STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

The Narragansett Electric Company
d/b/a Rhode Island Energy

Docket No. 23-48-EL

RE: FY 2025 Electric Infrastructure,
Safety, and Reliability Plan

PREFILED DIRECT TESTIMONY OF

Gregory L. Booth, PE
President, Gregory L. Booth, PLLC
On Behalf of Rhode Island Division of Public Utilities and Carriers

February 20, 2024

Prepared by:
Gregory L. Booth, PE
14460 Falls of Neuse Road Suite 149-110
Raleigh, North Carolina 27614
(919) 441-6440
gboothpe@gmail.com

Prefiled Direct Testimony of

Gregory L. Booth, PE, President
Gregory L. Booth, PLLC

On Behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 23-48-EL

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DIRECT TESTIMONY OF GREGORY L. BOOTH, PE

I. INTRODUCTION

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

A. My name is Gregory L. Booth. My company is Gregory L. Booth, PLLC ("Booth, PLLC"), with mailing address 14460 Falls of Neuse Road, Suite 149-110, Raleigh, North Carolina 27614.

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 ("Division").

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, and was inducted into the North Carolina State University Department of Electrical and Computer Engineering Alumni Hall of Fame in November 2016. I am a registered professional engineer in twenty-three (23) states, including Rhode Island, as well as the District of Columbia. I am 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"), the National Fire Protection Association ("NFPA"), and Professional Engineers in Private Practice ("PEPP"). I have also served as a member of the IEEE Distribution Subcommittee on Reliability and as an advisory member of the National Rural Electric Cooperative Association ("NRECA")-Cooperative Research Network, which is an organization similar to EPRI.

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 all aspects of electric utility planning, design and construction, including generation, transmission, and distribution systems, and North American Electric Reliability Corporation ("NERC") compliance.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE THE RHODE ISLAND PUBLIC UTILITIES COMMISSION?

A. Yes. I have testified before the Rhode Island Public Utilities Commission on numerous matters, including Docket Nos. 2489, 2509, 2930, 3564, 3732, 4029, 4218, 4237, 4307, 4360, 4382, 4770/4780, 4473, 4483, 4513, 4539, 4592, 4614, 4682, 4783, 4857, 4915, 4995, 5077, 5098, 5209, 5235, D-11-94, D-17-45, and D-21-09. My testimony in Rhode Island has included filed and live testimony on previous Electric Infrastructure, Safety and Reliability Plan Fiscal Year Proposal filings by National Grid in Docket Nos. 4218, 4307, 4382, 4473, 4539, 4592, 4682, 4783, 4915, 4995, 5098, 5209 and 22-53-EL.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT IN OTHER JURISDICTIONS?

A. I have testified before the Federal Energy Regulatory Commission ("FERC") and numerous state commissions, including in Connecticut, Delaware, Florida, Georgia, Maine, Maryland, Massachusetts, Minnesota, New Jersey, North Carolina, Pennsylvania, South Carolina and Virginia.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to introduce *Exhibit GLB-1*, Report of Gregory L. Booth, PE on the review of Rhode Island Energy's ("RIE" or "Company") Proposed FY 2025 Electric Infrastructure, Safety and Reliability Plan provided to the Division on October 13, 2023 ("ISR Plan"). My testimony will briefly summarize the collaborative process between the Division and RIE, which resulted in consensus of the final Electric Infrastructure, Safety, and Reliability Plan FY 2025 Proposal filed with the Commission by RIE on December 21, 2023. My testimony also summarizes certain details of *Exhibit GLB-1* and my recommendations.

III. ISR PLAN EVALUATION PROCESS

Q. WOULD YOU BRIEFLY OUTLINE THE PROCESS WHICH LEADS TO THE DIVISION'S SUPPORT OF THE RIE ISR PLAN FILED DECEMBER 21, 2023 IN THIS DOCKET?

A. Yes. I will first start with a broader overview, and then provide details. The Division and RIE proceeded through a much more collaborative process on the FY 2025 ISR Plan than the FY 2024 ISR Plan. Although the later timing of RIE's filing did not provide the

Division with the longer review timeframe which had become customary with National Grid, the conferences and work between RIE and the Division was relatively smooth and very cooperative. The Company provided its proposed budget for the upcoming FY 2025 Plan year and also submitted its first 10-year Long-Range Plan, which is a strategic investment plan primarily driven by Area Studies developed over the past ten years, advanced technology (grid modernization) programs, and advanced metering implementation. In its evaluation, the Division considered justification for near term projects, and given the Long-Range Plan submittal, turned a more critical eye towards the Company's future investment plans. For the FY 2025 Plan, there were areas lacking completed engineering justification such as the recloser additions, and at the Division's request, RIE committed to provide the details in advance of capital spending and advancing the recloser installations. Several initiatives required near-term spend to fully develop longer term projects or programs. For these, the Division concurred with FY 2025 Plan budgets, but the Division will require additional justification prior to approving future budgets. Other discretionary programs or projects were considered for adjustments to reach agreement on a balanced spending plan in FY 2025. My report provides significant discussion of these and many other areas. RIE has many new philosophies, guidelines and program advancements that are driving some of the capital spending programs. This among some other ISR Plan program additions, such as AMF investments under Docket 22-49-EL, has dramatically increased the total capital spending as demonstrated by the FY 2025 proposed budget and Long-Range Plan. The Division has had to navigate these differences as RIE has been explaining the justifications and rationale for capital spending.

Historically, the Company and Division recognized that the statutory 60-day collaboration period was insufficient to adequately address all issues and details, including allowing the Company time to respond to the Division's extensive data requests. For that reason, the Company would typically file its proposed ISR Plan in August or September, providing both parties at least 90 days for review of the 12-month plan. While RIE has not moved to that schedule and is only meeting the statutory requirements, the Division and Company managed to address all the capital programs to reach a consensus for FY 2025 based on some added commitments for engineering details to be provided by RIE throughout the year.

Q. YOU STATED THAT DURING THE CONFERENCES IT BECAME VERY EVIDENT THE PPL PHILOSOPHY WAS DIFFERENT THAN NATIONAL GRID. WOULD YOU ELABORATE?

A. Certainly. RIE indicated early on that the PPL risk assessment and risk tolerance was different than National Grid's. My observation is that the Company is inclined to increase or accelerate investments to offset perceived risks. RIE also takes a more aggressive stance on reliability performance. For example, RIE not only wants to meet and exceed regulatory reliability metrics, but the Company also wants to be "best in class" by making additional investments to further improve its very good reliability performance. RIE has made a real effort to also explain some of its philosophy differences and enhancements, including in areas such as vegetation management, system protective coordination and advancement of technology such as FLISR reclosers (defined also as self-healing circuits) and reliability goals. The Division and RIE have not completely reached consensus on all the philosophy changes. RIE has shown a willingness to modulate its capital spending and transition to some of its new philosophies and programs. The Division is currently satisfied with the compromises and collaborative process which has led to the FY 2025 ISR Plan as filed, but there is considerable work to take place between the Division and RIE to address longer term capital needs. The attached Exhibit GLB-1 discusses many areas of concern and continued analysis needed in the future. The Company has also agreed to track many of the estimated benefits in order for the Company, Division and Commission to have actual metrics which can be used to make future decisions and establish more realistic benefit versus cost analyses.

Q. IN THE PAST ISR PLAN FILINGS, YOU HAVE INCLUDED A TABLE SHOWING THE COMPANY'S ORIGINAL PROPOSAL AND THE ADJUSTED CONSENSUS POSITION OF THE DIVISION AND COMPANY. DO YOU HAVE A SIMILAR TABLE FOR THIS FILING?

A. Yes. While the table is somewhat different than seen in older testimony and reports I have filed, it provides the picture of the Company's initial capital spending position and the collaborative position reached between the Company and the Division. Exhibit GLB-1 ("Report"), Appendix 2 of my Report goes into great detail concerning our position on each category.

Q. IN SUMMARY, DID THE DIVISION REACH A CONSENSUS POSITION WITH THE COMPANY BASED ON THE COMPANY DELIVERING CERTAIN ADDITIONAL ENGINEERING ANALYSIS AND DETAILS PRIOR TO INSTALLING DISTRIBUTION AUTOMATION RECLOSERS (FLISR)?

A. Yes, we did. My Report Exhibit GLB-1, addresses the details and I will further summarize in this testimony.

Q. WOULD YOU PROVIDE AN OVERVIEW OF YOUR ISSUES AND HOW YOU HAVE ORGANIZED YOUR TESTIMONY TO PRESENT YOUR POSITION?

A. Certainly. We have approached our assessment and recommendations using the same process and applying the same standards as with prior ISR Plans. Infrastructure needs, safety and reliability are all assessed in the context of short-term and long-term costs and affordability to the ratepayer. The Report is more extensive than many of the previous reports since there are several issues which are new or have been substantially expanded from prior ISR Plans. Some of these areas which involved more joint efforts between the Division and RIE include Advanced Recloser additions and automation (FLISR) under three separate programs (ERR, CEMI-4 and DARP); the advancement of numerous substation asset condition projects; the need for more mobile substations and spare substation transformers and the new AMF program. Additionally, the continued escalation in cost due to inflation and the supply chain delays are also among the issues that continue to receive focus since the Pandemic. The following chart summarizes the adjustments by category and the agreement reached between the Division and RIE.

FY 2025 ISR Plan Proposed Capital Budget by Spending Rationale ($000)	RIE Initial Proposed 10-13-23	Net Adjustments	RIE FY 2025 Proposed 12-21-23	% of Total Budget
Customer Request/Public Requirements*	$ 30,162	$ 2,700	$ 32,862	23%
Damage/Failure Total	$ 17,013	$ 800	$ 17,813	13%
Subtotal Non-Discretionary	***$ 47,175***	***$ 3,500***	***$ 50,675***	**36%**
Asset Condition	$ 57,723	$ (6,678)	$ 51,045	36%
Non-Infrastructure	$ 1,712	$ (820)	$ 892	1%
System Capacity and Performance	$ 46,267	$ (7,964)	$ 38,303	27%
Subtotal Discretionary	***$ 105,702***	***$ (15,462)***	***$ 90,240***	**64%**
Grand Total without AMF	**$ 152,877**	**$ (11,962)**	**$ 140,915**	***100%***
AMF**		**$ -**	**$ 51,725**	
Grand Total with AMF			**$ 192,639**	

** Excludes $26.2 million in proposed Reimbursement to DG Customers being considered separately in Dockets 23-37-EL and 23-38-EL*

*** Reflects AMF capital investment proposal subject to Docket 22-49-EL*

IV. <u>REPORT SUMMARY</u>

Q. PLEASE BRIEFLY SUMMARIZE YOUR REPORT ATTACHED AS *EXHIBIT GLB-1* ("REPORT").

A. The Report contains an Introduction describing the overall process, including the progression through the October 13, 2023 and December 21, 2023 RIE proposed FY2025 ISR Plan filings. It summarizes the adjustments developed through a very collaborative process and Division's position on the final December 21, 2023 filing. The Company's initial October 13, 2023 filing proposed a capital spending budget of $152.9 million excluding the AMF capital. The Company and Division reached an agreement on a capital spending budget of $140.9 million excluding the AMF capital. The Division accepted the AMF proposed capital budget of $51.7 million as consistent with the expectations of the

Commission's order in Docket 22-49-EL. The Division and Company reached agreement on a Vegetation Management Program expense budget of $13.1 million. The Report discusses in detail each major category: Customer Request/Public Requirements; Damage/Failure; Asset Condition; Non-Infrastructure; and System Capacity and Performance. The Report addresses many of the projects and programs, particularly the new and expanded programs, in significant detail. There are numerous reasons for the increased detail in several areas including the fact that programs changed from historical capital levels and scope.

The Report focuses on each spending rationale, generally characterized as discretionary and non-discretionary spending with an assessment of the Company's proposed projects and associated spend for FY 2025. Customary programs and projects together with new and expanded programs are addressed with additional observations in areas that raise concerns for the Division and require further communications throughout FY 2025 between the Division and Company. The Report contains a conclusion that includes seventeen (17) recommendations related to capital investments and ongoing planning analysis. Many of these recommendations are a continuation of previous ISR Plan recommendations which had been adopted by National Grid and need to continue under the new ownership. These recommendations include, but are not limited to: recommendations that the Company modulate annual spend to mitigate upward pressure on rates due in part to major asset condition projects and the advancement of AMF; the Company deliver increased engineering analysis documents and justifications for certain program advancements; the Company improve the project cost estimation process and complex project execution; the Company continue its Damage/Failure category detailed tracking; the Company continue its Vegetation Management Program benefit cost assessments and analysis of the effectiveness of the enhancements to the program; and finalization of the Long-Range Plan with Division concurrence while beginning the next cycle of Area Studies. These are just a few of the recommendations which are in addition to the requisite analysis and documentation and quarterly reporting expected of the Company each year to support projects and programs.

V. SPARE TRANSFORMERS

Q. THE COMPANY IS PROPOSING THE PURCHASE OF ADDITIONAL SPARE SUBSTATION TRANSFORMERS AND MOBILE SUBSTATIONS WHICH ARE NEW AREAS OF CAPITAL SPENDING. WHAT IS YOUR RECOMMENDATION FOR THE REQUIRED NUMBER OF SPARES?

A. The Company has outlined the purchase of a significant number of spare transformers, mobile substations, and a mobile regulator in its Long-Range Plan. They are beginning this purchasing process in the FY 2025 ISR Plan. While the Division and I support the initiation of the purchases in the FY 2025 ISR Plan, we do not support the massive increase in the number of spare transformers proposed in the Long-Range Plan. During the PPL acquisition process the Company responded to several questions related to spare transformers and the need for additions to the existing fleet. The Company responded to data requests DIV 9-78, 9-79 and 9-80 related to spare transformers. At that time there were 7 distribution and 4 transmission spare transformers stored in Rhode Island. Over a ten-year period, Rhode Island only had to rely on spare transformers from National Grid Massachusetts three times. That history does not support the RIE projected requirement.

Furthermore, PPL had argued during the acquisition hearings that it would be supporting RIE upon acquisition and that there would not be a loss in synergies, however, based on RIE's request for significant transformer purchases, the level of synergies and support from PPL may not be as expected. The attached report goes into a great deal of detail concerning both the spare transformer and the mobile substation proposed additions.

Q. WHAT IS YOUR RECOMMENDATION FOR ADDITIONAL SPARE TRANSFORMERS?

A. While the Division and I support the proposed $736,000 of spending in FY 2025 and what will likely be $5.3 million over two or more years, at this time we do not support the purchase of 23 additional spare transformers in order to increase the fleet to 30 total spares at a cost of nearly $40 million as outlined in the Long-Range Plan documentation. The Division will continue its evaluation and anticipates detailed discussions with RIE to get a more accurate picture of exposure and risk which will inform support for future proposed spending. The Commission may want to evaluate whether some of the spare transformer synergy lost due to the acquisition should be a transition cost absorbed by the Company and not imposed on the ratepayer. The Report discusses this issue in significant detail. Furthermore, a great deal of work between the Division and Company is needed on this category in the Long-Range Plan in order to reach a potential consensus.

VI. RECLOSERS FOR CEMI-4, ERR AND DARP

Q. YOUR REPORT CONTAINS A VERY LONG DISCUSSION CONCERNING THE ADDITION OF RECLOSERS TO THE SYSTEM. WHY DID YOU FEEL SUCH A LONG DISCUSSION WAS NECESSARY?

A. The Division and I have a different view of the requirements for justification and need of reclosers than the Company. Much of our disagreement concerning justification was expanded upon in the last ISR Plan in Docket 22-53-EL. Advanced Reclosers are a large portion of the Company's grid modernization plan technology advancements. In this ISR Plan the Company is putting forth the addition of reclosers in three separate yet correlated programs which are the CEMI, ERR and DARP programs. These programs and areas of recloser additions are more focused and specifically justified by the Company in lieu of last year's unjustified broad recloser program and grid modernization recloser program. The Division supports a much more focused and justified program approach. Since the addition of Advanced Reclosers, including those to be utilized for FLISR (self-healing circuit) schemes, will continue for years to come, we believe it is appropriate for the report to establish some history and a baseline of what will amount to hundreds of millions of dollars in technology advancement through the application of circuit reclosers.

Q. WOULD YOU BRIEFLY SUMMARIZE THE COLLABORATIVE APPROACH BETWEEN THE DIVISION AND COMPANY, AND THE CONSENSUS PARAMETERS WHICH RESULTED IN THE INCLUSION OF 88 RECLOSERS IN THE ISR PLAN?

A. The Company's overall recloser strategy is that each overhead circuit on the system be considered for multiple reclosers amounting to 1,267 Advanced Recloser additions over seven years. For FY 2025, the Company initially proposed 166 Advanced Reclosers at a cost of $13.8 million in three programs (CEMI, ERR and DARP). The Division suggested this level of capital needed to be modulated for several reasons, including to reduce the impact on rates and in order to begin to establish a record of actual benefits. The Division and Company continue to disagree on the justification methodology, however, we did reach an agreement for the FY 2025 ISR Plan. The basis of the agreement is RIE's circuit prioritization list ranked by outage frequency, or CKAIFI. The Company originally proposed targeting circuits with a CKAIFI in excess of 1.5 to drive the addition of Advanced Reclosers. The Division and Company reached an agreement that a CKAIFI of 2.0 would be used for FY 2025, meaning that feeders performing at nearly twice the regulatory system threshold of 1.05 would be targeted. The Division's goal was to ensure that discretionary recloser additions were placed where the greatest benefits could be achieved under RIE's methodology. This resulted in an initial estimate of 88 reclosers for 23 circuits which included 73 Advanced Reclosers with FLISR schemes at a capital cost of $7.2 million. The Company admitted that detailed analysis and engineering would be needed to reach a precise solution for each circuit. Technically, the Company does not know how many reclosers will be installed, the location, or system coordination needs for each targeted circuit. The Division, of course, has remained a proponent of completing a systemwide protective coordination study which would identify the need and optimal number, location and protective scheme for each recloser on every circuit in advance. Then the Company could develop a comprehensive implementation program based on a holistic view. RIE's strategy first assumes that a recloser is the optimal solution, then the Company seeks a potential system issue to apply the recloser versus my recommendation to identify the need and determine if a recloser is the optimum solution. Setting aside these differences, the Company and Division reached agreement based on the Company's commitment to produce documentation to the Division 60 days in advance of installing the reclosers on each circuit. This agreement included a detailed memorandum containing the justifications, one line distribution circuit diagram and project details combined with an estimate of the benefits and tracking mechanisms for the outage reductions resulting from the recloser installations per circuit both on blue sky days and for storms. The Division finds this to be a satisfactory compromise position at this time to begin installing reclosers and advancing this technology which will be integrated with the new ADMS system coming from PPL.

Q. YOU WERE VERY ADAMANT DURING THE LAST ISR PLAN HEARING THAT A SYSTEMWIDE PROTECTIVE COORDINATION STUDY WAS ESSENTIAL FOR THE ADVANCEMENT OF THE RECLOSERS AND TECHNOLOGY PROPOSED BY THE COMPANY. WHAT HAS CHANGED?

A. Nothing has changed concerning my position on the need for a systemwide protective coordination study and its value in selecting optimum powerline protection and determining what is needed. A good example of this value arose when the Company presented an example memorandum recommending FLISR recloser additions on a feeder with a CKAIFI of 1.65. While this memorandum and solution appeared on the surface to be prudent, the circuit was not demonstrated to be a worst performer in regard to outage frequency and was not within the Company's 2.0 CKAIFI criteria for a circuit selection. If the system were studied holistically, however, the circuit may very well have been prioritized for a FLISR recloser solution. The Company has not performed this level of analysis on all the circuits, therefore neither the Company nor the Division knows if the feeder would be a better choice for recloser applications than any other circuit and particularly one with a CKAIFI above 2.0. The Company made the choice to use the CKAIFI level for prioritization rather than a study of all the circuits. Although the Division continues to prefer a study, it agreed in the short term to use the Company's methodology, even though the Company almost immediately moved off that to a circuit which it found to be, in its view, a better choice. Of course, since RIE had not performed this study on all the circuits, it cannot know if it is truly a better initial circuit choice.

Q. IS IT FAIR TO SAY THE DIVISION AGREED TO THE PRESENT SELECTION METHOD IN ORDER TO START ADVANCING THE RECLOSER SOLUTIONS, WHILE STILL BELIEVING A COMPLETE STUDY OF ALL THE CIRCUITS WOULD BE BETTER?

A. That is correct. Since the Division views this as an iterative process which will be enhanced over time, the Division is willing in the short term to agree to the Company's circuit selection. The Division also recognizes that actual benefits of Advanced Reclosers, and particularly those with automated schemes (FLISR), cannot be validated until units are placed in service and fully operating. The limited number of installations in FY 2025 will enable this first step and RIE is expected to collect and report data to reconcile benefits to initial forecasts.

Q. ARE THERE ADDITIONAL CONDITIONS GUIDING ADVANCED RECLOSER INSTALLATIONS?

A. Yes. RIE agreed to the Division's condition that the budget for Advanced Reclosers and associated work to implement FLISR schemes be capped at $5.957 in FY 2025. The Division believed that a budget cap was necessary to ensure that RIE would be held to the recloser count and costs which were still only estimates in the ISR Plan filing.

VII. CONCLUSION

Q. DO YOU AND THE DIVISION SUPPORT THE PROPOSED RIE FY 2025 ELECTRIC ISR PLAN BUDGET FOR $140.915 MILLION EXCLUDING AMF, AND $192.7 INCLUDING AMF, IN CAPITAL EXPENDITURES?

A. Yes, with the significant caveat that RIE delivers upon its commitment based on agreement between the Division and RIE to undertake the following actions: a) develop the additional engineering analysis and justification for Advanced Recloser additions, b) provide the analysis to the Division at least 60 days prior to advancing work on targeted feeders, c) establish cost and performance mechanisms, including specific measures for circuits with FLISR schemes, d) limit spend for Advanced Reclosers with FLISR schemes to $5.957 million in FY 2025, and e) other ongoing agreements associated with communications between RIE and the Division will continue.

Q. WHAT ARE THE RECOMMENDATIONS YOU HAVE MADE IN YOUR REPORT *EXHIBIT GLB-1*?

A. I have included seventeen (17) recommendations in my Report, fifteen (15) of which are identical to previous recommendations in past ISR plan processes, and two (2) of which are new recommendations or modifications. These recommendations are summarized in the following list and are provided with additional discussion in the Summary and Recommendations section of my Report.

1. The Company shall separately track and report recloser installations under the Distribution Automation Recloser Program and maintain an overall budget cap of

$5.957 million in FY 2025. The cap shall be separately administered from any potential ISR Plan budget discipline imposed by the Commission.

2. The Company shall complete a systemwide protective coordination study, demonstrating the need, the location, and/or the manner in which reclosers will be coordinated, in advance of progressing major recloser additions. The Division and Company will work to develop a mutually acceptable study format and content. The memorandum which the Company has already agreed to deliver before advancing reclosers and most particularly the FLISR schemes may substantially address the Division's needs.

3. The Company shall maintain and file with each proposed ISR Plan a holistic 10-year Long-Range Plan as contemplated in these Recommendations, with all strategic capital investments including AMF and GMP. The Long-Range Plan must be adequately supported and accompanied by a level of detail that allows stakeholders to sufficiently validate the need, timing and level of proposed investment. It shall also reflect the demand reduction which may transpire from the SRP program advancements.

4. The Company shall present new programs, major projects, or material modifications to existing programs to the Division in advance of including the programs in the ISR Plan. The Company shall produce requisite justification at a level of detail to sufficiently validate the need, timing and level of proposed investment, including a benefit-cost analysis. The Company shall also propose a methodology to separately track, measure

and validate program costs and benefits. Requisite justification and accompanying information shall be provided in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

5. The Company shall not include spend in the ISR Plan for initiatives or programs that are subject to Commission review and/or approval prior to the program progressing through a regulatory proceeding.

6. The Company shall continue to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement blanket programs to validate proper classifications.

7. The Company shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the System Reliability Procurement ("SRP") plans, Area Studies, ISR Plan, non-wires alternatives ("NWA") options and internal Design Criteria.

8. The Company shall continue enhancing current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum:
    - The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description,

condition assessment/criticality rankings, alternatives considered, solution, cost and timeline.

- Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, Distribution System Planning ("DSP"), Heat Maps, and emerging initiatives.
- A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning.
- An evaluation of potential incremental investments that support the Company's long-term grid modernization strategy. This includes description of technology or infrastructure investment, cost-benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. The GMP should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs.
- A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.
- A correlation of the 11 Area Studies to each other for the development of a holistic system Long-Range Plan which further informs the ISR Plan.

9. The Company shall continue to develop a System Capacity Load Study and a 10-year Long-Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall analyze the overall system in a holistic manner using the now completed 11 Area Studies to establish enhancements in the Area Study

solutions. The Company shall use the completed Area Studies to re-prioritize and sequence all solutions and major projects in the Long-Range Plan. The Company shall submit and present the outcome of each revised Area Study to the Division at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities, holistic system long-range plan development and revision of each current and future planned Area Study status at least 120 days prior to filing its FY 2026 ISR Plan Proposal, but in any event no later than August 31, 2025.

10. The Company shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.

11. The Company will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.

12. The Company shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The

Company will separately identify Level I projects repaired as a result of the I&M program.

13. The Company shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to allow for transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

14. The Company shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

15. The Company shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long-Range Plan in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

16. The Company shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program, a separate cost-benefit analysis on the Enhanced Hazard Tree Management program, and an additional assessment of the RIE modifications in the program proposed to deliver a 15 to 18 percent SAIFI

improvement for the Division's review prior to submitting the Company's FY 2026 ISR Plan Proposal, and in any event no later than August 31, 2025.

