Line 45 * Line 46		($18,554)	($39,434)
48	Book Depreciation	Line 31		$2,113	$4,227
49	Property Taxes	$0 in Year 1, then Prior Year (Line 13 + Line 21 + Line 32) * Property Tax Rate		$0	($21,523)
50					
51	**Annual Revenue Requirement**	**Sum of Lines 47 through 49**		**($16,441)**	**($56,730)**

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 (Order)

	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%

Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065 (Settlement)

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	46.05%	5.30%	2.44%		2.44%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	48.78%	9.80%	4.78%	2.57%	7.35%
	100.00%		7.31%	2.57%	9.88%

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

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

	Tax-Effected Weighted Cost		**Blended Tax-Effected Weighted Cost**
R.I.P.U.C. Docket No. 4065	9.88%	Apr 12 - Jan 13	8.23%
R.I.P.U.C. Docket No. 4323	9.68%	Feb 13 - Mar 13	1.61%
			9.84%

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Incremental Capital Investments

Line No.			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	
1	Capital Repairs Deduction				
2	Plant Additions	Page 4 of 12, Line 8	$144,256		
3	Capital Repairs Deduction Rate	Per Tax Department	21.05%		1/
4	Capital Repairs Deduction	Line 2 * Line 3	30,366		
5					
6	Bonus Depreciation				
7	Plant Additions	Line 1	$144,256		
8	Less Capital Repairs Deduction	Line 4	$30,366		
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8	$113,890		
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	85.00%		2/
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10	$96,806		
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	$84,705		
16					
17	Remaining Tax Depreciation				
18	Plant Additions	Line 2	$144,256		
19	Less Capital Repairs Deduction	Line 4	$30,366		
20	Less Bonus Depreciation	Line 15	$84,705		
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20	$29,185	29,185	
22	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	
23	Remaining Tax Depreciation	Line 21 * Line 22	$1,094	$2,107	
24					
25	Cost of Removal	Page 4 of 12, Line 23	($771,131)		
26					
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 4, 15, 23 and 25	($654,966)	$2,107	

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%.

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
FY 2012 - FY 2013 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Actual Fiscal Year 2013 (b)
	Capital Investment			
1	ISR - Eligible Capital Investment	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218, Att. WRR-1, Page 3 of 4, Line 20(b); Col (b) = Page 7 of 12, Line 31(b)	$48,946,456	$44,331,141
2	ISR - Eligible Capital Additions included in Rate Base per R.I.P.U.C. Docket No. 4323	Schedule MDL-3-ELEC Page 53, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b)	$48,802,200	$51,366,341
3	Incremental ISR Capital Investment	Line 1 - Line 2	$144,256	($7,035,200)
	Cost of Removal			
4	ISR - Eligible Cost of Removal	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b)= Attachment JLG-1, Page 15 of 22, Table 9	$5,807,869	5,179,941
5	ISR - Eligible Cost of Removal in Rate Base per R.I.P.U.C. Docket No. 4323	Workpaper MDL-19-ELEC Page 2, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b)	$6,579,000	$7,075,000
6	Incremental Cost of Removal	Line 4 - Line 5	($771,131)	($1,895,059)
	Retirements			
7	ISR - Eligible Retirements/Actual	Col (a)= FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) per Company Books	$7,740,446	14,255,714
8	ISR - Eligible Retirements/Estimated	Col (a)= FY 2012 ISR Proposal Filing Docket No. 4218; Col (b)= FY 2013 ISR Proposal Filing Docket No. 4307, Schedule WRR-1, Page 2 of 6, Line 5(a)	$7,720,508	$8,416,779
9	Incremental Retirements	Line 7 - Line 8	$19,938	$5,838,935

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

Line No.			As Approved in Docket No. 4307 (a)	Actuals (b)
	Non-Discretionary Capital			
1	FY 2012 Non-Discretionary Capital **ADDITIONS**	Docket No. 4218 FY12 Reconciliation Att. WRR-1, Page 3 of 4, Line 1	$30,087,700	$28,771,217
2	FY 2013 Non-Discretionary Capital **ADDITIONS**	Col (a) =Docket No. 4307 FY13 Plan Sch. WRR-1 Page 4 of 6, Line 2; Col (b) = Att. JLG-1, Page 15 of 22, Table 8	$28,619,000	$23,434,604
3	Cumulative Actual Non-Discretionary Capital Additions	Line 1 + Line 2	$58,706,700	$52,205,821
4				
5	FY 2012 Non-Discretionary Capital **SPENDING**	Docket No. 4218 FY12 Reconciliation Att. WRR-1, Page 3 of 4, Line 3	$31,341,500	$26,068,014
6	FY 2013 Non-Discretionary Capital **SPENDING**	Col (a) =Docket No. 4307 FY13 Plan Sch. WRR-1 Page 4 of 6, Line 5; Col (b) = Att. JLG-1, Page 2 of 22, Table 1	$30,428,000	$27,925,675
7	Cumulative Actual Non-Discretionary Capital Spending	Line 5 + Line 6	$61,769,500	$53,993,689
8				
9	Cumulative Allowed Non-Discretionary Capital Included in Rate Base	Lesser of Line 3 or Line 7	$58,706,700	$52,205,821
10	Prior Year Cumulative Allowed Non-Discretionary Capital Included in Rate Base	Docket No. 4218 FY12 Reconciliation Filing, Att. WRR-1 Page 3 of 4, Line 6	$30,087,700	$28,771,217
11	**Total Allowed Non-Discretionary Capital Included in Rate Base Current Year**	Line 9 - Line 10	**$28,619,000**	**$23,434,604**
12				
13				
14	**Discretionary Capital**			
15	FY 2012 Discretionary Capital **ADDITIONS**	Docket No. 4218 FY12 Reconciliation Filing, Att. WRR-1 Page 3 of 4, Line 10	$18,714,500	$22,878,442
16	FY 2013 Discretionary Capital **ADDITIONS**	Col (a) =Docket No. 4307 FY13 Proposal Sch. WRR-1 Page 4 of 6, Line 11; Col (b) = Att. JLG-1, Page 15 of 22, Table 8	$22,747,000	$20,896,537
17	Cumulative Actual Discretionary Capital Additions	Line 15 + Line 16	$41,461,500	$43,774,979
18				
19	FY 2012 Discretionary Capital **SPENDING**	Docket No. 4218 FY12 Reconciliation Filing, Att. WRR-1 Page 3 of 4, Line 12	$0	$24,424,047
20	FY 2013 Discretionary Capital **SPENDING**	Col (b) = Att. JLG-1, Page 2 of 22, Table 1		$21,589,109
21	Cumulative Actual Discretionary Capital Spending	Line 19 + Line 20	$0	$46,013,156
22				
23	FY 2012 Approved Discretionary Capital **SPENDING**	Docket No. 4218 FY12 Reconciliation, Att. WRR-1 Page 3 of 4, Line 14	$27,036,150	$27,036,150
24	FY 2013 Approved Discretionary Capital **SPENDING**	Docket No. 4307 FY13 Proposal Sch. WRR-1, Page 4 of 6, Line 14	$26,112,000	$26,112,000
25	Cumulative Actual Approved Discretionary Capital Spending	Line 23 + Line 24	$53,148,150	$53,148,150
26				
27	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 17, Line 21, or Line 25	$41,461,500	$43,774,979
28	Prior Year Cumulative Allowed Disretionary Capital Included in Rate Base	Docket No. 4218 FY12 Reconciliation Filing Att. WRR-1, Page 3 of 4, Line 17	$18,714,500	$22,878,442
29	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 27 - Line 28	**$22,747,000**	**$20,896,537**
30				
31	**Total Allowed Capital Included in Rate Base Current Year**	Line 11 + Line 29	**$51,366,000**	**$44,331,141**

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
True up for Capital Repairs Deduction and Rate of Return on FY 2012 Capital Investment

Line No.	True Up FY 2012 Revenue Requirement on FY 2012 Capital Investment for Capital Repairs Deduction included in the FY 2012 Revenue Requirement Reconciliation R.I.P.U.C. Docket No. 4218		Full Year (a)	Proration (b)	ISR Year (c)
1	Revenue Requirement using estimated capital repairs deduction rate of 18.60%	Docket No. 4218 FY12 Reconciliation, Attachment WRR-1, Page 1 of 4, Line 10(b)			$686,518
2	Revenue Requirement using actual capital repairs deduction rate of 21.05%	Page 9 of 12, Line 53(a)			$681,704
3	True Up Amount	Line 2 - Line 1			($4,814)
	True Up FY 2013 Revenue Requirement on FY 2012 Capital Investment for Capital Repairs Deduction & Weighted Actual Cost of Capital included in FY 2013 Revenue Requirement Proposal R.I.P.U.C. Docket No. 4307				
4	Revenue Requirement using estimated capital repairs deduction rate of 18.60% & previoulsy ordered Weighted Average Cost of Capital of 9.30%	Col (a) = Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 3 of 6, Line 32 (b); Col (c) = Col (a) * Col (b)	$2,775,419	* 10/12	$2,312,849
5	Revenue Requirement using actual capital repairs deduction rate of 21.05% & subsequently settled & prorated Weighted Average Cost of Capital of 9.84%	Col (a) = Page 11 of 12, Line 32(b); Col (c) = Col (a) * Col (b)	$2,833,560	* 10/12	$2,361,300
6	True Up Amount	Line 5 - Line 4			$48,451

Column (b) - represents the ten month (April 1, 2012 through January 31, 2103) prorated amount of the FY 2013 revenue requirement on vintage FY 2013 and FY 2012 ISR plant additions, which were rolled into the Company’s base rates effective February 1, 2013.

