nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel & Director

August 23, 2019

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4857 - Adoption of Performance Incentives Pursuant to R.I. Gen. Laws § 39-1-27.7.1(e)(3)
<u>Responses to Joint PUC Data Requests – Set 1</u>

Dear Ms. Massaro:

On behalf of National Grid[1] and the Rhode Island Division of Public Utilities and Carriers (Division), I have enclosed ten (10) copies of joint responses to the Public Utilities Commission's First Set of Joint Data Requests in the above-referenced docket. The Company and the Division are co-sponsoring Joint PUC 1-1 and Joint PUC 1-3 through Joint PUC 1-5.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket 4857 Service List
Leo Wold, Esq.
Christy Hetherington, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

August 23, 2019
Date

Docket No. 4915 - National Grid's Electric ISR Plan FY 2020
Docket No. 4857 - Performance Incentives Pursuant to R.I.GL. §39-1 27.7.1(e)(3)

Service List as of 8/15/2019

Name/Address	**E-mail Distribution**	**Phone**
Jennifer Hutchinson, Esq. **National Grid** 280 Melrose St. Providence, RI 02907	jennifer.hutchinson@nationalgrid.com; celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7288
National Grid Melissa Little Dennis Antonino Ryan Moe Adam Crary William Richer Patricia Easterly	Melissa.Little@nationalgrid.com; Ryan.Moe@nationalgrid.com; dennis.antonino@nationalgrid.com; Adam.Crary@nationalgrid.com; Patricia.easterly@nationalgrid.com; William.Richer@nationalgrid.com;	
Division of Public Utilities (Division) Christy Hetherington, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Chetherington@riag.ri.gov ; Dmacrae@riag.ri.gov; MFolcarelli@riag.ri.gov; John.bell@dpuc.ri.gov; kevin.lynch@dpuc.ri.gov; Jonathan.Schrag@dpuc.ri.gov; Kevin.Lynch@dpuc.ri.gov; Joseph.shilling@dpuc.ri.gov; Ronald.gerwatowski@dpuc.ri.gov;	
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440

Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616
Office of Energy Resources (OER) Andrew Marcaccio, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Andrew.marcaccio@doa.ri.gov;	401-222-3417
Christopher Kearns, OER Carrie Gill Nick Ucci	Christopher.Kearns@energy.ri.gov; Carrie.Gill@energy.ri.gov; Nicholas.Ucci@energy.ri.gov;	
File an original & ten copies w/: Luly E. Massaro, Commission Clerk John Harrington, Commission Counsel Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.harrington@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107

Joint PUC 1-1

Request:

Based on the description of projects eligible for the capital efficiency mechanism proposed in the DPUC's April 9th filing in Docket 4857, please provide the following:

a. For all Infrastructure, Safety, and Reliability Plans filed pursuant to R.I. Gen. Laws § 39-1-27.7.1, provide a list of all projects that would have qualified for the Capital Efficiency Mechanism (CEM) program.
   i. For the Division: please provide the source of the data predating FY 2012 in Chart 3 of Mr. Booth's testimony and how a plan variance was established for these years.

b. For all projects listed in part a, please show the target budget and actual cost of the projects at the time the project budget would have been formally set for the purpose of scoring the project in the CEM. Please also indicate what the expected budget variance was at the time the project budget would have been set for scoring the CEM. For example, if in FY 2012 through FY 2014 the expected project budget variance was +/-50% at the time the project budget would have been set for scoring the CEM, but since FY 2018 the variance would have changed to +/-10%, please indicate that.

c. For all projects listed in part a, lease provide the amount each eligible project was over or under budget using the responses in part b. For projects whose budget-to-completion period spans multiple years, correct the assumed inflation in the budget for actual inflation.

d. For all projects listed in part a, please provide the percentage over or under the budget using the responses from part c.

e. For all projects listed in part a, please provide the incentives (positive or negative) that would have been earned using both the Division's metric and National Grid's metric.

f. To the extent possible, please identify how project phases contributed to a project cost variance. Please indicate the cost variances before and after the time at which the project budget would have been formally set for the purposes of scoring the project in the CEM.

g. For all projects listed in part a, and to the extent possible, please describe the reasons why actual costs varied from the cost budget.

Start response on next page

Joint PUC 1-1, page 2

Response to part a (Joint):

The first step in determining which projects would qualify for the Capital Efficiency Mechanism (CEM) would be to identify those projects emanating from Area Studies, and which produce recommended discretionary projects in the System Capacity and Asset Condition categories of the ISR Plan. Next, only those projects exceeding $500,000, which have achieved a Project Grade estimate of +/- 10%, would be eligible for the CEM. For the purposes of this data request response, the terms Project Grade, Project Estimate, and Full Sanction are used interchangeably to refer to a project that has achieved a +/- 10% estimate.

To date, the Company has effectively completed three Area Studies as that term is used by the Rhode Island Division of Public Utilities and Carriers (Division) in assessing the ISR: Providence, East Bay, and Central Rhode Island East. There are multiple projects, or groups of projects, emanating from these Areas Studies that are included in the Company's current ISR Plan and are expected to exceed $500,000 (*i.e*. Warren Substation, East Providence Substation, and Providence Study projects). These projects are in preliminary stages of engineering and cost estimation, have not reached Full Sanction, and are not ready for construction. However, prior to implementing a more robust and formalized Area Study process, the Company performed smaller scale system evaluations in the Providence, Pawtucket, and Quonset geographical areas. Those studies produced recommended projects of South Street Substation Rebuild and Dyer Indoor Substation (Providence), Southeast Substation (Pawtucket), and Quonset Substation (Quonset), which could be considered as sample projects for the purposes of this data request response.

The South Street Rebuild was a major capital investment project that was driven by capacity and asset condition, but also included significant investment related to downtown Providence development and revitalization. It was a multi-year, complex project with transmission, substation and distribution components. Due to the multiple stakeholders and issues involved, it is not recommended as a sample project in response to this data request. The Dyer Street Substation and Southeast Substation projects are in final engineering, are not ready for construction and, therefore, do not have estimates that meet the threshold for the CEM. The Quonset Substation project, however, is nearing completion of construction. Although all costs have not been finalized, it would, in principle, qualify for the CEM as proposed by the Division. Therefore, the Division and Company propose using Quonset Substation as a representative project that qualifies for the CEM.

Prepared by or under the supervision of: Patricia C. Easterly and Gregory L. Booth, PE

Joint PUC 1-1, page 3

Response to part a (Division Only):

The source of the data pre-dating FY 2012 in Chart 3 of Mr. Booth's testimony came from Mr. Booth's FY 2012 testimony in Docket No. 4218, Exhibit GLB-4, which utilized the Company's response to Division 1-4 Information Request together with the Company's annual comparisons from each subsequent ISR Plan filing. The plan variance was established for these years by simply taking the difference between the filed and actual spending. PUC 1-a-i_Attachment 1 is Mr. Booth's pre-filed direct testimony in FY 2012 ISR Plan Docket No. 4218 and PUC 1-a-i_Attachment 2 is National Grid's response to Division's Information Request, Division 1-4.

Response to parts b-g (Joint):

b. The Quonset substation forecasted costs were compared to Full Sanction amounts in the summary below. The forecasted costs, and not actual costs, are used for this example because the final actual costs are not available as the project is not closed. The Full Sanction amounts reflect the Company's cost estimate within a +/- 10% variance. In the Quonset substation example, the CEM would have been established at the time of Full Sanction, therefore with a cost variance tolerance of +/-10%.

c. The project Final Sanction, or CEM benchmark in this example, as compared with the projected project cost are as follows:

	Full Sanction	Forecast	Under/ (Over) Sanction	Percent
Capital	8,630	8,528	102	1.2%
O&M	104	107	(3)	-2.6%
Removal	285	236	49	17.1%
Total	9,019	8,871	148	1.6%

This project spanned multiple years; however, prior to the new estimating processes, the Company's estimating details did not separately identify inflation. Therefore, inflation cannot be corrected for assumed vs. actual inflation.

Prepared by or under the supervision of: Patricia C. Easterly and Gregory L. Booth, PE

---

d. See table in part c. of this response, above.

e. Using the variance identified in the Table in the response to partc, above, the capital and removal underspending of $151,000 would yield an incentive using the Division's bandwidth of 1%, the project exceeded that bandwidth. The incentive would be $25,041 using the Company's calculation and $12,520, using the Division's calculation, based solely on the variance amount for capital and removal. As the Company suggested in its pre-filed Rebuttal testimony in this docket, additional attributes should be considered in identifying variances that represent efficiency (*i.e*. outputs).

f. The changes in project cost estimates occurred before Full Sanction; therefore, in the Project Development phase.

g. While the Company performed a detailed review of estimating variances for purposes of responding to this data request, that review was performed in conjunction with this docket. It is not possible to retroactively perform that analysis in detail as the project progressed because the variances that occurred were within the Company's existing tolerances. The review performed in conjunction with this docket indicates that variances were due to increasingly detailed project design information and scope changes driven by the customer driven aspect of the project. The Company believes that similar changes will be partially addressed by the new Complex Capital Delivery process through the sanction process, discussed in more detail in the response to Joint PUC Data Request 1-2, but not all such variances will be captured as that point. Previous to the new Complex Capital Delivery process, the Company would capture the Full Sanction amount after detailed engineering design and receipt of contractor bids, where applicable. The estimate at Full Sanction would have been considered the CEM benchmark. Under the new Complex Capital Delivery process detailed engineering design occurs after the Full Sanction point; further refinement of project details will occur after Full Sanction, which will likely impact project estimates. The response in Joint PUC 1-2 suggests that the benchmark cost for the CEM be set after the detailed design and bids are received.

   Since only one project was identified as a representative project that would be eligible for the CEM for purposes of this response, the Company and Division are proposing to use two existing projects--the Southeast Substation project and the Dyer Street project-- as test cases to further review and agree on the benchmark methodologies and further inform design of a CEM.