17. The Company shall provide continuous and timely updates on ISR Plan team members and responsibilities, material changes to Company guidelines, standards or processes that affect distribution planning, or any proposed changes to the ISR Plan process. The Company shall, at minimum, provide updates at quarterly presentations of the quarterly reports.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT OF GREGORY L. BOOTH, PE

Gregory L. Booth, does hereby depose and say as follows:

I, Gregory L. Booth, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 20th day of February, 2024.

Gregory L. Booth

I hereby certify this document was prepared by me or under my direct supervision. I also certify I am a duly registered professional engineer under the laws of the State of Rhode Island, Registration No. 8078.

GREGORY L. BOOTH
STATE OF RHODE ISLAND
No. 8078
REGISTERED
PROFESSIONAL ENGINEER
(ELECTRICAL)

Gregory L. Booth, PE

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

REPORT OF

Gregory L. Booth, PE
President, Gregory L. Booth, PLLC
On Behalf of Rhode Island Division of Public Utilities and Carriers
Concerning
The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Docket No. 23-48-EL

February 20, 2024

Prepared by:
Gregory L. Booth, PE
14460 Falls of Neuse Road, Suite 149-110
Raleigh, North Carolina 27614
(919) 441-6440
gboothpe@gmail.com

PREFACE

Gregory L. Booth, PLLC was engaged by the State of Rhode Island Division of Public Utilities and Carriers ("RIDPUC") to evaluate the Electric Infrastructure, Safety and Reliability ("ISR Plan" or "Plan") Plan FY 2025 Proposal submitted by Rhode Island Energy. As part of the review of the plan, numerous data requests were submitted and responses provided by Rhode Island Energy. Additionally, meetings and conferences were held with Rhode Island Energy and their key personnel involved in the development of the Plan. The Legislative Act amending Chapter 39-1 "Revenue Decoupling", §39-1-27.7.1, provided Rhode Island Energy the right to file an ISR Plan for the prospective fiscal year and receive considerations for the Plan. The statute provides for evaluation by the Division, and for Rhode Island Energy and the Division to attempt to reach an agreement on a proposed plan and submit a mutually agreed upon Plan. The following report describes the process and position reached between the Division and Rhode Island Energy.

REPORT OF

Gregory L. Booth, PE
President, Gregory L. Booth, PLLC
On Behalf of Rhode Island Division of Public Utilities and Carriers
Concerning
The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Docket 23-48-EL

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I. INTRODUCTION

Gregory L. Booth, PLLC ("Division Consultant"[1]) was engaged by the Rhode Island Division of Public Utilities and Carriers ("Division") to assist in the evaluation of the initial Rhode Island Energy ("RIE" or "Company") Electric Infrastructure, Safety, and Reliability Plan FY 2025 Proposal (the "ISR Plan" or "Plan") dated October 13, 2023, and the final Electric Infrastructure, Safety, and Reliability Plan FY 2025 Proposal dated December 21, 2023 filed in Docket 23-48-EL. This is the second ISR Plan[2] developed and filed by the Company since PPL's acquisition of Narragansett Electric Company, previously owned by National Grid. The evaluation followed the same process of analysis completed for each ISR Plan filed from FY 2012 through FY 2024. This Report includes an explanation of the process for the initial FY 2025 ISR Plan proposal evaluations and collaborative efforts, resulting in non-discretionary adjustments and a reduction of proposed FY 2025 capital spending for discretionary projects. The adjustments were applied to the Company's initial FY 2025 ISR Plan Proposal submitted to the Division on October 13, 2023 resulting in the final FY 2025 ISR Plan Proposal dated December 21, 2023.

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." Through this process, the Division and the Company ultimately reached agreement on select adjustments. In this report, I

[1] For the purposes of this report, reference to "Division Consultant", "I" and "my" are interchangeable.
[2] RIE's first ISR Plan filing consisted of a 21-month FY 2024 ISR Plan. The PUC held an Open Meeting on January 20, 2023 to address, among other items, whether a 21-month ISR Plan is consistent with statutory requirements. The Commission ultimately ruled that RIE must submit an ISR Plan reflecting a fiscal year spending period (April 1, 2023-March 31, 2024). RIE complied on January 27, 2023. The supplemental filing included revised budgets for fiscal year 2024, and RIE did not amend accompanying testimony or the ISR Plan document.

will discuss the areas of consensus between the Division and the Company. This involves an in-depth assessment of all spending categories that includes a detailed review of each project, proposed level of spend, and justification for inclusion in the ISR Plan. My evaluation considers the alignment of both non-discretionary and discretionary budgets with the Company's reliability and safety objectives, while promoting efficiencies that could reduce overall spend without compromising those critical objectives.

The Company's October 13, 2023, FY 2025 ISR Plan Division filing followed very closely the format and principals agreed to in previous submittals including a 12-month fiscal year plan as opposed to a 21-month calendar based plan proposed by RIE in FY 2024. Most of the Company's budget line items were structurally similar to the previous Plans, with modifications in the cost structure. The FY 2025 Plan also included several newly proposed or enhanced program additions. The Division Consultant performed its evaluations by reviewing the Company's pre-file planning information, Area Studies, and the proposed ISR Plan. The pre-file planning information is guided by Division recommendations and the Rhode Island Public Utilities Commission ("Commission") Report and Order from prior ISR proceedings. The materials evaluated include reliability reports, budget variance explanations, program cost benefit analyses, detailed budgets for major projects, completed Area Studies, Quarterly ISR Plan Reports, and other supplemental information. The Company proactively established several conference calls prior to the September pre-file to aid the Division in tracking FY 2024 performance while also sequentially bringing forward proposed budgets for ISR Plan spending rationales. An in-depth analysis of the pre-file planning information and each component of the proposed FY 2025 ISR Plan was undertaken. Overall, the collaborative effort during the FY 2025 process improved considerably over FY 2024. The evaluation and analysis included the actions and procedures detailed in Appendix 1.

The overall analysis was an iterative process, which included detailed discussions of each ISR Plan spending rationale category, including Capital Expenditures, the Vegetation Management ("VM") Plan, and the Inspection and Maintenance ("I&M") Plan. The Company included each of its subject matter experts in the discussions as we worked toward preliminary adjustments in the proposed FY 2025 Plan. Also, the Division along with an engineering consultant met with RIE staff and visited multiple substations to assess asset condition and associated projects. Additionally, a series of virtual web meetings, PowerPoint presentations, telephone conferences, materials related to Area Studies, and data request responses were utilized in discussions with various individuals in the Company to provide full assessment and gain clarification in each area and spending category. The data requests and responses referred to above, excluding those that are considered confidential or critical energy infrastructure information, have been submitted to the Commission by RIE in the Company's filing as Book 2 of 3 and Book 3 of 3. Area Studies with finalized reports are available on the Company's portal.

The Company's capital investment plans are significantly growing in terms of budget and complexity. For the FY 2025 ISR Plan, the Company included nine new or enhanced programs in addition to customary budget categories of spend and a significant number of Area Study substation and distribution projects in various phases. RIE will begin implementing its Advanced Metering Functionality (AMF) deployment under Docket 22-49-EL which will add considerable incremental capital needs in the near term. Other newly introduced components included a budgetary framework as part of Docket 23-34-EL aimed to address the ISR Plan budgeting and reconciliation process and a Long-Range Plan which reflects RIE's 10-year strategic capital investment strategy.

The Division's evaluation focused on newly introduced projects and programs to validate need, timing and pace while also re-visiting longer standing initiatives to ensure that scopes and budgets were reasonable. Non-discretionary programs were examined to confirm that anticipated expenses were appropriately categorized, aligned with respective budget categories, and reasonably projected based on historical trends. Planned work under recurring discretionary programs was examined to validate spending levels against program design. With the Company's completion of Area Studies, significant funding was proposed for major System Capacity and Asset Condition projects. These projects were assessed against original study recommendations and evaluated to ensure that the prioritization schedule and overall pace were justified by criticality or system needs. Agreement was reached on FY 2025 funding for Area Studies projects in construction and emerging project engineering. However, the Division continued to reinforce the need to optimize project implementation and spread implementation over longer time periods which is crucial during years of additional capital needs such as AMF implementation.

Specific attention was given to the Company's proposed reliability programs and related recloser additions. These initiatives were included in FY 2024 as Grid Modernization Plan (GMP) investments but were not approved in the ISR Plan. The Company modified and proposed the programs at a more tempered pace and investment level while integrating some components, such as reclosers, across multiple programs. The Division considered each program independently by evaluating investments as a part of business as usual advancing latest technologies for safety and reliability versus an integrated GMP proposal. As with all customary ISR Plan project reviews the justification, pace of deployment, and spend for each program was assessed against other discretionary but more critical projects. The evaluation resulted in some reductions to proposed spend with associated conditions that were found acceptable to both parties. The Company also proposed new programs to increase spare transformer and mobile substation inventories, a request that generated concurrence with limited initial spend while also raising concerns with lost synergies as a result of the PPL acquisition. The Company's budgetary framework was reviewed for consistency with current ISR Plan practices and several observations and language revisions were recommended for Commission consideration. Lastly, proposed AMF capital investments were not evaluated in detail but reviewed in total against RIE's originally proposed implementation plan and Commission Order.

Beginning with the FY 2015 ISR Plan, the Division recommended that the Company complete system studies and develop a 10-year Long-Range Plan (LRP) to guide the orderly expansion of the electric system. The Company has now completed all Area Studies, although the pace of completion has not met expectations, and has submitted its first Long-Range Plan as part of the FY 2025 ISR Plan document. The Long-Range Plan was not discussed at length with the Company but rather relied upon for a general view of the pace and timing of capital investments. Should the Company implement its strategic capital investment plan, there would be significant and untenable spend in the coming years, some reaching over $270 million with AMF included. This observation underpins the Division's ongoing concern with excessive investment levels and ratepayer impacts. While the Company proposed substantial incremental spend in FY 2025 relative to prior years, there were areas of adjustments that produced a more reasonable plan while balancing the need for safety and reliability. The Company's Long-Range Plan now indicates even higher levels of future spend with significant annual changes. The Company must carefully examine discretionary projects when preparing upcoming ISR Plans and make every effort to put forth a more judicious investment proposal than indicated in the Long-Range Plan. There are categories of spend and enhanced assessments discussed throughout this report that the Company should consider in striving for systematic project implementation and more evenly distributed spend across the planning horizon to avoid runaway spend.

Through the analysis and assessment process, consensus on the rationale for adjustments and the budget levels was reached between the Division and the Company. For the FY 2025 Plan, initial agreement was reached on adjustments resulting in a proposed capital investment budget of $140.9 million and $192.6 million including AMF. Appendix 2 lists a Summary of the Capital Outlays by key driver category and budget classification as originally proposed by the Company on October 13, 2023, with adjustments and the resulting final proposed budget filed by the Company on December 21, 2023. Appendix 3 provides RIE's historical Electric ISR Plan budgets compared to actual spend.

II. CAPITAL INVESTMENT PLAN

A. Overview

I have evaluated the $140.9 million FY 2025 Capital Spending Plan proposed by the Company, along with its supporting testimony and exhibits as contained in its filing dated December 21, 2023.[3] I first reviewed the September 8, 2023 pre-file ISR budget proposal submitted to the Division with capital investment ranges of $159 million to $185 million, and the initial October 13, 2023 proposed ISR Plan submitted to the Division in the amount of $152.9 million.[4] Over a period of approximately ten (10) weeks, there was an iterative process in which modifications to the Company's initial proposed Capital Spending Plan were discussed. Adjustments were accepted, including some increases, for each of the spending rationales and the five major categories. Following is a comparison of the Company's October 13, 2023 initial proposal, net adjustments, and the Company's proposed budget as shown in Chart 5 of the FY 2025 ISR Plan as filed on December 21, 2023 in Docket No. 23-48-EL. The level reached through the evaluation

[3] In the December 21, 2023 FY 2025 ISR Plan filing, RIE included a separate category in its Discretionary budget as authorized by the Commission under Docket 22-49-EL (page 74). The proposed $51.7 million AMF budget was not presented in RIE's preliminary capital budgets. The Division did not perform a detailed assessment of AMF spend in the FY 2025 ISR Plan review since the Division participated in, and supported, AMF implementation and costs in the AMF docket. The analysis in this report excludes the AMF capital budget.

[4] RIE's September 9th and October 13th budgets included non-discretionary spend of $26.2 million for reimbursements to DG Customers that are separately being considered in Dockets 23-37-EL and 23-38-EL. RIE and the Division agreed to remove DG reimbursements from the ISR Plan and the projects were not evaluated. All budget amounts indicated in this report exclude DG reimbursements.

process was $140.9 million. The chart includes RIE's proposed capital spend of $51.7 million to deploy its AMF program which was authorized under Docket 22-49-EL.

FY 2025 ISR Plan Proposed Capital Budget by Spending Rationale ($000)	RIE Initial Proposed 10-13-23	Net Adjustments	RIE FY 2025 Proposed 12-21-23	% of Total Budget
Customer Request/Public Requirements*	$ 30,162	$ 2,700	$ 32,862	23%
Damage/Failure Total	$ 17,013	$ 800	$ 17,813	13%
Subtotal Non-Discretionary	***$ 47,175***	***$ 3,500***	***$ 50,675***	**36%**
Asset Condition	$ 57,723	$ (6,678)	$ 51,045	36%
Non-Infrastructure	$ 1,712	$ (820)	$ 892	1%
System Capacity and Performance	$ 46,267	$ (7,964)	$ 38,303	27%
Subtotal Discretionary	***$ 105,702***	***$ (15,462)***	***$ 90,240***	**64%**
Grand Total without AMF	**$ 152,877**	**$ (11,962)**	**$ 140,915**	***100%***
AMF**		**$ -**	**$ 51,725**	
Grand Total with AMF			**$ 192,639**	

** Excludes $26.2 million in proposed Reimbursement to DG Customers being considered separately in Dockets 23-37-EL and 23-38-EL*

*** Reflects AMF capital investment proposal subject to Docket 22-49-EL*

The Company projects the need for non-discretionary expenditures of $32.9 million in Customer Request/Public Requirements spending, and $17.8 million in Damage/Failure spending. Except for known major projects, the majority of projects in the Customer Request/Public Requirements category are not precisely defined but are based on the Company's best forecast since specific customer requests have not been made. Historical spending levels tend to serve as the primary method to develop a budget. Additionally, economic conditions are a factor considered in adjusting historical costs. There are both upward and downward trends in new construction activity, combined with the effects of inflation on the cost of raw materials, transportation, and labor. For FY 2025, the Company is foreseeing equipment cost increases and must continue to manage supply chain problems to maintain adequate inventory levels.

During the course of discussions, the Company proposed a new category of spend in Customer Requirements to address distribution system loading violations. The proposed budget captures work for targeted system improvements when service quality falls below standards. RIE customarily performed this work as discretionary blanket projects, so the new category was simply a shift within the ISR Plan. The Division did not agree with the rationale to create a new non-discretionary budget and RIE agreed to remove the proposed spend from Customer Requirements and to rely on funding for necessary projects in the discretionary category.

The Damage/Failure category covers costs to replace equipment that unexpectedly fails or becomes damaged. The Company sets the budget based on historical spend and makes further adjustments to account for ongoing work from recent equipment failures. Spending continues to rise in this category and the FY 2025 budget is $2.6 million higher than the previous budget due to recent substation equipment failures. The Division has been working with the Company on enhancing the processes and definitions of Damage/Failure to improve the transparency and management of the costs in this category. It is expected that the Company will continue to refine internal processes to manage the Damage/Failure category and appropriately justify actual expenditures due to unplanned equipment failures.

For the FY 2025 ISR Plan proposal, the Company initially proposed to spend a total of $47.2 million for all non-discretionary projects. After net adjustments of $3.5 million, agreement between the Division and the Company was reached on a total proposed budget of $50.7 million. This represents thirty-six (36%) of the proposed capital budget. In Sections B and C, I discuss the Customer Request/Public Requirements and Damage/Failure categories in more detail.

Additional categories of spending rationale for the FY 2025 budget are Asset Condition, Non-Infrastructure, and System Capacity and Performance. These categories, which are discretionary in the sense they are based on engineering, safety, reliability and economic analyses, are budgeted at $90.2 million for the remaining sixty-four percent (64%) of the proposed capital budget excluding AMF capital. Proposed spend is over $20 million above the FY 2024 budget. The significant increase is driven by the Company's major asset condition and system capacity projects emanating from Area Studies. The projects inform a portion of RIE's comprehensive 10-year capital investment plan (Long-Range Plan) and are ultimately phased into the ISR Plan. Although delivery of the studies fell short of the Division's expected schedule, the Company met its commitment to complete all the studies by December 2021. Now that regional projects have been identified the Company has established an aggressive pace to complete the work. Discretionary spend increases are also influenced by the Company's desire to add a significant number of reclosers under three reliability programs; Customers Experiencing Multiple Interruptions (CEMI-4), Engineering Reliability Review (ERR) and the Distribution Automation Recloser Program (DARP). The Company previously proposed recloser additions under different programs in FY 2024, but lacking requisite justification, full approval was not granted. The Company repackaged the recloser programs in FY 2025 and expanded supporting documentation. Although deficiencies in justification and data gaps were observed, the Division ultimately concurred with a limited number of recloser additions with conditions to cap the annual budget and requirements for RIE to present more detailed information in advance of recloser installations.

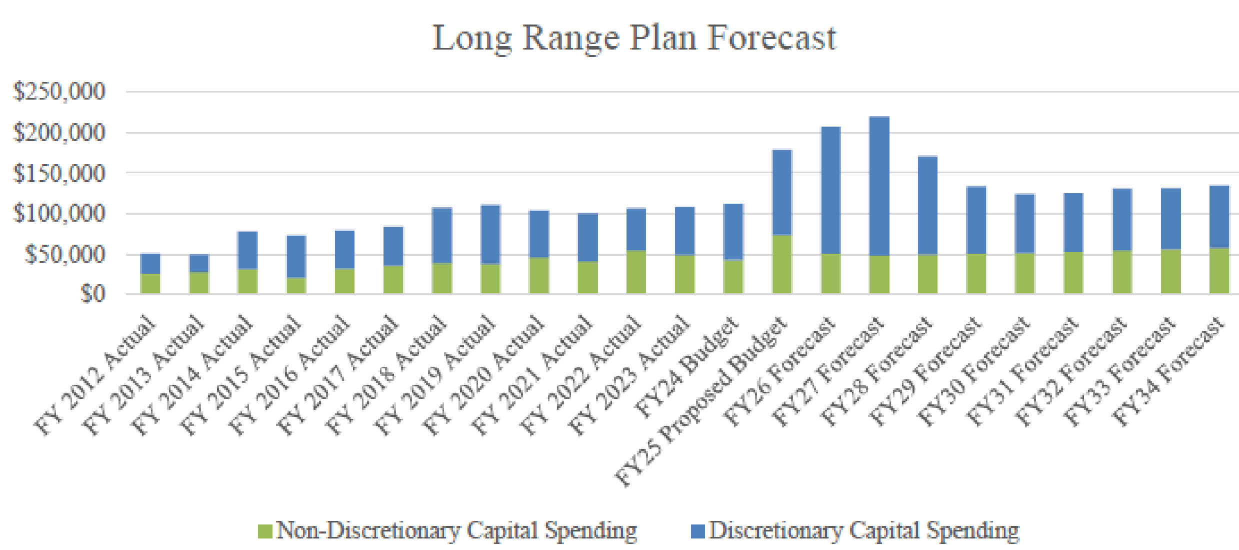
For the three categories (Asset Condition, Non-Infrastructure, and System Capacity and Performance), the initial proposed budget was $105.7 million, which was adjusted to $90.2 million in the FY 2025 ISR Plan Proposal filing based on agreement between the Division and the Company. Sections D through H addresses each of these categories and associated programs, explaining the adjustments.

The remaining Discretionary category of spend is a separate line item reflecting RIE's capital costs associated with the deployment of its AMF program described in Docket No. 22-49-EL. The

Company proposes to expend $51.7 million in FY 2025 to replace existing Automatic Meter Reading (AMR) with new advanced functionality meters. The capital costs for meters, networks, systems, and programs flow through the ISR Plan and recovery is in accordance with the PUC's decision in Docket No. 22-49-EL. The Division's review of AMF considers alignment of proposed ISR Plan capital spend with the Company's stated levels in the AMF Docket. I address AMF along with non-wires alternatives (NWA), Docket 4600, the Long-Range Plan, and the Company's proposed budgetary framework as part of Docket 23-34-EL in Additional Assessments (Section I).

For the total FY 2025 ISR Plan, RIE proposes non-discretionary and discretionary capital investments of $140.9 million without AMF, and $192.6 million including AMF. This compares to the FY 2024 ISR Plan budget of $112.3 million and forecast of $118.2 million. The Company's investment strategy is primarily driven by major substation projects identified through Area Studies that the Company performed from 2017-2021. A Division engineering consultant visited multiple substations in 2023 to assess asset condition. The physical inspection combined with RIE's study results confirm the need to prioritize major substation work in the coming years. Replacing aged and deteriorated infrastructure is critical to service continuity for large numbers of customers and conditions do not improve with time. Area Study projects driven by system capacity issues have more subjective implementation timeframes since needs are based on forecasted peak load which has been flat or even negative on some feeders due to distributed energy resources. When load growth does not develop as anticipated, project implementation can be delayed unlike Asset Condition which has more imminent needs. Substation Asset Condition and System Capacity projects should take precedence over efforts to advance smart grid technology on select feeders which serve fewer customers and ultimately rely on the integrity of substations. The spending levels are also impacted by increased equipment costs and inflation. RIE's long term projections as shown in Chart 6 of the Plan indicate a period of time where capital needs will far exceed historical levels, and then eventually taper lower but still remain higher than previous levels.

Chart 6
Projected Spending FY 2012 – FY 2034
as Outlined in the Long Range Plan (Excluding AMF)
($000)



This view excludes AMF which adds nearly $150 million in capital from FY 2025 to FY 2027. The need for budget and project execution discipline expressed by the Division is now more important than ever.

B. <u>Customer Request/Public Requirements Category</u>

The initial proposed FY 2025 ISR Plan included $30.2 million of Customer Request/Public Requirements cost which was increased by $2.7 million to reflect rising costs of distribution transformer purchases, for a total proposed budget of $32.9 million. This compares to a FY 2024 ISR budget and forecast of $27.5 million and $30.7 million, respectively.

ISR Plan Capital Budget Customer Request ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
Customer Request/ Public Requirements	27,514	3,221	30,735	30,162	2,700	32,862

The Company projects overspend in FY 2024 of $3.2 million. Contributing factors include higher public requirements than budgeted offset by lower meter costs. The major impact is from transformer, voltage regulators and capacitor costs which continue to trend higher and are projected at $3 million over budget. Material availability and cost will continue to be a factor going forward. The Company has anticipated higher prices for transformers and associated equipment in FY 2025 and increased the budget by $2.7 million. Although the Company has attempted to identify risks and adjust budget components for upcoming year, economic impacts remain unpredictable. The Division expects that the Company will adjust spend in discretionary categories to balance unplanned overspend that might occur in the non-discretionary categories.

C. Damage/Failure Category

The initial proposed FY 2025 ISR Plan included $17 million in the Damage/Failure category for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. The budget was increased by $800,000 to reconstruct a vault in Providence that was found in unsafe and deteriorated condition, bringing the total FY 2025 budget to $17.8 million. Of this, $11.3 million is designated for smaller scale and unidentified Blanket work, $2.5 million to address specific equipment failures, $3 million for storms and $1 million in reserves. This compares to a FY 2024 ISR Plan budget and forecast of $15.2 million and $17.2 million, respectively.

ISR Plan Capital Budget Damage/Failure ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
Damage/Failure	10,940	82	11,022	11,268	-	11,268
Vault Reconstruction	-	-	-	-	800	800
Reserves	979	(979)	-	1,008	-	1,008
Failed Assets	1,323	2,887	4,210	1,737	-	1,737
Storms	1,950	-	1,950	3,000	-	3,000
Total Damage/Failure	**15,192**	**1,989**	**17,182**	**17,013**	**800**	**17,813**

The Company considers Damage/Failure work unplanned but necessary, and budget variances are highly correlated to large equipment damage and storm activity. The Company continues to incur expenses over budget in this category with an overall FY 2024 variance projected at $2 million primarily due to expenditures for restoration after major asset failures. The Failed Asset budget, which includes continued spend for previously failed major assets, is $2.9 million over-budget due to higher than estimated civil construction bids for Nasonville with an offset due to delayed spare transformer delivery that replaces the unit used at Westerly #2. The Company continues work related to prior major equipment failures at Hopkins Hill, Apponaug, and Sprague Street. Expenditures cover items such as immediate repair/replacement, transformer inspection and failure reporting, and costs to replenish spare equipment used in restoration. The derivation of the budget is somewhat subjective as these events are unforeseen. The FY 2025 budget for Failed Assets and reserves appropriately rely on historical trends with adjustments for anticipated costs such the additional $800,000 vault reconstruction project. As of the second quarter, storm work was forecasted to meet the FY 2024 budget but that position could change based on weather events through the remainder of the fiscal year. The storm budget for FY 2025 was raised from $2 million to $3 million which is reasonable based on trending of higher impact storms.

Elements of Damage Failure which are unrelated to major storms or clear equipment failures are also budgeted based on historical work and the Company anticipates meeting its $11 million budget in FY 2024. These projects and their associated costs have been steadily increasing. The trend has been recognized for several years and the Company has been implementing a new practice of categorizing work meant to create more clarity around how to charge work in the field for damaged assets. The objective is to ensure that only projects required as a result of damaged or failed equipment are assigned to this category, while the remaining are captured under discretionary spend. The process appears effective and I am satisfied that the Company is closely monitoring work to validate classifications and further enhancements are not recommended at this time. For FY 2025, the Division supports the Company's proposed spend of $11.3 million for smaller scale work in Damage/Failure.