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
FY 2012 Reconciliation of Electric Capital Investment Incremental Revenue Requirement with Updated Capital Repairs Deduction Rate

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
1	Capital Investment Allowance				
2	*Non-Discretionary Capital*				
3	Lesser of Actual Cumulative Non-Discretionary Additions or Spending	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 2 of 4, Line 1		$26,068,014	$0
4					
5	*Discretionary Capital*				
6	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 2 of 4, Line 6		$22,878,442	$0
7					
8	Total Allowed Capital Included in Rate Base	Line 3 + Line 6		$48,946,456	$0
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	$0
12	Retirements	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 2 of 4, Line 12	1/	$7,740,446	$0
13	Net Depreciable Capital Included in Rate Base	Column(a) = Line 11 - Line 12		$41,206,009	$41,206,009
14					
15	Change in Net Capital Included in Rate Base				
16	Capital Included in Rate Base	Line 8		$48,946,456	$0
17	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$38,875,088	$0
18	Incremental Depreciable Amount	Column(a) = Line 16 - Line 17		$10,071,368	$10,071,368
19					
20	Cost of Removal				
21	Cost of Removal - Non-Discretionary	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 2 of 4, Line 21	2/	$2,998,483	$0
22	Cost of Removal - Discretionary	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 2 of 4, Line 22	2/	$2,809,385	$0
23	Total Cost of Removal	Column(a) = Line 21 + Line 22		$5,807,869	$5,807,869
24					
25	**Total Net Plant in Service**	**Line 18 + Line 23**		**$15,879,236**	**$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%	3.40%
29	Vintage Year Tax Depreciation:				
30	2012 Spend	Page 10 of 12, Line 27		$45,223,335	$714,849
31	Cumulative Tax Depreciation	Prior Year Line 31 + Current Year Line 30		$45,223,335	$45,938,184
32					
33	Book Depreciation	Column(a) = Line 13 * Line 28 * 50%; Column(b) = Line 13 * Line 28		$700,502	$1,401,004
34	Cumulative Book Depreciation	Column (a) = Current Year Line 33; Column (b) = Prior Year Line 34 + Current Year Line 33		$700,502	$2,101,506
35					
36	Cumulative Book / Tax Timer	Line 31 - Line 34		$44,522,832	$43,836,677
37	Effective Tax Rate			35.00%	35.00%
38	Deferred Tax Reserve	Line 36 * Line 37		$15,582,991	$15,342,837
39					
40	Rate Base Calculation:				
41	Cumulative Incremental Capital Included in Rate Base	Line 25		$15,879,236	$15,879,236
42	Accumulated Depreciation	-Line 34		($700,502)	($2,101,506)
43	Deferred Tax Reserve	-Line 38		($15,582,991)	($15,342,837)
44	Year End Rate Base	Sum of Lines 41 through 43		($404,257)	($1,565,107)
45					
46	Revenue Requirement Calculation:				
47	Average Rate Base	Column (a)= Current Year Line 44 ÷ 2; Column (b)= (Prior Year Line 44 + Current Year Line 44) ÷ 2		($202,129)	($984,682)
48	Pre-Tax ROR		3/	9.30%	9.84%
49	Return and Taxes	Line 47 * Line 48		($18,798)	($96,893)
50	Book Depreciation	Line 33		$700,502	$1,401,004
51	Property Taxes	$0 in Year 1, then Prior Year (Line 13 + Line 23 + Line 34) * Property Tax Rate		$0	$1,536,082
52					
53	**Annual Revenue Requirement**	**Sum of Lines 49 through 51**		**$681,704**	**$2,840,194**

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 (Order)

	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%

Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065 (Settlement)

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	46.05%	5.30%	2.44%		2.44%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	48.78%	9.80%	4.78%	2.57%	7.35%
	100.00%		7.31%	2.57%	9.88%

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

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

	Tax-Effected Weighted Cost		**Blended Tax-Effected Weighted Cost**
R.I.P.U.C. Docket No. 4065	9.88%	Apr 12 - Jan 13	8.23%
R.I.P.U.C. Docket No. 4323	9.68%	Feb 13 - Mar 13	1.61%
			9.84%

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Reconciliation of Incremental Capital Investments with Updated Capital Repairs Deduction Rate

Line No.			Fiscal Year 2012 (a)	
1	Capital Repairs Deduction			
2	Plant Additions	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 4 of 4, Line 1	$48,946,456	
3	Capital Repairs Deduction Rate	Per Tax Department	21.05%	1/
4	Capital Repairs Deduction	Line 2 * Line 3	$10,303,229	
5				
6	Bonus Depreciation			
7	Plant Additions	Line 1	$48,946,456	
8	Less Capital Repairs Deduction	Line 4	$10,303,229	
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8	$38,643,227	
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	85.00%	2/
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10	$32,846,743	
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	$28,740,900	
16				
17	Remaining Tax Depreciation			
18	Plant Additions	Line 2	$48,946,456	
19	Less Capital Repairs Deduction	Line 4	$10,303,229	
20	Less Bonus Depreciation	Line 15	$28,740,900	
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20	$9,902,327	
22	20 YR MACRS Tax Depreciation Rates		3.750%	
23	Remaining Tax Depreciation	Line 21 * Line 22	$371,337	
24				
25	Cost of Removal	Docket No. 4218 FY12 Reconciliation Filing, Attachment WRR-1, Page 4 of 4, Line 25	$5,807,869	
26				
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 4, 15, 23 and 25	$45,223,335	

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%.

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
Computation of Electric Capital Investment Revenue Requirement on FY 2012 Investment with Updated Capital Repairs Deduction Rate and Rate of Return

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)
	Capital Additions Allowance				
	Non-Discretionary Capital				
1	Actual Non-Discretionary Capital Additions	Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 3 of 6, Line 1(a)	1/	$30,087,700	$0
	Discretionary Capital				
2	Actual Discretionary Capital Additions	Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 3 of 6, Line 2(a)	1/	$18,714,500	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$48,802,200	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$48,802,200	$0
5	Retirements	Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 3 of 6, Line 5(a)	2/	$7,720,508	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$41,081,692	$41,081,692
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 4		$48,802,200	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$38,875,088	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$9,927,112	$9,927,112
	Cost of Removal				
10	Cost of Removal - Non-Discretionary	Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 3 of 6, Line 10(a)		$3,956,000	$0
11	Cost of Removal - Discretionary	Docket No. 4307 FY13 Proposal, Schedule WRR-1, Page 3 of 6, Line 11(a)		$2,623,000	$0
12	Total Cost of Removal	Column (a) = Line 10 + Line 11; Columns (b) and (c) = Prior Year Line 12		$6,579,000	$6,579,000
13	**Total Net Plant in Service**	**Line 9 + Line 12**		**$16,506,112**	**$16,506,112**
	Deferred Tax Calculation:				
14	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%
15	Vintage Year Tax Depreciation:				
16	2012 Spend	Page 12 of 12, Line 20		$42,633,408	$956,117
17	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		$42,633,408	$43,589,525
18	Book Depreciation	Column (a) = Line 6 * Line 14 * 50%; Column (b) = Line 6 * Line 14		$698,389	$1,396,778
19	Cumulative Book Depreciation	Prior Year Line 19 + Current Year Line 18		$698,389	$2,095,166
20	Cumulative Book / Tax Timer	Line 17 - Line 18		$41,935,019	$41,494,359
21	Effective Tax Rate			35.00%	35.00%
22	Deferred Tax Reserve	Line 20 * Line 21		$14,677,257	$14,523,026
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 13		$16,506,112	$16,506,112
24	Accumulated Depreciation	- Line 19		($698,389)	($2,095,166)
25	Deferred Tax Reserve	- Line 22		($14,677,257)	($14,523,026)
26	Year End Rate Base	Sum of Lines 23 through 25		$1,130,467	($112,080)
	Revenue Requirement Calculation:				
27	Average Rate Base	Column (a) = Current Year Line 26 ÷2; Column (b) = (Prior Year Line 26 + Current Year Line 26) ÷2		$565,233	$509,193
28	Pre-Tax ROR		3/	9.30%	9.84%
29	Return and Taxes	Line 27 * Line 28		$52,567	$50,105
30	Book Depreciation	Line 19		$698,389	$1,396,778
31	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 12 - Line 19) * Property Tax Rate	4/	$0	$1,386,678
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**		**$750,955**	**$2,833,560**

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

	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%	(a)

Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065 (Settlement)

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	46.05%	5.30%	2.44%		2.44%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	48.78%	9.80%	4.78%	2.57%	7.35%
	100.00%		7.31%	2.57%	9.88%

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

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

	Tax-Effected Weighted Cost		**Blended Tax-Effected Weighted Cost**	
R.I.P.U.C. Docket No. 4065	9.88%	Apr 12 - Jan 13	8.23%	
R.I.P.U.C. Docket No. 4323	9.68%	Feb 13 - Mar 13	1.61%	
			9.84%	(b)

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Capital Investments with Updated Capital Repairs Deduction Rate

			Fiscal Year 2012	Fiscal Year 2013	Fiscal Year 2014
			(a)	(b)	(c)
	Capital Repairs Deduction				
1	Plant Additions	Page 3 Line 3	$48,802,200		
2	Capital Repairs Deduction Rate		21.05%		
3	Capital Repairs Deduction	Line 2 x Line 3	$10,272,863		
	Bonus Depreciation				
4	Plant Additions	Line 1	$48,802,200		
5	Less Capital Repairs Deduction	Line 3	$10,272,863		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$38,529,337		
7	Percent of Plant Eligible for Bonus Depreciation		75.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 x Line 7	$28,897,003		
9	Bonus Depreciation Rate (April 2011 - December 2011)	1 * 75% * 100%	75.00%		
10	Bonus Depreciation Rate (January 2012 - March 2012)	1 * 25% * 50%	12.50%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10	87.50%		
12	Bonus Depreciation	Line 8 x Line 11	$25,284,878		
	Remaining Tax Depreciation				
13	Plant Additions	Line 1	$48,802,200		
14	Less Capital Repairs Deduction	Line 3	$10,272,863		
15	Less Bonus Depreciation	Line 12	$25,284,878		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$13,244,459	$13,244,459	$13,244,459
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 x Line 17	$496,667	$956,117	$884,333
19	Cost of Removal		$6,579,000		
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	$42,633,408	$956,117	$884,333

Testimony of Nancy Ribot

PRE-FILED DIRECT TESTIMONY

OF

NANCY RIBOT

August 1, 2013

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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 USA as an accounting analyst for Niagara Mohawk Power Corporation. In 2008, I transferred to the New England Electric Pricing Department. In 2011, I was promoted to Senior Analyst. My responsibilities include providing support for The Narragansett Electric Company's filings regarding its electric operations.

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

A. Yes. I have testified in reference to the FY 2012 Electric Infrastructure, Safety and Reliability ("ISR") Plan Reconciliation Filing, R.I.P.U.C. Docket No. 4218, and the FY 2014 ISR Plan, R.I.P.U.C. Docket No. 4382.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the following information regarding the Fiscal Year 2013 ("FY 2013") Electric ISR Plan:

- the results of the annual reconciliations of the actual fiscal year 2013 ("FY 2013") capital investment revenue requirement and the Operations and Maintenance ("O&M") expense [1] to the actual revenue billed;
- the status of the Fiscal Year 2012 ("FY 2012") CapEx and O&M reconciliations;

[1] The testimony of William R. Richer supports the calculation of the actual FY 2013 revenue requirement associated with capital investment and O&M under the Company's electric ISR Plan.