Prepared by or under the supervision of: Patricia C. Easterly and Gregory L. Booth, PE

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

RE: The Narragansett Electric Company
d/b/a National Grid's Proposed
FY 2012 Electric Infrastructure, Safety
and Reliability Plan

R.I.D.P.U.C. Docket No. 4218

PREFILED DIRECT TESTIMONY OF

Gregory L. Booth, PE, President
PowerServices, Inc. d/b/a PowerServices and Consulting, Inc.
On Behalf of Rhode Island Division of Public Utilities and Carriers

February 18, 2011

Prepared by:
Gregory L. Booth, PE

Power Services
Engineering & Management Services®
1616 E. Millbrook Road, Suite 210
Raleigh, NC 27609
(919) 256-5901 or (919) 441-6440
gbooth@powerservices.com

Gregory L. Booth, PE, President
PowerServices, Inc. d/b/a PowerServices and Consulting, Inc.
On Behalf of Rhode Island Division of Public Utilities and Carriers
Prefiled Direct Testimony

Table of Contents

Section	Description	
I	Introduction	
II	Purpose of Testimony	
III	Capital Investment Plan	
IV	Vegetation Management Plan	
V	Inspection and Management Plan	
VI	Conclusion	
Exhibits	GLB-1	Curriculum Vitae
	GLB-2	Data Request and Responses
	GLB-3	Proposed Budget Differences
	GLB-4	Capital Outlay by Category and Budget

DIRECT TESTIMONY OF GREGORY L. BOOTH, PE

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR EMPLOYER.

A. My name is Gregory L. Booth. I am employed by PowerServices, Inc. ("PowerServices"), UtilityEngineering, Inc. ("UtilityEngineering"), and Gregory L. Booth, PLLC ("Booth, PLLC") all located at 1616 E. Millbrook Road, Suite 210, Raleigh, North Carolina 27609.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers.

Q. WHAT IS YOUR POSITION WITH POWERSERVICES, INC., UTILITYENGINEERING, INC., AND BOOTH, PLLC?

A. I am president of PowerServices, Inc., an engineering and management services firm, UtilityEngineering, Inc., a design/build firm, and Booth, PLLC, an engineering firm. As such, I am responsible for the direction, supervision, and preparation of engineering projects and management services for our clients, including the corporate involvement in engineering planning, design, construction management, and testimony for our clients.

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A. I graduated from North Carolina State University in Raleigh, North Carolina in 1969 with a Bachelor of Science Degree in Electrical Engineering. I am a registered professional engineer in twenty one states, as well as District of Columbia, and including Rhode Island. I am also a registered land surveyor in North Carolina. I am also registered under the National Council of Examiners for Engineering and Surveying.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. I am an active member of the National Society of Professional Engineers ("NSPE"), the Professional Engineers of North Carolina ("PENC"), The Institute of Electrical and Electronics Engineers ("IEEE"), American Public Power Association ("APPA"), American Standards and Testing Materials Association ("ASTM"), and the Professional Engineers in Private Practice ("PEPP"). I am also a member of the IEEE Distribution Subcommittee on Reliability and the National Fire Protection Association, and an advisory member of the National Rural Electric Cooperative Association ("NRECA")-Cooperative Research Network, which is an organization similar to EPRI.

Q. HAVE YOU PUBLISHED ANY TREATISES, MANUALS, COURSES, OR TAUGHT SEMINARS?

A. Since 1972, I have authored manuals and taught numerous seminars each year on engineering matters, including reliability, rates and regulations, design and construction and construction management and services matters. I have also prepared engineering manuals and text for instruction, seminars and courses. My manuals and texts have included subjects such as the National Electrical Safety Code ("NESC"), Power Loss Management, Power System Protective Coordination, Long-Range Planning, Asset Management Strategic Planning, Electric Utility Best Practices, Power Factor Optimization, Power Quality, Underground Design Standards, Hazard Assessment and Arc Flash Mitigation, the National Electrical Code, and many others. My seminars, instructions, courses and speaking have been before state and national electric utility organizations across the United States. I have been nationally published on some of these subjects as well.

Q. HAVE YOU ATTACHED TO YOUR TESTIMONY A COPY OF YOUR CURRICULUM VITAE?

A. Yes. My curriculum vitae is attached as *Exhibit GLB-1*, and includes an overview of my experience since beginning my work in 1963.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH ELECTRIC UTILITIES.

A. I have worked in the area of electric utility and telecommunication engineering and management services since 1963. I have been actively involved in system planning and protective coordination and stability studies, including detailed analyses of all components of distribution and transmission systems including electric utilities in 40 states, and the District of Columbia, for over 300 utility clients. My experience includes all phases of consulting engineering, engineering design and management services from generation through transmission and substation design and distribution of power on electric utility systems. I have been actively involved in cost-of-service studies, rate studies and rate design, both retail and wholesale. My involvement has also included the planning, design, and construction management of generation, transmission, substation, and distribution line facilities. This involvement has included the inspection of these facilities and the evaluation of service reliability. I have performed hundreds of long-range and short-range planning studies, load flow studies, and cost estimates for electric utilities across the United States. I was involved in the management of all of the divisions of Booth & Associates, Inc. ("Booth & Associates"), for over 30 years, including transmission, substation, and distribution facilities design and construction management of approximately $100 million dollars per year in plant value additions. My involvement included electric utility systems in rural and urban areas as well as coastal, plain and mountain areas throughout the eastern United States and as far west as Arizona, Washington State, and Alaska, along with design and construction in light, medium and heavy loading districts as defined in the NESC. My work has included services to numerous electric systems in the northeast, including Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Virginia. I have been involved in power supply contract bids, negotiations, economic analyses and implementation, including evaluating the transmission system network capabilities. I have also been involved in projects to relieve or mitigate transmission congestion in the PJM area.

Q. DO YOU HAVE OTHER INVOLVEMENT AND EXPERIENCE WITH COMPANIES THAT PROVIDE YOU WITH ADDITIONAL EXPERTISE RELEVANT TO THIS DOCKET?

A. Yes. My electric utility reliability assessment work for the Rhode Island Division of Public Utilities and Carriers ("Division"), the New Jersey Board of Public Utilities ("NJBPU") and at the Pennsylvania PUC and the Virginia State Corporation Commission ("SCC") over the last ten years has involved in-depth assessment and working with northeastern electric utilities on reliability enhancement and the costs associated with such enhancement, including annual construction work plan development for electric utility systems. Also, I was directly involved in the purchase and transition of electric utility facilities from Progress Energy Florida (formerly Florida Power Corporation) to the City of Winter Park, Florida, and also the Fort Bragg Army Base electric utility system purchase by Sandhills Utilities, LLC and its transition along with Delmarva Power & Light distribution and transmission system on the Eastern Shore of Virginia purchased by A & N Electric Cooperative and the Potomac Edison Company entire

Virginia jurisdiction to Shenandoah Valley Electric Cooperative and Rappahannock Electric Cooperative. Along with these acquisitions, I prepared system condition assessments, construction work plans for annual infrastructure expansion, safety and reliability and loan purposes. These ranged from $50 million to $250 million, excluding the acquisition cost. Additionally, I investigate safety related accidents and testify as an expert in state and federal courts concerning safety related accidents involving electric utility systems averaging over 30 cases a year.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE STATE UTILITY COMMISSIONS, OTHER REGULATORY AGENCIES, AND/OR COURTS?

A. Yes. I have testified on numerous occasions before the Federal Energy Regulatory Commission ("FERC"), including pre-filed testimony in both wholesale rate matters as well as in electric utility reliability complaints, including Duke Power Company and Dominion Power issues. I have also testified before the New Jersey Board of Public Utilities, the Delaware Public Service Commission, Minnesota Department of Public Service Environmental Quality Board, Virginia State Corporation Commission, the Pennsylvania Public Utility Commission, and the North Carolina Utilities Commission, most of them on multiple occasions. I have testified before the Rhode Island Public Utilities Commission on numerous matters, including Docket Nos. 2489, 2930, 3564, 3732, and 4029.

Q. HAVE YOU BEEN ACCEPTED AS AN EXPERT BEFORE STATE OR FEDERAL COURTS?

A. Yes. I have been accepted as an expert in the area of electrical engineering and electric utility engineering, construction and reliability matters and the NESC, NEC, OSHA

EMF, and forensic engineering, including standard and customary construction practices in the electric utility industry and the electric industry before 12 state and federal courts.

PURPOSE OF TESTIMONY

Q. HAVE YOU REVIEWED THE TESTIMONY OF THE NATIONAL GRID WITNESSES, THEIR EXHIBITS, AND THE FILINGS?

A. Yes, I have reviewed all of the documents as filed in Docket No. 4218.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("Division").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the analysis, as completed by me on behalf of the Division, of the National Grid Electric Infrastructure, Safety and Reliability Plan FY 2012 Proposal (the "ISR Plan" or the "Plan") dated December 23, 2010. My testimony will include an explanation of the process of the initial ISR Plan evaluations and collaborative efforts resulting in a reduction of FY 2012 capital spending on infrastructure projects, operation and maintenance ("O&M") expenses for Vegetation Management ("VM"), and O & M expenses for an Inspection and Maintenance ("I&M") program from the Company's initial ISR Plan submitted to the Division in August 2010. This process, as provided for in Chapter 39-1-27.7.1 of the General Laws entitled "Revenue Decoupling", is for the Company, prior to the start of each fiscal year, to submit its ISR spending plan and consult with the Division regarding said plan. The Division is also bound by statute to "cooperate in good faith to reach an agreement on a proposed plan." This process ultimately resulted in the Division and the Company reaching agreement on an appropriate level of the capital spending and O&M expenses for FY 2012 to be included in what is now the Company's filing of an Electric ISR Plan in Docket No. 4218.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. I have organized my testimony so it matches the structure of the Company's testimony. In this initial portion of my testimony, I will provide an overview of the process. I will then address the Capital Investment Plan and the recommended adjustments adopted by the Company. I will discuss the Vegetation Management ("VM") Program and those components I supported and the portions of the plan I believed were more expensive than necessary based on current circumstances. I will provide testimony on the Inspection and Maintenance ("I&M") Program assessment, including from a historical perspective and prospective recommendations. Finally, I will provide a conclusion summarizing my analyses and recommendations.

Q. PLEASE EXPLAIN YOUR REVIEW PROCESS.

A. The Company provided its proposed plan to the Division in August, 2010. An in depth analysis of each component of the plan was undertaken. A series of data requests were served on the Company and the Company provided responses. Follow-up requests were sent to the Company and additional responses were received. These requests and responses shall be made a part of the record and are included as my *Exhibit GLB-2*. In November 2010, I provided an assessment to the Division and, subsequently, the Division delivered this assessment to the Company. A meeting was held at the Company's offices in Rhode Island, in which the ISR Plan and each element of the ISR Plan were discussed in detail. The Company provided a PowerPoint presentation which expanded on each element of the Plan, particularly the VM Plan. The Division staff and I asked numerous questions, and articulated our position on each element of the ISR Plan. The dialog at this meeting was very open and interactive. The Company addressed our questions and agreed to provide further information. Additionally, the Company elaborated on how certain programs, such as the I&M Program, would be transitioning in future years. A series of telephone conferences were held with the Company to discuss our assessment. Additional discussions specifically focusing on the VM Plan and I&M Plan were held.