This brings the total non-discretionary categories of Customer Request/Public Requirements and Damage/Failure to $50.7 million, which is thirty-six (36%) of the total Capital Investment Budget by Key Driver Category.

One additional matter to address is RIE's intention to recategorize discretionary work as non-discretionary. In the FY 2025 ISR Plan filing, the Company stated that it was "currently reviewing projects that have traditionally been in the Discretionary category, specifically related to criteria violations, to determine whether they should be moved to the Non-Discretionary category and anticipates having a determination by the FY 2025 Filing with the Commission."[5] To better understand the types of projects that the Company desired to reclassify, the Division requested a list of projects and costs for the previous five years. RIE provided examples of load and voltage violation projects.[6] The Company listed eight violations over the past five years for a total of $5 million of which $3.5 million was attributed to the Overloaded Transformer Program. Each issue was adequately funded and resolved under discretionary blanket, program, or project budgets. The

[5] Proposed FY 2025 ISR Plan (October 13, 2023); Section 2, page 21
[6] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 1-28

items listed by the Company are consistent with other work performed in the discretionary category. For instance, the Overloaded Transformer Program is a System Capacity & Performance line item program currently budgeted at $1.5 million each year. This is a program to proactively replace highly loaded distribution transformers before failure which is no different than the Company's efforts to identify and replace any equipment before it fails. All of this work is proactive and discretionary based on criticality. RIE also listed COVID related projects which were distribution line upgrades or conversions to address overloads due to changing work patterns during the pandemic. RIE proactively evaluated the system to anticipate and address the overloads which is no different than their ongoing annual capacity review which is funded and executed in the discretionary category. Furthermore, in the unfortunate event that system issues are caused by damaged infrastructure, repairs would be funded under the existing Damage/Failure category.

The Company's distribution planning and day-to-day operations processes are designed to identify and remedy system conditions to maintain continuity of service. These have been successfully managed under current ISR Plan project designations. Although RIE states that the new non-discretionary category would be for small scale unanticipated work, the basic definition of the category could lead to major capital projects shifting from discretionary to non-discretionary. There can be a fine line between anticipating and resolving a system issue as discretionary work and determining that a system issue is emergent and must be managed as non-discretionary. Creating and tracking a new non-discretionary category would require additional and unnecessary oversight since system issues are adequately managed under the current ISR Plan construct. The Division currently spends considerable time monitoring the non-discretionary Damage/Failure category to ensure discretionary work is not included in this category, which had regularly been occurring. The Division's concerns have resulted in requirements for RIE to produce quarterly Damage/Failure reports and to annually review projects to adjust for discretionary work that was incorrectly categorized. I do not endorse adding new non-discretionary categories of spend that would create opportunities to re-categorize projects currently managed as discretionary spend and also require significant analysis to audit annual results. The Company has not presented compelling rationale to create a new non-discretionary category. Furthermore, the significantly more granular data which will correlate to distribution transformer capacity that will be captured by the AMF is expected to provide much greater visibility to emerging overloads. During the ISR Plan review period, the Company ultimately proposed a new non-discretionary line item for Active Loading Violation budgeted at $1.5 million. Based on the assessment of representative projects, the Division did not concur, and the Company agreed to reverse the request. I caution that any future proposal to reclassify projects as non-discretionary be closely scrutinized, particularly if the Commission adopts a budgetary framework that excludes budget caps for non-discretionary work.

D. <u>Asset Condition Category</u>

The Asset Condition category, with an initial proposed budget of $57.7 million, represents a combination of strategies and programs targeting equipment replacement to maintain reliability performance. The Company identifies proposed projects as either Major Projects or Other. Major Projects are significant multi-year investments generally associated with substation and regional work identified in Area Studies. The Other category captures less complex Area Study projects and includes preliminary engineering and design work that produces refined project budgets. The Other category also includes the Inspection and Maintenance (I&M) program and new or recurring programs designed to replace groups of equipment throughout the system. Projects and programs in the Asset Replacement category have become increasingly significant in scope and budget. The Company continues to track and report major projects separately, which provides transparency and enables the Division to monitor budget estimates, scope, and actual construction spend from inception to completion. It also mitigates the Company's tendency to shift budgets between discretionary projects in order to meet an overall target, rather than managing independent projects based on need.

For FY 2025, RIE initially included Dyer Street, all of Providence Area Long Term Study projects, and Southeast as Major Projects. In the December ISR Plan filing, the Company revised the Major Project list based on its proposed criteria set forth in its proposed budgetary framework.[7] Since the Major Project list is evolving and may not be finalized until a later date, my evaluation of the Asset Condition category considers projects related to Area Studies separately from I&M and recurring programs.[8] Discussion with the Company for Asset Condition resulted in FY 2025 reductions of $6.7 million, and a final proposed budget of $51 million, which is thirty-six percent (36%) of the overall ISR Plan budget. This compares to the FY 2024 budget and forecasted actuals of $47.7 million and $50.4 million respectively. A detailed evaluation of each category follows:

ISR Plan Capital Budget Asset Condition ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
Dyer Street Substation*	-	2,080	2,080	15	-	15
Providence LT Study Programs*	24,314	(811)	23,503	28,395	(2,500)	25,895
Southeast Substation*	66	205	271	-	-	-
Other Area Study Projects (8 total)				5,997	(700)	5,297
Subtotal Area Study Projects	*24,380*	*1,474*	*25,854*	*34,407*	*(3,200)*	*31,207*
I&M	3,000	0	3,000	3,000	(1,470)	1,530
Programs	20,346	1,202	21,548	20,316	(2,008)	18,308
Total Asset Condition	**47,726**	**2,677**	**50,402**	**57,723**	**(6,678)**	**51,045**

** RIE designated Major Project in initial filing*

[7] Docket 23-48-EL, Proposed FY 2025 ISR Plan; RIE's Second Proposed Electric 5 ISR Plan Budgetary and Reconciliation Framework ("Second Proposed Framework"), Exhibit 2
[8] I consider Recurring Programs as individual legacy or newly proposed programs that RIE designates as "Other"

Asset Condition spend has steadily increased due to aging equipment and the natural deterioration over time throughout the service territory and the need for significant upgrades in highly loaded corridors. Major multi-year investments are included in the ISR Plan and, as legacy projects are completed, new projects are naturally phased in and aligned with previously performed Area Studies. It should be emphasized that portfolios of projects associated with Area Studies are categorized in either the Asset Replacement budget category or System Capacity budget category, and both of these categories are placing significant upward pressure on current and future discretionary spend. In July 2023 our team visited a significant number of substations which have proposed asset condition projects. While the Company has taken the Division and its consultant to substations requiring major rebuild due to age and condition, this is the first time the Division and its consultants have visited a significant number of sites since reliability assessments from 2002 through 2006. The information from the field visits helped establish our own substation asset condition priority list and details to be tracked against the Company's proposed projects.

1. Asset Condition - Area Study Projects

The Company is proposing continued work on multi-year asset condition projects emanating from Area Studies. The Company separately tracks and reports Major Projects which in the past were loosely identified as complex, multi-year projects with significant spend. RIE has now put forth more discrete criteria for Separately Tracked Major Projects as part to its budgetary framework in Docket 23-34-EL which is provided in Exhibit 2 of the FY 2025 ISR Plan filing. The Company generally proposes that multi-year substation projects valued at $10.0 million will be tracked separately, and that the Company will consider Division input to expand tracking for complex substation projects greater than $5.0 million. Based on this criteria, the Company proposes that Dyer Street, Admiral St., Kingston, and Phillipsdale be considered Major Projects. The Company no longer identifies the collective projects within the Providence Long Term Area Study as major although they comprise significant spend. The FY 2024 Forecast, proposed FY 2025 budget, and proposed 5-year ISR Plan budget for each Area Study related project are below:

ISR Plan Capital Budget Asset Condition Area Study Related Projects ($000)	FY 2024 Forecast	FY 2025 Budget	+ 4 years Budget	Total 5-Year Budget
Major				
Dyer Street Substation	2,080	15	-	15
Admiral St 12kV Substation		5,513	2,500	8,013
Kingston Equipment Replacement	-	400	16,405	16,805
Phillipsdale Substation	-	100	14,740	14,840
Other				
BSVS Area Study	-	781	7,449	8,230
CRIE Area Study	-	200	6,268	6,468
CRIW Area Study	-	1,883	20,634	22,517
East Bay Area Study	-	100	1,835	1,935
Newport Area Study	-	766	15,194	15,960
NWRI Area Study	-	500	7,414	7,914
Providence Area Study	-	492	28,715	29,207
Area Study Projects - SCW	-	-	3,326	3,326
Tiverton Substation	-	75	2,357	2,432
Providence Area LT Supply & Distrib Study*	23,503	20,382	17,644	38,026
TOTAL	**25,583**	**31,207**	**144,481**	**175,688**

**RIE removed from Major Projects*

I have reviewed the justification for each project either through previous ISR Plan evaluations or Area Studies and continue to support inclusion in the Company's capital investment plan. Discussions focused on the criticality of these projects and establishing a reasonable and achievable timeline to replace deteriorated assets. Adjustments to the initially proposed FY 2025 budget were put forth by the Company to reflect supply chain delays affecting Providence work and a decrease in Blackstone Valley South to account for work completed in FY 2024. The Division accepted the adjustments.

Dyer Street is an indoor station initially constructed in 1924 and identified for replacement in the Providence Long term Study. After project development was paused in FY 2021 due to complexities involving the historical building rehabilitation, the project was rescoped to rebuild the station at South Street. RIE reports that all significant work will be complete in FY 2024 which is forecasted at $2 million overbudget due to delays from FY 2023. Remaining work in FY 2025 is AC building removal budgeted at $15,000. This amount was not adjusted.

Admiral St. is an indoor substation originally constructed in 1930 and is part of an older area supply and distribution network serving the Providence area. The station has deteriorated and obsolete infrastructure. The substation project evolves from the Providence Area Study[9] where the Company recommends expanding the 12.47kV system and retiring 11.5kV and 4.16 kV indoor stations, with Admiral St. being second highest priority behind Dyer St. The ISR Plan includes a new 115kV/12.47 substation with two transformers and feeder positions and removal of the existing Admiral station. There is considerable work related to substation retirements, distribution voltage conversions and underground work as part of the Providence Long Term Study identified as other asset condition projects, but RIE has designated only Admiral Substation as a separately tracked Major Project. Admiral St. is not a specific project in the Long-Range Plan but based on the ISR Plan filing,[10] the project is in construction and scheduled for completion in FY 2026. Previous spend for Admiral Street was $2.7 million against a $12.8 million total project budget which should have a +/-10% tolerance based on RIE's major project lifecycle status. The Division continues to support the Providence area

[9] Preceded by the Providence Area Long Term Supply and Distribution Study completed in 2014 which established long term strategic recommendations and advanced Southeast and Dyer St. substation rebuilds. The Providence Area Study, completed in 2017, is considered the implementation plan for recommendations.
[10] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 3.

projects and no adjustments were recommended to the proposed Admiral St. budget of $5.5 million in FY 2025.

Kingston is a 23/4.16kV substation in the Newport area and is one of eight stations with identified asset and safety issues. As part of the Area Study completed in 2022, the Company recommended replacing a substantial amount of equipment at the site including two transformers, updating circuit breakers and configuration, and adding eight circuit positions to provide operational flexibility. The Long-Range Plan indicates an implementation timeline from FY 2025 to FY 2029 with a $16.8 million total budget that is consistent with the proposed ISR Plan. The Company identifies the current phase as "Proposal" in Attachment 3 which is not a defined stage in the Company's major project lifecycle. Presumably, the project is in the engineering phase and the cost estimate will be further refined to a +/-10% tolerance which may increase future budgets or extend the project past FY 2029. There were no adjustments to the FY 2025 budget of $400,000.

Phillipsdale is a 23/12.47kV substation serving load in an electrically islanded area comprised of East Providence, Barrington, Warren and Bristol. The substation consists of non-standard equipment and construction with a number of reliability issues. The voltage from the station only phases with select feeders in the area creating a pocket of load that is out of phase with the rest of the system. The 23kV station is fed from the adjacent Phillipsdale 115/23kV substation that has asset condition issues including aged transformers and unreliable or obsolete equipment. The Company's recommended solution to resolve all issues (East Bay Study completed in 2015) is a new 115/12.47kV station at Phillipsdale with a single 40MVA transformer and four new feeders which would eliminate the need for the out of phase 23kV substation. The ultimate buildout would be two transformers, a tie breaker and eight feeders. The new station and feeders would also facilitate other area station retirements, increase operational flexibility and reduce load at the existing Phillipsdale 115kV station that will continue to serve two remaining 23kV customers until they can be converted to 12.47kV in the future. The Phillipsdale work is a subset of several East Bay solutions that are separate from this major project. The Long-Range Plan indicates an implementation timeline from FY 2025 to FY 2029 with a $16.8 million total budget that is inconsistent with the proposed ISR Plan budget of $14.8 million over the same period. The Company indicates the current phase as "Proposal" which is not a defined stage in the Company's major project lifecycle. If the project is in early stages (engineering), the cost estimate is subject to further refinement to achieve to a +/-10% tolerance. However, the current ISR Plan proposed budget of $14.8 million is well over the initial $6 million capital estimate which raises questions on actual scope, budget and status of the project. Although the Division supports advancing Phillipsdale in the FY 2025 ISR Plan with a budget of $100,000, the Company should improve their reporting mechanisms so projects and budgets can be reconciled back to an Area Study and aligned with the Long-Range Plan to understand the status, scope, proposed implementation time and budget.

Other Area Study projects, not considered Major Projects, are grouped by the associated regional study. Except for Providence Area Long Term, no projects incurred spend in FY 2024 which indicates that RIE is simultaneously progressing preliminary engineering for eight Area Study projects with projected spend of $4.8 million in FY 2025 and nearly $100 million over a 5-year period. The cost estimates at this phase would be considered +50%/-25% based on RIE's aim for complex projects to come out of an Area Study with this tolerance. This step will be followed by more detailed engineering to finalize design, complete bid drawings, procure material, receive permits, and issue contractor RFPs. Once construction contracts are awarded, the cost estimate is considered +/-10% accuracy.

The most significant projects in the engineering phase are Providence related with a 5-year proposed spend of $29.2 million. These projects are in addition to ongoing complex distribution conversion work and substation retirements under the Providence Long Term study (previously designated as Major Projects) which are budgeted at $20.4 million in FY 2025 and $38 million over five years. I have addressed the criticality of asset replacement in the Providence urban region which consists of older, underground distribution facilities and indoor substations dating back to when the system was originally installed in the 1920's. I had prepared an asset condition report for the Division as far back as early 2000. This is when it was very apparent that the Providence area and its extremely old distribution plant would need major upgrades over decades. The existing Area Study and Providence plans with a multi-year implementation is an outgrowth of this need which should not be deferred. The Company's LRP indicates Providence related work continuing through FY 2033, and at completion, system improvements will have addressed asset conditions at five indoor substations and on over 25 miles of underground cable.

While Providence work advances other significant Area Study projects are expected to develop from studies in the engineering phase. The largest are Central Rhode Island West with a 5-year budget of $22.5 million and Newport at $16 million. My objective has always been to monitor projects emanating from Area Studies to ensure that scopes and costs are reasonable and aligned with the outcome of the study. However, absent additional engineering there is less clarity on the specific projects involved or what might be considered Major Projects. There is also a concern that in some cases, solutions were developed in studies completed over nine years ago and although asset conditions are likely to still exist, surrounding system changes or technology advancements may compel scope changes. At this juncture the Division cannot make a final determination on advancing every "Other Area Study" projects included in the

ISR Plan but support is given for proposed FY 2025 engineering and design spend. As a project lifecycle evolves the Division anticipates that RIE will produce information to aid in aligning the final scope against the original Area Study, ensuring that the ISR Plan prioritization is justified, understanding drivers for cost revisions, and determining Major Project eligibility. This review should also revisit Providence Area Long Term projects that RIE removed as Major Projects. I expect that the assessments can occur throughout the year and in particular during quarterly ISR Plan reviews when the Company provides updates on project execution. Meeting outcomes will inform future ISR Plans with the goal to better understand progressing projects and identify Major Projects in advance of annual filings.[11] Furthermore, the Division and RIE must work through the preliminary Long-Range Plan to assure optimum coordination of projects and assurance that these asset condition projects are appropriately modulated to mitigate rate impact without adversely impacting reliability and safety. There is most certainly a great deal of future effort required between the Division and RIE to reach a consensus. As the projects advance through construction, I will also examine actual expenditures against budgeted amounts to determine the Company's success at managing multi-year projects to budgets while maintaining reasonable discretionary investment levels.

In summary, the Asset Condition category includes Area Study related projects that are either considered major and separately tracked or presented as a regional group of projects. For the FY 2025 ISR Plan, the Company appropriately designated Dyer St., Admiral St., Kingston and Phillipsdale as major projects which are in various phases. These projects are budgeted at $6 million with increased spend expected in future years as scopes are refined and construction advances. There are multiple additional studies with projects in the engineering phase that are

[11] The Division endeavors to identify separately tracked projects in advance of annual ISR Plan filings. However, a project may be designated as a Major Project or identified for separate tracking at any time of the year which is primarily a matter of RIE adjusting its reporting format.

progressing simultaneously. The FY 2025 budget to advance engineering is $4.3 million. Forecasted future spend will likely rise as design is complete and cost estimates are finalized. Providence area related projects dominate the FY 2025 budget at $20.8 million. The 5-year forecasted spend in the Providence area is over $67 million to address old and deteriorated assets, some dating back to the 1920s. The preponderance of spend is for complex distribution replacement and voltage conversion work driven by substation retirements. The Division continues to support the critical work in Providence. In order to monitor projects emanating from Area Studies, some of which were completed over nine years ago, the Division anticipates that RIE will produce information to aid in aligning the final scope with the original Area Study solution, ensuring that the ISR Plan prioritization is justified, understanding drivers for cost revisions, and determining Major Project eligibility. While the Division is supportive of prioritizing asset condition projects, the Company's overall capital investments are reaching unchartered territory. Cost risk management continues to be increasingly important due to inflationary pressures and the Company's project execution will be evaluated as these complex projects move through construction. Over the course of this ISR review, the Company's proposal of $31.2 million for Area Study related projects was accepted.

2. <u>Asset Condition – Other Programs</u>

The Asset Replacement category contains new or recurring programs aimed to replace equipment based on age, condition, criticality rankings, or other risk factors. The majority have been included and reviewed in prior ISR Plan filings such as substation batteries, substation breakers and reclosers, underground and Underground Residential Distribution ("URD"), and the Blanket Projects category established for asset condition field work. A new Substation Spares program was introduced which is an initiative to purchase additional spare substation power transformers as replacements in event of a failure. For FY 2025, the Company initially proposed a $20.3 million budget for programs to replace infrastructure. This compares to a FY 2024 budget and forecast of $20.3 million and $21.6 million respectively. Based on discussions with the Division, RIE decreased the budget by $2 million for a final proposed budget of $18.3 million for all programs.

ISR Plan Capital Budget Asset Condition Programs ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
Underground Cable Replacement	5,500	297	5,797	5,500	-	5,500
URD Cable Replacement	6,276	(864)	5,412	7,008	(2,008)	5,000
Blanket Projects	5,220	0	5,220	6,177	-	6,177
Substation Spares	437	790	1,227	736	-	736
Batteries / Chargers	230	(0)	230	195	-	195
Recloser Replacements	1,300	(93)	1,207	-	-	-
UG Improvements and Other	1,383	1,073	2,456	700	-	700
Total Programs	**20,346**	**1,202**	**21,548**	**20,316**	**(2,008)**	**18,308**

My evaluation of proposed spend for various programs first determines if work is aligned with an Area Study. This ensures that equipment replacement considers broader area needs, is sufficiently sized for load growth, and includes compatible technology for future grid modernization. Next, I evaluate projects in terms of level of spend and criticality. Unless there is an emerging need, the Company relies on historical work completed and associated spend as a metric for current budgets. As each year progresses, the Company methodically replaces the most critical assets, which is practical given that system reliability has not been sacrificed under this strategy. To evaluate the need for projects within this category, the Company customarily provides studies, condition assessments, criticality rankings, or other planning documents containing updated support information.

For FY 2025, discussions focused on the Company's rationale to increase spend for the URD Program to $7 million from a $6.3 million budget in FY 2024 and actual forecasted spend of $5.4 million. This program along with underground cable replacement have been subject to numerous adjustments in the past when the Company proposed budgets that were inconsistent with historical spend and otherwise unjustified. The Division suggested a reduction in the URD program and the Company proposed a $2 million adjustment for an agreed upon final budget of $5 million. I remain supportive of both programs to replace underground cable and encourage the Company to continue efforts to regulate discretionary spending by deferring projects to accommodate more emergent work while meeting an overall budget target. This creates a lag time in project completion but this is a prudent strategy when more critical projects within the ISR Plan require capital investment such as substations with asset condition issues. Additionally, tempered spend for underground cable replacement has not resulted in safety or reliability degradation, therefore the Company's monitoring of safety and reliability concerns related to these projects has worked adequately. The Division also accepted the Company's proposal of $6.2 million for Blanket Project spend and $900,000 for smaller asset replacement needs including underground improvements and substation battery replacements, all of which are recurring programs.

Lastly, the Company also established a Substation Spares program (budgeted under Substation Breakers & Reclosers in Attachment 3) described as procurement of spare transformers, breakers, and regulators with ISR Plan funding of $736,000 in FY 2025 and $5.3 million over the next two years. The Company references the Spare Transformers program documentation in the Long-Range Plan[12] as justification for substation power transformer purchases within this spending category. The Company indicates that it currently has seven spare power transformers but calculates that 30 spares of varying operating voltages are needed

[12] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 5, pp. 50-52.

to maintain system reliability. RIE proposes the purchase of 23 power transformers through FY 2031 at a cost of over $40 million[13]. The FY 2025 spend of $736,000 is for a transformer downpayment with plans to initially purchase three spares, along with bushing and regulator purchases. The Division has no objections with advancing the FY 2025 budget but a closer examination of program justification for spare transformers raises multiple concerns with RIE's potential future purchases beyond what is indicated in the current ISR Plan.

It is standard utility practice for electric utilities to maintain a fleet of spare power transformers in the event of a failure. Availability of a spare reduces restoration time to original system configuration. If a system spare is not available, a mobile substation may be relied upon or, for many utilities, replacement transformers may be available from another utility through a shared or leasing arrangement. Until a replacement transformer is installed, however, a utility like RIE can operate in an alternate configuration to maintain continuity of service except in limited locations and only at the peak times of year (contingencies). It is not ideal to operate in an alternate configuration for a long period of time, but it is an acceptable option under critical circumstances. There is no standard number of spare transformers to have on a system which is a decision guided by several factors such as risk of failure, outage exposure, the availability of mobiles, operational flexibility including N-1 capability, and access to spares through other agreements. Furthermore, power transformers rarely fail and a robust monitoring program including power factor testing, dissolved gas analysis and other technology provide an excellent view of the unit's condition and risk of failure long before an occurrence. A portfolio of options produces the most cost-effective strategy to manage transformer failures.

[13] Future spend is indicated in Attachment 5 but not included in the ISR Plan or Long-Range Plan.

Evaluation of RIE's spare transformer program raises many questions regarding the optimal level of spare inventory, including why 23 additional spare transformers are required now, and how the Company is leveraging shared agreements to manage risks. In essence, what has changed in recent history to compel RIE's spare transformer strategy and proposed purchases? Previously under National Grid ownership, the Company had spare transformers and mobile substations on its system in addition to the ability to share spares and mobiles across four New England operating companies.[14] That allowed the Company to leverage a significant inventory of transformers with similar operating voltages but at a fraction of the price of outright ownership. The synergies enjoyed under National Grid are not available under PPL ownership due to "voltage differences between the operating companies which makes it difficult to adopt a common spare transformer strategy."[15]

Under PPL ownership, the Company indicates that it currently has seven spare distribution transformers but proposes that 30 distribution power transformers are needed to maintain system reliability. RIE's assumption is that increased transformer lead times, approaching 3-years that were previously closer to 12 to 14 months pre-pandemic, are driving the need to increase inventory. I believe that RIE's assumption that a 3-year lead time will persist is unnecessarily increasing the number of proposed spare transformer purchases. I am not satisfied with the Company's assumptions and calculations, and certainly do not agree with their findings which I address in more detail below. I also believe that some purchases are driven by the change in Company ownership. The Company states that "In total, 15 of the proposed 23 new spare transformers would have been required even if the National Grid fleet of spare transformers were still available to RIE" and that seven of the 15 are needed because

[14] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 2-1 and DIV 2-3.
[15] Docket 23-48-EL, Proposed FY 2025 ISR Plan DIV 2-3.

the "in-service transformers that these seven spare transformers provide coverage for did not have an adequate spare transformer at National Grid."[16] RIE does not clarify that mobile substations were available to the Company under National Grid ownership which resolved the contingencies,[17] thereby making spare transformer purchases unnecessary. My interpretation is that the Company is now purchasing spare transformers that were previously available under a shared agreement or unnecessary due to the mobile substation inventory available through National Grid, and these ended with PPL ownership. For the remaining eight spares, the Company asserts that RIE ratepayers did not pay for the spares initially but would have to pay for them if RI needed to use one of the transformers, so the purchases are not duplicative costs.[18] This is certainly misguided and misses the point that the benefit of shared inventory is that ratepayers do not have to pay for the spare unless needed, thus avoiding an expenditure of tens of millions of dollars. My overall opinion after reviewing multiple responses to the Division's data requests is that the proposed spare inventory level and purchase of 23 additional transformers remains unjustified and that a portion of the spares were likely previously available to RIE and would be considered a redundant purchase.