- the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2013; and
- the proposed Summary of Retail Delivery Rates, R.I.P.U.C. No. 2095, reflecting the new reconciling factors.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section III presents the Summary of FY 2013 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 presents the results of the FY13 CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation, the calculation of the proposed CapEx Reconciling Factors, and the status of the FY12 CapEx reconciliation;
- Section VI presents the results of the FY13 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the status of the FY12 O&M reconciliation; and
- Section VII 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 pursuant to the ISR Provision require the comparison of the actual revenue billed during the plan year through the approved CapEx and O&M Factors to the actual CapEx and O&M revenue requirement. The calculation of the actual revenue requirement is presented in the testimony of Company Witness William R. Richer. Attachment NR-1 indicates that the result of the CapEx reconciliation is an over recovery of $505,592 and the result of the O&M reconciliation is an over recovery of $578,866.

Q. Please briefly summarize the operation of the tariff provision that provides the Company the opportunity to recover certain costs through the ISR Plan.

A. 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 ISR 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 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.

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 presented in Attachments NR-2 and NR-3, respectively. The current tariff contains the CapEx and O&M Reconciling Factors in effect during the period October 1, 2012 through September 30, 2013. The proposed tariff contains the proposed CapEx and O&M Reconciling Factors which, if approved, will become effective October 1, 2013 through September 30, 2014.

V. CAPEX RECONCILIATION & PROPOSED CAPEX RECONCILING FACTORS

Q. What is the result of the CapEx Reconciliation for FY 2013?

A. The FY 2013 CapEx Reconciliation by rate class is presented in Attachment NR-4, page 1, Lines 4 through 6. Line 5 shows that CapEx Revenue billed during the period April 1, 2012 through March 31, 2013 totaled $2,831,615. Line 4 shows the actual CapEx

Revenue Requirement of $2,326,023. Line 6 shows the difference of $505,592, representing an over recovery of this revenue requirement.

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 1, 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 general rate case, Docket No. 4065. It is important to note that the Rate Base Allocator approved in the Company's most recent general rate case, Docket No. 4323, was effective February 1, 2013. However, in order to maintain consistency with the rate design of the FY 2013 CapEx Factors, which were based upon the Docket No. 4065 Rate Base Allocator, the Company is allocating the actual FY 2013 revenue requirement on cumulative capital investment by the same Rate Base Allocator upon which the currently effective CapEx factors were designed and which are the subject of this reconciliation.

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

A. As shown on Attachment NR-4, page 1, the allocated actual FY 2013 capital investment revenue requirement, as shown on Line 4, is subtracted from the CapEx Factor revenue for each rate class, as shown on Line 5, resulting in an over recovery from each rate class, as shown on Line 6, which totals $505,592. The detail of each rate class' CapEx revenue billed is presented on Attachment NR-4, page 2.

Q. Why does the billed revenue shown on Attachment NR-4, page 2, decrease significantly in the months of February and March?

A. In Docket No. 4323, the Commission approved the transfer of CapEx revenue requirement being recovered through the CapEx Factors to distribution Base Rates. The transfer became effective February 1, 2013. As of that date, the CapEx Factors were set to zero beginning with usage on and after February 1, 2013 to reflect this change. The revenue shown on Attachment NR-4, page 2 for the months of February 2013, March 2013, and April 2013 pertain to usage prior to February 1, 2013 that was billed during these months.

Q. How is the Company proposing to refund the FY 2013 CapEx over recovery?

A. The Company is proposing to implement a CapEx Reconciling 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 recoveries on Line 6 are divided by each class' forecasted kWh deliveries for the period October 1, 2013 through September 30, 2014. The class-specific CapEx reconciling factors, as shown on Line 8, are as follows:

Rate Class	Charge/(Credit) per kWh
A-16 & A-60	(0.009¢)
C-06	(0.007¢)
G-02	(0.005¢)
G-32 & B-32	(0.003¢)
G-62 & B-62	(0.003¢)
Streetlights	(0.009¢)
X-01	(0.009¢)

Q. Is the Company providing the status of the net over collection of the FY 2012 CapEx Reconciliation?

A. Yes, the status of the FY 2012 CapEx Reconciliation net over collection is presented in Attachment NR-4, page 3. As of June 30, 2013, there is an over recovery balance of $38,785. The Company will continue to refund this balance through September 30, 2013.

Q. How will the Company propose to refund or recover residual balances as of September 30, 2013?

A. Per the ISR Provision, 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. Therefore, the Company will present any residual balances in the Fiscal Year 2014 (FY 2014) ISR Reconciliation Filing and include each rate class' residual balance with the FY 2014 CapEx Reconciliation Factors.

VI. <u>OPERATION & MAINTENANCE RECONCILIATION & PROPOSED O&M RECONCILING FACTOR</u>

Q. What is the result of the O&M Reconciliation for FY 2013?

A. The O&M Reconciliation for FY 2013 is presented in Attachment NR-5, page 1. Line 1 shows O&M Revenue billed through the O&M Factors from April 1, 2012 through March 31, 2013 which totaled $10,431,881. Line 2 shows the actual O&M expense for FY 2013 of $9,853,015, which is supported in the testimony of Mr. Richer. Line 3 shows the difference of $578,866, representing an over recovery.

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

A. The proposed O&M Reconciling Factor is calculated on Attachment NR-5, page 1, lines 4 and 5. The over recovery of $578,866 is divided by the forecasted kWhs during the recovery period, October 1, 2013 through September 30, 2014, of 7,591,810,844 kWh, resulting in a credit of 0.007¢ per kWh.

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

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

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.

Q. Is the Company providing the status of the net under collection of the FY 2012 O&M Reconciliation?

A. Yes, the status of the FY 2012 O&M Reconciliation is presented in Attachment NR-5, page 3. As of June 30, 2013, there is an under recovery balance of $56,053. The Company will continue to recover this balance through September 30, 2013.

Q. How will the Company propose to refund or recover residual balances as of September 30, 2013?

A. Per the ISR Provision, 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 future O&M Reconciling Factors. Therefore, the Company will present any residual balances in the FY 2014 ISR

Reconciliation Filing and include the residual balance with the FY 2014 O&M Reconciliation Factor.

VII. 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 a decrease of $0.08, or approximately 0.1%, from $78.97 to $78.89.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

Attachment NR-1

Attachment NR-1

FY2013 ISR Plan Annual Reconciliation Summary

FY 2013 ISR Plan Annual Reconciliation Summary

Line No.		CapEx (4/1/12-1/31/13)	O&M	Total
		(a)	(b)	(c)
(1)	Actual Revenue Requirement	$2,326,023	$9,853,015	$12,179,038
(2)	Revenue Billed	$2,831,615	$10,431,881	$13,263,497
(3)	Total Over Recovery	$505,592	$578,866	$1,084,459

Line Descriptions:

(1) column (a) per Attachment WRR-1, Page 1, Column (c), Line 15
column (b) per Attachment WRR-1, page 1, Column (c), Line 5

(2) column (a) per Attachment NR-3, Page 2, column (h); column (b) per Attachment NR-4, Page 2, column (a)

(3) Line (2) - Line (1)

Attachment NR-2

Attachment NR-2

Current 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	O&M Reconciliation Factor	CapEx Factor Charge	CapEx Reconciliation Factor	RDM Adj Factor	Pension Adjustment Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting	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	J=C+D+E+F +G+H+I	K	L	M=K+L	N	O	P	Q	R=O+P+Q	S	T	U=S+T	V	W=J+M+N+ R+U+V
A-16																						
Basic Residential																						
Rate	Customer Charge	$5.00							$5.00				$0.83									$5.83
R.I.P.U.C. No. 2100	kWh Charge	$0.03664	$0.00190	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	$0.03812	$0.00005	($0.00003)	$0.00002		$0.02139	($0.00128)	$0.00025	$0.02036	$0.00142	$0.00020	$0.00162	$0.00906	$0.06918
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
A-60																						
Low Income Rate	Customer Charge	$0.00							$0.00				$0.83									$0.83
R.I.P.U.C. No. 2101	kWh Charge	$0.02317	$0.00190	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	$0.02465	$0.00005	($0.00003)	$0.00002		$0.02139	($0.00128)	$0.00025	$0.02036	$0.00142	$0.00020	$0.00162	$0.00906	$0.05571
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
B-32																						
Large Demand Back-																						
up Service Rate	Customer Charge	$825.00							$825.00				$0.83									$825.83
R.I.P.U.C. No. 2137	Backup Demand Charge - in excess of 200 kW	$0.19	$0.57		$0.00				$0.76													$0.76
	kW Charge - in excess of 200 kW	$3.70			$0.00				$3.70													$3.70
	kW Charge (all kW)								$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.00551	$0.00090	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	$0.00599	$0.00005	($0.00003)	$0.00002		$0.00785	$0.00036	$0.00021	$0.00842	$0.00142	$0.00020	$0.00162	$0.00906	$0.02511
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*4/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
B-62																						
Optional Large																						
Demand Back-up																						
Service Rate	Customer Charge	$17,000.00							$17,000.00				$0.83									$17,000.83
R.I.P.U.C. No. 2138	Backup Demand Charge	$0.01	$0.32		$0.00				$0.33													$0.33
	kW Charge	$2.99	$0.32		$0.00				$3.31													$3.31
	kW Charge (all kW)													$3.23			$3.23					$3.23
	kWh Charge	$0.00000	$0.00000	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	-$0.00042	$0.00005	($0.00003)	$0.00002		$0.00824	($0.00132)	$0.00018	$0.00710	$0.00142	$0.00020	$0.00162	$0.00906	$0.01738
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*4/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
C-06																						
Small C&I Rate	Customer Charge	$10.00							$10.00				$0.83									$10.83
R.I.P.U.C. No. 2104	Unmetered Charge	$6.00							$6.00				$0.83									$6.83
	kWh Charge	$0.03253	$0.00213	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	$0.03424	$0.00005	($0.00003)	$0.00002		$0.02148	$0.00029	$0.00027	$0.02204	$0.00142	$0.00020	$0.00162	$0.00906	$0.06698
	Additional Minimum Charge (per kVA in excess of 25 kVA)	$1.85							$1.85													$1.85
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
G-02																						
General C&I Rate	Customer Charge	$135.00							$135.00				$0.83									$135.83
R.I.P.U.C. No. 2139	kW > 10 Charge	$4.85			$0.00				$4.85													$4.85
	CHP Minimum Demand Charge (effective 1/1/13	$4.85			$0.00				$4.85													$4.85
	kW Charge								$0.00					$2.89			$2.89					$2.89
	kWh Charge	$0.00468	$0.00146	$0.00002	$0.00000	($0.00003)	($0.00044)	$0.00000	$0.00569	$0.00005	($0.00003)	$0.00002		$0.00860	($0.00165)	$0.00021	$0.00716	$0.00142	$0.00020	$0.00162	$0.00906	$0.02355
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	