An iterative process began with detailed discussions of each ISR Plan spending Rationale Category, including Capital Expenditures, the VM Plan, and the I&M Plan. The Company included each of its area experts in the discussions as we worked towards a final plan for FY 2012 which would have the support of the Division. This ISR Plan is reflected in the Company's December 2010 filing with the Commission.

CAPITAL INVESTMENT PLAN

Q. HAVE YOU EVALUATED THE COMPANY'S FY 2012 CAPITAL INVESTMENT PLAN AS FILED?

A. Yes. I have evaluated the $58.4 million FY 2012 Capital Spending Plan proposed by the Company, along with its supporting testimony and exhibits.

Q. WOULD YOU DESCRIBE THE PROCESS OF YOUR EVALUATION?

A. Yes. I first reviewed the initial proposed ISR Plan submitted to the Division in August 2010. As I discussed earlier, there was a meeting, a series of data requests and associated responses, and numerous telephone conferences. Over a period of approximately three (3) months, there was an iterative process in which modifications to the Company's original proposed Capital Spending Plan were discussed. A consensus was reached concerning each of the Spending Rationales and the six (6) major categories. Chart GLB-1 below summarizes the initial planned spending level for each of the Company's categories for FY 2012 as contained on the Company's Chart 1 and the consensus level reached through the evaluation process.

CHART GLB - 1

SPENDING RATIONALE	INITIAL FY2012 PROPOSED BUDGET	FILED FY2012 PROPOSED BUDGET	% Diff
Statutory/Regulatory	$ 21,636,500	$ 21,636,500	100%
Damage/Failure	$ 9,705,000	$ 9,705,000	100%
Subtotal	$ 31,341,500	$ 31,341,500	100%
Asset Condition Total	$ 11,118,050	$ 9,737,050	88%
Non-Infrastructure Total	$ 278,000	$ 278,000	100%
System Capacity and Performance Total	$ 17,962,450	$ 15,821,100	88%
Subtotal	$ 29,358,500	$ 25,836,150	88%
Grand Total	$ 60,700,000	$ 57,177,650	94%
Flood Damage Aviodance Engineering Studies	$ 1,200,000	$ 1,200,000	100%
Grand Total including Flood-Related Studies	$ 61,900,000	$ 58,377,650	94%

Q. WOULD YOU FIRST EXPLAIN YOUR ASSESSMENT OF THE STATUTORY / REGULATORY AND DAMAGE / FAILURE CATEGORY?

A. Generally speaking, a utility's capital spending to meet its regulatory obligations to extend service to new customers, upgrade basic service to existing customers, interface facilities with other agencies, such as the Rhode Island Department of Transportation, and to restore power by repairing failed or damaged equipment can account for fifty percent (50%) or more of a fiscal year capital budget. The Company projects the need for $21.6 million in Statutory / Regulatory spending and $9.7 million in Damage / Failure spending. This is approximately fifty-five percent (55%) of the ISR Plan Capital requirements. These budgeted levels are reasonably supported by historical spending levels. None of the projects in these categories is precisely defined because specific customer requests have not been made and damage or failure is yet to occur. For that reason, historical spending serves as the primary method to develop a budget. The economic conditions are a factor considered in adjusting historical costs. There are both upward and downward trends in new construction costs combined with the effects of inflation on construction cost. The housing and commercial construction industry remains depressed while the cost of raw materials and construction cost have seen dramatic escalation. My analysis supports the Company's projections.

Q. WHAT IS YOUR OPINION CONCERNING AN ANNUAL TRUE UP FOR THE TWO CATEGORIES OF STATUTORY / REGULATORY AND DAMAGE / FAILURE?

A. During our discussions with the Company, I proposed there should be a true up adjustment or reconciliation. There are two primary driving factors. First, as discussed in the Company's testimony on pages 11 and 12, the projected $31.3 million is non-discretionary in terms of scope and timing. Regardless of all other capital project demands, the Company must expend the funds necessary to meet the requests for new services or increased service capacity and other facility requests, all of which are driven by others and outside the control of the Company. Additionally, the Company must repair or replace damaged or failed equipment. Since the budgets for these categories are not project specific but rather based on the Company's best estimate using historical cost trends combined with most recent trend data, a mechanism for reconciliation of the actual expenditures to the budget projections is essential to protect both the rate payers and the Company. Mr. David E. Tufts describes in his testimony, beginning on Page 136 (page 6 of 10 of Tufts testimony), the mechanism for the true up. This mechanism will reconcile the annual differences between the projected budget and the actual expenditures for the non-discretionary capital spending. I support the annual ISR Plan reconciliation of each year's revenue requirements for the non-discretionary categories of Statutory / Regulatory and Damage / Failure only.

Q. THE COMPANY CHART 1 FOR PROPOSED FY 2012 HAS FOUR DISCRETIONARY CATEGORIES ACCOUNTING FOR $27,036,150. WOULD YOU DISCUSS YOUR ANALYSIS OF THESE CATEGORIES?

A. The four categories, which are discretionary in the sense they are based on engineering, safety, reliability and economic analyses rather than being mandatory as are the previous two categories discussed, account for the remaining forty-five percent (45%) of the proposed capital budget. These categories are Asset Condition, Non-infrastructure, System Capacity, and Performance and Flood Damage Avoidance Engineering Studies. I will discuss each category separately.

Asset Condition

Dating back to 2001, I was involved in a reliability assessment of the Company which included the evaluation of its Asset Management Plans. This assessment resulted in an initial report published in March 2003 and a final report dated March 31, 2006 which I prepared on behalf of the Division The final reliability assessment report included a set of Action Items and an "Ongoing" process for evaluation and monitoring of reliability enhancement performance by the Company. The Company provided annual reports to the Division outlining its reliability performance and progress on the Action Items. These annual reports concluded with a final 2010 report. The predominant programs that resulted from this reliability assessment and annual reporting process included a Feeder Hardening Program, a Feeder Health Program, and associated Operation & Maintenance reliability enhancements. These programs were successful and have now matured, resulting in the need for a transition to a continually sustainable program. The Company, in its preliminary August 2010 filing, proposed a program overlap which maintained the Feeder Hardening and Reliability O&M programs in FY 2012 while it added the new I&M Program, which is intended to be a portion of the future sustainable infrastructure asset management program. I identified several duplications in capital costs during the analysis of the Company's initial proposal. After numerous conferences with Company representatives, it was mutually agreed to reduce the capital programs in a portion of the Feeder Hardening and I&M Programs. This reduced the Asset Condition category from $11,118,050 to $9,737,050. I would recommend $9,737,050 as sufficient for FY 2012 to meet the needs for adequate asset management and infrastructure condition enhancement necessary to avoid safety and reliability deterioration due to infrastructure failure from condition degradation. Later, I will discuss the I&M Program O&M expense budget and how it transitions from the previous programs.

Non-Infrastructure

This category is for telecommunications and other capital expenditures needed for operation, which are neither related to condition nor system capacity. I consider this $278,000 of capital expenditures prudent and necessary.

System Capacity and Performance

The $15,821,100 in the System Capacity and Performance category represents 90 projects, including increased substation capacity, distribution conductor replacement, and the addition of capacitors and sectionalizing equipment in order to meet the capacity and voltage delivery requirements of the system predicated on existing and future projected load additions. Equipment and power line thermal stress, outage contingency switching and maintenance of adequate voltage delivery were the primary drivers identified with the proposed capital projects. I found the projects to be justified and based on sound and prudent engineering and economics.

Flood Damage Avoidance

Rhode Island experienced significant flooding in March 2010 which caused widespread customer outages. Nine substations were affected that continue to be vulnerable to future adverse impact from flooding. The Company proposes to expend $1,200,000 in engineering during FY 2012 to determine the most cost effective way to mitigate future widespread outages from flooding. I strongly support the expenditure of up to

$1,200,000 for engineering. However, the Division and the Commission should carefully evaluate the mitigation plans resulting from this study and determine the risk mitigation value before any commitment is made to expend significant capital in future years beginning with FY 2013.

Overall

Exhibit GLB-3 compares the Company's August 2010 proposed capital expenditure levels to those the Division and the Company ultimately agreed upon as reflected in the Company's ISR Plan filed December 2010. The consensus ISR Plan is nearly a twelve percent (12%) reduction in the discretionary capital spending budget from the August 2010 proposed level. The overall capital spending reduction exceeded six percent (6%) or $3,522,350.

Q. DID YOU REVIEW AS PART OF YOUR ANALYSIS THE COMPANY'S EXHIBIT 1 WITH THE DETAILS ON THE SPECIFIC PROJECTS?

A. Yes.

Q. WHAT WAS THE OUTCOME OF THAT ANALYSIS?

A. The analysis indicated the Company made the reductions in each category and specific projects as we recommended during our evaluation of its initial proposed ISR Plan budget submitted in August 2010. The initial ISR Plan was substantially similar in structure and descriptions as contained in Exhibit 1 attached to Docket No. 4218. The Company made adjustments as agreed upon with the Division and incorporated additional discussion of each category to more fully explain the requirements for the FY 2012 ISR Plan Proposed Budget. The Company's Chart 1 and Exhibit 1 are consistent with the derived budget by category and project as agreed to between the Company and the Division.

Q. HOW DOES THE COMPANY'S REQUESTED REVENUE REQUIREMENT CALCULATION NOW COMPARE WITH ITS REVENUE REQUIREMENT OF THE AUGUST 2010 INITIAL ISR PLAN?

A. The reductions from the initial ISR Plan of August 2010 revenue requirements to the Proposed ISR Plan revenue requirement appear consistent with the consensus, and plant-in-service amounts were also adjusted downward. The Company's Chart 2 reflects the Division's agreement for the level of Capital to be placed in service in FY 2012 plus the Cost of Removals. The revenue requirement declined nearly twelve percent (12%) from the original August 2010 proposal provided to the Division. David Effron, on behalf of the Division, will address the revenue requirement effects of the Plan more specifically in a separate submission in this proceeding.