The Company derived the targeted number spares by using a Poisson probability distribution (Reliability Criterion Model) to assess the probabilities of transformer failure, with its chosen set of inputs. RIE's objective is to meet a 0.9950 system reliability which "indicates that the company will have a spare available 99.5% of the time."[19] Overall, the use of the Poisson distribution is an appropriate tool for assessing the probability of equipment failures such as transformers as long as the inputs are reasonable and unbiased. The inputs needed to

[16] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 2-3.
[17] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 7-4.
[18] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 2-3.
[19] FY 2025 ISR Plan, Section 2, Attachment 5, pp. 50-51. RIE states that the 99.5% benchmark is cited by IEEE to be a common benchmark amongst a wide number of utilities.

use the Poisson distribution are: 1) expected number of transformer failures per interval, usually derived from averages based on historical observations, 2) the number of occurrences for which you are assessing the probability, 3) the interval over which the probability is assessed, and 4) the number of transformers in the relevant inventory. My general observations of key assumptions or inputs are:

- A 99.5% benchmark is extremely high and is subjective. A small reduction in this benchmark could provide reasonable results with minimal change in risk, which is an area to be explored.
- RIE uses a failure rate of 0.5% which estimates that approximately 3-4 transformers will fail over the next five years. This number could trend lower particularly since the Company has and continues to make extraordinary levels of investments to replace aged assets that are prone to failure with newer and hence more reliable assets.
- The interval used by RIE is 3-years reflecting current transformer lead times and this input has the most significant effect on model outcomes. The Company assumes that near term supply chain aberrations will persist which is unproven. Supply chain constraints are improving to a large extent, due to the elimination of supply bottlenecks during the Covid pandemic shutdown. RIE has stated in discussions with the Division that transformer production slots are opening up, which would lead to decreased delivery times. RIE defends the 3-year lead time by alluding to nationwide electrification that will create more demand and drive longer lead times for station equipment in the future.[20] RIE mentions several factors that impact the demand side of the equation that would limit existing manufacturers from meeting increased demands for transformers. They do not acknowledge the supply side of the markets to assess whether with increased demand and the lure of increased profits, existing manufacturers may ramp up production and new suppliers may well enter the market to capture the increased economic rents arising from rising demand. At minimum, spare transformer levels should be evaluated using shorter lead-times. Furthermore, utilities with transformer manufacturing slots or units in production often allow the transfer of those slots or units to other utilities in need thus dramatically reducing the actual lead time.
- The RIE analysis ignores a very critical component. RIE and all electric utilities have a robust power transformer testing program and protocols which provide excellent data for transformer failure prediction therefore, power transformer failures are actually rare because the high probability of failure is known and the transformer is replaced before failure.

[20] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 2-23

- Lastly, RIE seems to ignore the benefits of mobiles and N-1 capabilities that also mitigate risks.

To illustrate the effect of slight but reasonable adjustments, alternate scenarios have been prepared using Poisson estimates with various inputs. While a lower benchmark and failure rate drive some reductions in additional spares, the most dramatic effect is from lower lead times. This is by far the most uncertain and unsubstantiated input. A re-calculation is provided to make the case that RIE could need as few as 12 additional spare transformers assuming adjusted inputs including 1.5-year lead times as opposed to 3-year lead times, as shown below:

Poisson Estimates using Alternate Scenarios	Benchmark	Failure Rate	Lead time (years)	Transformer Failures	Additional Spares
RIE Base Case	99.5% (1 in 200)	0.50%	3	32	23
Lower Benchmark	99.0% (1 in 100)	0.50%	3	30	21
+Lower failure rate	99.0% (1 in 100)	0.40%	3	29	20
+Lower lead time	99.0% (1 in 100)	0.40%	1.5	21	**12**
+Lower lead time	99.0% (1 in 100)	0.40%	1	13	4

I am not suggesting that the Poisson model be relied upon as the single supporting mechanism to determine an appropriate level of spares, but when utilized, the assumptions should be realistic and substantiated. Furthermore, this model fails to account for the transformer testing program which determines failure risk level and thus replacement in advance of failure. A long term spare transformer inventory level should not be based on short term market anomalies. The model outcome can be used as one data point but the Company's ultimate strategy should consider a portfolio of options to manage risk and minimize the need to purchase excess strategic spares. In the short term, the Company intends to purchase three spares and has a transformer agreement with National Grid to access spares in Massachusetts. I believe this is the optimal approach in the foreseeable future as RIE determines what is actually needed on the system versus what is desired. Unfortunately, RIE is minimally considering short term solutions and chooses instead to rely on "PPL procurement that does not predict significant reductions in the lead times of power transformers in the short term"[21]. The Company is invoking an unnecessary "zero-risk" tolerance that is driving potentially significant spend. While the Company's proposed expenditures of $736,000 in the Substation Breakers & Reclosers Substation are supported for FY 2025, the Division will continue its evaluation and anticipates detailed discussions with RIE to get a more accurate picture of exposure and risk which will inform support for future proposed spend. The Commission may want to evaluate whether some of the spare transformer synergy lost due to the acquisition should be a transition cost absorbed by the Company and not imposed on the rate payer.

In total, agreement was reached on a FY 2025 proposed budget of $18.3 million for Asset Condition programs designed to replace deteriorated infrastructure and a newly proposed program for spare power transformer additions. Although the Division concurred with near term spend for limited spare transformer purchases, there are multiple concerns with the number of planned additions over the program duration. The Division will have further discussions with RIE to explore a more reasonable long term strategy given the true exposure and risk. This is currently one of the areas in the Long-Range Plan in which the Division contends substantial analysis and adjustments are necessary. The Division is hopeful that it and the Company can progress through our collaborative process on the Long-Range Plan and reach agreement before the FY 2026 ISR Plan is prepared and submitted.

3. Inspection & Maintenance Program & Other O&M

The I&M Program is designed to provide the Company with comprehensive system-wide information on the condition of overhead and underground components. The program includes

[21] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 2-23.

a capital component for strategic replacement of deteriorated assets identified during inspections, operational expenses related to asset replacement, and for costs to inspect the system. The Company also incurs O&M expenses related to a Volt-VAR Optimization and Conservation Voltage Reduction ("VVO/CVR") expansion program and continuation of mobile elevated voltage testing. Since the FY 2025 ISR Plan filing included the Company's proposed Long-Range Plan, RIE excluded development costs from O&M expenditures. The initial proposed FY 2025 ISR Plan included $3 million for I&M capital costs and $1.2 million for all other O&M expenses. This compares to a total FY 2024 ISR budget of $3 million for I&M program capital and $1.2 million for all other O&M. The Company projects FY 2024 spend at levels near the budget. Discussions with the Company resulted in reductions to the capital portion resulting in a final proposed program budget of $1.5 million for the I&M Program and $1.2 million for O&M spend in FY 2025.

ISR Plan O&M Budget I&M and Other Programs ($000)	FY 2024			FY 2025 RIE Proposed 12-21-23
	Budget	Variance Over/(Under)	Forecast (as of Q2)	
I&M Program Capital (included in Asset Condition budget)	3,000	-	3,000	1,530
I&M Program Spend (O&M)	400	-	400	500
I&M Opex Related to Capex	338	112	450	200
System Planning & Protection Study	25	(25)	-	-
Removal Costs*		-		153
VVO/CVR Program	400	-	400	365
Total O&M	**1,163**	**87**	**1,250**	**1,218**

**Removal Costs not identified in RIE's FY 2024 Second Supplemental Budget (Docket 22-53-EL)*

The I&M Program funds a five-year inspection cycle with a goal to replace assets over ten years. The Company is not meeting the ten-year replacement goal due to the backlog of identified work but has streamlined the program to prioritize critical repairs when identified and working the backlog within an annual budget. I have evaluated the I&M program in detail and maintain that it is mature and successful implementation has produced excellent reliability results at the current pace of asset replacement. The Company is managing minor asset replacements under this I&M repair program, Damage/Failure, and the discretionary Asset Replacement program. There are new and enhanced programs such as CEMI-4 and ERR being introduced as part of the PPL transition which also incorporate targeted system improvements and asset replacements for reliability. The suite of programs has similar objectives which is small scale, proactive infrastructure replacement to maintain safety and reliability. Although the Division supports both new and recurring reliability initiatives in FY 2025, overall budgets must take into account that RIE system reliability is excellent. There is limited rationale for significant funding in any independent program and ultimately RIE should consider revising or integrating similar programs into a single program in the future as each program reaches maturity.

For the O&M component of the I&M program, I continue to recommend a ten-year inspection cycle since the same system deficiencies are likely being repeatedly documented in each five year cycle. The Company previously petitioned to maintain the current five-year cycle since it is aligned with contact voltage testing, consistent with its Massachusetts and New York requirements, and an effective method to proactively address deteriorated equipment before failure. The Company should reevaluate its position since it is no longer affiliated with Massachusetts or New York. This program and cycle should be re-evaluated during FY2025 and appropriate modifications proposed to better align with the RIE operations and a single state view.

An additional component of I&M is the Company's contact voltage detection, repair and reporting program required under the Rhode Island Contact Voltage statute § 39-2-25(b)(6). Under the program, a vendor uses a mobile detection system to survey and test a minimum of

20% of designated areas. Events of elevated voltages and other findings are reported annually under PUC Docket 4237. The Company filed its Revised 2023 Annual Contact Voltage Report on January 31, 2024 for testing completed in December 2022. This was a year behind schedule as a result of the transition between National Grid and RIE (PPL). The Division addresses the Contact Voltage Report annually and will file its comments on this year's report on March 1, 2024. The Division's report will address many changing issues including the identification of significantly more mobile events. This is predominantly a result of the vendor selection and technology being implemented to comply with IEEE standard P1695. The leading edge technology and consistency of vendor staff performing the assessment have resulted in more events being identified and a superior program. RIE and Division have agreed that transiting back to the implementation schedule prior to 2020 would be most appropriate. The details of the Division's assessment and recommendations will be contained in its March 1, 2024 filing in Docket 4237. I have found the Company's approach to the Contact Voltage Program acceptable, including their efforts to maintain quality vendors, leading edge technology and reliable testing methodologies. The gap in reporting will be managed now that the transition from National Grid to RIE for this program is complete. The Division supports continued funding of the program in the FY 2025 ISR Plan which appropriately balances statutory obligations with safety requirements. I will evaluate the Company's vendor and monitor program progress as part of the Division's annual review of the Contact Voltage Program under Docket 4237.

Lastly, the proposed FY 2025 budget includes continued funding for O&M to maintain existing VVO/CVR systems. The Company paused new VVO/CVR investments and now plans to reinstate the program described as Smart Capacitors and Regulators which may include modifications to existing installations. I discussed the program and Division support for advancing VVO/CVR investments in Section F.2. The Division expects that annual O&M expenditures related to future installations will not be included in the ISR Plan. Further, consideration should be given to removing the ongoing O&M for previous installations from the ISR Plan. This should align with the FY 2026 ISR Plan year when future Smart Capacity and Regulator installations commence.

In summary, concurrence was reached on I&M program and all O&M budget line items, resulting in a FY 2025 proposed capital budget of $1.5 million for the I&M Program and $1.2 million for O&M. This brings the total FY 2025 ISR proposed capital budget for Asset Condition to $51 million, comprised of $31.2 million for Area Study related projects, $18.3 million for other Programs projects, and $1.5 million for the I&M program.

E. Non-Infrastructure Category

This category, initially proposed at $1.7 million in FY 2025, is for telecommunications and other capital expenditures needed for operation, which are neither related to condition nor system capacity. A major component is a project to convert Verizon copper to fiber at approximately 25 distribution substations each year. Verizon dictates the schedule and only 5-6 stations are being completed annually since FY 2021. The lower amount of work combined with RIE's plan to transition to a cellular based EMS system (aligning with PA) will decrease future costs[22]. To account for these changes, RIE proposed a $820,000 budget reduction. The Division concurred for a final FY 2025 proposed budget of $892,000 in the Non-Infrastructure category.

[22] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 6-5.

F. System Capacity and Performance Category

The System Capacity and Performance category is comprised of projects and programs for load relief, reliability, and system performance. Similar to Asset Condition, the Company identifies proposed projects as either Major Projects or Other. Major Projects are significant multi-year investments generally associated with substation and regional work identified in Area Studies. The Other category captures less complex Area Study projects and new and recurring programs with varying objectives such as replacing equipment with more advanced technology, system upgrades for targeted reliability improvements, and proactive investments to enable DER and system optimization. Except for projects needed to resolve imminent overloads or system performance issues, I consider investments in this category to be more subjective and flexible. A significant portion of this budget is dedicated to Area Study substation and system capacity expansion projects. There are more variables involved in determining the need and implementation horizon of projects in this category than Asset Condition. For instance, system capacity projects are driven by actual loading which may, and usually does, vary from original forecasts. Since the distribution system is incurring little to no load growth these projects may often be deferred unless there is an imminent need. Similarly, programs for reliability or system performance may offer incremental improvements over an otherwise acceptably performing system. The benefits come with costs that are often significant thus making a case to modulate execution when other more critical projects should be prioritized. The Division takes into consideration that as a whole, the Company is meeting and exceeding its regulatory reliability thresholds. Despite RIE's desire to achieve "top tier" performance relative to other utilities, proposed investments may bring limited tangible benefits while increasing ratepayer costs. Increased discretionary spend to improve reliability must be justified.

For FY 2025, The Company initially proposed a $46.3 million budget that was adjusted to $38.3 million which is twenty-seven percent (27%) of the total ISR Plan budget. The FY 2024 budget and forecast for this same category are $20.2 million and $19.1 million respectively. I will address projects related to Area Studies, Programs, and separately discuss programs related to recloser additions.

ISR Plan Capital Budget System Capacity & Performance ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
Aquidneck Island	1,038	2,080	1,114	-	-	-
New Lafayette Substation	750	(811)	795	910	-	910
Warren Substation*	1,969	205	2,156	2,800	(1,000)	1,800
Nasonville Substation	1,912	297	1,731	3,674	-	3,674
East Providence Substation*	1,330	(864)	1,275	6,285	-	6,285
Weaver Hill Road Substation	1,507	0	279	1,105	-	1,105
Tiverton D-Line	109	17	126	328	-	328
Other Area Study Projects (7 total)	4,068	-	692	5,609	-	5,609
Subtotal Area Study Projects	*12,683*	*924*	*8,169*	*20,711*	*(1,000)*	*19,711*
CEMI, ERR, DARP (Reclosers)**	1,230	(93)	1,230	17,186	(6,610)	10,576
Programs	6,284	1,863	9,724	8,370	(576)	8,016
Total System Capcity & Performance	**20,197**	**2,694**	**19,122**	**46,267**	**(8,186)**	**38,303**

** RIE designated Major Project in initial filing*

*** A small portion of CEMI and ERR include other system improvements*

1. <u>System Capacity & Performance – Area Study Projects</u>

System Capacity Area Study projects are a mixture of legacy projects, or those projects that have been independently studied and historically considered for inclusion in the ISR Plan, in addition to multiple proposed projects in various phases. For legacy projects, Aquidneck is scheduled for completion in FY 2024 and no spend was proposed in FY 2025. This project included a new substation and related line work to provide load relief to the City of Newport.

The new Jepson substation was related to the project, serving Middletown. These initiatives were sanctioned at over $80 million which warrants a review in FY 2025 once the project is completed so that budgets can be reconciled to actual spend. The Company has designated Warren Substation and East Providence Substation as Major Projects for separate tracking, consistent with their proposed budgetary framework. The Company is also advancing additional independent projects and commencing engineering for seven Area Studies. The FY 2024 Forecast, proposed FY 2025 budget, and proposed 5-year ISR Plan budget for each Area Study related project are below:

ISR Plan Capital Budget System Capacity Area Study Related Projects ($000)	FY 2024 Forecast	FY 2025 Budget	+ 4 years Budget	Total 5-Year Budget
Major				
East Providence Substation	1,275	6,285	10,012	16,297
Warren Substation	2,156	1,800	3,801	5,601
Other				
Aquidneck Island	1,114	-	-	-
New Lafayette Substation	795	910	6,037	6,947
Nasonville Substation	1,731	3,674	3,717	7,391
Weaver Hill Road Substation	279	1,105	10,254	11,359
Tiverton D-Line	126	328	2,080	2,408
BSVS Area Study	-	680	1,649	2,329
CRIW Area Study	-	1,441	2,925	4,366
East Bay Area Study	-	84	756	840
Newport Area Study	-	793	1,437	2,230
NWRI Area Study	692	-	-	-
SCE Area Study	-	1,684	6,737	8,421
SCW Area Study	-	927	16,763	17,690
TOTAL	**8,169**	**19,711**	**66,168**	**85,880**

I have reviewed the initial justification for each project either through previous ISR Plan evaluations or Area Studies and continue to support inclusion in the Company's capital investment plan. However, the precise implementation timeline and prioritization are subject to further evaluation as refined scopes and budgets are developed for individual projects. As I discussed previously, system capacity project needs are driven by actual loads which may vary from initial forecasts. If loads do not develop, a project can be deferred, or alternately, a project may need to be accelerated. There is a balance in achieving the optimal timing since improvements should be in place prior to overloaded conditions transpiring. The Company is well positioned to optimize project implementation since load growth is minimal or even negative in regions due to DER, which should provide adequate time for advance analysis. Additionally, the SRP demand response efforts could further reduce peak demand on the system. Discussions with the Company for the FY 2025 Plan focused on major projects undergoing engineering and procurement along with impacts of extended equipment lead times. Adjustments to the initially proposed FY 2025 budget were put forth by the Company due to supply chain delays shifting Warren Substation work into FY 2026 which the Division accepted.

The East Providence Major Project consists of a new 115/12.47 kV substation located on a gas company owned parcel next to a 115kV transmission right of way. The substation will resolve contingency load at risk on several area feeders and reduce loading and dependence on the 23 kV sub-transmission system which avoids reconductoring nearly 7.5 miles of line. The planned configuration is a single 40MVA transformer serving four feeder positions[23] with ultimate build out of two transformers, a tie breaker and eight feeders. East Providence is a part of a comprehensive area solution that also includes Warren Substation expansion, distribution work and asset condition projects such as Phillipsdale. The ISR Plan indicates project spend of $17.5 million from FY 2024 through FY 2027 which has not been confirmed at a +/-10% tolerance. Project costs will likely be higher than initial estimates since the

[23] The FY 2025 ISR Plan, Section 2, page 39, indicates six feeder positions. The Company should reconcile scope differences prior to construction.

associated East Bay study was completed in 2015 and estimates are outdated. The proposed FY 2025 budget of $6.3 million was not adjusted and based on the high inflation rate in the electric utility industry the cost will most certainly be much higher.

Warren Substation, also a Major Project emanating from the East Bay Study, is designed to expand the existing station to provide additional capacity to Warren and Barrington. Completion of the station will also facilitate retirement of two area substations and sub-transmission with safety and asset condition issues. The Company is coordinating work with RIDOT's Warren Bridge relocation. The ISR Plan indicates spend of nearly $8 million from FY 2024 to FY 2027 but the total cost estimate and tolerance is unknown. Similar to East Providence, costs could rise since initial estimates are outdated. Due to equipment delays, the Company proposed a $1 million reduction to the initial FY 2025 budget of $2.8 million and the Division accepted a final proposed budget of $1.8 million. The Division anticipates that RIE will provide more detailed information for both East Bay and Warren substations as they advance to construction and are separately tracked.

The remaining individual Area Study projects are in various phases. New Lafayette Substation was identified in the South County East Area Study and was previously presented with an estimated total project cost of $13.3 million. The new substation addresses regional reliability and condition issues by expanding the 12.47 kV distribution system. The Company will also retire the existing Lafayette substation and deteriorated 34.5 kV sub-transmission, some of which is constructed in wetlands. The Company previously accelerated aspects of site work to create efficiencies with the Wickford Junction generation project located on the same parcel. However, the project has experienced deferrals since FY 2023 due to transmission outage coordination issues but is currently projected for completion in FY 2028. The FY 2025 proposed budget is $910,000 which was unadjusted. Lafayette should also be re-examined for potential tracking as a Major Project.

The Nasonville Substation project includes a new 115kV overhead supply line and additional second transformer to alleviate an existing contingency load-at-risk due to the loss of the existing station transformer. The project is the recommended solution in the recently completed Northwest RI Area Study. The station experienced a severe bus fault and failed switchgear in 2022. The failed equipment replacement and restoration work are captured under Asset Condition. For reliability related work, the Company is proceeding with the second transformer as the restoration work is completed. The expanded portion of the substation will be constructed in FY 2024 and fed by the existing transformer. Work in FY 2025 will prepare the site for the second transformer with delivery and complete installation by FY 2027. This is only a portion of the total solution and the Company's assessment for the need and feasibility of a second 115kV transmission supply should be evaluated further. For the immediate planned work, the Division does not propose modifications to the Company's project implementation plans or budgets and has concurred with the FY 2025 budget of $3.7 million as proposed.

Weaver Hill Road Substation and Tiverton distribution work are projects that the Company claims should be accelerated under Section 5.4 of Tariff 2258 due to distributed energy interconnections and may be subject to cost sharing. There are separate dockets to address the acceleration and cost sharing mechanism[24] which could have implications in the ISR Plan. I have emphasized that the decision to advance a load relief project must also consider whether actual loading or system conditions have materialized to the levels identified in the original

[24] Tiverton Docket No. 23-37-EL and Weaver Hill Docket 23-38-EL. The proposed DG reimbursement for both projects totals $24.7 million and was removed from the FY 2025 ISR Plan budget.

Area Study that prompted the need for the project. My review for this report will focus on that analysis which the Company should customarily provide when load relief projects are initiated. The Division will be filing separate testimony and a position on the cost sharing for both of these substations and the associated subtransmission and distribution construction. The Commission's ultimate order will impact the capital spending to be incorporated into the ISR Plan.

Weaver Hill Substation was proposed in the Central Rhode Island West (CRIW) Area Study, completed in 2022, as the preferred solution to address Hopkins Hill 63F6 summer normal overload projected at 104% and highly loaded Coventry 54F1 projected at 94% of summer normal by 2035[25]. The Company's current feeder loading report[26] indicates that Hopkins Hill 63F6 forecasted load is 88% of summer normal and Coventry 54F1 is 84% of summer normal in 2024.

A summary is as follows:

CRIW Area Feeder Loading % Summer Normal	Current Forecast			CRIW Study	
	2024	2025	2026	2020	2035 Forecast
Hopkins Hill 63F6	88%	89%	89%	93%	94%
Coventry 54F1	84%	84%	84%	102%	104%

The current load forecasts indicate that loads are lower than those presented in 2020. The feeders have experienced decreasing load and considering projected nominal growth, it is likely that summer normal overloads will occur well past 2035. This suggests that both Weaver Hill and Coventry projects could be deferred past the implementation period identified in the study. The details and Division position will be included in Docket 23-38-EL.

[25] Central Rhode Island West Area Study, Table 4.1 (page 14) and page 29.
[26] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 1-2.

As part to the Tiverton Area Study completed in 2022, the Company forecasted that three of the four Tiverton Substation feeders would be overloaded or highly loaded by 2035. The study indicated that all four feeders had load at risk by 2035 primarily due to limited switching options available in the edge of RI territory[27]. The recommended solution was a new feeder 33F6 that would also be used to interconnect a DG customer. Extending the new 33F6 feeder would address overloads and load at risk violations which is the portion of the distribution project being evaluated here. Review of the Company's feeder loading in the study as compared to current forecasts indicates that all four feeders are at or slightly lower than initial study values. The only feeder originally projected to be overloaded in 2035 is 33F3, indicated at 100% loaded in 2021 and projected at 101% in 2035. The Company now shows feeder 33F3 is at 88% of summer normal in 2024 which indicates declining load[28].

A summary follows:

Tiverton Feeder Loading % Summer Normal	Current Forecast	Tiverton Study	
	2024	2021	2035 Forecast
33F1	97%	97%	98%
33F2	91%	95%	96%
33F3	87%	100%	101%
33F4	92%	88%	89%

Based on this data, the need for the feeder extension could be later than 2035. The need to resolve feeder contingency load at risk could be a rationale to proceed with the line extension earlier but it is unclear if contingencies persist given lower area load. Delaying a contingency solution may be a reasonable option if outage risks are low and when current system conditions

[27] Tiverton Area Study, Tables 4.1 and 4.2.
[28] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 1-2. Forecasts beyond 2024 include the proposed additional 33F6 feeder. Load across all feeders declines from 2024 to 2026.

provide adequate day-to-day continuity of service. My general analysis of the Tiverton line extension is that the required project completion date is beyond what was proposed in the Area Study due to declining loads. Again, the details and Division position on cost sharing will be addressed in the Division's filed testimony in Docket 23-37-EL. The Commission's ultimate order in that docket will impact the contribution in aide of construction for the DG developer and thus the capital requirement in the ISR Plan.

I raise these observations for Weaver Hill and Tiverton to illustrate the continuous analysis that must transpire before initiating projects, especially those designed to resolve a future problem based on forecasted conditions in outdated area studies. There must be reasonable certainty that the system condition will materialize prior to project implementation. Asset Condition projects tend to be more definitive – equipment is either deteriorated and performing unreliably, or not. Long term system capacity projects are influenced by many variables including the natural declining load levels, DER additions, demand response enhancements, energy efficiency impacts, and technology changes which are changing load levels and project selection. The Company may have additional justification beyond load relief to prioritize a project yet that does not always mean that an entire portfolio of projects in an Area Study must progress at once unless they are inextricably linked.