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

Effective: 07/01/2013
(Replacing R.I.P.U.C No. 2095 effective 04/01/13)
Issued: 07/10/2013

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2100, 2101, 2104, 2108 through 2112, 2137 through 2141
D. - G. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2118
H. per Revenue Decoupling Mechanism Provision, R.I.P.U.C. No. 2073
I. per Pension Adjustment Mechanism Provision, R.I.P.U.C. No. 2119
J. Col C+ Col D+ Col E+ Col F + Col G + Col H + Col I
K. per Net Metering Provision, R.I.P.U.C. No. 2099
L. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2125 & 2127
M. Col K+ Col L
N. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
O. - Q. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2115
R. Col O+ Col P + Col Q
S. - T. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1188
U. Col S+ Col T
V. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2114, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
W. Col J+ Col M+ Col N+ Col R + Col U + Col V

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	Pension Adjustment Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting	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	J=C+D+E+F+G+H+I	K	L	M=K+L	N	O	P	Q	R=O+P+Q	S	T	U=S+T	V	W=J+M+N+R+U+V
G-32																						
Large Demand Rate	Customer Charge	$825.00							$825.00				$0.83									$825.83
R.I.P.U.C. No. 2140	kW Charge - in excess of 200 kW	$3.70			$0.00				$3.70													$3.70
	CHP Minimum Demand Charge (effective 1/1/13	$3.70			$0.00				$3.70													$3.70
	kW Charge								$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.00551	$0.00090	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	$0.00599	$0.00005	($0.00003)	$0.00002		$0.00785	$0.00036	$0.00021	$0.00842	$0.00142	$0.00020	$0.00162	$0.00906	$0.02511
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%	$0.00000		$0.00000				-1.0%													-1.0%
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
G-62																						
Optional Large																						
Demand Rate	Customer Charge	$17,000.00							$17,000.00				$0.83									$17,000.83
R.I.P.U.C. No. 2141	kW Charge	$2.99	$0.32		$0.00				$3.31													$3.31
	CHP Minimum Demand Charge (effective 1/1/13	$2.99	$0.32		$0.00				$3.31													$3.31
	kW Charge								$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.00000	$0.00000	$0.00002	$0.00000	$0.00000	($0.00044)	$0.00000	($0.00042)	$0.00005	($0.00003)	$0.00002		$0.00824	($0.00132)	$0.00018	$0.00710	$0.00142	$0.00020	$0.00162	$0.00906	$0.01738
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
X-01																						
Electric Propulsion																						
Rate	Customer Charge	$16,500.00							$16,500.00				$0.83									$16,500.83
R.I.P.U.C. No. 2108	kW Charge	$0.00							$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.01600	$0.00146	$0.00002	$0.00000	$0.00001	($0.00044)	$0.00000	$0.01705	$0.00005	($0.00003)	$0.00002		$0.00824	($0.00132)	$0.00018	$0.00710	$0.00142	$0.00020	$0.00162	$0.00906	$0.03485
	Effective Date	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
M-1																						
Station Power																						
Delivery &																						
Reliability Service																						
Rate	Option A:																					
R.I.P.U.C. No. 2109	fixed charges	$3,959.09	$0.00		$0.00				$3,959.09				$0.83	$0.00	$0.00	$0.00	$0.00	$3,500.00	$0.00	$3,500.00	$800.00	$8,259.92
	variable charges	$0.00	$0.00		$0.00				$0.00					$0.00	$0.00	$0.00	$0.00	$0.00142	$0.00020	$0.00162	$0.00906	$0.01068
	(transition and conservation charges																					
	billed on higher of fixed charges																					
	or kWhs times variable charges)																					
	Option B:																					
	fixed charge	$3,959.09	$0.00		$0.00				$3,959.09				$0.83									$3,959.92
	kWh charge													$0.00000	$0.00000	$0.00000	$0.00000	$0.00142	$0.00020	$0.00162	$0.00906	$0.01068
	Effective Date	*2/1/13*	*4/1/13*		*4/1/13*	*10/1/12*					*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
S-06																						
Decorative Street																						
and Area Lighting																						
Service																						
R.I.P.U.C. No. 2110																						
S-10																						
Limited Service -																						
Private Lighting																						
R.I.P.U.C. No. 2111																						
S-14	Customer Charge												$0.83									$0.83
General Street and																						
Area Lighting																						
Service	kWh Charge	$0.00000	$0.01338	$0.00002	$0.00003	($0.00002)	($0.00044)		$0.01297	$0.00005	($0.00003)	$0.00002		$0.00977	$0.00198	$0.00014	$0.01189	$0.00142	$0.00020	$0.00162	$0.00906	$0.03556
R.I.P.U.C. No. 2112	*Effective Date*	*2/1/13*	*4/1/13*	*10/1/12*	*4/1/13*	*10/1/12*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	

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

Effective: 07/01/2013
(Replacing R.I.P.U.C No. 2095 effective 04/01/13)
Issued: 07/10/2013

Column Descriptions:

A. - C. per retail delivery tariffs
D. - G. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2118
H. per Revenue Decoupling Mechanism Provision, R.I.P.U.C. No. 2073
I. per Pension Adjustment Mechanism Provision, R.I.P.U.C. No. 2119
J. Col C+ Col D+ Col E+ Col F + Col G + Col H + Col I
K. per Net Metering Provision, R.I.P.U.C. No. 2099
L. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2125 & 2127
M. Col K+ Col L
N. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
O. - Q. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2115
R. Col O+ Col P + Col Q
S. - T. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1188
U. Col S+ Col T
V. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2114, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
W. Col J+ Col M+ Col N+ Col R + Col U + C

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate		Charge Description	Distribution Charge			
A		B	C			
Rate S-06		Fixture Charges				
Decorative Street and Area Lighting Service						
R.I.P.U.C. No. 2110			Full Service S-06	Full Service S-10	Full Service S-14	Temp-off S-14
		Luminaires				
Rate S-10						
Limited Service - Private Lighting	Incandescent					
R.I.P.U.C. No. 2111	Roadway	LUM INC RWY 105W	n/a	$77.43	$77.43	$46.46
		LUM INC RWY 205W (S-14 Only)	n/a	n/a	$77.43	$46.46
	Mercury Vapor					
Rate S-14	Roadway	LUM MV RWY 100W	n/a	$78.06	$78.06	$46.84
General Street and Area Lighting Service		LUM MV RWY 175W	n/a	$78.06	$78.06	$46.84
R.I.P.U.C. No. 2112		LUM MV RWY 250W (S-14 Only)	n/a	n/a	$120.39	$72.23
		LUM MV RWY 400W	n/a	$163.46	$163.46	$98.08
		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	$181.37	$181.37	$108.82
		LUM MV FLD 1000W	n/a	$181.37	$181.37	$108.82
	Sodium Vapor					
	Roadway	LUM HPS RWY 50W	n/a	$77.43	$77.43	$46.46
		LUM HPS RWY 70W	n/a	$76.91	$76.91	$46.15
		LUM HPS RWY 100W	n/a	$78.06	$78.06	$46.84
		LUM HPS RWY 150W	n/a	$78.58	$78.58	$47.15
		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	$146.11	$146.11	$87.67
		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	$98.99	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	$292.34	n/a	n/a	n/a
		DEC HPS AG 100W	$280.77	n/a	n/a	n/a
		DEC HPS WL 50W	$325.35	n/a	n/a	n/a
		DEC HPS WL 100W	$325.30	n/a	n/a	n/a
		DEC HPS TR-TW 50W	$506.29	n/a	n/a	n/a
		DEC HPS TR-TW 100W	$509.46	n/a	n/a	n/a
		DEC HPS AG-TW 50W	$693.84	n/a	n/a	n/a
		DEC HPS AG-TW 100W	$670.71	n/a	n/a	n/a
		DEC HPS WL-TW 50W	$759.87	n/a	n/a	n/a
		DEC HPS WL-TW 100W	$759.77	n/a	n/a	n/a
		Standards				
		POLE-WOOD	n/a	$133.71	$133.71	$133.71
		POLE FIBER PT EMB <25' w/out foundation	n/a	$260.22	$260.22	$260.22
		POLE FIBER RWY <25 w/ foundation	n/a	$424.14	$424.14	$424.14
		POLE FIBER RWY => 25 w/ foundation	n/a	$473.53	$473.53	$473.53
		POLE METAL EMBEDDED (S-14 Only)	n/a	n/a	$405.16	$405.16
		POLE METAL=>25FT (with foundation)	n/a	$484.72	$484.72	$484.72
		DEC VILL PT/FDN	$566.70	n/a	n/a	n/a
		DEC WASH PT/FDN	$575.78	n/a	n/a	n/a
		Effective Date	*2/1/13*	*2/1/13*	*2/1/13*	*2/1/13*

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

Effective: 07/01/2013
(Replacing R.I.P.U.C No. 2095 effective 04/01/13)
Issued: 07/10/2013