VEGETATION MANAGEMENT PROGRAM

Q. WOULD YOU SUMMARIZE YOUR EVALUATION OF THE COMPANY'S VEGETATION MANAGEMENT PROGRAM?

A. Yes. My evaluation was performed on multiple levels. First, I considered the overall Company reliability indices and determined they have continued to remain better than the Commission's benchmarks. Second, I carefully considered the Company's justification for its more aggressive VM Program and its incorporation of an Enhanced Hazard Tree Mitigation ("EHTM") Program. The Company provided an excellent presentation to the Division and me on these programs. I found the Company has developed an industry leading program. I will address my concerns later in my testimony, which deal with the overall cost of the programs and the benefit cost analysis. Third, I evaluated the Company's anticipated reliability improvement and the justification for the proposed budget expenditures, considering both the Company's reliability performance and the present depressed economy. The Company and Division reached a compromise position balancing all of these issues and concerns.

Q. COULD YOU FIRST SUMMARIZE THE CONSENSUS POSITION REACHED BEFORE YOU DISCUSS EACH EVALUATION COMPONENT INDIVIDUALLY?

A. The Company's initial ISR Plan submitted to the Division in August 2010 included $9,826,000 for the VM Program including the EHTM Program. We fully support a vegetation management program that yields benefits commensurate with the program costs. The Division convinced the Company to reduce the VM Program budget to $8,069,000, or nearly twenty percent (20%) below the initial proposed budget. I found the Company's estimated reliability improvement was based on data from a small portion of the system. I recommended a lower VM Program expenditure until such time as more data was available to support the Company's estimates. Additionally, through the data request process it was determined some of the percentage improvements were incorrectly stated. Furthermore, to the extent the Company's predicted reliability improvements and damage repair costs are improved, there will be an overall net budget benefit. Considering the present difficult economic environment combined with an acceptable reliability history, I recommended a slower transition from the historical VM Program to the Company's proposed more aggressive spending level.

Q. WOULD YOU NOW DISCUSS IN DETAIL EACH AREA OF YOUR VM PROGRAM EVALUATION?

A. First, even though trees account for nearly 30 percent of the Customer Minutes Interrupted ("CMI"), the overall reliability performance is still very acceptable. Furthermore, there is a variance each year in tree related CMI which does not directly support the new VM Program having an indisputable positive trend. This first level of evaluation does not definitively support the proposed VM Program absent other benefits. Second, the incorporation of an Enhanced Hazard Tree Mitigation Program based on the direct damage repair cost creates an economic benefit. Based on the Company's benefit/cost analysis ratio of 4:1 ($3,200/$820), there should be a decline in the O&M expenses and capital budgets for damage/failure in the future. Considering the Company's current projections for FY 2013 through FY 2016 show an increasing Damage/Failure Capital Cost trend of 13 percent, it will be critical to carefully track the actual benefits to assure there is a real and <u>not</u> imaginary benefit to cost ratio associated with the VM Program and EHTM Program. The Company accepted the Division's recommendation of a $1,061,000 reduction in the EHTM Program for FY 2012, or nearly sixty percent (60%) reduction.

I support the 4 year vegetation clearing cycle. Generally, across the utility industry, a 4 year clearing cycle on feeder lines is customary with small tap line clearing cycles less frequently.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION THAT THE RISK OF ELECTRIC SHOCK TO THE PUBLIC/WORKFORCE AND THE RISK OF FIRE IS SIGNIFICANT IF THERE IS CONDUCTOR-VEGETATION CONTACT?

A. Yes. In areas of the country where vegetation management has been significantly deferred and tree growth has begun consuming the power lines, we are seeing significant public injury incidents. For example, this problem in the Florida Power & Light ("FPL") area has reached a point that FPL is instituting a more aggressive vegetation management program and now sending letters to its customers asking for cooperation in its program to re-clear areas.

Q. DO YOU SUPPORT THE BUDGET LEVEL FOR VEGETATION MANAGEMENT PROPOSED BY THE COMPANY?

A. Yes. I find the $8,069,000 FY 2012 level and a 4 year clearing cycle based on the Company's enhanced Vegetation Management Program to be appropriate considering the anticipated level of benefits while balancing today's difficult economic environment.

INSPECTION AND MAINTENANCE PROGRAM

Q. HOW DID YOU EVALUATE THE COMPANY'S INSPECTION AND MAINTENANCE I&M PROGRAM?

A. I started by reviewing in detail all of the Capital Projects and the O&M Expenses included in the August 2010 Initial ISR Plan submitted to the Division. Through data requests and a meeting, combined with telephone conferences, I obtained a complete understanding of the new I&M Program and how it relates to the previous reliability and feeder hardening programs. Through the iterative process, I established there was a certain level of redundancy associated with the transition from the prior programs to the new I&M Program and its processes. I concur with the Company's proposed I&M Program processes based on its maturity of the Feeder Hardening and reliability programs that were an outgrowth of the Reliability Assessment Project from 2001. The Company agreed to adjust the Capital Budget and O&M spending levels to $880,100 and $1,340,385, respectively, based on the Division's recommendations. Chart 5 on Page 26 of the Company's filing represents the agreement reached between the Division and the Company.

Q. WHAT WAS THE PURPOSE FOR THE I&M PROGRAM ADJUSTMENTS?

A. I recommended the Company only complete the Feeder Hardening projects for an additional 209 miles during FY 2012, which represents projects already engineered and in some stage of the process. This avoids a loss of already expended resources and cost with this program which will end in FY 2012. It will be transitioned into the new I&M program. The future I&M program will include a component for feeder hardening in the overall evaluation process. This eliminates any duplication of programs and permits the new I&M program to most efficiently indentify the projects by feeder based on all of the needs including reliability, condition and performance.

Furthermore, I concur with the need to complete the replacement of the potted porcelain cutouts scheduled for FY 2012. This will enhance reliability while eliminating safety hazards.

<u>CONCLUSION</u>

Q. WOULD YOU SUMMARIZE THE EVALUATION PROCESS AND YOUR RECOMMENDATIONS?

A. The collaborative process between the Company and the Division resulted in an ISR Plan which sets forth a capital budget, VM Program and I&M Program, and associated O&M activities which balances the need for safety and reliability with the efficient benefit/cost considerations. *Exhibit GLB-3* summarizes by spending rationale (category) and individual budget class within each category the Company's initially proposed ISR Plan in August 2010 and the resulting ISR Plan FY 2012 Proposed Budget reached through an iterative process of exchange in ideas between the Division and the Company contained in its filing. While the Budget for the Statutory/Regulatory and Damage/Failure portions of the FY 2012 Proposed Budget were not adjusted for reasons previously discussed, significant adjustments through a cooperative process of balancing cost with safety and reliability were achieved in the other capital and O&M categories. This will result in a lower annual revenue requirement than originally proposed in the August 2010 initial ISR Plan document.

There will be numerous challenges in the near term through FY 2016. *Exhibit GLB-4* provides both a historical budget perspective and a prospective view from the Company of the fiscal years 2013 through 2016. While many of the same competing interests of safety, reliability, benefit to cost, and economic pressures will need to be considered going forward, the Division has established a number of important areas of consideration for the Company in establishment of future budgets. The flood related mitigation projects will potentially account for as much as ten percent (10%) of the capital budget over FY 2013 and FY 2014. It will be critical to carefully evaluate the risk mitigation benefits associated with the flood related projects developed during the FY 2012 engineering studies. I re-emphasize my recommendation that the approval for the flood mitigation engineering studies budgeted in FY 2012 does not automatically approve the flood related projects in future years.

I support the FY 2012 Capital Budget as proposed at $58,377,650 with a value for the capital placed in to service in FY 2012 plus cost of removal at $55,381,000. I also support the FY 2012 proposed VM Program at $8,069,000, and the I&M Program and O&M Program at $1,138,845.

Furthermore, I am a proponent for an annual adjustment process for the categories of Statutory/Regulatory and Damage/Failure.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT

GLB-1

GREGORY L. BOOTH, PE, PLS
President
PowerServices, Inc.
Gregory L. Booth, PLLC

RESUME

Gregory L. Booth is a registered professional engineer with engineering, financial, and management services experience in the areas of utilities, industry private businesses and forensic investigation. He has been representing over 300 clients in some 40 states for more than 40 years.

Mr. Booth has been accepted as an expert before state and federal regulatory agencies, including the Federal Energy Regulatory Commission, the Delaware Public Service Commission, the Minnesota Department of Public Service Environmental Quality Board, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, and the Virginia State Corporation Commission. He has been accepted as an expert in both state and federal courts, including Delaware, Florida, New York, North Carolina, Pennsylvania, Virginia, West Virginia, and Federal Court. Investigation and testimony experience includes areas of wholesale and retail rates, utility acquisition, territorial disputes, electric service reliability, right-of-way acquisition and impact of electromagnetic fields and evaluation of transmission line options for utility commissions. Additionally, Mr. Booth has extensive experience serving as an expert witness before state and federal courts on matters including property damage, forensic evaluation, fire investigations, fatality, and areas of electric facility disputes and Occupational, Safety and Health Administration violations and investigations together with National Electric Code and National Electrical Safety Code and Industry Standard compliance.

The following pages provided are the education and experience from 1963 through the present. Also included are courses taught, publications and a list of cases from 1981 to present.

Resume

GREGORY L. BOOTH, PE, PLS

Mr. Booth is a Registered Professional Engineer with engineering, financial, and management experience assisting local, state, and federal governmental units; rural electric and telephone cooperatives; investor owned utilities, industrial customers and privately owned businesses. He has extensive experience representing clients as an expert witness in regulatory proceedings, private negotiations, and litigation.

PROFESSIONAL EDUCATION:

NORTH CAROLINA STATE UNIVERSITY; Raleigh NC, Bachelor of Science, Electrical Engineering, 1969

REGISTRATIONS:

Registered as Professional Engineer in Alabama, Arizona, Colorado, Connecticut, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Commonwealth of Virginia, West Virginia, and Wisconsin

Professional Land Surveyor in North Carolina

Council Record with National Council of Examiners for Engineering and Surveying

EXPERIENCE:

1963-1967
Technician
Booth & Associates

Transmission surveying and design assistance, substation design assistance; distribution staking; construction work plan, long-range plan, and sectionalizing study preparation assistance for many utilities, including Cape Hatteras EMC, Halifax EMC, Delaware Electric Cooperative, Prince George Electric Cooperative, A&N Electric Cooperative; assistance generation plant design, start-up, and evaluations.