The remaining Area Study projects are grouped by the associated regional study. The Company is simultaneously progressing projects associated with seven Area Studies. Total projected spend in FY 2025 is $5.6 million and primarily for engineering, design and initial material procurement. Planned spend is $35.9 million over a 5-year period. As refined scopes and budgets are presented, the projects associated with this group of Area Studies will be evaluated in more detail to ensure alignment with originally designed solutions and confirm that implementation timelines are supported by forecasted system conditions or otherwise sequenced to avoid unnecessary costs. The FY 2025 proposed budget of $5.6 million was accepted without adjustment.

The analysis and discussions of Area Study related projects in the System Capacity category resulted in a $1 million adjustment to the originally proposed $20.7 million budget. Concurrence was reached on a final proposed FY 2025 ISR Plan budget of $19.7 million. The Company appropriately designates East Providence and Warren Substations as Major Projects to be separately tracked but there may be additions based on Division review of progressing projects. The Division remains supportive of advancing system capacity projects when need and timing are clearly demonstrated, and risk factors have been appropriately considered to support project prioritization. In order to monitor projects emanating from Area Studies, the Division anticipates that RIE will produce information to aid in aligning the final scope with the original Area Study solution, validating that expected system conditions are materializing, ensuring that the ISR Plan prioritization is justified, understanding drivers for cost revisions, and determining Major Project eligibility. Cost risk management continues to be increasingly important due to inflationary pressures and the Company's project execution will be evaluated as these complex projects move through construction. I continue to emphasize that that the Company proposes extraordinary levels of capital spend over the next five years. The Division and RIE must work through the preliminary Long-Range Plan in order to substantiate optimum coordination of projects and assurance that these system capacity projects are appropriately modulated to mitigate rate impact without adversely impacting reliability and safety. There is most certainly a great deal of future effort required between the Division and RIE to reach a consensus. This work and consensus building does not however impact this ISR Plan.

2. System Capacity & Performance – Other Programs

For the FY 2025 ISR Plan, the Company continues funding customary programs including 3V0, EMS/RTU (SCADA) expansion, overhead transformer replacements, blanket projects and other smaller initiatives. RIE is proposing three additional programs which were previously presented as part of its grid modernization strategy. These are electromechanical relay upgrades, a fiber network, and Volt-Var Optimization (VVO) which is re-activation of a previous program implemented on select circuits. The Company initially proposed an $8.4 million budget for all programs which was adjusted to $8 million. This compares to a FY 2024 budget and forecast of $6.3 million and $9.7 million respectively.

ISR Plan Capital Budget System Capacity & Performance Programs ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
3V0	1,095	-	1,095	540	(354)	186
EMS/RTU	658	-	658	135	-	135
Overloaded Transformer Replcmts	1,500	-	1,500	1,500	-	1,500
Blanket Projects	2,490	1,379	3,869	2,605	-	2,605
Electromech RelayUpgrades	-	-	-	1,234	-	1,234
Fiber Network	-	-	-	200	-	200
VVO - Smart Capacitors and Regulators	-	217	217	400	-	400
Mobile Substation	-	-	-	1,278	-	1,278
Other projects and programs	541	1,844	2,385	478	-	478
Total Programs	**6,284**	**3,440**	**9,724**	**8,370**	**(354)**	**8,016**

The evaluation of programs in this category takes into account several factors. For ongoing programs that were previously found acceptable in prior ISR Plan reviews, the alignment with program objectives or targeted installations is assessed along with annual funding levels. Newly introduced programs are subject to more robust analysis considering system need, benefits, costs, and implementation strategy. Initial funding is often approved for program development which is further analyzed once produced.

For FY 2025, the Company proposed funding several ongoing programs. This includes completing zero sequence overvoltage (3V0) protection at Clarkson St. Substation to enable DG interconnections. Clarkson St. is the last substation of the Company's initially targeted 15 sites. The Company has discussed expanding the list but as I have noted in previous reviews, at some point the customer benefits may not outweigh the costs. Although the proposed FY 2025 spend is acceptable, future installations will require additional vetting before commencing. The Company also plans continued SCADA expansion at Wampanoag and W. Greenville Substations which provides enhanced system monitoring and control along with systematic replacement of overloaded distribution transformers. In addition, the Blanket category funds targeted work identified by field operations. All four of these programs continue to be supported by the Division and concurrence was reached on a final FY 2025 budget of $4.4 million.

The Company put forth several additional programs in FY 2025 including upgrade of approximately 205 electromechanical relays to solid state/digital relays. In FY 2024, RIE introduced this work as foundational grid modernization infrastructure which was not approved in the ISR Plan. At that time, I observed that this infrastructure is customarily installed as part of a utility's normal course of business and not considered grid modernization. Digital relays are simply the next iteration of technology available to electric utilities for power line fault detection and protection. The Company has been systematically replacing relays on its system and this initiative continues those efforts. I fully support relay upgrades and the Company's FY 2025 budget of $1.2 million for work at four substations. The Division will require more comprehensive documentation identifying the full scope and implementation plan to substantiate the Long-Range Plan budget of $6.8 million through FY 2029.

Next, the Company proposed resuming the VVO/CVR program, now described as Smart Capacitors and Regulators. I have addressed VVO/CVR investments and system benefits at length in previous Plan reviews. This initiative is an example of technology deployment which brings necessary grid enhancements and an ongoing net benefit to the consumer as evidenced by the positive results of the Company's Volt/Var Optimization pilot. I am supportive of a system-wide program design and the Company's proposed FY 2025 budget of $400,000 for engineering, design and procurement associated with the installation of smart capacitors and regulators. This is a significant multi-year program that is more complex than "one-for-one" technology upgrades like the relay program. The Division will require more comprehensive documentation identifying the full scope and implementation plan to substantiate the Long-Range Plan budget of $65 million through FY 2034. The Division anticipates further discussions with the Company to determine how projected energy and demand reductions will be measured and reported. While the VVO/CVR pilot program demonstrated significant power cost reduction benefits, RIE has tempered its estimates stating that the penetration of DER will reduce the overall benefits from VVO/CVR. Tracking of benefits and costs and providing new analysis and BCA as this equipment is advanced will be essential to assure all benefits outweigh costs. In general, the electric utility industry is continuing to advance VVO for both power cost reduction, feeder voltage profile enhancement and to increase the effectiveness of self-healing circuits.

The Company also proposes mobile substation purchases which is similar to the Spare Transformer program in that the objective is to increase the inventory of equipment to use in emergency situations such as power transformer failures. Mobile substations can be installed within 24-36 hours of a transformer failure, providing rapid restoration until a more permanent solution can be implemented. They have versatility by providing support during routine maintenance that avoids service interruptions and also provides the ability to more cost-effectively sequence construction for complex substation projects. The Company currently owns and maintains two distribution mobile substations that are capable of supporting 80 of the approximately 200 distribution transformers on the system. RIE proposes the purchase of three additional mobile substations[29] and one mobile regulator to fill the gap at a budget of $12.8 million over three years. Similar to spare transformers, the Company had access to multiple mobile substations under National Grid ownership[30]. The Company lost the ability to leverage a significant level of compatible spare inventory after the PPL acquisition. RIE now relies on a mobile lease agreement with National Grid[31]. I believe the lease agreement is adequate in the short term but agree that additional mobile substations and a mobile regulator would be prudent purchases. The level of desired inventory warrants more evaluation which will occur during future discussions with the Company regarding the Spare Transformer program and the Long-Range Plan assessment. This should produce an overall strategy for both spares and mobiles to inform future spend. For the current FY 2025 ISR Plan, however, the Division concurred with the proposed $1.3 budget to proceed with mobile substation purchases. The Division will also review whether some of the cost of spare equipment should be considered transition costs borne by PPL.

Lastly, the Company proposes a plan to replace cellular services connecting substations across the system with fiber optic cable. The Company's general justification is that cellular is used to communicate with automated devices and that lease cellular service has limited bandwidth and is subject to greater interference, offering inadequate functionality and added

[29] RIE calculated a proposed number of mobile substations to achieve coverage of the approximately 200 transformers in service.
[30] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 2-27.
[31] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 2-22.

reliability and resiliency system risk[32]. RIE previously introduced the Fiber Network as a grid modernization program that was not approved in FY 2024. This is a substantial infrastructure investment that essentially replaces one successfully operating technology for another with a proposed cost of $48 million over four years. Many electric utilities rely on privately owned fiber networks and/or cellular for communications but there are costs and benefits to each approach. As it stands, the Company claims that without this program, "station communications cost will rise greater than the cost of this program."[32] The Company provided no support for this assertion and certainly did not produce evidence that cellular communications would limit the Company's ability to reliably serve customers. There is far more information required of the Company before the Division can consider a major fiber infrastructure expansion. The Company plans to conduct a detailed fiber deployment study that will further develop scope, prioritize deployment, and refine future year execution and spend. (ISR Plan page 73) The Division agrees with this approach and accepted the proposed FY 2025 budget of $200,000 to conduct the Fiber Network study. Approval of future spend will depend on the study outcome and Division assessment and ultimately the Commission's acceptance in future ISR Plans.

This brings the total proposed FY 2025 budget for System Capacity & Performance Programs, excluding programs related to recloser additions, to $8 million.

G. Reclosers

In the FY 2024 ISR Plan (Docket 22-53-EL), RIE proposed significant recloser investments described as either Mainline Reclosers or Advanced (GMP) Reclosers. The

[32] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 5, page 47.

overarching rationale was the Company's internal assessment that there were an inadequate number of reclosers on the system and additions were deemed necessary. As explained in my FY 2024 ISR Plan report, reclosers are distribution devices mounted on poles at select locations along circuits. Their primary function is sensing line conditions and acting like a circuit breaker when anomalies occur (faults or overloads). If a problem is temporary, reclosers have the capability to open, allow a faulted condition to clear, and then reclose again helping to maintain service continuity thus creating a momentary interruption rather than a sustained outage. If the fault is not temporary, reclosers in strategic locations can open to protect the faulted section and minimize the number of customers affected by an outage. Reclosers are common equipment on distribution systems and also leveraged by utilities for switching schemes in operations. The Company has hundreds of reclosers on its system, categorized as dark (no communication or remote control), remotely operated (two-way commands), and Advanced Reclosers (also referenced as GMP enabled) which are capable of network connection for automated schemes[33]. Whether existing reclosers are labeled as "Mainline", "Advanced" or "GMP", they are essentially the same equipment with the same underlying specifications, but each may be outfitted with varying control technologies to enable advanced functionality.

In its revised FY 2024 ISR Plan[34], the Company proposed $9.5 million to install 100 mainline reclosers and also put forth a $23 million funding request for a separate Advanced Recloser program under the Grid Modernization Plan category. The Company proposed the Mainline Recloser program because it had "determined that the lack of reclosers is a contributing factor to the rising System Average Interruption Frequency Index ("SAIFI")

[33] Docket 22-53-EL, Proposed FY 2024 ISR Plan Attachment DIV 5-3-1_Recloser List.
[34] RIE initially filed a 9-month CY 2023 Plan and a 12-month CY 2024 Plan. The PUC directed RIE to submit a revised 12-month FY 2024 Plan.

values" and that the "recloser program is intended to create near term SAIFI benefits to reverse the Company's current upward trend in this metric."[35] The Company proposed GMP-Advanced Reclosers to "provide a number of benefits including system visibility and sensing and operational efficiencies, but their primary benefit is improving system reliability."[35] The Company primarily cited increasing distributed energy resource penetration and electrification under a GMP hypothetical future worst case scenario as the cause of potential system issues that would necessitate investments in Advanced Reclosers.

The Company included these recloser programs in its final FY 2024 ISR Plan filing although the Division opposed both programs for multiple reasons. The primary issue was that the Company had, and continues to achieve, system reliability performance that is well within the Commission's SAIDI and SAIFI guidelines. RIE's claims of deteriorating reliability were unsubstantiated and the Company was already heavily investing in major projects and enhanced vegetation management to further improve reliability. The incremental investment in reclosers to solve a problem that did not exist lacked adequate justification in the filed plan. The Company was unable to sufficiently validate the need, scope, timing, and investment level. RIE relied on its internal conclusion that massive amounts of recloser additions were needed but the Company never produced adequate justification including comprehensive benefit-cost analyses. RIE's overarching strategy was to install enough reclosers on the system to achieve an arbitrary goal of 500-750 customer served beyond a recloser and add additional reclosers for automated switching schemes ("FLISR"). RIE fell short of substantiating the need for the number and pace of recloser additions and certainly did not produce any alternatives such as

[35] Docket 22-53-EL, Proposed FY 2024 ISR Plan, DIV 1-23.

lower cost sectionalizing devices, sensors and smart switches that could offer similar fault detection and protection.

In addition, I noted that the Company was pushing recloser installations through two unrelated programs, Mainline Reclosers and GMP. Both programs were reliability driven but not coordinated. The Company purported that Mainline Reclosers would be installed in optimal physical locations but only identified a list of candidate circuits. The GMP recloser installations were part of the GMP Roadmap, so merely a vision and unjustified otherwise. The Company even designated reclosers differently in the ISR Plan, with Mainline being discretionary and GMP being non-discretionary, although the reclosers would serve the same functions. Most importantly, RIE had put forth a plan to add nearly $130 million dollars of reclosers through 2027 without performing any system-wide protective coordination study. As explained in my FY 2024 report, the Division and I stated that a protective coordination study is essential before a massive recloser addition program is advanced. RIE stated that would be done after the fact. I made it clear that a protective coordination study is the standard of care performed on a regular basis by nearly all utilities and as outlined in IEEE standards. The fact is that RIE set a goal for an arbitrary number of recloser additions and then attempted to justify its proposed effort without a single detailed study.

My position in the FY 2024 ISR Plan review was, and continues to be, that the Division has consistently supported and encourages appropriate technology deployment for safety, reliability and to optimize operations. I continue to emphasize that I am not opposed to recloser additions, but I strongly disagreed with the Company's approach at that time. My primary recommendation was that the Company should propose recloser installations in a system-wide coordinated fashion, fully justified, and supported by communication and protective coordination studies in advance of implementation. Anything less would fall far below the standard of good utility practice in the industry and, therefore, would have to be deemed imprudent. To overcome these deficiencies, I recommended that the Mainline Recloser program should be paused until these items are incorporated and, furthermore, installations should be coordinated with Advanced Reclosers. The Company should treat the installation of all underlying reclosers and associated communications, whether deemed Mainline or GMP, as discretionary spend for reliability.

The Commission proceedings to approve FY 2024 ISR Plan ultimately addressed the differing positions of the Company and the Division regarding recloser additions. The Commission denied all but a small number of GMP reclosers and rejected the new Mainline Recloser program. The Commission decision[36] is summarized as follows (***emphasis included***):

> *Specifically,* ***the Commission removed a new Grid Modernization category and funding, redirectined [SIC] a small amount of funding to the Asset Condition category for a small number of reclosers that can properly fall within that category****. The Commission also followed Mr. Booth's recommendation and reduced the budget for major projects within the Asset Condition category by $10 million finding that the remaining budget allowance is sufficient to support a reasonable implementation schedule and is still greater than what was allowed in FY 2023.* ***The Commission rejected the new Mainline Recloser program that was proposed within the System Capacity and Performance budget, finding that it was not adequately supported by the record for inclusion in the FY 2024 budget****. The result was a $53.461 million reduction to the FY 2024 capital budget.*

The Commission is also clearly aligned with my continuous demand that RIE's investments be fully supported[37]:

> *It is the Company that has the burden of proving that its investment budget is reasonable and supported by the evidence. It must show that the investment is needed in the short and long term to provide safe and reliable service. It must identify the problem on the system, the location on the system, how the investment will solve the*

[36] Docket 22-53-EL, Proposed FY 2024 ISR Plan, Report and Order, page 2, footnote 9.
[37] Docket 22-53-EL, Proposed FY 2024 ISR Plan, Report and Order, pp. 15-16.

stated problem, and how the investment is consistent with the Least Cost Procurement Standards.

Based on the outcome of the FY 2024 ISR Plan proceedings, RIE filed its proposed FY 2025 ISR Plan but repackaged the proposed recloser programs. The Company no longer proposes installations under discrete line items previously labeled Mainline Reclosers and Advanced Reclosers and no longer correlates investment need to a Grid Modernization Plan. The Company now proposes a significant number of reclosers as discretionary spend, mainly through work planned under the CEMI-4, ERR and Distribution Automation Recloser Programs to address circuit specific reliability. Under these programs, RIE's underlying strategy is:

i. Target recloser additions on every overhead distribution circuit to achieve 500-750 customer count per segment. There are 336 overhead circuits to be prioritized by ranking their reliability, line exposure, and distributed generation protection[38],

ii. Every recloser installed will be an Advanced Recloser which is equipped with full control and communication packages at an estimated installed cost of $81,600 per recloser in 2025[39], and

iii. Every recloser will ultimately be incorporated in a FLISR scheme[40], which requires a minimum of 2 to 3 additional Advanced Reclosers per feeder. The FLISR scheme will rely on ADMS which is expected to be functional in 2024[41].

The recloser additions are projected over seven years, a timeline determined by RIE that could be modulated. A comparison below shows that RIE's unapproved FY 2024 ISR Plan proposed a 5-year spend of $138 million for reclosers and RIE's preliminary FY 2025 ISR Plan proposal included a 5-year spend of $86 million for reclosers[39]:

[38] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 6, pp. 6-7.
[39] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 6, page 13, Figure 12.
[40] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-29.
[41] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-31.

Proposed Recloser Budgets ($M)	Program	Spending Rationale	Prospecitve ISR Plan Recloser Spend	5-year ISR Plan Recloser Spend
FY 2024 ISR PLAN (not approved)	Mainline Reclosers	Discretionary	$9.5	$9.5
	Advanced Reclosers	Non-Discretionary	$23.0	$128.0
		Total FY 24	***$32.5***	***$137.5***
FY 2025 ISR PLAN	CEMI-4	Discretionary	$3.7	$12.5
	ERR	Discretionary	$2.4	$10.2
	Distribution Automation	Discretionary	$7.4	$62.7
		Total FY 25	***$13.5***	***$85.5***

My general assessment of the FY 2025 ISR Plan proposal is that the Company adopted the Division recommendation and Commission support for categorizing recloser investments as discretionary. The Company put forth lower budgets than previously requested, presumably to address major concerns with the level of investment and overall affordability expressed by both the Division and Commission. The Company's rationale for recloser additions going forward is reliability based and no longer presented as necessary in the near term for visibility and control of DER that was expected to impact the system under the Company's GMP assumptions. RIE departed from its assertion that reclosers were "foundational" to grid modernization. These recharacterizations also appear to be in response to reservations raised by both the Division and Commission regarding the urgency of GMP investments. RIE provided program documentation with BCAs[42] that were the basis of more detailed analysis for each program.

My recommendation that the Company produce a system wide protective coordination study in advance of implementing a recloser program, however, was rejected by RIE. This study produces a single coordinated plan to add reclosers across the system based on circuit characteristics that take into account grid connectivity and protection requirements. The plan

[42] The ERR BCA was not provided in the October 13, 2023 FY 2025 ISR Plan. The December 21, 2023 filing includes Docket 4600 evaluation for ERR, indicating a BC ratio without supporting information. RIE subsequently provided documentation in response to DIV 7-7.

would indicate the optimal locations for reclosers and also identify system reconfiguration and improvements that would be required to optimize recloser functionality. RIE would know the number, location, and estimated cost of system-wide recloser additions with much greater accuracy prior to implementation and could pace recloser additions based on capital budget availability. In contrast, RIE has derived a targeted number of recloser additions for the system but will select and evaluate circuits after the fact. The Company established its recloser strategy using a subjective customer segment target to calculate the need for 1,267[43] reclosers across the system, estimated an installed cost of $81,600 (2025) per recloser, and spread the work over seven years[44]. The Company then uses circuit performance and other factors to prioritize circuits that may benefit from reclosers and budgets for additions under one of three programs in an ISR Plan year. However, the actual need for a recloser on a targeted circuit, location, number, cost, required system upgrades, coordination study, etc. would not be identified or performed until engineering is complete which is predominantly *after* the ISR Plan is filed. RIE has indicated that recloser needs and locations are often obvious based on circuit performance and topography, thereby not requiring my recommended study. The Company's assessment is not obvious to stakeholders, especially RIE's position that every overhead circuit is a candidate for an automated switching scheme (FLISR) regardless of circuit performance or characteristics. While the Company and I disagree on this matter, a compromise position was reached where Division support for recloser additions is contingent on RIE delivering more robust justification prior to installations[45].

[43] As fully explained in response to DIV 4-29: RIE takes the total customer count 497,500 divided by 500 customers per recloser, which results in an approximate mainline recloser count of 995 reclosers. Then subtracting the 400 existing and adding 2 open point reclosers per feeder for the feeders under consideration (336) equals 1267.
[44] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 6, page 13, Figure 12 and Figure 13.
[45] This concept was incorporated into conditions of agreement for the final recloser budget.

Although RIE has made some satisfactory program modifications, the proposed FY 2025 ISR Plan continued to include considerable discretionary recloser spend to address performance on a system that meets and exceeds Rhode Island regulatory reliability thresholds. RIE reliability results indicate improving SAIFI and SAIFI metrics over the past five years[46]. RIE met 1st quartile performance for both SAIFI and SAIDI on a national basis in 2022 (benchmarking using IEEE 1366-2003/2012 calculations) but achieved 3rd and 4th quartile for IEEE SAIFI over 2 years when compared to Northeast Investor-Owned utilities[47]. Except for the minimal data regarding regional SAIFI performance, the collective statistics portray a system that is not suffering from poor reliability.

RIE also references its results from the J.D. Power Electric Utility Residential Customer Satisfaction Study (JD Power survey) as rationale for reliability investments. Here, the Company falls in the 3rd Quartile for overall satisfaction and specifically for Power Quality and Reliability in Q3 2023. This is an improvement compared to 2022 where the Company fell in the 4th quarter. Ranking RIE's performance in each category of the JD Power survey suggests that while there is additional room for improvement in Power Quality and Reliability, customers appear less satisfied in other areas including communications, customer care, overall satisfaction, and price. I also expect that the survey results for reliability should further improve based on RIE's plans to invest over $500 million in additional discretionary projects over the next five years, primarily replacing deteriorated equipment.

[46] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-28.
[47] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-1. The Division requested regional IEEE results, but RIE did not provide SAIFI results prior to 2021 or any regional results for SAIDI.

J.D. Powers Results 2022 (Q3)	East Midsize Average	RIE	Difference
Communications	676	621	55
Customer Care	772	720	52
Overall Satisfaction	709	667	42
Price	632	591	41
Power Quality & Reliability	757	717	40
Corporate Citizenship	652	612	40
Billing & Payment	774	748	26

Ref. DIV 3-3 response

The information on recloser additions put forth by the Company was evaluated in great detail. Multiple data requests were served and several conference calls were held. Ultimately, for many of the reasons mentioned above along with detailed reviews of each recloser related program in this report (CEMI-4, ERR and DARP), I concluded that RIE's proposed level and pace of recloser additions remained unjustified. A major sticking point was RIE's proposal to install Advanced Reclosers with automation (FLISR[48]) to address reliability without examining the root cause of outages. Under RIE's strategy, Advanced Reclosers and FLISR schemes under the DARP could be proposed on circuits that have acceptable reliability[49].

The question of need and benefit of FLISR shaped the ultimate agreement on recloser spend. RIE and the Division concurred with a reduced level of recloser additions aimed to address the top tier of worst performing circuits rather than every circuit proposed by the Company in FY 2025. This would ensure that a reliability need existed. The budget also allows limited FLISR work to progress in order to evaluate actual performance and benefits over time.

[48] A FLISR scheme requires 2 to 3 Advanced Reclosers per circuit adding a minimum of $160,000 - $240,000.
[49] For instance, *Attachment A – Preliminary Prioritization List – Circuits with Frequency > 1.05* (FY 2025 ISR Plan, Section 2, Attachment 6, pp 14-16) indicates 8 Advanced Reclosers on Pawtucket Feeder 53-107W80 which has a CKAIFI of 1.1 compared to RIE's regulatory threshold of 1.05. This example raises questions on the need to invest nearly $650,000 (8 reclosers @ $80,000 per recloser) to improve performance that is not an outlier.

The results are expected to inform future levels of FLISR investments. The Company agreed that the portfolio of circuits to be addressed in FY 2025 include only those with Circuit Average Interruption Frequency Index (CKAIFI) of 2.0 or greater which is nearly twice the regulatory threshold of 1.05. The Company and Division determined eligible circuits using the Company's prioritization list, which I reference as "Attachment A" (*Attachment A – Preliminary Prioritization List – Circuits with Frequency > 1.05*; FY 2025 ISR Plan, Section 2, Attachment 6, pp 14-16). This results in 23 circuits with 88 proposed Advanced Reclosers at a total budget of $7.2 million. Of these, RIE proposes that 73 Advanced Reclosers in the Distribution Automation Recloser Program to be incorporated into FLISR schemes among varying circuits. Fifteen Advanced Reclosers will be installed as Mainline Reclosers in the CEMI-4 and ERR programs and may be incorporated in future FLISR schemes. While RIE points to PPL and many other utilities rapidly advancing FLISR (Self-healing circuits), a fact the Division and I clearly recognize, the Division does not believe that is adequate justification considering the existing system reliability combined with the tremendous level of asset condition improvements required over the next five to ten years. The Division recommended, and RIE agreed to, several conditions including:

- Capping the FY 2025 budget for Advanced Reclosers.
- Providing specific information to the Division (such as analysis, solution development and justification, recloser locations, estimated costs, etc.) at least 60 days prior to advancing work on any feeders.
- Establishing cost and performance tracking mechanisms, including specific measures for circuits with FLISR schemes.