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2110 through 2112

Attachment NR-3

Attachment NR-3

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	O&M Reconciliation Factor	CapEx Factor Charge	CapEx Reconciliation Factor	RDM Adj Factor	Pension Adjustment Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting	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	J=C+D+E+F+G+H+I	K	L	M=K+L	N	O	P	Q	R=O+P+Q	S	T	U=S+T	V	W=J+M+N+R+U+V
A-16																						
Basic Residential																						
Rate	Customer Charge	$5.00							$5.00				$0.83									$5.83
R.I.P.U.C. No. 2100	kWh Charge	$0.03664	$0.00190	($0.00007)	$0.00000	($0.00009)	($0.00044)	$0.00000	$0.03794	$0.00005	($0.00003)	$0.00002		$0.02139	($0.00128)	$0.00025	$0.02036	$0.00142	$0.00020	$0.00162	$0.00906	$0.06900
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
A-60																						
Low Income Rate	Customer Charge	$0.00							$0.00				$0.83									$0.83
R.I.P.U.C. No. 2101	kWh Charge	$0.02317	$0.00190	($0.00007)	$0.00000	($0.00009)	($0.00044)	$0.00000	$0.02447	$0.00005	($0.00003)	$0.00002		$0.02139	($0.00128)	$0.00025	$0.02036	$0.00142	$0.00020	$0.00162	$0.00906	$0.05553
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
B-32																						
Large Demand Back-																						
up Service Rate	Customer Charge	$825.00							$825.00				$0.83									$825.83
R.I.P.U.C. No. 2137	Backup Demand Charge - in excess of 200 kW	$0.19	$0.57		$0.00				$0.76													$0.76
	kW Charge - in excess of 200 kW	$3.70			$0.00				$3.70													$3.70
	kW Charge (all kW)								$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.00551	$0.00090	($0.00007)	$0.00000	($0.00003)	($0.00044)	$0.00000	$0.00587	$0.00005	($0.00003)	$0.00002		$0.00785	$0.00036	$0.00021	$0.00842	$0.00142	$0.00020	$0.00162	$0.00906	$0.02499
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*4/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
B-62																						
Optional Large																						
Demand Back-up																						
Service Rate	Customer Charge	$17,000.00							$17,000.00				$0.83									$17,000.83
R.I.P.U.C. No. 2138	Backup Demand Charge	$0.01	$0.32		$0.00				$0.33													$0.33
	kW Charge	$2.99	$0.32		$0.00				$3.31													$3.31
	kW Charge (all kW)													$3.23			$3.23					$3.23
	kWh Charge	$0.00000	$0.00000	($0.00007)	$0.00000	($0.00003)	($0.00044)	$0.00000	-$0.00054	$0.00005	($0.00003)	$0.00002		$0.00824	($0.00132)	$0.00018	$0.00710	$0.00142	$0.00020	$0.00162	$0.00906	$0.01726
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*4/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
C-06																						
Small C&I Rate	Customer Charge	$10.00							$10.00				$0.83									$10.83
R.I.P.U.C. No. 2104	Unmetered Charge	$6.00							$6.00				$0.83									$6.83
	kWh Charge	$0.03253	$0.00213	($0.00007)	$0.00000	($0.00007)	($0.00044)	$0.00000	$0.03408	$0.00005	($0.00003)	$0.00002		$0.02148	$0.00029	$0.00027	$0.02204	$0.00142	$0.00020	$0.00162	$0.00906	$0.06682
	Additional Minimum Charge (per kVA in excess of 25 kVA)	$1.85							$1.85													$1.85
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
G-02																						
General C&I Rate	Customer Charge	$135.00							$135.00				$0.83									$135.83
R.I.P.U.C. No. 2139	kW > 10 Charge	$4.85			$0.00				$4.85													$4.85
	CHP Minimum Demand Charge (effective 1/1/13	$4.85			$0.00				$4.85													$4.85
	kW Charge								$0.00					$2.89			$2.89					$2.89
	kWh Charge	$0.00468	$0.00146	($0.00007)	$0.00000	($0.00005)	($0.00044)	$0.00000	$0.00558	$0.00005	($0.00003)	$0.00002		$0.00860	($0.00165)	$0.00021	$0.00716	$0.00142	$0.00020	$0.00162	$0.00906	$0.02344
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	

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

Effective: 10/01/2013
(Replacing R.I.P.U.C No. 2095 effective 04/01/13)
Issued: 08/01/2013

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2100, 2101, 2104, 2108 through 2112, 2137 through 2141
D. - G. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2118
H. per Revenue Decoupling Mechanism Provision, R.I.P.U.C. No. 2073
I. per Pension Adjustment Mechanism Provision, R.I.P.U.C. No. 2119
J. Col C+ Col D+ Col E+ Col F + Col G + Col H + Col I
K. per Net Metering Provision, R.I.P.U.C. No. 2099
L. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2125 & 2127
M. Col K+ Col L
N. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
O. - Q. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2115
R. Col O+ Col P + Col Q
S. - T. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1188
U. Col S+ Col T
V. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2114, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
W. Col J+ Col M+ Col N+ Col R + Col U + Col V

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	Pension Adjustment Factor	Billing Distribution Charge	Net Metering Charge	Long-Term Contracting	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	J=C+D+E+F +G+H+I	K	L	M=K+L	N	O	P	Q	R=O+P+Q	S	T	U=S+T	V	W=J+M+N+ R+U+V
G-32																						
Large Demand Rate	Customer Charge	$825.00							$825.00				$0.83									$825.83
R.I.P.U.C. No. 2140	kW Charge - in excess of 200 kW	$3.70			$0.00				$3.70													$3.70
	CHP Minimum Demand Charge (effective 1/1/13	$3.70			$0.00				$3.70													$3.70
	kW Charge								$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.00551	$0.00090	($0.00007)	$0.00000	($0.00003)	($0.00044)	$0.00000	$0.00587	$0.00005	($0.00003)	$0.00002		$0.00785	$0.00036	$0.00021	$0.00842	$0.00142	$0.00020	$0.00162	$0.00906	$0.02499
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%	$0.00000		$0.00000				-1.0%													-1.0%
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
G-62																						
Optional Large Demand Rate	Customer Charge	$17,000.00							$17,000.00				$0.83									$17,000.83
R.I.P.U.C. No. 2141	kW Charge	$2.99	$0.32		$0.00				$3.31													$3.31
	CHP Minimum Demand Charge (effective 1/1/13	$2.99	$0.32		$0.00				$3.31													$3.31
	kW Charge								$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.00000	$0.00000	($0.00007)	$0.00000	($0.00003)	($0.00044)	$0.00000	($0.00054)	$0.00005	($0.00003)	$0.00002		$0.00824	($0.00132)	$0.00018	$0.00710	$0.00142	$0.00020	$0.00162	$0.00906	$0.01726
	High Voltage Delivery Discount	($0.42)							($0.42)													($0.42)
	High Voltage Delivery Addt'l Discount (115kV)	($2.75)							($2.75)													($2.75)
	Second Feeder Service	$2.75							$2.75													$2.75
	Second Feeder Service - Addt'l Transformer	$0.42							$0.42													$0.42
	High Voltage Metering Discount	-1.0%							-1.0%													-1.0%
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
X-01																						
Electric Propulsion Rate	Customer Charge	$16,500.00							$16,500.00				$0.83									$16,500.83
R.I.P.U.C. No. 2108	kW Charge	$0.00							$0.00					$3.23			$3.23					$3.23
	kWh Charge	$0.01600	$0.00146	($0.00007)	$0.00000	($0.00009)	($0.00044)	$0.00000	$0.01686	$0.00005	($0.00003)	$0.00002		$0.00824	($0.00132)	$0.00018	$0.00710	$0.00142	$0.00020	$0.00162	$0.00906	$0.03466
	Effective Date	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
M-1																						
Station Power Delivery & Reliability Service Rate	Option A:																					
R.I.P.U.C. No. 2109	fixed charges	$3,959.09	$0.00		$0.00				$3,959.09				$0.83	$0.00	$0.00	$0.00	$0.00	$3,500.00	$0.00	$3,500.00	$800.00	$8,259.92
	variable charges	$0.00	$0.00		$0.00				$0.00					$0.00	$0.00	$0.00	$0.00	$0.00142	$0.00020	$0.00162	$0.00906	$0.01068
	(transition and conservation charges billed on higher of fixed charges or kWhs times variable charges)																					
	Option B:																					
	fixed charge	$3,959.09	$0.00		$0.00				$3,959.09				$0.83									$3,959.92
	kWh charge													$0.00000	$0.00000	$0.00000	$0.00000	$0.00142	$0.00020	$0.00162	$0.00906	$0.01068
	Effective Date	*2/1/13*	*4/1/13*		*4/1/13*	*10/1/13*					*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	
S-06																						
Decorative Street and Area Lighting Service																						
R.I.P.U.C. No. 2110																						
S-10																						
Limited Service - Private Lighting																						
R.I.P.U.C. No. 2111																						
S-14	Customer Charge												$0.83									$0.83
General Street and Area Lighting Service	kWh Charge	$0.00000	$0.01338	($0.00007)	$0.00003	($0.00009)	($0.00044)		$0.01281	$0.00005	($0.00003)	$0.00002		$0.00977	$0.00198	$0.00014	$0.01189	$0.00142	$0.00020	$0.00162	$0.00906	$0.03540
R.I.P.U.C. No. 2112	*Effective Date*	*2/1/13*	*4/1/13*	*10/1/13*	*4/1/13*	*10/1/13*	*7/1/13*	*2/1/13*		*4/1/13*	*7/1/13*		*1/1/13*	*4/1/13*	*4/1/13*	*4/1/13*		*4/1/13*	*4/1/13*		*2/1/13*	

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

Effective: 10/01/2013
(Replacing R.I.P.U.C No. 2095 effective 04/01/13)
Issued: 08/01/2013

Column Descriptions:

A. - C. per retail delivery tariffs
D. - G. per Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2118
H. per Revenue Decoupling Mechanism Provision, R.I.P.U.C. No. 2073
I. per Pension Adjustment Mechanism Provision, R.I.P.U.C. No. 2119
J. Col C+ Col D+ Col E+ Col F + Col G + Col H + Col I
K. per Net Metering Provision, R.I.P.U.C. No. 2099
L. per Long-Term Contracting for Renewable Energy Recovery Provision, R.I.P.U.C. No. 2125 & 2127
M. Col K+ Col L
N. per LIHEAP Enhancement Plan Provision, R.I.P.U.C. No. 2079
O. - Q. per Transmission Cost Adjustment Provision, R.I.P.U.C. No. 2115
R. Col O+ Col P + Col Q
S. - T. per Non-Bypassable Transition Adjustment Provision, R.I.P.U.C. No. 1188
U. Col S+ Col T
V. per Energy Efficiency Program Provision, R.I.P.U.C. No. 2114, also includes $0.00030 per kWh Renewable Energy Charge per R.I.G.L. §39-2-1.2
W. Col J+ Col M+ Col N+ Col R + Col U + C