1967-1973
Project Engineer
Booth & Associates

Transmission line and substation design; distribution line design; long-range and construction work plans; rate studies in testimony before State and Federal commissions; power supply negotiations; all other facets of electrical engineering for utility systems and over 30 utilities in 10 states.

1973-1975
Professional Engineer
Associates
1975-1994
Executive Vice President
Booth & Associates

Directed five departments of Booth & Associates, Inc.; provided engineering services to electric cooperatives and other public Booth & power utilities in 23 states; provided expert testimony before state regulatory commissions on rates and reliability issues; in accident investigations and tort proceedings; transmission line routing and designs; generation plant designs; preparation and presentation of long-range and construction work plans; relay and sectionalizing studies; relay design and field start-up assistance; generation plant designs; rate and cost-of-service studies; reliability studies and analyses; filed testimony, preparation and teaching of seminars; preparation of nationally published manuals; numerous special projects for statewide organizations, including North Carolina EMC. Work was provided to over 130 utility clients in 23 states, PWC of the City of Fayetteville, NC, Cities of Wilson, Rocky Mount and Greenville are among the utilities in which I have provided engineering services in North Carolina during this time frame. Services to industrial customers include Texfi Industries, Bridgestone Firestone, Inc and many others.

1994-2004 President Booth & Associates	Responsible for the direction of the engineering and operations of Booth & Associates, Inc. for all divisions and departments. The engineering work during this time frame has continued to be the same as during 1974 through 1993 with the addition of greater emphasis on power supply issues, including negotiating power supply contracts for clients; increased involvement in peaking generation projects; development of joint transmission projects, including wheeling agreements, power supply analyses, and power audit analyses. The work during this time frame includes providing services to over 200 utility clients across the United States, including NCEMC and NRECA.
2004-Present President Gregory L. Booth, PLLC	Providing engineering and management services to the electric industry, including planning and design. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serve as an expert witness in state and federal regulatory matters and state and federal court.
2005-Present President PowerServices, Inc.	Providing engineering and management services to the electric industry, including planning and design and utility acquisition. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serve as an expert witness in state and federal regulatory matters and state and federal court.

WORK AND EXPERTISE:

Electric Utilities: (more than 300 clients)

- Utility acquisition expert, including providing condition assessment, system electrical and financial valuation, electrical engineering assessment, initial Work Plan and integration plans, acquisition loan funds, testimony, assessment and consulting services for numerous electric utility acquisitions. Utility clients for acquisition projects include Winter Park, FL acquisition of Progress Energy, FL, system in the City limits, A & N Electric Cooperative acquisition of the Delmarva Power & Light Virginia jurisdiction, Shenandoah Valley Electric Cooperative acquisition of Allegheny Energy Virginia jurisdiction, Rappahannock Electric Cooperative acquisition of Allegheny Energy Virginia jurisdiction, and numerous other past and currently active electric utility acquisitions.
- System studies, including long-range and short-range planning, sectionalizing studies, transmission load flow studies, system stability studies (including effects of imbalance and neutral-to-earth voltage), environmental analyses and impact studies and statements, construction work plan, power requirements studies, and feasibility studies.
- Fossil and hydro generation plan analysis, design, and construction observation.
- Transmission line design and construction observation through 230 kV overhead and underground.

- Switching station and substation design and construction observation through 230 kV.
- Distribution line design and staking, overhead and underground.
- Design of submarine cable installations.
- Supervisory control and data acquisition system design, installation and operation assistance.
- Load management system design, installation and operation assistance.
- Computer program development.
- Load research and alternative energy source evaluation.
- Field inspection, wiring, and testing of facilities.
- Relay and energy control center design.
- Mapping.
- Specialized grounding for abnormal lightning conditions.
- Ground potential rise protection.
- Protective system/relay coordination.

TELECOMMUNICATION: UTILITIES:

- Subscriber and trunk carrier facilities design.
- Stand-by generation and DC power supplies
- DC-AC inverters for interrupted processor supplies.
- Plant design and testing.
- Fiber optics and other transmission media.
- Microwave design.

FINANCIAL SERVICES:

- Long-term growth analyses and venture analyses.
- Lease and cost/benefit analyses.
- Capital planning and management.
- Utility rate design and service regulations.
- Cost-of-Service studies.
- Franchise agreements.
- Corporate accounting assistance.

FORENSIC ENGINEERING:

- Compliance with NESC, NEC, OSHA other codes and industry standard.
- Equipment and product failure and analysis and electrical accident investigation.
- Stray voltage, electrical shocking, and electrocution investigations.
- Building code investigations.
- New product evaluation.

INDUSTRIAL/ELECTRICAL ENGINEERING:

- Building design (commercial and industrial).
- Building code application and investigation.
- Electric thermal storage designs for heating, cooling, and hot water.
- Standby generation and peaking generation design

INSTRUCTIONAL SEMINARS AND TEXT:

- Seminars taught on arc flash hazards and safety, including National Electrical Safety Code regulations for utilities
- Courses taught on National Electrical Safety Code and National Electrical Code.
- Courses taught on Distribution System Power Loss Evaluation.
- Courses taught on Distribution System Protection.
- Text prepared on Distribution System Power Loss Management.
- Text prepared on Distribution System Protection.
- Seminars taught on substation design, NESC capacitor application, current limiting fuses, arresters, and many others electrical engineering subjects.
- Courses taught on accident investigations and safety.

TESTIMONY AS AN EXPERT:

- Concerning rate and other regulatory issues before Federal Energy Regulatory Commission and state commissions in North Carolina, Virginia, Delaware, New Jersey, Pennsylvania, Rhode Island, and Minnesota.
- Concerning property damage or personal injury before courts in Maryland, Minnesota, North Carolina, Virginia, West Virginia, Wisconsin, New York, South Carolina, Texas and Pennsylvania.

FIELD ENGINEERING:

- Transmission line survey.
- Distribution line staking.
- Property surveying.
- Relay and recloser testing.
- Substation start-up testing.
- Generation acceptance and start-up testing.
- Ground resistivity testing.
- Work order inspections.
- Operation and maintenance surveys.

PROFESSIONAL ORGANIZATIONS:

a. National Society of Professional Engineers (NSPE)
b. Professional Engineers in Private Practice (PEPP)
c. National Council of Examiners for Engineering & Surveying (NCEES)
d. Professional Engineers of North Carolina (PENC)
e. National Fire Protection Association (NFPA)
f. Associate Member of the NRECA
g. NRECA Cooperative Network Advisory Committee (NRECA-CRN)
h. The Institute of Electrical and Electronics Engineers (IEEE) (Distribution sub-committee members on reliability)
i. American Standards and Testing Materials Association (ASTM)
j. Occupational Safety and Health Administration (OSHA) Certification
k. American Public Power Association (APPA)

EXHIBIT

GLB-2

EXHIBIT

GLB-3

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	August Report	Proposed FY2012	% Diff
Statutory/ Regulatory	3rd Party Attachments	641,000	641,000	
	Land and Land Rights - Dist	321,000	321,000	
	Meters – Dist	1,803,000	1,803,000	
	New Business - Commercial	6,157,500	6,157,500	
	New Business - Residential	3,917,000	3,917,000	
	Outdoor Lighting - Capital	718,000	718,000	
	Outdoor Lighting - Capital MV	300,000	300,000	
	Public Requirements	3,968,000	3,968,000	
	Transformers & Related Equipment	3,811,000	3,811,000	
Statutory/Regulatory Total		**21,636,500**	**21,636,500**	100.00%
Damage/ Failure	Damage/ Failure	9,245,000	9,245,000	
	Major Storms – Dist	460,000	460,000	
Damage/Failure Total		**9,705,000**	**9,705,000**	100.00%
Subtotal Statutory/Regulatory - Damage/Failure		**31,341,500**	**31,341,500**	100.00%
Asset Condition	Woonsocket & Related	5,005,000	5,005,000	
	Asset Replacement	4,732,050	4,732,050	
	Asset Replacement - I&M (NE)	1,381,000	-	
	Substation Capital - Dist	-	-	
	Safety	-	-	
Asset Condition Total		**11,118,050**	**9,737,050**	87.58%
Non-Infrastructure	Corporate/Admin/General	-	-	
	Facilities	-	-	
	General Equipment	278,000	278,000	
	Telecommunications Capital - Dist	-	-	
Non-Infrastructure Total		**278,000**	**278,000**	100.00%
System Capacity and Performance	Coventry & Related	1,000,000	1,000,000	
	Hopkinton & Related	800,000	800,000	
	Newport & Related	720,000	720,000	
	West Warwick & Related	520,000	520,000	
	Load Relief	6,492,920	6,492,920	
	Reliability	5,199,430	3,938,180	
	Reliability - FEEDER HARDENING	3,230,100	2,350,000	
System Capacity and Performance Total		**17,962,450**	**15,821,100**	88.08%
Grand Total		**60,700,000**	**57,177,650**	94.20%
	Add: Flood Related Capital and Studies	1,200,000	1,200,000	
Total Electric Distribution		**61,900,000**	**58,377,650**	94.31%
Vegetation Management Program	Cycle Trimming	5,902,000	5,300,000	
	Hazard Tree	1,811,000	750,000	
	Sub-T	267,000	267,000	
	Police/Flagman Detail	585,000	491,000	
	All Other Activities	1,261,000	1,261,000	
Vegetation Management Program Total		**9,826,000**	**8,069,000**	82.12%
Inspection and Maintenance Program	Operation and Maintenance Expenses:	-	-	
	Opex related to Capex	1,725,285	993,900	
	Repair - Related Costs	609,000	-	
	Inspections - Related Costs 2	144,945	144,945	
Inspection and Maintenance Program Total		**2,479,230**	**1,138,845**	45.94%