Discussions resulted in a $6.6 million reduction in Advanced Recloser spend. The initial proposed and adjusted budgets for reclosers within FY 2025 ISR Plan programs are shown below. I discuss individual programs in more detail in the remainder of this report section.

CEMI-4, ERR, & DARP ADVANCED RECLOSERS ONLY ($000)	FY 2025 RIE Initial Proposed 10-13-23	Net Adjustments	RIE FY 2025 Proposed 12-21-23	Recloser Count
CEMI-4 and ERR*	6,341	(5,141)	1,200	15
Dist. Automation Recloser Program	7,426	(1,469)	5,957	73
Total	**13,767**	**(6,610)**	**7,157**	**88**

**The recloser budget is a portion of CEMI-4 and ERR Programs which include additional system improvement investments*

H. Reliability Programs

The Company is proposing three discretionary programs with the objective to target select feeders for reliability improvements. The CEMI-4 program commenced in FY 2024, the ERR program is an enhancement of previous work performed under a blanket category, and the DARP is principally a re-introduction of RIE's GMP-Advanced Recloser program that was denied by the Commission in FY 2024[50]. All three programs are incorporating advanced technology as a solution for reliability enhancement. The CEMI-4 and ERR programs consider recloser additions as a subset of options to improve reliability on select circuits while the DARP is focused solely on adding reclosers to every overhead line over time that is not addressed in CEMI-4, ERR, or possibly other projects that involve recloser installations. The Company developed a prioritization list of potential circuits based on criteria of each program (Attachment A), and then assigned circuits to the CEMI-4, ERR and DARP to avoid overlapping initiatives. As discussed in the previous section, RIE and the Division agreed on a portfolio of circuits to be addressed under these three programs in FY 2025 along with a budget for 88 Advanced Reclosers. My evaluation of each program highlights observations or

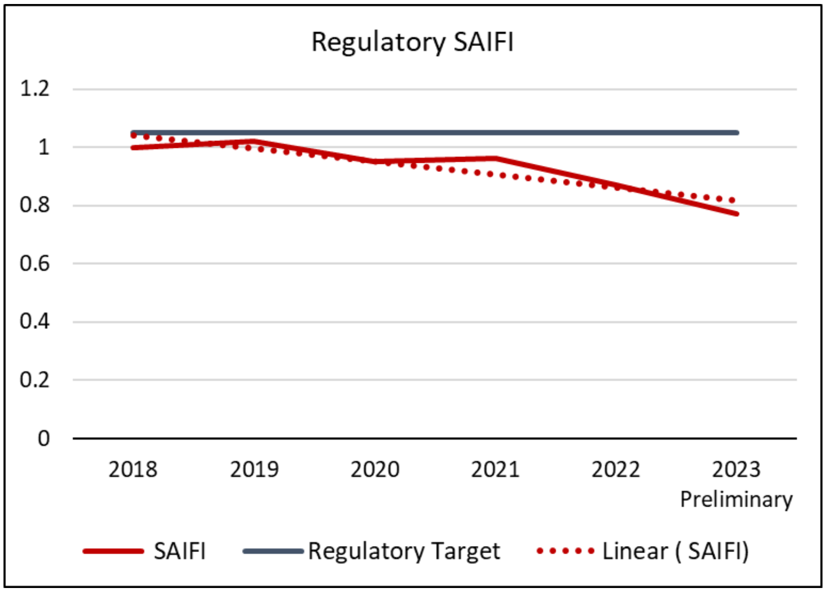
[50] Docket 22-53-EL, RIE's FY 2024 ISR Plan Proposal, Report and Order, page 22: The Company had proposed Grid Modernization budget line item $35.257M. That amount was denied. However, the Commission ordered the reallocation of $1.3M to the Asset Condition category to fund replacement of 18 reclosers that were at the end of their useful life.

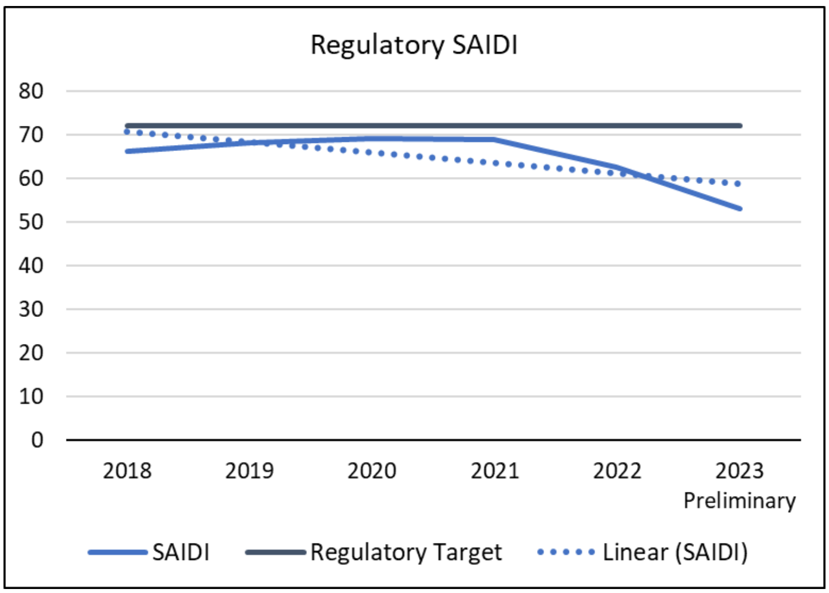
concerns regarding program justification including objectives, structure, criteria used to choose targeted circuits, pace and level of overall spend, and expected benefits.

The three programs were initially proposed at $17 million in FY 2025 ($14 million attributed to reclosers) and $103 million for the 5-year investment plan ($86 million attributed to reclosers). RIE states that of these programs, the CEMI-4 and Distribution Automation programs are designed to address immediate needs and have a sunset of 5 to 10 years. After the sunset period, the Company expects to continue the ERR program, which will incorporate distribution automation as needed based on changing system configurations and CEMI-4 considerations[51].

RIE acknowledges that it has been meeting its state regulatory reliability performance but references an upward trend in both SAIDI and SAIFI as rationale for significant incremental spend to address reliability. However, the most recent six years offers a different perspective on reliability results. During this period the Company has heavily invested in major substation projects, extensive distribution work, and asset replacements due to condition. The Company also enhanced its proactive vegetation management program. These efforts have positive effects on system performance and reliability results. SAIFI and SAIDI results from 2021 to 2022 trended lower (favorable) and preliminary results from 2023 show even further reductions[52]. From a trending perspective, the Company's regulatory reliability results have been improving since 2018. The Company is certainly meeting and exceeding its regulatory reliability targets.

[51] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-2.
[52] Docket 23-48-EL, Proposed FY 2025 ISR Plan; PUC 3-17.





When asked to explain what the Company believes is the need for the DARP, CEMI-4 and ERR considering regulatory reliability performance is currently being met, RIE states that generally the need is to address areas of system that are above system regulatory reliability thresholds[53]. The Company intends to target feeders with higher frequencies of outages compared to the system average. To accomplish their objectives, RIE has developed aggressive

[53] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-1.

reliability goals within each program that drives sizable investment, the majority of which is the Company's desire to install one recloser for every 500 customers on overhead lines. As I discussed previously, extensive discussions with the Company focused on the need and justification for reclosers which concluded with an agreed upon budget and targeted recloser additions under each program. The agreed upon $6.6 million adjustment for the three programs was driven by Advanced Recloser reductions. For these three programs, the FY 2024 budgets and forecasts, along with FY 2025 initial proposed and final budgets are as follows:

ISR Plan Capital Budget System Capacity & Performance Reliability Programs ($000)	FY 2024			FY 2025		
	Budget	Variance Over/(Under)	Forecast (as of Q2)	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
CEMI-4	1,230	(93)	1,230	5,312	(2,693)	2,619
ERR	-		-	4,448	(2,448)	2,000
Distrib Automation Recloser Program	-		-	7,426	(1,469)	5,957
Total Reliability Programs*	**1,230**	**(93)**	**1,230**	**17,186**	**(6,610)**	**10,576**

** Total includes $7.2 million budget for Advanced Reclosers*

1. CEMI-4

The CEMI-4[54] program was introduced in FY 2024 at a budget of $1.2 million and was initially proposed at $5.3 million in the FY 2025 Plan. The program objective is to identify and fix reliability issues for customers who are experiencing significantly poorer service than system or circuit averages. A prioritized list of feeders will be developed each year using both rolling 3-year and 12-month CEMI data. Event details for selected circuits are examined and solutions sets engineered with "an understanding of the customer, damage location, and protective device locations."[55] Solutions development considers several traditional options such as vegetation management, animal guards, and hardening but may

[54] IEEE 1366 – 2003 defines CEMI n (Customers Experiencing Multiple Interruptions) as the ratio of individual customers experiencing more than n sustained interruptions to the total number of customers served.
[55] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 7, page 8.

also recommend larger efforts such as reconductoring. Advanced Reclosers and automation are additional options. As explained in more detail below, the number of targeted circuits is driven by RIE's goal to reduce the number of customers at the CEMI 4+ by approximately 9,000 each year.

Specifically, the program objective is to drive CEMI-4 performance to Electric Edison Institute first quartile level of 4.67 % within 5 years. Meeting a 4.67% CEMI-4 goal means that less than 4.67% of all customers will experience 4 or more interruptions per year. The Division previously supported the program and considered the nominal budget in FY 2024 to be an appropriate level of spend to remedy poor circuit performance. In FY 2025, RIE delivered a more comprehensive program justification document with a BCA. RIE also increased the budget to reflect recloser additions that are identified in the Distribution Automation program but assigned to CEMI-4.

A detailed review of the newly presented information raised several key observations. The initial issue is that RIE sets a static goal of 4.67% to attain 1st quartile performance when actual thresholds change annually. The target is based on a single year of CEMI results but could be higher or lower in future years. The program documentation implies that the Company's goal is 4.67% yet achieving that target does not guarantee 1st quartile performance. Although RIE "anticipates an alignment between the performance year and the survey year as the program matures"[56] the CEMI-4 program goal should be further clarified. This will be an iterative and evolutionary process which will be evaluated and adjusted as the program matures. The Memorandum examples attached to the RIE response

[56] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-20.

to DIV 4-13 are a good start for the transparency of the need and solutions and cost to be measured against the results achieved.

In addition, the 4.67% target is aggressive and if RIE's intention is to achieve that target every year for 5 years, it could drive investment levels that may not be needed for reasonable reliability performance. RIE uses a 4.67% target which is the lowest EEI CEMI-4 first quartile threshold in the past five years along with a 30% adjustment factor to create an annual targeted work list that impacts 9,000 customers. RIE's methodology[57] drives higher annual spend to meet an arbitrary target. Additionally, RIE selected the 4.67% target (2020 reporting year) because it was a relatively stable year with no widespread weather events or storms[55] yet the CEMI program uses storm data to determine candidate circuits. Achieving "blue-sky" reliability results for "dark-sky" conditions could drive unnecessary investment, or at minimum, accelerate spend in the initial years of the program to reach an aggressive budget. This is one of the major reasons that RIE's annual CEMI-4 circuit selection and budget levels warrant comprehensive reviews each year.

Another concern is RIE's benefit-cost analysis in general and the assumptions in particular. On the cost side, the Company assumes costs that are uncertain and based on sample circuit proposed work. Actual costs will vary based on circuit selections and solutions that will not be engineered until after annual ISR Plan filings, so future costs can change dramatically from initial assumptions. Benefits assume that each customer impacted by the program will experience 3 fewer interruptions for the life of the system

[57] The calculation is more fully explained in the proposed FY 2025 ISR Plan, Section 2, Attachment 7, page 7: Currently, 11.46% of the company's customers experience 4 or more interruptions per year (see Table 2). The EEI first quartile performance target is 4.67 % (see Table 3) of the reporting company's customer served. Therefore, to meet a first quartile target in 5 years, RI Energy will reduce the number of CEMI 4+ customers from 57,250 to 23,350, a difference of 33,900 customers. To achieve the 5-year goal, work influencing approximately 6,780 customers annually is required to meet targets. To account for variability in additional customers that are impacted each year, a 30% factor is added to the calculated value. This results in an annual targeted work list that impacts approximately 9,000 customers.

improvement, or 20 years. It is, in RIE's opinion, a conservative estimate but there is no independent basis to support the number. RIE also uses an average outage duration of 4 hours which the Company states is a typical planning assumption[58]. This value presumably includes major storms which are highly variable. The outage duration should be further substantiated.

The Company then uses the assumptions in the Interruption Cost Estimate (ICE) Calculator to estimate the value of the reliability improvements. Other inputs include customer counts by class, estimated inflation at 2% and a discount rate of 6%. Using program costs and ICE Calculator results, RIE derived a benefit/cost ratio of 1.82 for the CEMI-4 program. Although the Division does not solely rely on the BCA to determine program advancement, there are several areas of refinement that would produce a more defendable BC ratio when initially justifying a reliability program. First, I recommend that there be some attempt to inject a degree of stochasticism in the modeling to impute some probability distributions on the assumptions in recognition of the random nature of outage frequency and duration as demonstrated by looking at the variability from the past and also the inherent inaccuracies of forecasts. Next, there should also be alternative scenarios as regards to inflation. Lastly, the Division has used the Weighted Average Cost of Capital (WACC) as the discount rate in other arenas and I would assert that it is appropriate to do so in the ICE Calculator. The present WACC for RIE is 6.97%.

With regards to use of the ICE Calculator to quantify customer benefits, I am not fully convinced that the tool appropriately reflects the value of reliability improvements. Customers value continuity of service differently. For some, a three minute outage is just

[58] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-35.

as unfavorable as a 30 minute outage. Others are fairly indifferent as long as interruptions are not frequent. Most likely accept some degree of interruptions during major storms, so there is less sensitivity and discontent during weather events. I have concerns that the ICE calculator cannot quantify varying degrees of customer tolerance and it likely overstates the benefits of reliability step-change improvements. Also, customers continue to have increasing options with regard to outages. These include: consumer-owned back-up generation, battery storage, and insurance against outages. As more of these options become available, it is a reasonable expectation that the consumer's willingness to pay for improved reliability through increased electric rates should diminish. I think this is especially true for the larger customers from which the most benefit occurs. The current version of the ICE Calculator, which is that basic tool that RIE uses to estimate benefits for its proposed programs does not address willingness to pay. That said, the newer version of the ICE Calculator, which is expected to be released sometime in 2024, makes some (as yet unknown) attempt to include willingness to pay in its interruption cost and reliability improvements estimates. Finally, I would only expect the range of options to broaden going forward as technology improves the capability of individuals to deploy options to ameliorate outages.

An additional observation is that CEMI 4 circuit selections will be ready for proposed ISR filings but a complete list of improvements, firm project scopes, and cost estimates will not be finished ahead of the ISR filing process[59]. I believe that the selection, analysis and solutions development for targeted circuits demand more Division scrutiny than other programs that typically include "one-for-one" equipment replacement or repairs such as

[59] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-18.

substation batteries, underground cable replacement, and other asset condition projects. The Division will want to confirm that the most cost-effective remedies are identified and solutions are optimized for the short and long term. The Company's proposed timeline will not allow requisite evaluation. However, RIE's agreement to provide the Division with specific information 60 days prior to advancing work on a feeder should satisfy my concern.

Lastly, and most importantly, RIE has not acknowledged that the program goal to drive CEMI-4 performance to Electric Edison Institute first quartile level of 4.67 % within 5 years was met in 2022. RIE's CEMI-4 result in 2022 was 3.09% which was below the EEI 1st quartile threshold of 4.96% and well below the Company's internal target of 4.67%[60]. RIE achieved first quartile performance in all CEMI-n categories. The Division asked the Company if the CEMI-4 program would cease once first quartile performance is achieved. RIE responded that "Once first quartile performance is achieved, the CEMI-4 program will continue but at a much reduced investment level to maintain performance. The Company is receptive to ending the formal program and incorporating a CEMI prioritization requirement into the Engineering Reliability Review (ERR) program. Because maintaining the program after achieving first quartile performance will result in ad-hoc analysis and work, RIE has not developed an investment plan."[61] The Company's performance indicates that forecasted investments could be tapered or even end well before 5 years.

Although the Division has not discussed RIE's position on program continuation in light of 2022 results, concurrence with FY 2025 CEMI-4 spend was reached despite RIE achieving its stated goals. I recognize that a single snapshot of reliability results does not

[60] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-16.c and 3-16.d.
[61] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 3-12.d.

reflect the future. However, trending is positive and maintaining reasonable performance is important. There are feeders that have customers experiencing unusually high numbers of interruptions that warrant attention. Division support of the CEMI-4 program is a starting point that will require careful monitoring and evaluation to assure the spending rationale is sound in the future and that the outcome is close to the predictions. I support the CEMI-4 program to address the worst performing feeders by assessing event histories and developing solution sets to mitigate interruptions. The solution may include Advanced Reclosers with FLISR to the extent RIE can demonstrate that circuit configuration is conducive to self-healing schemes and that benefits would be achieved. As previously stated, Advanced Recloser installations would be limited to feeders with CKAIFI of 2.0 or greater and be subject to an annual cap in FY 2025. RIE must present analysis and details of proposed solutions in 60-days in advance of implementation each year. Lastly, I expect RIE to proactively offer suggestions to moderate spend and potentially sunset the CEMI-4 program before five years when there are indications that goals have been achieved. At that point, I support addressing CEMI-4 performance as needed under the ERR program as RIE suggests[62]. At the conclusion of extensive discussions with the Company, the CEMI-4 program budget was reduced by $2.7 million, resulting in a FY 2025 budget of $2.6 million.

2. Enhanced Reliability Review (ERR)

The ERR Program was initially proposed at $4.5 million in the FY 2025 ISR Plan and was not specifically budgeted in FY 2024. ERR is essentially an enhancement of select feeder reliability work previously performed under the discretionary Distribution Blanket. The Company has now formalized its approach by proposing to address the 5% worst

[62] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-2.

performing feeders on the system under a dedicated budget. Program documentation states that "the aim of this program is to put forward projects to reduce circuit outage frequency (CKAIFI), and circuit outage duration (CKAIDI) by targeting the poorest performing circuits that are operating below our regulatory targets."[63] In general, the Company plans to review and rank circuits annually, prioritizing the worst performers. A field engineer will review the frequency and duration performance from the previous 5 years to find event trends and recommend solutions[64]. Solutions development considers several traditional options such as vegetation management, animal guards, and hardening but may also recommend larger efforts such as reconductoring. Advanced Reclosers and automation are additional options. Once high-level estimates are completed, the most favorable projects are forwarded for design and construction.

Similar to the CEMI-4 Program, I support efforts to identify and address feeders that have customers experiencing high numbers or durations of interruptions. The Company currently reports 5% of worst performing circuits in its quarterly Feeder Ranking Report (Docket 3628). The report includes feeder outage information and power line repairs completed by field personnel to immediately restore interrupted customers. The Company does not leverage the data to track or identify chronic conditions that warrant long term corrective actions[65]. This is a reactive position. The ERR Program remedies this deficiency by formalizing annual reviews and advancing strategic circuit improvement.

The Company provided a list of proposed ERR Program circuits for FY 2025 that includes 17 feeders[66]. Generally, the objective of the program is to address circuits with

[63] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 8, page 3.
[64] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-5.
[65] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-6.
[66] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 4-12.

interruption frequencies greater than 1.5 as compared to the system regulatory frequency of 1.05. My primary concern, however, is that over time and as systemwide reliability improvements are implemented, the top 5% of worst performing circuits may be comprised of feeders performing marginally above regulatory requirements but not at a level requiring corrective actions. Addressing these feeders would result in unnecessary investments. I expect that criteria guiding feeder selection will be reviewed annually by the Company and Division to ensure that reasonable budgets are established and that improvements are aimed where there is a demonstrated need.

From information provided, the Company appears to be developing sufficient analysis of each circuit and considering a broad portfolio of solutions[67]. RIE expects that work will concentrate on the main line sections of this circuit because it has the greatest statistical impact on the circuit[68]. Although targeted circuits will be developed prior to annual ISR Plan filings, engineering and design will occur after the filing and make any analysis of recommendations, scope and cost estimates nearly impossible during the ISR Plan review process. However, RIE's agreement to provide the Division with specific information 60 days prior to advancing work on a feeder should satisfy this concern.

The Company did not provide an ERR BCA discussion or calculation methodology in its initial filing but did present a Docket 4600 analysis in the December 21, 2023 filing. The Division followed up with a request for all BCA workpapers, assumptions and supporting documents[69] . Review of the information indicates that RIE estimated a 25% reduction in CKAIFI and CKAIDI for each targeted circuit which was then converted into

[67] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-13.
[68] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-8.
[69] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 7-7.

system reductions. The reductions along with requisite information (number of customers by class, inflation and discount rates) were applied to the ICE Calculator to derive a reliability benefit. The Company assumed the benefits accrue over a 20 year period and that the upfront cost of the program is $2 million. The Company calculated a Net Benefit/Cost ratio of over $21 million and a BC ratio of 8.69 which is extremely favorable but still unsubstantiated at this point.

Similar to the CEMI-4 program, the Division does not solely rely on the BCA to determine program advancement, but there are several areas of refinement that would produce a more defendable BC ratio. My observations and concerns with the Company's BCA methodology, assumptions and use of the ICE calculator noted in the CEMI-4 section are applicable here. The more important matter is tracking future costs and performance to assess program effectiveness. The Company has put forth an approach to measure and report ERR performance results as follows:[70]

> "Reliability investments are investments in the future. Time will tell how successful these reliability investments have been. CKAIFI and CKAIDI are the metrics we use to measure this performance and by putting forward projects to directly reduce the number of customer interruptions and the duration of outages, over time we will see a positive downward trend. Since weather has a direct impact on reliability statistics, improvements need to be looked at as a trend over multiple years. The Company will review the ERR feeders average CKAIFI and CKAIDI values at 3-years and 5-years post ERR review to gauge how successful the recommendations have been with improving reliability."

RIE's proposal is consistent with Division expectations and will be valuable in solution justification and BCA refinement. The ERR Program is a longer standing initiative and measurement and validation will be critical to support program structure and ongoing

[70] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 8, page 5.

spend. At the conclusion of extensive discussions with the Company, the ERR program budget was reduced by $2.5 million, resulting in a FY 2025 budget of $2.0 million.

3. Distribution Automation Recloser Program (DARP)

The Distribution Automation Recloser Program was initially proposed at $17.2 million in the FY 2025 ISR Plan with nearly $45 million in the 5-year spending plan that is only a portion of the anticipated 7-year spend. Within the program, the Company proposes Advanced Reclosers on each overhead circuit to achieve its intended sectionalizing scheme and will add additional reclosers to enable automated switching to restore power to customers served by unaffected portions of circuits in the event of a fault (FLISR). Some reclosers will be installed under the CEMI-4 and ERR programs, while the remaining are installed under the DARP. The Company derived a BC ratio for the DARP of 1.19 which was re-calculated at 1.11 to reflect revised customer counts[71]. The December 21, 2023 filing indicated a BC ratio of 1.05. I have multiple concerns with the DARP including areas of minimal justification, the reliance on generalized benefits to support advancement, the lack of options analysis, and RIE's approach in defaulting to reclosers as the reliability solution without outage root cause analysis. This is an example of industry inertia driving a technology advancement simply because the technology is available. Considering the asset condition issues yet to be resolved and the relatively high retail rates, RIE needs to take a more measured approach to the DARP than may be occurring in other jurisdictions with lower power cost in the $0.12/kWh range.

[71] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 4-34.

A primary objective in evaluating the DARP is to understand the benefits of a mainline recloser as compared to the incremental benefits of another 2 to 3 reclosers with a FLISR scheme. This was challenging since recloser installations were captured in the DARP and presumably justified by an overall benefit-cost analysis, yet actual installations are under one of three programs. If a recloser is installed in another program, the Company adjusted the BCA in that program to include the recloser cost and a calculated benefit. The recloser benefit was derived by RIE's assumption that DARP would achieve the intended goal to reduce main line interruption frequency. The ISR Plan explains and calculates that a mainline recloser would result in a net system reduction for mainline events of 25%, and modeling this within the ICE Calculator results in an additional benefit of $28,000 per year per feeder[72]. This implies that the benefit of a mainline recloser is $28,000, but not necessarily the benefit of 2 to 3 additional reclosers and a FLISR scheme. The Division attempted to gain further clarification by asking for estimated outage reductions for circuits with reclosers but without FLISR. The Company response follows:[73]

> This question may be attempting to explore what the benefits might be with a sectionalizing recloser only, avoiding a recloser at an open points. In this case, a rough approximation of the benefit would be half of the estimated 25% main line frequency reduction or a 12.5% reduction. This rough approximation is simply derived from recognition that for downstream faults of a new sectionalizing recloser, the upstream customers would avoid an interruption.

Based on RIE's estimates, if FLISR accounts for half the benefit, then the quantified FLISR benefit would be one-half of $28,000 or $14,000 per year per feeder. Although the Company's filing and data responses are generalized, a FLISR BCA can be calculated. Assuming a $240,000 investment for 3 reclosers with FLISR ($80,000 each) that yields

[72] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 7, pp. 10-11.
[73] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-37.

$14,000 of benefits over 20 years, the resulting BC ratio is 0.71 using a 6% discount factor. Although this is a simplified view, it highlights the potential diminishing returns of significant recloser additions. The value of additional reclosers also declines as investments are made on circuits that are performing near or even below (better than) system average. Also, benefits only accrue if the FLISR scheme operates. RIE calculates that each scheme would be expected to operate roughly 37% per year[74] to achieve intended interruption frequency reductions. Characterizing this differently, roughly one third of FLISR installations on the system would need to operate each year to achieve the targeted SAIFI reductions yet the BCA assumes that all customers fully benefit from recloser additions. This does not seem logical.