THE NARRAGANSETT ELECTRIC COMPANY
Summary of Retail Delivery Rates

Rate		Charge Description	Distribution Charge			
A		B	C			
Rate S-06		Fixture Charges				
Decorative Street and Area Lighting Service						
R.I.P.U.C. No. 2110			Full Service	Full Service	Full Service	Temp-off
			S-06	S-10	S-14	S-14
		Luminaires				
Rate S-10						
Limited Service - Private Lighting	Incandescent					
R.I.P.U.C. No. 2111	Roadway	LUM INC RWY 105W	n/a	$77.43	$77.43	$46.46
		LUM INC RWY 205W (S-14 Only)	n/a	n/a	$77.43	$46.46
	Mercury Vapor					
Rate S-14	Roadway	LUM MV RWY 100W	n/a	$78.06	$78.06	$46.84
General Street and Area Lighting Service		LUM MV RWY 175W	n/a	$78.06	$78.06	$46.84
R.I.P.U.C. No. 2112		LUM MV RWY 250W (S-14 Only)	n/a	n/a	$120.39	$72.23
		LUM MV RWY 400W	n/a	$163.46	$163.46	$98.08
		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	$181.37	$181.37	$108.82
		LUM MV FLD 1000W	n/a	$181.37	$181.37	$108.82
	Sodium Vapor					
	Roadway	LUM HPS RWY 50W	n/a	$77.43	$77.43	$46.46
		LUM HPS RWY 70W	n/a	$76.91	$76.91	$46.15
		LUM HPS RWY 100W	n/a	$78.06	$78.06	$46.84
		LUM HPS RWY 150W	n/a	$78.58	$78.58	$47.15
		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	$146.11	$146.11	$87.67
		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	$98.99	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	$292.34	n/a	n/a	n/a
		DEC HPS AG 100W	$280.77	n/a	n/a	n/a
		DEC HPS WL 50W	$325.35	n/a	n/a	n/a
		DEC HPS WL 100W	$325.30	n/a	n/a	n/a
		DEC HPS TR-TW 50W	$506.29	n/a	n/a	n/a
		DEC HPS TR-TW 100W	$509.46	n/a	n/a	n/a
		DEC HPS AG-TW 50W	$693.84	n/a	n/a	n/a
		DEC HPS AG-TW 100W	$670.71	n/a	n/a	n/a
		DEC HPS WL-TW 50W	$759.87	n/a	n/a	n/a
		DEC HPS WL-TW 100W	$759.77	n/a	n/a	n/a
		Standards				
		POLE-WOOD	n/a	$133.71	$133.71	$133.71
		POLE FIBER PT EMB <25' w/out foundation	n/a	$260.22	$260.22	$260.22
		POLE FIBER RWY <25 w/ foundation	n/a	$424.14	$424.14	$424.14
		POLE FIBER RWY => 25 w/ foundation	n/a	$473.53	$473.53	$473.53
		POLE METAL EMBEDDED (S-14 Only)	n/a	n/a	$405.16	$405.16
		POLE METAL=>25FT (with foundation)	n/a	$484.72	$484.72	$484.72
		DEC VILL PT/FDN	$566.70	n/a	n/a	n/a
		DEC WASH PT/FDN	$575.78	n/a	n/a	n/a
	Effective Date		*2/1/13*	*2/1/13*	*2/1/13*	*2/1/13*

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

Effective: 10/01/2013
(Replacing R.I.P.U.C No. 2095 effective 04/01/13)
Issued: 08/01/2013

Column Descriptions:

A. - C. per retail delivery tariffs R.I.P.U.C. Nos. 2110 through 2112

Attachment NR-4

Attachment NR-4

CapEx Reconciliations and Proposed CapEx Reconciling Factors

Proposed CapEx Reconciling Factors
For Fiscal Year 2013 ISR Plan
For the Recovery (Refund) Period October 1, 2013 through September 30, 2014

Line No.		Total	Residential A-16 / A-60	Small C&I C-06	General C&I G-02	200 kW Demand B-32 / G-32	3000 kW Demand B-62 / G-62	Lighting S-10 / S-14	Propulsion X-01
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
(1)	Actual FY2013 Capital Investment Revenue Requirement	$2,326,023							
(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 FY2013 Capital Investment Revenue Requirement	$2,326,023	$1,177,023	$213,309	$381,837	$322,714	$94,099	$126,464	$10,578
(5)	CapEx Revenue Billed	$2,831,615	$1,478,706	$252,901	$451,950	$385,374	$117,036	$132,796	$12,852
(6)	Over Recovery	$505,592	$301,683	$39,592	$70,113	$62,660	$22,937	$6,332	$2,275
(7)	Forecasted kWhs - October 1, 2013 through September 30, 2014	7,591,810,844	3,026,321,326	549,812,783	1,260,793,248	2,013,915,611	651,113,479	66,737,142	23,117,255
(8)	Proposed Class-specific CapEx Reconciling Factor(Credit) per kWh		($0.00009)	($0.00007)	($0.00005)	($0.00003)	($0.00003)	($0.00009)	($0.00009)

Line No.
(1) per Attachment WRR-1, Page 1, Column (c), Line 15
(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 2
(6) Line (5) - Line (4)
(7) per Company forecasts
(8) -1 x [Line (6) ÷ Line (7)], truncated to 5 decimal places

Fiscal Year 2013 CapEx Factor Revenue
For the Period April 1, 2012 through March 31, 2013
For the Recovery/Refund Period October 1, 2013 through September 30, 2014

CapEx Factor Revenue:

	Month	A16/A60 CapEx Revenue (a)	C06 CapEx Revenue (b)	Streetlights CapEx Revenue (c)	X01 CapEx Revenue (d)
(1)	Apr-12	$28,067	$4,775	$2,390	$97
	May-12	$109,535	$21,576	$11,387	$1,268
	Jun-12	$128,417	$24,177	$10,111	$1,297
	Jul-12	$176,474	$27,901	$11,539	$1,197
	Aug-12	$205,319	$31,481	$11,644	$1,397
	Sep-12	$175,367	$29,126	$13,831	$1,309
	Oct-12	$121,518	$22,423	$14,592	$1,236
	Nov-12	$118,901	$21,659	$16,083	$1,307
	Dec-12	$146,858	$25,050	$17,493	$1,108
	Jan-13	$164,806	$27,110	$19,660	$1,303
	Feb-13	$101,688	$17,713	$4,003	$1,255
	Mar-13	$1,783	($88)	($4)	$78
(2)	Apr-13	($25)	($4)	$67	($0)
	Total	$1,478,706	$252,901	$132,796	$12,852

	Month	G02 CapEx Revenue (e)	B32/G32 CapEx Revenue (f)	B62/G62 CapEx Revenue (g)	Total CapEx Revenue (h)
(1)	Apr-12	$9,568	$8,201	$1,660	$54,759
	May-12	$42,166	$37,124	$10,874	$233,930
	Jun-12	$47,216	$40,332	$11,701	$263,252
	Jul-12	$50,401	$42,548	$12,299	$322,359
	Aug-12	$49,251	$42,895	$12,423	$354,411
	Sep-12	$49,346	$43,089	$13,483	$325,550
	Oct-12	$44,612	$37,811	$12,009	$254,201
	Nov-12	$44,992	$36,884	$11,246	$251,071
	Dec-12	$39,902	$33,860	$10,785	$275,056
	Jan-13	$41,860	$35,430	$10,376	$300,544
	Feb-13	$31,770	$25,700	$9,932	$192,060
	Mar-13	$818	$1,501	$248	$4,337
(2)	Apr-13	$47	$0	$0	$85
	Total	$451,950	$385,374	$117,036	$2,831,615

Column Descriptions:
(a) - (g) from monthly revenue reports
(h) sum of columns (a) through (g)

(1) Reflects kWhs consumed after April 1st 42.09%
(2) Reflects kWhs consumed prior to April 1st 58.00%

Fiscal Year 2012 CapEx Reconciliation of Over Recovery
For the Period April 1, 2011 through March 31, 2012
For the Recovery Period October 1, 2012 through September 30, 2013

Status Update as of June 2013

Line No.		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	Beginning Over(Under) Recovery	$65,588		$10,137		$2,346		$41,706		$11,264
(2)	CapEx Reconciling Factors			$0.00000		$0.00000		($0.00003)		$0.00000
			A16/A60 kWhs	A16/A60 CapEx Reconciling Factor Revenue	C06 kWhs	C06 CapEx Reconciling Factor Revenue	G-02 kWhs	G-02 CapEx Reconciling Factor Revenue	B-32 / G-32 kWhs	B-32 / G-32 CapEx Reconciling Factor Revenue
(3)	Oct-12	($1,299)	90,409,530	$0	17,630,262	$0	41,994,021	($1,260)	66,314,539	$0
	Nov-12	($3,068)	212,308,534	$0	40,957,859	$0	98,820,356	($2,965)	157,798,682	$0
	Dec-12	($3,100)	262,483,084	$0	47,298,764	$0	99,435,080	($2,983)	160,192,871	$0
	Jan-13	($3,238)	294,661,412	$0	51,048,120	$0	103,578,144	($3,107)	165,210,789	$0
	Feb-13	($3,515)	275,974,425	$0	51,199,306	$0	113,723,829	($3,412)	176,799,557	$0
	Mar-13	($3,110)	251,101,587	$0	48,155,908	$0	100,736,603	($3,022)	161,195,965	$0
	Apr-13	($3,111)	238,458,753	$0	48,236,868	$0	100,694,568	($3,021)	161,047,030	$0
	May-13	($3,091)	211,292,853	$0	46,167,078	$0	100,833,213	($3,025)	166,668,566	$0
	Jun-13	($3,271)	230,238,986	$0	48,537,075	$0	106,954,703	($3,209)	167,696,752	$0
	Jul-13	$0	-	$0	-	$0	-	$0	-	$0
	Aug-13	$0	-	$0	-	$0	-	$0	-	$0
	Sep-13	$0	-	$0	-	$0	-	$0	-	$0
(4)	Total	($26,803)	2,066,929,164	$0	399,231,240	$0	866,770,517	($26,003)	1,382,924,751	$0
(5)	Ending Over(Under) Recovery	$38,785		$10,137		$2,346		$15,703		$11,264

Line No.		3000 kW Demand B-62 / G-62		Lighting S-10 / S-14		Propulsion X-01	
		(j)	(k)	(l)	(m)	(n)	(o)
(1)	Beginning Over(Under) Recovery		($1,482)		$2,011		($394)
(2)	CapEx Reconciling Factors		$0.00000		($0.00002)		$0.00001
		B-62 / G-62 kWhs	B-62 / G-62 CapEx Reconciling Factor Revenue	S-10 / S-14 kWhs	S-10 / S-14 CapEx Reconciling Factor Revenue	X-01 kWhs	X-01 CapEx Reconciling Factor Revenue
	Oct-12	18,989,254	$0	2,326,033	($47)	773,078	$8
	Nov-12	44,951,030	$0	6,138,253	($123)	1,953,798	$20
	Dec-12	42,917,554	$0	6,675,827	($134)	1,654,207	$17
	Jan-13	41,237,325	$0	7,504,431	($150)	1,945,270	$19
	Feb-13	49,632,967	$0	6,116,885	($122)	1,872,605	$19
	Mar-13	41,724,269	$0	5,232,817	($105)	1,692,846	$17
	Apr-13	44,101,963	$0	5,440,613	($109)	1,852,188	$19
	May-13	43,842,178	$0	4,295,980	($86)	2,017,577	$20
	Jun-13	42,921,026	$0	4,069,439	($81)	1,885,083	$19
	Jul-13	-	$0	-	$0	-	$0
	Aug-13	-	$0	-	$0	-	$0
	Sep-13	-	$0	-	$0	-	$0
(4)	Total	370,317,566	$0	47,800,278	($956)	15,646,652	$156
(5)	Ending Over(Under) Recovery		($1,482)		$1,055		($237)