EXHIBIT

GLB-4

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2006 Budget	FY 2006 Actual	FY 2007 Budget	FY 2007 Actual	FY 2008 Budget	FY 2008 Actual	FY 2009 Budget	FY 2009 Actual
Statutory/	3rd Party Attachments	-	362.916	-	75,680	280.000	(123.199)	208.000	873,018
Regulatory	Land and Land Rights - Dist	180,000	199.978	180,000	244,275	230.000	313.141	291.200	310,128
	Meters – Dist	1.976,000	1,609.398	1,900,000	1.748,581	1,950.000	2,194,959	2.101.000	2,135,191
	New Business - Commercial	6,192,000	6,178,305	4,425,000	7,782,725	7,210,000	7,602,534	5,691.500	6,993,422
	New Business - Residential	4,500,000	5,111,949	4,200,000	6,564,788	5,900.000	4,951,161	5,512.000	2,856,774
	Outdoor Lighting - Capital	400,000	523,859	400,000	573,758	1,000,000	712,536	1,001.200	1,236,779
	Outdoor Lighting - Capital MV	-	-	-	-	-	-	350,000	-
	Public Requirements	3,814,000	4,393,841	3,297,500	(790,093)	3,010,000	1,640,703	3,906,968	1,465,029
	Transformers & Related Equipment	3,240,000	4,504,947	3,500,000	4,812,334	5,050.000	6,595,658	4,960,500	5,301,415
Statutory/Regulatory Total		**20,302,000**	**22,885,193**	**17,902,500**	**21,012,048**	**24,630,000**	**23,887,492**	**24,022,668**	**21,171,756**
Damage/	Damage/ Failure	3,250,000	7,655,568	4,550,000	6,764,097	5,650,000	7,266,897	6,496,000	7,488,952
Failure	Major Storms – Dist	-	609,088	-	678,175	10,000	375,380	100,000	856,490
Damage/Failure Total		**3,250,000**	**8,264,656**	**4,550,000**	**7,442,272**	**5,660,000**	**7,642,277**	**6,596,000**	**8,345,442**
Subtotal Statutory/Regulatory - Damage/Failure		**23,552,000**	**31,149,849**	**22,452,500**	**28,454,320**	**30,290,000**	**31,529,769**	**30,618,668**	**29,517,198**
Asset	Woonsocket & Related	-	-	-	-	1,014.000	80,639	2,550.000	57,883
Condition	Asset Replacement	9,323,000	5,828,465	8,241,000	8,314,885	8,631,000	12,381,390	7,050,732	10,793,745
	Asset Replacement - I&M (NE)	-	-	400,000	28,022	300.000	20.727	325,000	112,553
	Substation Capital - Dist	-	-	-	-	-	-	-	-
	Safety	-	-	-	-	75,000	76,680	65,000	(22,943)
Asset Condition Total		**9,323,000**	**5,828,465**	**8,641,000**	**8,342,907**	**10,020,000**	**12,559,436**	**10,090,732**	**10,941,238**
Non-	Corporate/Admin/General	-	(3,136,053)	-	2,441,291	-	(60,904)	-	(3,464)
Infrastructure	Facilities	693,000	742,137	890,000	563,836	-	121,166	-	134,036
	General Equipment	100,000	54,233	100,000	12,601	75,000	324,847	67,600	154,236
	Telecommunications Capital - Dist	-	143 386	-	23,333	-	-	175,000	-
Non-Infrastructure Total		**793,000**	**(2,196,297)**	**990,000**	**3,041,061**	**75,000**	**385,109**	**242,600**	**284,808**
System	Coventry & Related	-	-	-	-	-	4,345	950,000	89,324
Capacity and	Hopkinton & Related	-	-	-	-	-	372	150,000	96,615
Performance	Newport & Related	-	394	1,155,000	4,139	1,215,000	305,411	950,000	715,163
	West Warwick & Related	-	-	-	-	-	-	-	-
	Load Relief	5,964,000	7,306,395	4,648,000	6,694,784	5,030,000	3,486,228	4,335,500	5,988,143
	Reliability	2,922,500	3,022,794	5,745,000	3,529,669	5,104,000	5,446,383	5,667,500	3,878,186
	Reliability - FEEDER HARDENING	1,390,000	650,810	1,413,500	1,316,796	1,085,000	4,315,685	4,654,000	3,828,491
System Capacity and Performance Total		**10,276,500**	**10,980,393**	**12,961,500**	**11,545,608**	**12,434,000**	**13,558,424**	**16,707,000**	**14,595,922**
Grand Total		**43,944,500**	**45,762,410**	**45,045,000**	**51,383,896**	**52,819,000**	**58,032,738**	**57,659,000**	**55,339,166**
	Less: Facilities(where reported)	693,000	742,137	890,000	563,836		121,166		134,036
Total Electric Distribution (excluding Flood)		**43,251,500**	**45,020,273**	**44,155,000**	**50,820,060**	**52,819,000**	**57,911,572**	**57,659,000**	**55,205,130**
	Add: Flood Related Capital and Studies								
Total Electric Distribution		**43,251,500**	**45,020,273**	**44,155,000**	**50,820,060**	**52,819,000**	**57,911,572**	**57,659,000**	**55,205,130**
Vegetation	Cycle Trimming						4,141,000		5,574,000
Management	Hazard Tree						721,000		757,000
Program	Sub-T						294,000		436,000
	Police/Flagman Detail						340,000		187,000
	All Other Activities						1,134,000		903,000
Vegetation Management Program Total		-	-	-	-	-	**6,630,000**	-	**7,857,000**
Inspection and Operation and Maintenance Expenses:									
Maintenance	Opex related to Capex								
Program	Repair - Related Costs								
	Inspections - Related Costs 2								
Inspection and Maintenance Program Total		-	-	-	-	-	-	-	-

Power Services

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2010 Budget	FY 2010 Actual	FY 2011 Budget	FY 2011 Forecast	FY 2012 Proposed	Final Adjustments	Final Filing Proposed
Statutory/ Regulatory	3rd Party Attachments	306,000	780,847	620,000	795,000	641,000	-	641,000
	Land and Land Rights - Dist	326,000	274,560	309,000	292,000	321,000	-	321,000
	Meters – Dist	2,690,000	2,042,048	2,040,000	2,150,000	1,803,000	-	1,803,000
	New Business - Commercial	5,801,000	4,705,078	5,550,000	5,100,000	6,157,500	-	6,157,500
	New Business - Residential	2,699,000	3,256,239	3,750,000	3,560,000	3,917,000	-	3,917,000
	Outdoor Lighting - Capital	945,000	941,164	680,000	700,000	718,000	-	718,000
	Outdoor Lighting - Capital MV	300,000	61,933	-	23,000	300,000	-	300,000
	Public Requirements	4,126,000	3,121,260	3,810,000	3,130,000	3,968,000	-	3,968,000
	Transformers & Related Equipment	6,533,000	4,128,756	4,255,000	3,100,000	3,811,000	-	3,811,000
Statutory/Regulatory Total		**23,726,000**	**19,311,885**	**21,014,000**	**18,850,000**	**21,636,500**		**21,636,500**
Damage/ Failure	Damage/ Failure	7,419,000	9,143,559	8,925,000	8,000,000	9,245,000	-	9,245,000
	Major Storms – Dist	500,000	(112,426)	440,000	3,400,000	460,000	-	460,000
Damage/Failure Total		**7,919,000**	**9,031,133**	**9,365,000**	**11,400,000**	**9,705,000**		**9,705,000**
Subtotal Statutory/Regulatory - Damage/Failure		**31,645,000**	**28,343,018**	**30,379,000**	**30,250,000**	**31,341,500**		**31,341,500**
Asset Condition	Woonsocket & Related	2,108,000	1,043,789	6,080,000	2,400,000	5,005,000	-	5,005,000
	Asset Replacement	10,847,000	11,530,572	721,000	3,500,000	4,732,050	-	4,732,050
	Asset Replacement - I&M (NE)	1,298,000	490,942	400,000	200,000	1,381,000	(1,381,000)	-
	Substation Capital - Dist	-	-	-	-	-	-	-
	Safety	-	-	-	-	-	-	-
Asset Condition Total		**14,253,000**	**13,065,303**	**7,201,000**	**6,100,000**	**11,118,050**		**9,737,050**
Non-Infrastructure	Corporate/Admin/General	-	(1,238,810)	-	-	-	-	-
	Facilities	-	255,800	-	200,000	-	-	-
	General Equipment	161,000	391,872	200,000	250,000	278,000	-	278,000
	Telecommunications Capital - Dist	7,000	-	485,000	350,000	-	-	-
Non-Infrastructure Total		**168,000**	**(590,138)**	**685,000**	**800,000**	**278,000**		**278,000**
System Capacity and Performance	Coventry & Related	1,128,000	558,222	300,000	100,000	1,000,000	-	1,000,000
	Hopkinton & Related	645,000	547,535	200,000	125,000	800,000	-	800,000
	Newport & Related	5,731,000	2,926,839	1,500,000	1,750,000	720,000	-	720,000
	West Warwick & Related	195,000	114,900	450,000	100,000	520,000	-	520,000
	Load Relief	6,780,000	4,650,580	1,958,000	4,225,000	6,492,920	-	6,492,920
	Reliability	3,641,000	5,768,069	2,214,000	3,750,000	5,199,430	(1,261,250)	3,938,180
	Reliability - FEEDER HARDENING	4,314,000	2,888,145	2,013,000	1,100,000	3,230,100	(880,100)	2,350,000
System Capacity and Performance Total		**22,434,000**	**17,454,290**	**8,635,000**	**11,150,000**	**17,962,450**		**15,821,100**
Grand Total		**68,500,000**	**58,272,473**	**46,900,000**	**48,300,000**	**60,700,000**		**57,177,650**
	Less: Facilities(where reported)		256,800		200,000			1,200,000
Total Electric Distribution (excluding Flood)		**68,500,000**	**58,015,673**	**46,900,000**	**48,100,000**	**60,700,000**		**58,377,650**
	Add: Flood Related Capital and Studies					1,200,000		
Total Electric Distribution		**68,500,000**	**58,015,673**	**46,900,000**	**48,100,000**	**61,900,000**		**58,377,650**
Vegetation Management Program	Cycle Trimming		4,552,000		2,881,000	5,902,000	(602,000)	5,300,000
	Hazard Tree		709,000		283,000	1,811,000	(1,061,000)	750,000
	Sub-T		302,000		475,000	267,000	-	267,000
	Police/Flagman Detail		241,000		105,000	585,000	(94,000)	491,000
	All Other Activities		1,078,000		1,085,000	1,261,000	-	1,261,000
Vegetation Management Program Total		-	**6,882,000**	-	**4,829,000**	**9,826,000**		**8,069,000**
Inspection and Operation and Maintenance Expenses:						-	-	-
Maintenance Program	Opex related to Capex					1,725,285	(731,385)	993,900
	Repair - Related Costs					609,000	(609,000)	-
	Inspections - Related Costs 2					144,945	-	144,945
Inspection and Maintenance Program Total		-	-	-	-	**2,479,230**		**1,138,845**