The Division specifically requested a BCA for the DARP assuming that all proposed reclosers are installed without an automated scheme. Again, this was an attempt to understand the value of mainline reclosers and the incremental value of FLISR. The Company's response[75] indicates a program BC ratio of 0.76 for a scenario where all proposed reclosers are installed but without a FLISR scheme. This was derived by reducing benefits by one-half and maintaining full costs of the reclosers. This compares to the RIE's BCA for the DARP (reclosers with FLISR scheme) of 1.05. The Company's response to the data request suggests that FLISR improves the program BC ratio from 0.76 to 1.05. The calculation is misleading since all proposed reclosers would not be installed unless

[74] The Company adds in response to DIV 4-36 that "(w)hile RIE completed the calculations for purposes of this response, the Company does not suggest that a calculation to estimate how often a scheme operates is meaningful. Instead, the Company suggests consideration of the goal of main line frequency reduction of 25%." This statement is confusing since the program objective is to install reclosers to achieve main line frequency reductions. Reclosers would be expected to operate to achieve intended results. If the reclosers did not operate and mainline frequency reductions occurred, then a case could be made that reclosers were unnecessary. This relationship drives program assumptions and the BCA.
[75] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-35.

FLISR schemes were implemented (a FLISR scheme requires 2 to 3 additional reclosers). Adjusting the BCA costs to reflect a lower number and cost of reclosers, or only mainline reclosers, provides a more accurate representation. Assuming that RIE installs 595 mainline reclosers[76] over the program term while maintaining the same benefits, the BC ratio becomes 1.61 which is well above the program BC ratio of 1.05 estimated by RIE. This is a subjective exercise but is presented to show that baseline benefits achieved with only mainline reclosers can well exceed costs and as additional reclosers are added for FLISR schemes, costs outweigh benefits.

Although the true costs and benefits will be documented and analyzed after approved reclosers are installed in FY 2025, I offer the following observations on expected outcomes:

- RIE proposes the DARP to address circuits with higher frequencies of interruptions and estimates the benefits by quantifying reductions in circuit level SAIFI. Yet when operating, FLISR schemes will actually increase momentary interruptions for customers, some of which would not have experienced an interruption. RIE acknowledges this outcome by assuming that FLISR recloser actions will result in an approximate 2 minute momentary interruption and adjusts the BCA accordingly. This paper exercise fails to consider the true customer experience. Short interruptions are more than a nuisance, particularly for commercial and industrial customers, and can be costly. RIE should consider these impacts when designing automated schemes and minimize increased interruptions for sensitive loads.

[76] Reference DIV 4-29; this is determined by taking the total customer count 497,500 divided by 500 customers per recloser, which results in an approximate mainline recloser count of 995 reclosers, then subtracting 400 existing reclosers for a total of 595 mainline reclosers.

- A significant advantage of a properly operating FLISR scheme is outage duration reduction. Automated switching to restore service avoids manual intervention whether the action is remotely controlled through a control center or physical switching in the field. RIE acknowledges that "In the absence of FLISR, the customers will remain without service until the circuit was manually isolated by a line crew or remotely switched by a system operator."[77] However, RIE proposes the DARP to reduce the *frequency* of mainline outages that accounted for approximately 80% of all RIE's reportable SAIFI. While the program BCA considers both SAIFI and SAIDI reductions, program objectives and realized benefits may not be aligned and must be verified through performance tracking.

- The Rhode Island PUC definition of sustained interruption is loss of electric power lasting equal to or more than one minute. The IEEE definition is loss of electric power lasting five or more minutes. RIE will initially report program results using both methods but intends to transition to the IEEE definition stating it "is important and necessary for the Distribution Automation program as the FLISR schemes typically trigger in less than 2 minutes, but more than 1 minute."[78] The Company's transition creates a buffer, essentially making it more likely that the automated scheme will contribute to a reportable decrease in SAIFI. RIE's primary obligation is reliability reporting using the PUC's definition and the Division believes that the Company should not transition to IEEE but continue to report under both methodologies for purposes of measuring program effectiveness. This should apply across programs.

[77] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-43.f.
[78] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-26.

- The utility industry focus on self-healing (FLISR) type schemes as a smart grid enhancement results in SAIDI improvements particularly during storm events (major or otherwise). Outage duration appears to be a more important focus versus a momentary interruption which will occur in every case. Whether 1 minute or 5 minutes is the momentary interruption threshold analysis time has no real bearing on the customer perception since the customer actually experiences the interruption in real time. Changing from the Commission 1 minute standard to the IEEE 5 minute standard is simply a statistical game and does not change the customer experience.

Another concern with RIE's program design is the failure to consider alternatives for sectionalizing. RIE defaults to fully automated reclosers for every installation. Utilities often use a combination of lower cost devices to accomplish sectionalizing schemes such as standard reclosers (without advanced functionality) that cost $20,000 to $30,000 and fault savers that cost $10,000. RIE expects that less advanced equipment would not capture data required due to moderate to high DER penetration and that the lack of functionality could lead to high probability of early obsolescence. The RIE approach is contrary to what other utilities are applying. The Company believes they have taken a measured approach and that the BCA supports their decision[79]. I am not convinced that Advanced Reclosers must be installed in every situation and especially in the immediate future to monitor and manage DERs. The Company is making global statements to justify their strategy with no effort to evaluate the efficacy of viable alternatives. RIE has certainly not produced any options analysis which leads stakeholders to believe that installing 1,267 Advanced

[79] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-42.

Reclosers across the system is the only path forward. Given the magnitude of the program, I believe a more robust evaluation would be expected before a systemwide launch.

Lastly, I am concerned that RIE does not intend to address the root cause of outages under the DARP and will only install reclosers to address reliability. This contrasts with the CEMI-4 and ERR programs where a variety of circuit improvements are considered to reduce interruptions with reclosers being one of the options, not the default solution. Although the Company has verbally committed to addressing concentrated outage causes when engineering recloser placement, the program documentation does not facilitate the expected depth of evaluation. I am concerned that the DARP proposes reclosers when there is no obvious need. I reference Coventry Circuit 56-54F1 to illustrate this point. The Company indicates that the circuit had a 5-year average CKAIFI of 2.4. RIE proposes an additional 5 open reclosers under the FY 2025 DARP[80] presumably to incorporate a FLISR scheme. The need for these reclosers is not obvious, particularly given that:

- Circuit 56-54F1 was included in the FY 2024 CEMI-4 program which is designed to identify and fix reliability issues for customers experiencing poor service. The Company has made investments to improve reliability but has not considered the outcome before planning additional recloser investments.
- There are seven existing mainline reclosers on Coventry Circuit 56-54F1 with 336 customers per line section which is well below RIE's target of 500 customers per line section. One of these was a mainline recloser installed on or after April 1, 2022 and that recloser has not operated[81]. The circuit is adequately sectionalized which should produce expected reliability improvements.

[80] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 4-43-1.
[81] Docket 23-48-EL, Proposed FY 2025 ISR Plan; DIV 4-38.

- RIE identified Coventry 54F1 for targeted vegetation management under the Pockets of Poor Performance program in FY 2021. After two years of tracking, the Company indicates roughly 60% to 80% average reductions in outage events for circuits in the program[82]. Although the Pockets of Poor Performance data is limited and would benefit from a standardized assessment as the program progresses, it does demonstrate the value of addressing the root cause of events. It could be that additional tree work resolved a great number of main line outage issues on the Coventry feeder, making the need for 5 additional reclosers questionable. Trees and branches are the leading cause of interruptions on RIE's system and the vegetation management program has and will continue to be a critical core maintenance activity.
- The related Area Study-Central RI West proposes reconductoring a 4.5 mile section of Coventry 54F1 that contributes to poor reliability due to tree contact[83]. The project is expected to improve SAIFI and SAIDI 16% and 17% respectively. The study also indicates that 54F1 is heavily loaded and that a portion of the circuit will be transferred to a new distribution feeder out of the future Weaver Hill Substation. This work will result in additional reliability improvements that, again, makes the need for 5 additional reclosers questionable.

The Coventry 54F1 example shows that RIE should provide considerably more information to justify recloser additions on select circuits. The DARP documentation and BCA do not support proposed recloser installations since they fail to account for circuit characteristics, outage causes, and other initiatives to improve reliability. To remedy this

[82] FY 2025 ISR Plan Pre-File; Recommendation #15 Vegetation Management Cost-Benefit Analysis, Table 7.
[83] RIE has implemented enhanced tree trimming practices to increase clearances. The Division would expect the reconductoring project to be evaluated against enhanced vegetation management/tree removals which could be a lower cost and equally effective solution that addresses the root cause of outages.

gap, RIE agreed to provide the Division with information prior to progressing programmatic recloser additions.

I have gone into great detail to highlight deficiencies in RIE's justification for the DARP. The Company comingles the expected performance and benefits in a way that it is impossible to distinguish why it is necessary and cost-effective to consider a minimum of 2 to 3 Advanced Reclosers with FLISR, in addition to mainline reclosers, on every circuit across the system. Setting aside concerns with relying on the ICE Calculator to quantify benefits I am not convinced that RIE has appropriately evaluated costs and benefits of the DARP and particularly FLISR. RIE's BC ratio for the DARP is 1.05 and while the Division does not solely rely on a BCA in determining support to advance new programs the results are not compelling. I believe that the preponderance of benefits can be achieved with mainline reclosers where necessary and that incremental costs of adding reclosers for self-healing circuit functionality appear to outweigh benefits. Justification for additions on select circuits is not obvious and RIE must produce more comprehensive analysis. These factors, combined with reservations regarding the lack of a system-wide sectionalizing study, contribute to my reluctance in fully endorsing the Distribution Automation Recloser Program. Despite these reservations the Division does acknowledge that there are strategic locations that would benefit from recloser installations and that targeting the worst performing feeders is a logical starting point. The concerns regarding cost and performance can only be addressed through actual data and the Division ultimately agreed to a budget that allows limited FLISR work to progress in order to demonstrate actual performance and benefits over time. The Company agreed to work with the Division to establish requisite analysis and derive cost and performance tracking mechanisms. The results are expected to inform future levels of DARP investments. At the conclusion of extensive discussions with the Company, the DARP budget was reduced by $1.5 million, resulting in a FY 2025 budget of $6 million. The Company has acknowledged the need to take a measured approach and assure affordability.

In summary, the FY 2025 ISR Plan includes a combined budget $10.6 million for the CEMI-4, ERR and Distribution Automation Recloser Programs. Proposed spend includes $7.2 million for 88 Advanced Reclosers. To reach consensus, the Division put forth the position and conditions shown below:

FY 2025 ISR Plan Division Position on Reclosers and Budget

1. Division confirms agreement with 15 mainline reclosers proposed at a budget of $1.2 million in the CEMI-4 and ERR Programs.
2. Additional reclosers and all associated work to implement FLISR schemes are conditionally supported to address top worst performing circuits. The portfolio of circuits to be only those with average CKAIFI of 2.0 or greater, as determined from *Attachment A – Preliminary Prioritization List – Circuits with Frequency > 1.05* (October 13, 2023 Proposed FY 2025 ISR Plan, page 133). This results in 73 reclosers at a budget of $5.957 million in the Distribution Automation Recloser Program.
3. Conditions:
    a. The budget for reclosers and all associated work to implement FLISR schemes will be capped at the levels stated above.
    b. RIE will work with Division to:
        i. Establish specific information to be provided to the Division 60 days prior to RIE advancing work on any CEMI-4, ERR or Distribution Automation circuit in FY 2025.
        ii. Establish cost and performance tracking mechanisms, including specific measures for circuits with FLISR schemes.

RIE accepted the position during discussions and acknowledged agreement with providing information in advance of progressing any recloser installations and also providing cost and performance tracking information[84]. RIE also agreed that feeders in the FY 2025 Plan under

[84] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Joint Testimony, page 16, lines 6-17.

the Distribution Automation Recloser Program would be selected based on a CKAIFI level above 2.0[85] which is consistent with the Division's expectations. The Company has agreed but does not acknowledge in its testimony or filing that the budget for reclosers and work to implement FLISR will be capped at $5.957 million in FY 2025. The DARP gaps and deficiencies outlined in this report are cause for stricter oversight as the program launches. The Division recommends that the DARP be separately tracked and be subject to an overall budget cap of $5.957 million in FY 2025. The cap should be separately administered from any potential ISR Plan budget discipline imposed by the Commission.

I. <u>Additional Assessments</u>

1. <u>Non-Wires Alternatives</u>

As part of the Company's Area Studies, projects are screened for non-wires alternatives (NWA). The thresholds that determine when a NWA should be considered are established through the Company's SRP plans and incorporated into the Company's distribution planning guidelines. Projects meeting the thresholds are evaluated against both utility-owned and third party owned alternatives that progress through a bid process. The Company selects the least cost, fit-for purpose option which advances through the SRP if a NWA is chosen, or through the ISR Plan if a traditional capital solution is selected. The Company has completed efforts to consider six NWAs and there is one pending NWA solicitation with no impact on this ISR Plan other than some initial engineering costs. Looking over the longer term, the Company has considered possible increases to the System Capacity and Performance investments in the Long-Range Plan as a result of transportation and heating electrification. Although the pace and timing of electrification and electric vehicle charging load is uncertain, increased loads

[85] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, page 41.

will drive the need for system investments that would be screened for NWAs. The Division anticipates increasing opportunities for successful NWAs to meet those future system needs, particularly as the cost of alternative technologies such as batteries decreases over time. Furthermore, it is more likely these loads will be much slower to develop than the state goals. Conversion costs for heat pumps has dramatically increased since the pandemic and EV sales have been slowing across the country.

The NWA process has significantly evolved, yet it remains unclear what might be the requirement or rationale for having a customer implement a NWA strategy when a system capacity project is driven by that same customer's increasing load. Additionally, the SRP process is expanding most particularly in the area of demand response. It is anticipated this will actually result in demand reduction and it will significantly reduce the need for traditional capacity related projects. These impacts require much more assessment in the Long-Range Plan.

2. Docket 4600

The Company identifies new or incremental programs in the proposed ISR Plan and describes how each advances, detracts, or is neutral to each goal in Docket 4600[86]. The Company also applies a benefit-cost analysis ("BCA") to new or incremental programs using the Docket 4600 Framework. For the FY 2025 ISR Plan, the Company applied the Docket 4600 benefit-cost framework to the Distribution Automation Recloser Program and Engineering Reliability Review Program. Although the data presented by the Company for Docket 4600 analysis is not relied upon to reach concurrence on the ISR Plan, the underlying assumptions and BCA calculations are informative and evaluated in detail. As I discussed in

[86] Docket No. 4600A – Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid, dated October 27, 2017.

this report, there are several problems with the Company's benefit cost analysis in general and the assumptions in particular. I expect that the Company will address areas of refinement to produce a more defendable BCA and proactively provide data to support the inclusion of new projects in the ISR Plan during the Division's review.

3. <u>AMF</u>

The Company included a discretionary spending category associated with the deployment of its Advanced Metering Functionality program ("AMF")[87]. The FY 2025 proposed budget is $51.7 million comprised of four spending categories as follows:

ISR Plan Capital Budget AMF ($000)	FY 2024 Budget	FY 2025 RIE Proposed 12-21-23
Meter Costs	-	28,655
Network Costs	-	4,935
System Costs	-	14,356
Program Costs	-	3,779
Total AMF	**-**	**51,725**

RIE states that the AMF annual spending projections are in line with the project cost cap approved by the Commission and references the business case in Docket No. 22-49-EL (AMF Docket). The Division's review of AMF considers alignment of proposed ISR Plan capital spend with the Company's stated levels in the AMF Docket. There are timing variations in implementation, some due to delays in program launch and others due to the fiscal year of the ISR Plan versus the calendar year of the AMF Docket. Since AMF was separately considered under Docket 22-49-EL, and the Division participated in that docket, the Division

[87] As described in Docket No. 22-49-EL as authorized by the Commission at the Open Meeting on September 27, 2023.

in the ISR Plan is simply evaluating AMF capital cost for compliance with the Commission's order.

4. Long-Range Plan

Over the course of many proceedings, I detailed several observations that impact the Company's ISR Plan and raised concerns with the Company's efforts to manage those issues. These generally included the lack of transparency and cohesiveness between the Company's design criteria, System Reliability Procurement, and Area Studies, in addition to delays in producing a Long-Range Plan. The Company has been responsive to Division recommendations and has made iterative improvements to planning documentation while also proactively engaging the Division throughout the year to provide updates on current project execution and prospective ISR Plan proposals. This on-going process is beneficial for the Division's review of ISR Plan filings and ultimately crafting enhancements that assist the Commission and stakeholders in understanding the complexity of the planning process and the Company's justification for capital investments.

The Company has now completed all Area Studies, although the pace of completion has not met expectations, and it put forth a 10-year Long-Range Plan[88]. The Division requested that the Company develop this comprehensive strategic capital investment plan based on the results of Area Studies and to include forecasted spend for each category of the ISR Plan. This is the Company's first submittal which provides spend by ISR Plan category for years 1 through 5 (Long-Range Plan Step 1) which is intended to reflect budgeted capital in the proposed 5-year ISR Plan. The Long-Range Plan Step 2 extends forecasted spend for years 6

[88] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Section 2, Attachment 5.

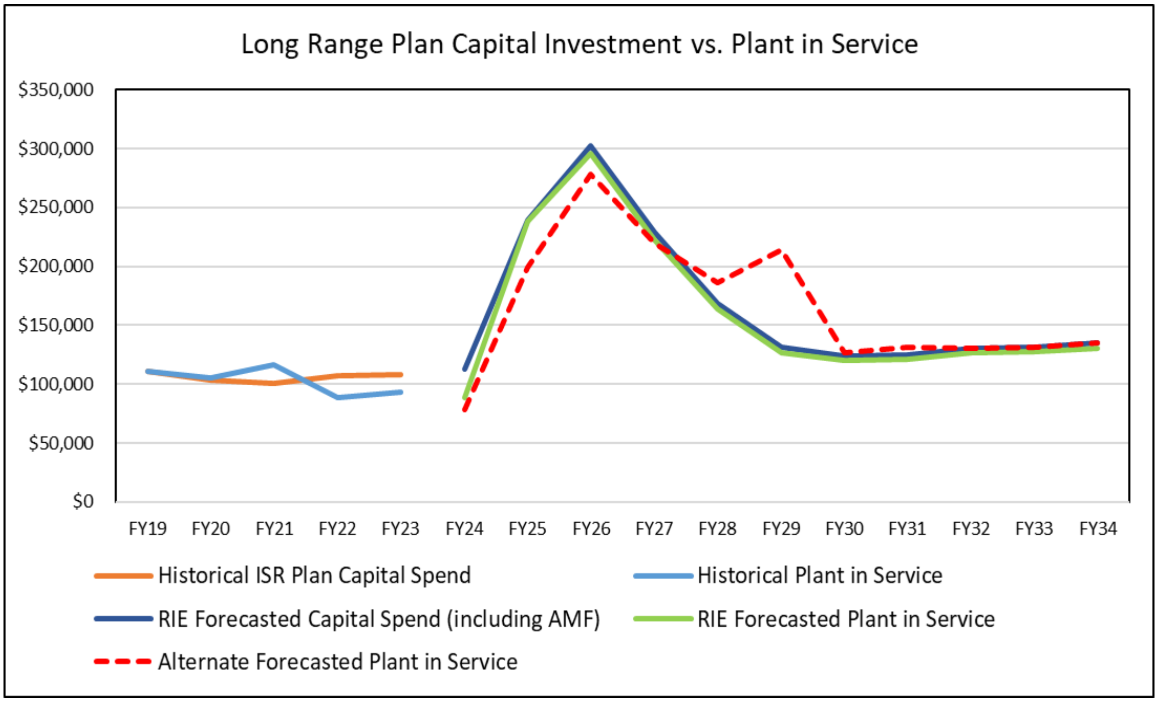
through 10. Discretionary spend in the Long-Range Plan predominantly supports projects identified in Area Studies that are proposed for completion in the initial 5-year period. Incremental capital investments from external initiatives such as AMF are excluded in the plan. Accompanying information broadly describes the development methodology and provides summary results of each Area Study and recommendations.

The Long-Range Plan was not discussed at length with the Company but rather relied upon for a general view of the pace and timing of capital investments. The Company's submittal reflects their continued position to compress Area Study project construction into the first five years of a 10-year period. This would increase annual discretionary spend over 50% and when considering AMF deployment, capital spend could reach over $270 million in a single year but drop back to $125 million in subsequent years. The potential levels and variability of future spend are troublesome, particularly any year where proposed investments reach $270 million as compared to roughly $100 million in prior years. I have consistently recommended more modulated spend by stretching project implementation which is crucial during years of additional capital needs such as AMF implementation. System capacity projects could be further deferred particularly considering the lack of load growth and peak reduction contributions due to DER and the expected reductions driven by SRP demand response programs. Other discretionary spend for reliability should be tempered given RIE's very good system reliability performance. I believe these principles have guided agreement on a balanced spending plan for FY 2025 and will also offer opportunities for adjustments in future ISR Plans, particularly in the System Capacity category once RIE completes engineering and cost estimates for remaining Area Study projects. The Company must carefully examine discretionary projects when preparing upcoming ISR Plans and make every effort to put forth a more judicious investment proposal than indicated in the currently filed Long-Range Plan.

There is significant collaborative work to take place between the Division and RIE which has not progressed at this time.

In addition to projected levels of spend, forecasted plant in service must also be considered which is the basis for rate adjustments. Assuming the Long-Range Plan reflects future investments, the Company forecasts plant in service levels that roughly follow annual spend. RIE's forecast methodology assumes that 97% of capital spend is in service each year based on average historical data[89]. However, the Company's proposed future plans include more multi-year substation and large distribution projects than in previous years. These projects are not in service until all construction is complete. Assuming the projects are forecasted to be in service in the last year of the implementation[90], a much different pattern of plant in service is observed. The following graph illustrates historical and future forecasts based on RIE's methodology and my alternate estimate:

[89] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Attachment DIV 6-8.
[90] This illustrative analysis was performed by totaling Long-Range Plan Area Study project budgets (except for Providence Study) and assuming the total becomes plant in service in the last year of construction. All other capital investments are assumed plant in service in the same year of spend.



Future spend and actual plant in service levels are unknown but there will most certainly be significant upward pressure in the near term driven by AMF investments. Ratepayer impacts and affordability considerations are of paramount importance, particularly given that Rhode Island currently has the some of the highest rates in the United States[91]. To aid in future evaluation of ISR Plans and the Long-Range Plan, RIE should prioritize propagating their distribution model (CYME) with AMF data to produce higher quality load profiles and enhanced load distribution models for each circuit before any massive spending programs are advanced as rapidly as the Company proposes. Furthermore, RIE needs to improve its consideration of the SRP process and impact on reduction in peak load. Utilities have consistently found that once the AMF meter data is used in the system modeling, it uncovers different solution sets and provides a far better picture of the overall system. Since AMF is now being advanced, major projects which do not demonstrate an existing problem

[91] EIA 2022 Electricity Profile - Rhode Island.

that requires immediate attention are candidates for deferral. The Long-Range Plan and ultimately the ISR Plan should be supported with project criticality or similar risk rankings. Although the Company has added qualitative risk assessments for select Asset Condition Area Study projects, the criticality of one project over another is not obvious. The System Capacity Area Study project summaries do not assess risks. I continue to recommend a more robust risk analysis to support proposed implementation timelines. These are examples of enhanced assessments that the Division and RIE will explore to strive for systematic project implementation and more evenly distributed spend across the planning horizon to avoid runaway spend.

5. Budgetary Framework

The Company filed a newly proposed ISR Plan Budgetary and Reconciliation Framework[92] in response to an initial framework drafted by the Commission. The version in the FY 2025 ISR Plan was the second iteration presented and reflects "the Company's consideration of the feedback it received from the parties in response to the First Proposed Framework."[93] RIE has requested that the Commission approve the framework and if granted, subject to modifications and additional directives from the Commission, RIE will submit a tariff for review and Commission approval. RIE proposes to apply the framework to the FY 2025 Electric ISR Plan.

The Division participated in a technical conference on the matter and provided informal feedback to RIE during ISR Plan conference calls. The proposed framework put forth in the FY 2025 ISR Plan filing does not fully reflect the Division's positions. With the understanding

[92] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Joint Testimony – Exhibit 2, pp. 1-3.
[93] Docket 23-48-EL, Proposed FY 2025 ISR Plan; Joint Testimony, page 25, lines 15-17.

that approval and additional directives rest with the Commission, I address each component, highlighting concerns and recommended revisions for the Commission's consideration in determining the final framework.

Within category 1 of the framework, RIE proposes that Non-Discretionary Capital Investments relate "to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission" and further that Non-Discretionary Investments are uncapped and "subject only to prudency review, as long as the definition for this category is strictly met." In categories 2 and 3, the Company defines Customer Requests/Customer Requirements and Damage Failure, the two spending rationales considered Non-Discretionary. The definitions generally align with language the Company has historically used in ISR Plan filings to describe the type of investments considered under each rationale. However, RIE also includes the statement that "The Damage/Failure budget may also include the cost of purchasing strategic spares to respond to equipment failures." This definition could be interpreted as the need to replace spare equipment that is put into service when a failure occurs or could be interpreted as support for RIE's proposal to significantly increase its spare inventory, particularly substation transformers. The Division would agree with replacing spares that are put into service, but as I discuss in this report, there are multiple concerns with RIE's spare equipment program including the risk of making sizeable and unnecessary investments (see Section D.2) To alleviate misinterpretation or Division concerns otherwise, it is recommended that the last sentence of the Damage Failure definition be struck. Alternately, the Division proposes the following revision to RIE's proposed language:

> The Damage/Failure budget may also include the cost of purchasing ~~strategic~~ <u>replacement</u> spares <u>for equipment placed in service</u> to respond to ~~equipment~~ failures.