Column Descriptions:
(a) Column (c) + (e) + (g) + (i) + (k) + (m) + (o)
(b) from Company revenue report
(c) Column (b) x CapEx Reconciling Factor
(d) from Company revenue report
(e) Column (d) x CapEx Reconciling Factor
(f) from Company revenue report
(g) Column (f) x CapEx Reconciling Factor
(h) from Company revenue report
(i) Column (h) x CapEx Reconciling Factor
(j) from Company revenue report
(k) Column (j) x CapEx Reconciling Factor
(l) from Company revenue report
(m) Column (l) x CapEx Reconciling Factor
(n) from Company revenue report
(o) Column (n) x CapEx Reconciling Factor

Line Descriptions:
(1) per R.I.P.U.C. Docket No. 4218, Attachment NR-4, page 2, line (6)
(2) per R.I.P.U.C. Docket No. 4218, Attachment NR-4, page 2, line (8)
(4) sum of kWhs & revenue
(3) prorated for usage on and after October 1st
(5) Line (1) + Line (4)

Attachment NR-5

Attachment NR-5

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2013 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For the Period April 1, 2012 through March 31, 2013
For the Recovery Period October 1, 2013 through September 30, 2014

(1)	O&M Revenue Billed	$10,431,881
(2)	Actual O&M Revenue Requirement	$9,853,015
(3)	Over Recovery	$578,866
(4)	October 1, 2013 through September 30, 2014 Forecasted kWh Sales	7,591,810,844
(5)	Proposed O&M Reconciling Factor Credit per kWh	($0.00007)

Line Descriptions:
(1) per Page 2, column (a)
(2) per Attachment WRR-1, page 1, Column (c), Line 5
(3) Line (1) - Line (2)
(4) per Company forecast
(5) Line (3) ÷ Line (4), truncated to 5 decimal places

Fiscal Year 2013 Operations & Maintenance Reconciliation
For the Period April 1, 2012 through March 31, 2013
For the Recovery/Refund Period October 1, 2013 through September 30, 2014

O&M Factor Revenue:

	Month	Total Revenue (a)
(1)	Apr-12	$309,017
	May-12	$712,185
	Jun-12	$797,604
	Jul-12	$972,710
	Aug-12	$1,090,257
	Sep-12	$1,002,059
	Oct-12	$766,369
	Nov-12	$756,985
	Dec-12	$853,694
	Jan-13	$928,314
	Feb-13	$914,097
	Mar-13	$826,137
(2)	Apr-13	$502,454
	Total	$10,431,881

(1) Reflects kWhs consumed after April 1st	42.09%
(2) Reflects kWhs consumed prior to April 1st	58.00%

Fiscal Year 2012 O&M Reconciliation of Under Recovery
For the Period April 1, 2012 through March 31, 2012
For the Recovery Period October 1, 2012 through September 30, 2013

Status Update as of June 2013

Line No.		Total
(1)	Over(Under) Recovery	($159,045)
(2)	O&M Reconciling Factor	$0.00002

		Total kWhs	Total Revenue
		(a)	(b)
	Oct-12	238,436,718	$4,769
	Nov-12	562,928,512	$11,259
	Dec-12	620,657,387	$12,413
	Jan-13	665,185,491	$13,304
	Feb-13	675,319,574	$13,506
	Mar-13	609,839,995	$12,197
	Apr-13	599,831,983	$11,997
	May-13	575,117,445	$11,502
	Jun-13	602,303,064	$12,046
	Jul-13	-	$0
	Aug-13	-	$0
	Sep-13	-	$0
(3)	Total	5,149,620,169	$102,992
(4)	Over(Under) Recovery		($56,053)

Line Descriptions:
(1) per R.I.P.U.C. Docket No. 4218, Attachment NR-5, page 1, line (3)
(2) per R.I.P.U.C. Docket No. 4218, Attachment NR-5, page 1, line (5)
(3) sum of kWhs & revenue
(4) Line (1) + Line (3)

Column Descriptions:
(a) per Company Records
(b) per Company records; or Line (2) x Column (a)

Attachment NR-6

Attachment NR-6

Typical Bill Analysis

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 Customers
150	$27.94	$11.06	$16.88	$27.91	$11.06	$16.85	($0.03)	-0.1%	13.7%
300	$49.81	$22.12	$27.69	$49.77	$22.13	$27.64	($0.04)	-0.1%	17.5%
400	$64.40	$29.50	$34.90	$64.32	$29.50	$34.82	($0.08)	-0.1%	11.8%
500	$78.97	$36.87	$42.10	$78.89	$36.88	$42.01	($0.08)	-0.1%	10.8%
600	$93.55	$44.24	$49.31	$93.44	$44.24	$49.20	($0.11)	-0.1%	9.4%
700	$108.14	$51.62	$56.52	$108.01	$51.62	$56.39	($0.13)	-0.1%	7.7%
1,000	$151.88	$73.74	$78.14	$151.69	$73.74	$77.95	($0.19)	-0.1%	15.0%
2,000	$297.68	$147.48	$150.20	$297.30	$147.48	$149.82	($0.38)	-0.1%	14.1%

Present Rates

Customer Charge		$5.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.02036
Distribution Energy Charge (1)	kWh x	$0.03812
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07079

Proposed Rates

Customer Charge		$5.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.02036
Distribution Energy Charge (2)	kWh x	$0.03794
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07079

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

Note (2): includes the proposed CapEx Reconciling of (0.009¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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 Customers
150	$20.63	$11.06	$9.57	$20.60	$11.06	$9.54	($0.03)	-0.1%	10.7%
300	$40.39	$22.12	$18.27	$40.34	$22.12	$18.22	($0.05)	-0.1%	23.2%
400	$53.58	$29.50	$24.08	$53.50	$29.50	$24.00	($0.08)	-0.1%	14.9%
500	$66.75	$36.87	$29.88	$66.66	$36.87	$29.79	($0.09)	-0.1%	12.2%
600	$79.92	$44.24	$35.68	$79.81	$44.24	$35.57	($0.11)	-0.1%	9.6%
700	$93.11	$51.62	$41.49	$92.98	$51.62	$41.36	($0.13)	-0.1%	7.3%
1,000	$132.64	$73.74	$58.90	$132.45	$73.74	$58.71	($0.19)	-0.1%	12.3%
2,000	$264.41	$147.48	$116.93	$264.03	$147.48	$116.55	($0.38)	-0.1%	9.8%

<u>Present Rates</u>

Customer Charge		$0.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.02036
Distribution Energy Charge (1)	kWh x	$0.02465
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07079

<u>Proposed Rates</u>

Customer Charge		$0.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.02036
Distribution Energy Charge (2)	kWh x	$0.02447
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07079

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

Note (2): includes the proposed CapEx Reconciling of (0.009¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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 Customers
250	$48.15	$19.43	$28.72	$48.11	$19.43	$28.68	($0.04)	-0.1%	35.2%
500	$85.03	$38.86	$46.17	$84.94	$38.86	$46.08	($0.09)	-0.1%	17.0%
1,000	$158.78	$77.73	$81.05	$158.62	$77.73	$80.89	($0.16)	-0.1%	19.0%
1,500	$232.53	$116.59	$115.94	$232.28	$116.59	$115.69	($0.25)	-0.1%	9.8%
2,000	$306.28	$155.46	$150.82	$305.95	$155.46	$150.49	($0.33)	-0.1%	19.1%

<u>Present Rates</u>

Customer Charge		$10.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.02204
Distribution Energy Charge (1)	kWh x	$0.03424
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

<u>Proposed Rates</u>

Customer Charge		$10.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.02204
Distribution Energy Charge (2)	kWh x	$0.03408
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

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

Note (2): includes the proposed CapEx Reconciling of (0.007¢)/kWh and the proposed O&M Reconciling of (0.007)¢/kWh

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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	$661.32	$310.92	$350.40	$660.86	$310.92	$349.94	($0.46)	-0.1%
50	10,000	$1,516.83	$777.29	$739.54	$1,515.68	$777.29	$738.39	($1.15)	-0.1%
100	20,000	$2,942.68	$1,554.58	$1,388.10	$2,940.39	$1,554.58	$1,385.81	($2.29)	-0.1%
150	30,000	$4,368.55	$2,331.88	$2,036.67	$4,365.11	$2,331.88	$2,033.23	($3.44)	-0.1%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (1)	kWh x	$0.00569
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (2)	kWh x	$0.00558
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

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

Note (2): includes the proposed CapEx Reconciling of (0.005¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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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	$865.84	$466.38	$399.46	$865.15	$466.38	$398.77	($0.69)	-0.1%
50	15,000	$2,028.13	$1,165.94	$862.19	$2,026.41	$1,165.94	$860.47	($1.72)	-0.1%
100	30,000	$3,965.30	$2,331.88	$1,633.42	$3,961.86	$2,331.88	$1,629.98	($3.44)	-0.1%
150	45,000	$5,902.45	$3,497.81	$2,404.64	$5,897.29	$3,497.81	$2,399.48	($5.16)	-0.1%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (1)	kWh x	$0.00569
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (2)	kWh x	$0.00558
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

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

Note (2): includes the proposed CapEx Reconciling of (0.005¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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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	$1,070.35	$621.83	$448.52	$1,069.43	$621.83	$447.60	($0.92)	-0.1%
50	20,000	$2,539.43	$1,554.58	$984.85	$2,537.14	$1,554.58	$982.56	($2.29)	-0.1%
100	40,000	$4,987.90	$3,109.17	$1,878.73	$4,983.32	$3,109.17	$1,874.15	($4.58)	-0.1%
150	60,000	$7,436.36	$4,663.75	$2,772.61	$7,429.48	$4,663.75	$2,765.73	($6.88)	-0.1%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (1)	kWh x	$0.00569
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (2)	kWh x	$0.00558
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