updated: 2/7/2011

2 of 3

Power Services
Engineering & Management Services

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2013 Proposed	FY 2014 Proposed	FY 2015 Proposed	FY 2016 Proposed
Statutory/ Regulatory	3rd Party Attachments	660.000	678,000	698,000	704.000
	Land and Land Rights - Dist	332,000	343,000	355,000	360,000
	Meters – Dist	1.910.000	2,019,000	2,169,000	2,273.000
	New Business - Commercial	6.064.500	6,317,000	6,628,000	6,849,000
	New Business - Residential	4 137,000	4,362,000	4,612,000	4,779,000
	Outdoor Lighting - Capital	747,000	775,000	809,000	825.000
	Outdoor Lighting - Capital MV	1,400.000	2,500,000	-	-
	Public Requirements	4.069.000	3,830,000	4,029,000	4,160,000
	Transformers & Related Equipment	4.077,000	4,323,000	4,667,000	4,901.000
Statutory/Regulatory Total		**23,386,500**	**25,147,000**	**23,967,000**	**24,851,000**
Damage/ Failure	Damage/ Failure	9.566.000	9,884,000	10.269,000	10,426.000
	Major Storms – Dist	480.000	500,000	520,000	540,000
Damage/Failure Total		**10,046,000**	**10,384,000**	**10,789,000**	**10,965,000**
Subtotal Statutory/Regulatory - Damage/Failure		**33,432,500**	**35,531,000**	**34,756,000**	**35,816,000**
Asset Condition	Woonsocket & Related	600.000	-	-	-
	Asset Replacement	7.107.135	12,905,585	15,688,500	15,651.875
	Asset Replacement - I&M (NE)	1.168.000	1,168,000	1,168,000	685,000
	Substation Capital - Dist	-	-	-	-
	Safety	-	-	-	-
Asset Condition Total		**8,875,135**	**14,073,585**	**16,856,500**	**16,336,875**
Non-Infrastructure	Corporate/Admin/General	-	-	-	-
	Facilities	-	-	-	-
	General Equipment	296.000	313,000	336,000	361,000
	Telecommunications Capital - Dist	-	100,000	-	-
Non-Infrastructure Total		**296,000**	**413,000**	**336,000**	**351,000**
System Capacity and Performance	Coventry & Related	874.000	-	-	-
	Hopkinton & Related	4,500,000	400,000	-	-
	Newport & Related	9.006.000	3,050,000	750,000	-
	West Warwick & Related	3.100.000	4,100,000	200,000	-
	Load Relief	5.484,865	5,294,415	6,019,500	8,211.125
	Reliability	5.131.500	4,738,000	5,282,000	5,285.000
	Reliability - FEEDER HARDENING	-	-	-	-
System Capacity and Performance Total		**28,096,365**	**17,582,415**	**12,251,500**	**13,496,125**
Grand Total		**70,700,000**	**67,600,000**	**64,200,000**	**66,000,000**
	Less: Facilities(where reported)				
Total Electric Distribution (excluding Flood)		**70,700,000**	**67,600,000**	**64,200,000**	**66,000,000**
	Add: Flood Related Capital and Studies	6.207.000	4,844,000	1.664,000	260.000
Total Electric Distribution		**76,907,000**	**72,444,000**	**65,864,000**	**66,250,000**

Vegetation Management Program	Cycle Trimming				
	Hazard Tree				
	Sub-T				
	Police/Flagman Detail				
	All Other Activities				
Vegetation Management Program Total		-	-	-	-

Inspection and Operation and Maintenance Expenses:					
Maintenance Program	Opex related to Capex				
	Repair - Related Costs				
	Inspections - Related Costs 2				
Inspection and Maintenance Program Total		-	-	-	-

Division 1-4

Request:

Referring to Section 5, Attachment 1, Page 2, please provide workpapers supporting the Cost of Removal on Line 13.

Response

The detail to support the estimated COR is shown in the attached table. Please note that the Company budgets for the cost of removal prior to the installation of assets. We therefore estimate the COR based on the projected capital outlays, not on the expected capital to be placed into service in a particular year. The assumptions used to project the estimated COR are based on prior experience for a particular budget classification.

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2006 Budget	FY 2006 Actual	FY 2007 Budget	FY 2007 Actual	FY 2008 Budget	FY 2008 Actual	FY 2009 Budget	FY 2009 Actual	FY 2010 Budget	FY 2010 Actual	FY 2011 Budget	FY 2011 Forecast	FY 2012 Proposed
Statutory/	3rd Party Attachments	-	362,916	-	75,680	280,000	(123,199)	208,000	873,018	306,000	780,847	620,000	795,000	641,000
Regulatory	Land and Land Rights - Dist	180,000	199,978	180,000	244,275	230,000	313,141	291,200	310,128	326,000	274,560	309,000	292,000	321,000
	Meters – Dist	1,976,000	1,609,398	1,900,000	1,768,581	1,950,000	2,194,959	2,101,000	2,135,191	2,690,000	2,042,048	2,040,000	2,150,000	1,803,000
	New Business - Commercial	6,192,000	6,178,305	4,425,000	7,782,725	7,210,000	7,602,534	5,691,500	6,993,422	5,801,000	4,705,078	5,550,000	5,100,000	6,157,500
	New Business - Residential	4,500,000	5,111,949	4,200,000	6,564,788	5,900,000	4,951,161	5,512,000	2,856,774	2,699,000	3,256,239	3,750,000	3,560,000	3,917,000
	Outdoor Lighting - Capital	400,000	523,859	400,000	573,758	1,000,000	712,535	1,001,200	1,236,779	945,000	941,164	680,000	700,000	718,000
	Outdoor Lighting - Capital MV	-	-		-	-	-	350,000	-	300,000	61,933	-	23,000	300,000
	Public Requirements	3,814,000	4,393,841	3,297,500	(790,093)	3,010,000	1,640,703	3,906,968	1,465,029	4,126,000	3,121,260	3,810,000	3,130,000	3,968,000
	Transformers & Related Equipment	3,240,000	4,504,947	3,500,000	4,812,334	5,050,000	6,595,658	4,960,800	5,301,415	6,533,000	4,128,756	4,255,000	3,100,000	3,811,000
Statutory/Regulatory Total		**20,302,000**	**22,885,193**	**17,902,500**	**21,032,048**	**24,630,000**	**23,887,492**	**24,022,668**	**21,171,756**	**23,726,000**	**19,311,885**	**21,014,000**	**18,850,000**	**21,636,500**
Damage/	Damage/ Failure	3,250,000	7,655,568	4,550,000	6,764,097	5,650,000	7,266,897	6,496,000	7,488,952	7,419,000	9,143,559	8,925,000	8,000,000	9,245,000
Failure	Major Storms – Dist	-	609,088		678,175	10,000	375,380	100,000	856,490	500,000	(112,426)	440,000	3,400,000	460,000
Damage/Failure Total		**3,250,000**	**8,264,656**	**4,550,000**	**7,442,272**	**5,660,000**	**7,642,277**	**6,596,000**	**8,345,442**	**7,919,000**	**9,031,133**	**9,365,000**	**11,400,000**	**9,705,000**
Asset	Woonsocket & Related	-	-		-	1,014,000	80,639	2,650,000	57,883	2,108,000	1,043,789	6,080,000	2,400,000	5,005,000
Condition	Asset Replacement	9,323,000	5,828,465	8,241,000	8,314,885	8,631,000	12,381,390	7,050,732	10,793,745	10,847,000	11,530,572	721,000	3,500,000	4,732,050
	Asset Replacement - I&M (NE)	-	-	400,000	28,022	300,000	20,727	325,000	112,553	1,298,000	490,942	400,000	200,000	1,381,000
	Substation Capital - Dist	-	-		-		-	-	-	-	-	-	-	-
	Safety	-	-		-	75,000	76,680	65,000	(22,943)	-	-	-	-	-
Asset Condition Total		**9,323,000**	**5,828,465**	**8,641,000**	**8,342,907**	**10,020,000**	**12,559,436**	**10,090,732**	**10,941,238**	**14,253,000**	**13,065,303**	**7,201,000**	**6,100,000**	**11,118,050**
Non-	Corporate/Admin/General	-	(3,136,053)		2,441,291		(60,904)	-	(3,464)	-	(1,238,810)	-	-	-
Infrastructure	Facilities	693,000	742,137	890,000	563,836		121,166	-	134,036	-	256,800	-	200,000	-
	General Equipment	100,000	54,233	100,000	12,601	75,000	324,847	67,600	154,236	161,000	391,872	200,000	250,000	278,000
	Telecommunications Capital - Dist	-	143,386		23,333	-	-	175,000	-	7,000	-	485,000	350,000	-
Non-Infrastructure Total		**793,000**	**(2,196,297)**	**990,000**	**3,041,061**	**75,000**	**385,109**	**242,600**	**284,808**	**168,000**	**(590,138)**	**685,000**	**800,000**	**278,000**
System	Coventry & Related	-	-	-	-		4,345	950,000	89,324	1,128,000	558,222	300,000	100,000	1,000,000
Capacity and	Hopkinton & Related	-	-	-	-		372	150,000	96,615	645,000	547,535	200,000	125,000	800,000
Performance	Newport & Related	-	394	1,155,000	4,139	1,215,000	305,411	950,000	715,163	5,731,000	2,926,839	1,500,000	1,750,000	720,000
	West Warwick & Related	-	-	-	-		-		-	195,000	114,900	450,000	100,000	520,000
	Load Relief	5,964,000	7,306,395	4,648,000	6,694,784	5,030,000	3,486,228	4,335,500	5,988,143	6,780,000	4,650,580	1,958,000	4,225,000	6,492,920
	Reliability	2,922,500	3,022,794	5,745,000	3,529,889	5,104,000	5,446,383	5,667,500	3,878,186	3,641,000	5,768,069	2,214,000	3,750,000	5,199,430
	Reliability - FEEDER HARDENING	1,390,000	650,810	1,413,500	1,316,796	1,085,000	4,315,685	4,654,000	3,828,491	4,314,000	2,888,145	2,013,000	1,100,000	3,230,100
System Capacity and Performance Total		**10,276,500**	**10,980,393**	**12,961,500**	**11,545,608**	**12,434,000**	**13,558,424**	**16,707,000**	**14,595,922**	**22,434,000**	**17,454,290**	**8,635,000**	**11,150,000**	**17,962,450**
Grand Total		**43,944,500**	**45,762,410**	**45,045,000**	**51,403,896**	**52,819,000**	**58,032,738**	**57,659,000**	**55,339,166**	**68,500,000**	**58,272,473**	**46,900,000**	**48,300,000**	**60,700,000**

The Narragansett Electric Company
d/b/a National Grid
Draft Electric ISR Plan
Attachment 1 to DIV 1-4

Joint PUC 1-2

Request:

At the May 14, 2019 technical session, National Grid represented that changes in its budgeting process has had a significant effect on how actual costs for capital projects compare to budgeted costs compared to previous time periods. Regarding this representation:

a. Please describe the changes to budgeting, project management, or any other process that were changed,

b. Please provide the problems the changes were addressing, and include National Grid's formal problem statement if one exists,

c. Please provide the information and/or analysis that identified and substantiated the existence of the problem.