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

Note (2): includes the proposed CapEx Reconciling of (0.005¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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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	$1,274.87	$777.29	$497.58	$1,273.73	$777.29	$496.44	($1.14)	-0.1%
50	25,000	$3,050.74	$1,943.23	$1,107.51	$3,047.87	$1,943.23	$1,104.64	($2.87)	-0.1%
100	50,000	$6,010.50	$3,886.46	$2,124.04	$6,004.77	$3,886.46	$2,118.31	($5.73)	-0.1%
150	75,000	$8,970.27	$5,829.69	$3,140.58	$8,961.67	$5,829.69	$3,131.98	($8.60)	-0.1%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (1)	kWh x	$0.00569
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (2)	kWh x	$0.00558
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

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

Note (2): includes the proposed CapEx Reconciling of (0.005¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,479.40	$932.75	$546.65	$1,478.02	$932.75	$545.27	($1.38)	-0.1%
50	30,000	$3,562.04	$2,331.88	$1,230.16	$3,558.60	$2,331.88	$1,226.72	($3.44)	-0.1%
100	60,000	$7,033.10	$4,663.75	$2,369.35	$7,026.23	$4,663.75	$2,362.48	($6.87)	-0.1%
150	90,000	$10,504.18	$6,995.63	$3,508.55	$10,493.86	$6,995.63	$3,498.23	($10.32)	-0.1%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (1)	kWh x	$0.00569
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.89
Transmission Energy Charge	kWh x	$0.00716
Distribution Demand Charge-xcs 10 kW	kW x	$4.85
Distribution Energy Charge (2)	kWh x	$0.00558
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07462

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

Note (2): includes the proposed CapEx Reconciling of (0.005¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,502.07	$2,922.50	$2,579.57	$5,497.07	$2,922.50	$2,574.57	($5.00)	-0.1%
750	150,000	$20,386.91	$10,959.38	$9,427.53	$20,368.16	$10,959.38	$9,408.78	($18.75)	-0.1%
1,000	200,000	$27,152.74	$14,612.50	$12,540.24	$27,127.74	$14,612.50	$12,515.24	($25.00)	-0.1%
1,500	300,000	$40,684.41	$21,918.75	$18,765.66	$40,646.91	$21,918.75	$18,728.16	($37.50)	-0.1%
2,500	500,000	$67,747.74	$36,531.25	$31,216.49	$67,685.24	$36,531.25	$31,153.99	($62.50)	-0.1%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (1)	kWh x	$0.00599
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (2)	kWh x	$0.00587
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$7,486.45	$4,383.75	$3,102.70	$7,478.95	$4,383.75	$3,095.20	($7.50)	-0.1%
750	225,000	$27,828.31	$16,439.06	$11,389.25	$27,800.19	$16,439.06	$11,361.13	($28.12)	-0.1%
1,000	300,000	$37,074.62	$21,918.75	$15,155.87	$37,037.12	$21,918.75	$15,118.37	($37.50)	-0.1%
1,500	450,000	$55,567.23	$32,878.13	$22,689.10	$55,510.98	$32,878.13	$22,632.85	($56.25)	-0.1%
2,500	750,000	$92,552.43	$54,796.88	$37,755.55	$92,458.68	$54,796.88	$37,661.80	($93.75)	-0.1%

<u>Present Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (1)	kWh x	$0.00599
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

<u>Proposed Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
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Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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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	$9,470.82	$5,845.00	$3,625.82	$9,460.82	$5,845.00	$3,615.82	($10.00)	-0.1%
750	300,000	$35,269.72	$21,918.75	$13,350.97	$35,232.22	$21,918.75	$13,313.47	($37.50)	-0.1%
1,000	400,000	$46,996.49	$29,225.00	$17,771.49	$46,946.49	$29,225.00	$17,721.49	($50.00)	-0.1%
1,500	600,000	$70,450.03	$43,837.50	$26,612.53	$70,375.03	$43,837.50	$26,537.53	($75.00)	-0.1%
2,500	1,000,000	$117,357.12	$73,062.50	$44,294.62	$117,232.12	$73,062.50	$44,169.62	($125.00)	-0.1%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (1)	kWh x	$0.00599
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (2)	kWh x	$0.00587
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$11,455.20	$7,306.25	$4,148.95	$11,442.70	$7,306.25	$4,136.45	($12.50)	-0.1%
750	375,000	$42,711.13	$27,398.44	$15,312.69	$42,664.25	$27,398.44	$15,265.81	($46.88)	-0.1%
1,000	500,000	$56,918.37	$36,531.25	$20,387.12	$56,855.87	$36,531.25	$20,324.62	($62.50)	-0.1%
1,500	750,000	$85,332.85	$54,796.88	$30,535.97	$85,239.10	$54,796.88	$30,442.22	($93.75)	-0.1%
2,500	1,250,000	$142,161.81	$91,328.13	$50,833.68	$142,005.56	$91,328.13	$50,677.43	($156.25)	-0.1%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (1)	kWh x	$0.00599
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (2)	kWh x	$0.00587
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$13,439.57	$8,767.50	$4,672.07	$13,424.57	$8,767.50	$4,657.07	($15.00)	-0.1%
750	450,000	$50,152.54	$32,878.13	$17,274.41	$50,096.29	$32,878.13	$17,218.16	($56.25)	-0.1%
1,000	600,000	$66,840.24	$43,837.50	$23,002.74	$66,765.24	$43,837.50	$22,927.74	($75.00)	-0.1%
1,500	900,000	$100,215.66	$65,756.25	$34,459.41	$100,103.16	$65,756.25	$34,346.91	($112.50)	-0.1%
2,500	1,500,000	$166,966.49	$109,593.75	$57,372.74	$166,778.99	$109,593.75	$57,185.24	($187.50)	-0.1%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (1)	kWh x	$0.00599
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00842
Distribution Demand Charge - > 200 kW	kW x	$3.70
Distribution Energy Charge (2)	kWh x	$0.00587
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	600,000	$92,849.20	$43,837.50	$49,011.70	$92,774.20	$43,837.50	$48,936.70	($75.00)	-0.1%
5,000	1,000,000	$142,942.54	$73,062.50	$69,880.04	$142,817.54	$73,062.50	$69,755.04	($125.00)	-0.1%
7,500	1,500,000	$205,559.21	$109,593.75	$95,965.46	$205,371.71	$109,593.75	$95,777.96	($187.50)	-0.1%
10,000	2,000,000	$268,175.87	$146,125.00	$122,050.87	$267,925.87	$146,125.00	$121,800.87	($250.00)	-0.1%
20,000	4,000,000	$518,642.55	$292,250.00	$226,392.55	$518,142.55	$292,250.00	$225,892.55	($500.00)	-0.1%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (1)	kWh x	($0.00042)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (2)	kWh x	($0.00054)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	900,000	$120,199.20	$65,756.25	$54,442.95	$120,086.70	$65,756.25	$54,330.45	($112.50)	-0.1%
5,000	1,500,000	$188,525.87	$109,593.75	$78,932.12	$188,338.37	$109,593.75	$78,744.62	($187.50)	-0.1%
7,500	2,250,000	$273,934.21	$164,390.63	$109,543.58	$273,652.96	$164,390.63	$109,262.33	($281.25)	-0.1%
10,000	3,000,000	$359,342.54	$219,187.50	$140,155.04	$358,967.54	$219,187.50	$139,780.04	($375.00)	-0.1%
20,000	6,000,000	$700,975.88	$438,375.00	$262,600.88	$700,225.88	$438,375.00	$261,850.88	($750.00)	-0.1%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (1)	kWh x	($0.00042)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (2)	kWh x	($0.00054)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,200,000	$147,549.20	$87,675.00	$59,874.20	$147,399.20	$87,675.00	$59,724.20	($150.00)	-0.1%
5,000	2,000,000	$234,109.20	$146,125.00	$87,984.20	$233,859.20	$146,125.00	$87,734.20	($250.00)	-0.1%
7,500	3,000,000	$342,309.21	$219,187.50	$123,121.71	$341,934.21	$219,187.50	$122,746.71	($375.00)	-0.1%
10,000	4,000,000	$450,509.21	$292,250.00	$158,259.21	$450,009.21	$292,250.00	$157,759.21	($500.00)	-0.1%
20,000	8,000,000	$883,309.22	$584,500.00	$298,809.22	$882,309.22	$584,500.00	$297,809.22	($1,000.00)	-0.1%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (1)	kWh x	($0.00042)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (2)	kWh x	($0.00054)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,500,000	$174,899.20	$109,593.75	$65,305.45	$174,711.70	$109,593.75	$65,117.95	($187.50)	-0.1%
5,000	2,500,000	$279,692.54	$182,656.25	$97,036.29	$279,380.04	$182,656.25	$96,723.79	($312.50)	-0.1%
7,500	3,750,000	$410,684.21	$273,984.38	$136,699.83	$410,215.46	$273,984.38	$136,231.08	($468.75)	-0.1%
10,000	5,000,000	$541,675.87	$365,312.50	$176,363.37	$541,050.87	$365,312.50	$175,738.37	($625.00)	-0.1%
20,000	10,000,000	$1,065,642.55	$730,625.00	$335,017.55	$1,064,392.55	$730,625.00	$333,767.55	($1,250.00)	-0.1%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (1)	kWh x	($0.00042)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (2)	kWh x	($0.00054)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh

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

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,800,000	$202,249.20	$131,512.50	$70,736.70	$202,024.20	$131,512.50	$70,511.70	($225.00)	-0.1%
5,000	3,000,000	$325,275.87	$219,187.50	$106,088.37	$324,900.87	$219,187.50	$105,713.37	($375.00)	-0.1%
7,500	4,500,000	$479,059.21	$328,781.25	$150,277.96	$478,496.71	$328,781.25	$149,715.46	($562.50)	-0.1%
10,000	6,000,000	$632,842.54	$438,375.00	$194,467.54	$632,092.54	$438,375.00	$193,717.54	($750.00)	-0.1%
20,000	12,000,000	$1,247,975.88	$876,750.00	$371,225.88	$1,246,475.88	$876,750.00	$369,725.88	($1,500.00)	-0.1%

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (1)	kWh x	($0.00042)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kWh x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$3.23
Transmission Energy Charge	kWh x	$0.00710
Distribution Demand Charge	kW x	$3.31
Distribution Energy Charge (2)	kWh x	($0.00054)
Transition Energy Charge	kWh x	$0.00162
Energy Efficiency Program Charge	kWh x	$0.00906
Renewable Energy Distribution Charge	kW x	$0.00002
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07014

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

Note (2): includes the proposed CapEx Reconciling of (0.003¢)/kWh and the proposed O&M Reconciling of (0.007¢)/kWh