Response:

a. The Company launched a new Complex Capital Delivery process in April of 2018 and since that date is using the new process to develop all new, complex electric system projects. The Complex Capital Delivery process engages a newly formed Options Solution Engineering Group (OSEG) that works with the Distribution Planning and Asset Management (DPAM) team when detailed option analysis is undertaken within Area Studies and other complex project sponsorship efforts.

   OSEG is responsible and accountable to provide estimates for all complex electric system projects. OSEG performs a multi-step process in developing initial option estimates, including assessing whether the options fit an available set of standard designs and, if not, developing specific cost estimates with the Estimating Department. These initial cost estimates will be used by DPAM to select an initial preferred option that is included in the Long-Term Investment Plan. Estimates at this stage have limited-scope definition and therefore require a corresponding level of estimate accuracy.

   The project then progresses to the Development Phase, which can generally last between 6 and 24 months. During this phase, the scope is completed using more refined estimating tools, incorporating site investigation, permitting, and stakeholder involvement earlier in the process and integrating a risk assessment workshop into the analysis. As a result, risks are incorporated more formally within this phase, and design requirements are identified earlier to minimize future scope changes.

By the end of the Development Phase, a formal Project Estimate is developed by the Estimating Department and used for a full project sanction, with a governance tolerance of +/-10%.

After the full sanction, a project progresses to the next stage where detailed engineering design is completed and work that will be done by contractors is put out for bid. Project cost estimates will be updated and re-sanctioned if they exceed the 10% tolerance. The Company believes this is the correct point from which to set the benchmark cost for the Capital Efficiency Mechanism (CEM). As project estimates are refined and progressed throughout the project's life cycle, the Company updates the forecasted capital spend as part of its existing forecast processes.

The Complex Capital Delivery process was implemented with goals that include:

- Efficient progress supported by a Stage/Gate delivery model and reporting;
- Smooth achievement of necessary sanctions;
- Early agreement on scope, baseline schedule, and baseline cost;
- Accurate identification of risks and estimation of costs;
- Effective decision-making and analysis, reducing or eliminating need to revisit decisions; and
- Efficient assumption of project responsibilities by the downstream project leader.

b. Our core business performance heavily depends on the success of its capital deployment, and the Company annually invests substantially in complex capital projects. Therefore, efficient and effective delivery of complex capital projects is a core capability requirement of NGUSA. NGUSA did not identify a specific problem but rather identified an aspiration to improve our capital delivery process. The ambition of designing an improved Complex Capital Delivery process is to significantly improve our complex capital project management capabilities to be best in class within 3 years by delivering complex capital projects fit for purpose at a lower unit cost, on time and within budget.

c. See response to b, above

Prepared by or under the supervision of: Patricia C. Easterly

---

Joint PUC 1-3

Request:

Considering all projects listed in PUC 1a, please provide the following:

a. Identify all time periods during which National Grid feels there were differences in the way budgeting and/or project management were conducted such that these differences would cause an important difference in the average variance between the budget and actual cost of Capital Efficiency Mechanism-eligible projects (the changes described in responses to PUC 2a, for example, might be identified in this response depending on the respondent's opinion).

b. Please calculate the unweighted mean and standard deviation for all projects using the inflation-adjusted data responding to PUC 1c.

c. Please calculate the weighted mean (using project budget as the weighting parameter) and standard deviation for all projects using the inflation-adjusted data responding to PUC 1c.

d. Please calculate the unweighted mean and standard deviation for each period identified in part a.

e. Please calculate the weighted mean and standard deviation for each period identified in part a.

f. Please perform a normality test of the respondent's choice on the distributions in parts b, c, d, and e.

Response:

a. Since the response to Joint PUC 1-1a includes an analysis for only one project and the variance identified in Joint PUC 1-1c is not substantial, that analysis did not identify any changes to the processes that would have changed the variance by a significant amount.

b-c. Since the response to Joint PUC 1-1a includes analysis for only one project and the estimating details for that project did not separately identify inflation, the Company and the Division did not consider these questions to be applicable.

Prepared by or under the supervision of: Patricia C. Easterly and Gregory L. Booth, PE

Joint PUC 1-3, page 2

d-e. Since the response to Joint PUC 1-1a includes an analysis for only one project, it is not possible to calculate the unweighted and weighted mean and standard deviation for the variance identified in Joint PUC 1-1c.

f. Please see the response to parts b, c, d, and e, above.

Prepared by or under the supervision of: Patricia C. Easterly and Gregory L. Booth, PE

Joint PUC 1-4

Request:

Using the data responses in PUC 3d and 3e please calculate an effect size for each pre- and post-change period pair identified in PUC 3a (assuming the distributions are sufficiently normal). Please indicate what measure of effect size was used (for example, Cohen's *d*).

Response:

See response to Joint PUC 1-3. Since only one project was analyzed in Joint PUC 1-1, this question is not applicable to one project.

Joint PUC 1-5

Request:

Please recalculate all parts of PUC 3 and PUC 4, but exclude the budgeted and actual costs for project phases that would have occurred before the time at which the project budget would have been formally set for the purposes of scoring the project.

Response:

See response to Joint PUC 1-3 and Joint PUC1-4. Since only one project was analyzed in Joint PUC 1-1, this question is not applicable to one project.

Joint PUC 1-6

Request:

Based on the responses above and any other information the respondent feels is relevant, please describe how the capital efficiency mechanism will change the utility's performance. In addition:

a. Please indicate if the data supports underperformance (for example, National Grid's actual costs are higher than budgeted costs by an important difference)

b. Please indicate if the data supports an opportunity for improved performance (for example, an important difference in budget variance can be achieved during the project phases that would occur after the project officially entered the Capital Efficiency Mechanism program).

Response (a-b):

A well-designed capital efficiency mechanism, by providing the Company a revenue opportunity tied to the delivery of customer savings, will enable the Company to focus resources on the identification and execution of incremental savings opportunities. By providing the Company a meaningful performance incentive related to its capital project execution, it will encourage the Company to 1) rigorously search for new efficient delivery options and 2) implement options for mitigating risks associated with project execution efficiencies. Pursuing such options might entail additional analysis, time, and resources to identify innovative potential savings opportunities and might also involve exposure to more uncertainty. Analysis would also be required to assess uncertainties, the efficiency they might deliver and propose mitigating measures to offset any additional risk.

As noted in the Joint response to PUC 1-1, only one project, Quonset Point, was identified for assessing impacts under the CEM. The Company and Division, therefore, concluded that one project is not able to provide sufficient data for assessing under-performance or opportunity for improvement. However, there is no reason to believe that all potential efficiencies have been captured. An objective of this incentive is to establish a framework that better mirrors the outcomes of competitive markets, where firms have an ever-present incentive to innovate to lower costs. That said, given the limited data available, the Company and Division are suggesting using the Southeast substation and Dyer Street Substation projects as test cases to further inform the design of a CEM.

Prepared by or under the supervision of: Patricia C. Easterly and Meghan McGuinness

---

Joint PUC 1-7

Request:

Has the respondent identified specific opportunities for cost savings in its existing capital project process that could be addressed by the Capital Efficiency Mechanism? If so, what are the opportunities?

Response:

As noted in the Company's Rebuttal Testimony in this docket submitted on May 3, 2019, the Company supports an efficiency mechanism that optimizes risk and spending for the benefit of customers. To accomplish that goal, we believe a method that encompasses a full scope of efficiency opportunity should be developed.

The Capital Efficiency Mechanism (CEM) focuses on actual costs as compared with estimated costs submitted prior to the commencement of construction, which only captures execution savings and only one part of the overall planning lifecycle. The planning lifecycle consists of four general phases, Needs Case, Options Selection, Project Development, and Execution. While we believe that there are still opportunities for further efficiency in the Execution phase, the Company believes that the CEM, as designed, misses opportunities to drive potentially large efficiencies in the other three phases. A broader incentive that captures all four phases will provide the greatest benefits to customers. In addition, the Company recommended a bandwidth of 10% given the limited population of projects expected to be under the scope of the Division's proposal. The Company believes that a higher bandwidth than 1% is appropriate given the limited ability to manage variances with a small portfolio of projects.

The Company does identify continuous improvement efficiency opportunities that are used to adjust designs and construction sequences. These efficiencies often are already captured in the project estimates but may not be in all circumstances if they are identified after the project estimate is established. The execution phase of a project lifecycle is primarily subject to risks, which generally escalate project costs. The Company currently evaluates options for reducing these risks, and an incentive would encourage further review of options to balance risks and costs.

As discussed in Joint PUC 1-6, the value of the incentive is that it enables the Company to focus resources on identifying potential opportunities to manage risk during the execution phase and achieve efficiencies that might otherwise be overlooked. absent the management focus the

---

incentive provides. Also, the value of the incentive is to provide the Company with the potential payoff necessary to work through challenges or risks associated with potential opportunities for savings that might otherwise impede the achievement of those savings. Not all potential savings are currently known. An objective of this incentive is to establish a framework that better mirrors the outcomes of competitive markets, where firms have an ever-present incentive to innovate to lower costs.

Prepared by or under the supervision of: Patricia C. Easterly and Meghan McGuinness