I also highlight potential issues with limiting Non-Discretionary investments to prudency reviews as long as the definition for the category is strictly met. As proposed, the definitions would govern what investments are subject to specific reviews. Depending on interpretation there could be unintended consequences of allowing spend that would be considered Discretionary, and subject to robust evaluation and a spending cap, as uncapped Non-Discretionary spend with limited review. The Division will continue to evaluate each proposed project and program in the ISR Plan filings to determine the appropriate category and while the Company's definitions can be relied upon for general guidance, the Division's review may indicate alternate findings.

For the Discretionary categories 5 and 6, RIE proposes treating Asset Condition and System Capacity & Performance (excluding Major Projects) as one budget with a 2.5% overspend tolerance. RIE proposes the same 2.5% overspend tolerance for Non-Infrastructure (category 7) except for corporate overheads, which would not have a formal cap but would be subject to accounting review. The Division concurs with this approach which provides the Company with flexibility to manage individual project uncertainties that affect scope and cost, while maintaining annual budget discipline. RIE proposes that when actual spend exceeds the tolerance in any proposed budget grouping, any revenue requirement adjustments should be applied to all overspend, including that within the tolerance margin and that those costs could be included in the next ISR factor. In addition, RIE proposes that when a specific need causes budgets to exceed thresholds, the Company will discuss with the Division the potential to include overspend in the current ISR reconciliation. The Division is amenable to this provision but emphasizes that the Division always reserves it right to review and comment on budget overspends and any associated requests for rate recovery.

In category 9, RIE combines all O&M (Vegetation Management, I&M & Other O&M) with a 2.5% overspend tolerance. The Division does not concur. Consistent with past practices, Vegetation Management should be separately managed while I&M and other O&M may be combined. New categories of O&M such as AMF should be separately managed as well. Each separately managed category would be subject to an overspend tolerance. RIE proposes that overspend be considered in the next ISR factor. This is a reasonable proposal and the Division is not opposed. The Company does not propose potential discussions with the Division to capture overruns in a current ISR factor, indicating that RIE likely has more control in O&M.

A separate tracking mechanism is proposed for Major Projects in category 8 which is a continuance of the Company's agreement reached with the Division in the FY 2017 ISR Plan. At that time, the Division recommended, and the Company agreed to manage the South Street budget separate from other discretionary projects, such that any budget variances (underspend) would not be utilized in other areas of the Plan. RIE continues to track major projects separately but the mechanism to identify candidate projects is informal, so the definitions will provide meaningful guidance. The proposed budget discipline establishes specific screening criteria and puts forth additional aspects to consider when the Company and the Division discuss inclusion of new projects. RIE proposes the following:

Screening Criteria (to be considered for a separately tracked major project):
1. Project spans greater than two ISR fiscal years.
2. Excludes programs (e.g. breaker replacements, URD, UG).
3. Substation project with a total project cost >$10 million.
*The Company would be open to discussing with the Division including additional substation projects >$5 million.

Discussion Phase with Division to Determine if this is a Separately Tracked Major Project:
1. Risk Potential (based on subject matter experts and similar projects)
2. Execution Complexity
3. Scope Complexity

It is difficult to set hard parameters on what constitutes a Major Project. I believe that new substations, expansions, or replacements could be separately tracked due to inherent complexities, regardless of cost. Associated distribution work is more routine and predictable but there could be instances where a challenging scope warrants separate tracking, such as cases involving underground, river crossings, building in congested or sensitive areas, new rights-of-way, etc. I disagree that programs should be excluded but suggest that multi-year programs would be candidates. The rationale is that the Company puts forth capital investment programs designed to conclude at a specific time or when a program objective is met. Some examples are upgrading electromechanical relays, achieving reliability targets through CEMI-4 initiatives, or potentially installing fiber communications infrastructure. The Company presents program documentation establishing components such as program scope, cost, length, and expected performance improvements. The Division relies on this information when concurring with program advancement. If RIE is only held to annual spend in the Discretionary category, the program could hypothetically be implemented in perpetuity with no accountability for total program costs, scope or performance. Separately tracking these programs would provide needed accountability and transparency, particularly for the cost component. I am not suggesting that all programs be subject to separate tracking but that inclusion would be based on Division and RIE discussions considering the same criteria suggested for Major Projects and taking into account complexity and risk. Programs such as one-for-one relay upgrades may not warrant tracking but would be managed under the Discretionary budget. Similarly, I do not recommend that ongoing asset condition programs such as URD or UG replacement be considered for separate tracking. Given these observations, I do not recommend RIE's prescriptive definitions but that the proposed language, as revised below, be used to guide the Division and RIE in determining potential candidates and ultimate selections for separately tracked projects or programs.

Screening Criteria (to be considered for a separately tracked major project or program):
1. ~~Project~~ ~~s~~Spans greater than two ISR fiscal years.
2. Excludes ongoing asset condition programs (e.g. ~~breaker replacements,~~ URD, UG)
3. ~~Substation project with a~~ ~~t~~Total ~~project~~ cost >$10 million
*The Company would be open to discussing with the Division including additional ~~substation~~ projects or programs >$5 million.

Discussion Phase with Division to Determine if this is a Separately Tracked Major Project or Program:
1. Risk Potential (based on subject matter experts and similar projects)
2. Execution Complexity
3. Scope Complexity

RIE proposes that selected projects be held to budgetary constraints based on the Construction Resource Procurement phase which has an estimate accuracy of +/-10%. I concur with establishing the budget target at this phase since the project would have progressed through detailed engineering, design and bid negotiations making it the most refined estimate possible. I recommend that multi-year programs be subject to the same conditions. Although RIE does not necessarily progress programs in the same manner as projects, the Company should be required to develop a similar program estimate. Additional flexibility is recommended in the event that annual budget oversight is desired. The framework imposes budget caps on total costs which are unknown until the project or program concludes and is reconciled. Annual spend is hypothetically unlimited. There may be instances where an annual cap is desired to either help manage the overall ISR Plan capital budget or even limit annual programmatic investments rather than total program spend. The agreement between the Division and RIE to cap FY 2025 spend in the Distribution Automation Recloser Program is an example of a program that could be separately tracked and subject to an annual cap. RIE proposes that costs exceeding the estimate accuracy of 10% may not be included in the current

ISR reconciliation factor but could be included in the next ISR factor. I recommend that the same treatment apply to separately tracked programs and also to costs that exceed applicable annual thresholds. Based on these comments, the following revisions are recommended:

> The Company would discuss with the Division what will be a separately tracked large project <u>or program</u> when a project is first initiated <u>or when a program is first proposed in an ISR Plan</u>. The Company would be held to budgetary constraints after the Construction Resource Procurement phase when estimate accuracy is refined to +/-10% <u>for Major Projects or to a Company derived estimate for programs</u>. If costs for a project <u>or program</u> exceed its estimate accuracy of 10%, <u>or if costs exceed an annual threshold otherwise approved by the Commission</u>, the Company may not include the amount of budget overrun in the current ISR reconciliation factor. These costs could be included in the next ISR factor.

Lastly, the Division recommends that RIE's proposed separately tracked Major Projects in the FY 2025 ISR Plan be revisited in light of potential changes to the selection criteria. The Division and RIE did not discuss potential projects that meet the criteria, nor is there a clear understanding of what constitutes "when a project is first initiated." There are several budget line items reflecting Area Studies and presumably a subset of those budgets would be separately tracked Major Projects. This warrants further evaluation along with a review of other programs that would be eligible for separate tracking beginning in FY 2025.

III. VEGETATION MANAGEMENT

The Company proposes Vegetation Management expenditures of $13.1 million in FY 2025. This compares to a $14 million budget and forecasted spend in FY 2024. The Vegetation Management Program, which includes customary programs, risk reduction enhancements, and a new tree growth regulator treatment was not adjusted.

ISR Plan O&M Budget Vegetation Management ($000)	FY 2024 RIE Budget & Forecast	FY 2025 RIE Proposed 12-21-23
Cycle Pruning (with Enhanced Trimming)	9,960	8,400
Cycle Trimming Treatment (TGR)	-	125
Risk Reduction Work - on cycle	290	750
Risk Reduction - off cycle (formerly EHTM)	625	400
Sub-T (off & on road)	540	700
Police/Flagman Detail	860	900
Pockets of Poor Performance	120	50
All Other Activities*	1,555	1,750
Total Vegetation Management	**13,950**	**13,075**

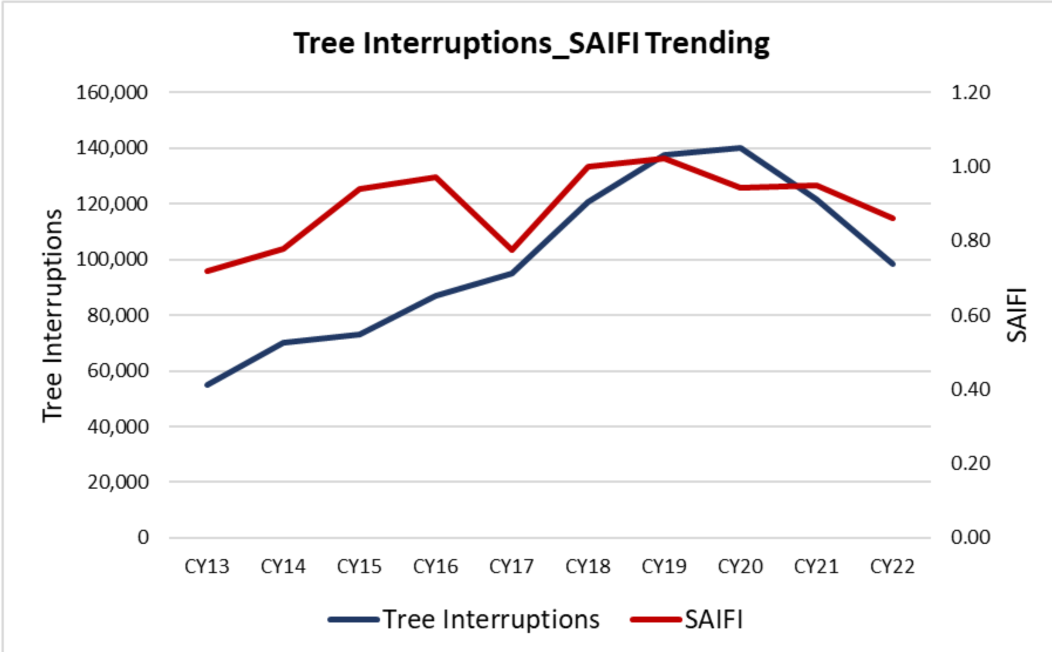
** Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.*

Consistent with historical budgets, the major spending component is Cycle Pruning budgeted at $8.4 million. The Company has moved from a prescriptive four-year pruning cycle and although circuits remain scheduled on a fixed timeline or rotation, the work is informed by data analytics to identify risks and develop specific workplans for each circuit based on actual vegetation health and conditions. The Company applies analytics to pinpoint the annual feeder list for circuit clearing as opposed to a feeder list based solely on geography and not system conditions. The evaluation uses data sources such as previous outages, land types, and prevailing storm winds to locate system risks. (page 214) The Company anticipates that circuits will fall in a three to five year window. Once feeders are identified the Company also applies On-Cycle Risk Reduction by examining the circuit in advance using data and field observation to identify areas where tree-related outage risks are high. Crews complete prescribed work such as hazard tree removals during the cycle trim schedule to avoid interim return trips.

Other recurring components of the vegetation management program are for hazard tree removals due to pest infestation, sub-transmission clearing, and core activities such as spot trimming, customer requests, and emergency response. This portion of the vegetation management is consistent with prior Enhanced Hazard Tree Management. The Company continues to require vendor bids for cycle trim work to include traffic control in the pricing instead of a pass-through cost in an effort to ensure that vendors manage costs effectively. The proposed FY2025 budget for all of these activities are at levels consistent with the prior year. The Company is proposing continued funding for Pockets of Poor Performance but at declining levels. After two years of tracking the Company indicates that the outcome of the work has been encouraging. Although more data collection over time is needed to determine definitive results, statistics for a sample circuit show a nearly 60% reduction in tree events after treatment. (Prefile Recommendation #15) The Company anticipates that poor performance areas will be addressed in the normal cadence of work when data analytics and technology are incorporated, and therefore forecasts minimal future funding for a separate program. The reliability improvements suggest that the program should continue, and I support the Company's efforts to collapse this work into normally scheduled activities.

For FY 2025, the Company introduced a new trial program to apply Tree Growth Regulators (TGR) to specific fast growing trees. RIE states that the treatment is a tool used in the Utility Arboriculture industry and when applied to a tree near power lines, the treatment reduces regrowth that occurs after cycle trim activities. The Company indicates that savings may be achieved by either moving feeders to a longer pruning cycle or reducing the amount of future tree work. Maintenance costs may be reduced between 35%-60% versus untreated trees and if approved, municipally owned trees would first be targeted. The Division agreed with advancing the trial and proposed FY 2025 budget of $125,000. The Company should put forth a definitive timeline, scope and cost for the TGR trial, along with how performance will be measured and reported to determine program effectiveness.

I have evaluated the Vegetation Management Program in detail and on multiple levels in prior ISR Plan assessments and continue to support the Company's funding categories with proposed level and frequency of planned work. Trees remain the leading cause of customer interruptions (23%) and I strongly endorse efforts to address the root cause of outages as opposed to restoration investments that only minimize the number of customers affected but don't eliminate the source. I have previously commented on the importance of vegetation management, since protecting core distribution facilities from the dangers of falling limbs and trees will be more critical as grid connected technologies are deployed that rely on an intact and functioning system to provide intended benefits. There are no cost-effective substitutes for robust vegetation management and the Company's proactive approach, balanced with cost management, continues to be integral to system reliability. The Company has consistently reported improved reliability in areas of the system undergoing cycle clearing or hazard tree removals and is augmenting practices with data-analytics that are expected to drive further improvements. The benefit of addressing the top cause of outages is compelling when correlating the number of interruptions due to trees and system SAIFI results.



I am in full support of the Company's efforts to improve and cost effectively manage vegetation. The Division concurs with RIE's proposed program enhancements and spend for FY 2025 in the amount of $13.1 million. I continue to anticipate that the Company will put forth a plan document for Division review in advance of any future material changes that includes program modifications and a cost-benefit analysis that is well supported by quantifiable metrics. Lastly, RIE must continue to assure that approximately 25 percent of the system vegetation is managed each year and that over a 4 year cycle all vegetation has been addressed. This shall include field assessment and continued monitoring of contractor performance and compliance with RIE vegetation management specifications.

IV. SUMMARY AND RECOMMENDATIONS

The process between the Company and the Division resulted in a FY 2025 Electric ISR Plan which sets forth a capital budget, Vegetation Management Program and I&M Program, and associated O&M activities that balance the need for safety and reliability with efficient benefit/cost considerations. Appendix 2, Summary of Capital Outlays by Key Driver Category and Budget Classification, summarizes by spending rationale (category) and individual budget class within each category, differences between the Company's initially proposed ISR Plan of October 13, 2023, and the resulting December 21, 2023 filing of the FY 2025 ISR Plan Proposal. The consensus ISR Plan reflects a $140.9 million budget which is a 25% increase compared to the FY 2024 ISR Plan budget. The FY 2025 ISR Plan capital budget with AMF totals $192.6 million which is over 70% above the FY 2024 capital budget.

This is the second ISR Plan developed and filed by the Company since PPL's acquisition of Narragansett Electric Company. The Company remained engaged throughout the year to keep the Division apprised of developments that impact the current ISR Plan while also presenting preliminary budgets leading up to pre-file information. The Company's capital investment plans are significantly growing in terms of budget and complexity. For the FY 2025 ISR Plan, the Company included nine new or enhanced programs in addition to customary budget categories of spend. After completing Area Studies, RIE developed a Long-Range Plan which is a 10-year strategic capital investment strategy. The Company's submittal reflects their continued position to compress Area Study project construction into the first five years of a 10-year period, which drives a significant number of substation and distribution projects in the ISR Plan. RIE will begin implementing its AMF deployment under Docket 22-49-EL in FY 2025 which will also add considerable incremental capital needs in the near term. RIE also offered a budgetary framework as part of Docket 23-34-EL aimed to address the ISR Plan budgeting and reconciliation process.

For FY 2025, review of the proposed ISR Plan and discussions with the Company continued to address the reasonableness of non-discretionary budget levels for customary projects, many of which are part of mature programs. For the discretionary category, the Company proposed an expanded portfolio of capital investments for load relief and to replace aging and obsolete infrastructure. The Division visited several substation sites and inspection results confirmed the need to prioritize asset condition major projects. Projects driven by system capacity issues have more subjective implementation timeframes since needs are based on forecasted peak load which has been flat or even negative on some feeders. The Division expects that major load relief projects will be re-analyzed with current forecasts to justify inclusion in the Plan before significant expenditures are incurred. To achieve this balance, the Division and RIE must work through the preliminary Long-Range Plan in order to substantiate optimum coordination of projects and assurance that projects are appropriately modulated to mitigate rate impact without adversely impacting reliability and safety.

The Company put forth customary discretionary programs for equipment replacements. The Division continued to support smaller scale asset replacement programs, consistent with historical levels of spend. New proposals to significantly increase RIE's spare substation transformer and mobile transformer inventory were supported on a limited basis. Further detailed discussions with RIE are needed to get a more accurate picture of exposure and risk which will inform support for future proposed spend. The Division observed that RIE customers are now faced with additional capital costs resulting from RIE's loss of access to a significant inventory of National Grid's mobile substations and spare transformers. There may be an argument that some of this cost should be absorbed in the transition costs borne by PPL.

In the system performance category, RIE proposed customary programs along with a suite of GMP related initiatives that were not approved in FY 2024. The Division supported advancing several programs considered to be either part of the Company's normal course of technology improvements (such as upgrading electromechanical relays) or providing customer net benefits otherwise (such as VVO/CVR). Specific attention was given to the Company's proposed reliability programs and related recloser additions (CEMI-4, ERR and DARP) aimed for targeted reliability improvements. Review of the proposals considered that RIE meets and exceeds regulatory reliability thresholds and performance has been improving since 2018, in part due to the significant capital investments made over that time period. The Division outlined multiple concerns with the aggressive level of recloser additions across the programs and highlighted justification gaps and deficiencies. Reservations regarding the lack of a system-wide sectionalizing study contributed to my reluctance in fully endorsing the DARP. Despite these reservations the Division acknowledged that there are strategic locations that would benefit from recloser installations and that targeting the worst performing feeders is a logical starting point. To reach consensus, the Division and RIE agreed to a set of conditions limiting the number of recloser installations in FY 2025, requiring additional support before advancing implementation, and setting a DARP budget cap. The Division recommends separately administering the budget cap from any potential ISR Plan budget discipline imposed by the Commission.

For many years, the Division has encouraged RIE to manage costs, including short term inflationary impacts, while warning of significant upward pressure on the ISR Plan budget to accommodate future projects and initiatives. That time has arrived as evidenced by the Company's massive increase in proposed capital spend over the next three years driven by AMF implementation. The Company will need to lengthen complex project implementation schedules and moderate spend in other discretionary programs in order to maintain reasonable overall budgets without compromising necessary reliability programs. The Company must remain engaged throughout the year to refine its Long-Range Plan and also keep the Division apprised of developments that impact the ISR Plan. The Division will continue to be vigilant in its oversight of these impacts to ensure that: 1) changes are necessary and produce quantifiable benefits which accrue to ratepayers that outweigh costs, 2) there is no degradation to service, and 3) ratepayers do not incur excess or duplicative costs.

For FY 2025, I support the ISR Plan Capital Budget as proposed at $140.9 million, the proposed Vegetation Management Program at $13.1 million and the I&M Program Operations and Maintenance Expenses at $1.2 million. The Company also included $51.7 million in capital expenditures for AMF implementation, resulting in a Proposed FY 2025 ISR Plan total of $192.6 million. I continue to endorse the sixteen recommendations included in my previous report, as updated, with an additional FY 2025 recommendation as follows:

Recommendations

1. The Company shall separately track and report recloser installations under the Distribution Automation Recloser Program and maintain an overall budget cap of $5.957 million in FY 2025. The cap shall be separately administered from any potential ISR Plan budget discipline imposed by the Commission.

2. The Company shall complete a systemwide protective coordination study, demonstrating the need, the location, and/or the manner in which reclosers will be coordinated, in advance of progressing major recloser additions. The Division and Company will work to develop a mutually acceptable study format and content. The memorandum which the Company has already agreed to deliver before advancing reclosers and most particularly the FLISR schemes may substantially address the Division's needs.

3. The Company shall maintain and file with each proposed ISR Plan a holistic 10-year Long-Range Plan as contemplated in these Recommendations, with all strategic capital investments including AMF and GMP. The Long-Range Plan must be adequately supported and accompanied by a level of detail that allows stakeholders to sufficiently validate the need,

timing and level of proposed investment. It shall also reflect the demand reduction which may transpire from the SRP program advancements.

4. The Company shall present new programs, major projects, or material modifications to existing programs to the Division in advance of including the programs in the ISR Plan. The Company shall produce requisite justification at a level of detail to sufficiently validate the need, timing and level of proposed investment, including a benefit-cost analysis. The Company shall also propose a methodology to separately track, measure and validate program costs and benefits. Requisite justification and accompanying information shall be provided in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

5. The Company shall not include spend in the ISR Plan for initiatives or programs that are subject to Commission review and/or approval prior to the program progressing through a regulatory proceeding.

6. The Company shall continue to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement blanket programs to validate proper classifications.

7. The Company shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the System Reliability Procurement ("SRP") plans, Area Studies, ISR Plan, non-wires alternatives ("NWA") options and internal Design Criteria.

8. The Company shall continue enhancing current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum:

   - The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline.
   - Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, Distribution System Planning ("DSP"), Heat Maps, and emerging initiatives.
   - A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning.
   - An evaluation of potential incremental investments that support the Company's long - term grid modernization strategy. This includes description of technology or infrastructure investment, cost-benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. The GMP should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs.
   - A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.
   - A correlation of the 11 Area Studies to each other for the development of a holistic system Long-Range Plan which further informs the ISR Plan.

9. The Company shall continue to develop a System Capacity Load Study and a 10-year Long-Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall analyze the overall system in a holistic manner using the now completed 11 Area Studies to establish enhancements in the Area Study solutions. The Company shall use the completed Area Studies to re-prioritize and sequence all solutions and major projects in the Long-Range Plan. The Company shall submit and present the outcome of each revised Area Study to the Division at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities, holistic system long-range plan development and revision of each current and future planned Area Study status at least 120 days prior to filing its FY 2026 ISR Plan Proposal, but in any event no later than August 31, 2025.

10. The Company shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.

11. The Company will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.

12. The Company shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.

13. The Company shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to allow for transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

14. The Company shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

15. The Company shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long-Range Plan in advance of the FY 2026 ISR Plan Proposal filing, and in any event no later than August 31, 2025.

16. The Company shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program, a separate cost-benefit analysis on the Enhanced Hazard Tree Management program, and an additional assessment of the RIE modifications in the program proposed to deliver a 15 to 18 percent SAIFI improvement for the Division's review prior to submitting the Company's FY 2026 ISR Plan Proposal, and in any event no later than August 31, 2025.

17. The Company shall provide continuous and timely updates on ISR Plan team members and responsibilities, material changes to Company guidelines, standards or processes that affect distribution planning, or any proposed changes to the ISR Plan process. The Company shall, at minimum, provide updates at quarterly presentations of the quarterly reports.

APPENDIX 1

Appendix 1
FY 2025 ISR Plan Evaluation Actions and Procedures

Item No.	Date	Actions and Procedures (*Conference calls included the Division, Division consultants, and RIE)*
1	May 23, 2023	Conference call to discuss proposed revisions to FY2024 ISR Plan in accordance with Commission decision in Docket 22-53-EL. Categories for investment modifications included Grid Modernization Plan and ISR Investments, Asset Replacement Projects Deferred, and Reclosers. RIE presented potential Area Study Adjustments and presented a reliability study for Waterman Ave Substation Feeder 78F3.
2	May 31, 2023	Conference call to discuss Vegetation Management Reporting, Long-Range Plan and Other Recommendations and Additional Recloser Discussion Items.
3	May 31, 2023	The Division provided RIE with a list of Vegetation Management discussion topic.
4	June 19, 2023	Call to address Division's questions on FY 2024 ISR Plan Q4 report and FY 2025 ISR Plan recloser strategy. RIE provided an FY 2025 ISR Plan budget update.
5	June 21, 2023	Call to discuss the level of RIE's FY 2025 proposed recloser additions, costs and benefits. RIE separately provided its proposed Long-Range Plan format outline.
6	June 28-30, 2023	RIE and the Division exchange updates on action/outstanding items. The Division provides RIE with discussion topics on reclosers, the Long-Range Plan and Vegetation Management.
7	July 11, 2023	RIE provides a preliminary FY 2025 ISR Plan non-discretionary budget.
8	July 13, 2023	Call to review preliminary FY 2025 non-discretionary budget. RIE presented overview of separate petitions for DG developer reimbursement (Tiverton and Weaver Hill).
9	July 14, 2023	RIE responds to the Division's Vegetation Management questions.
10	July 25-26, 2023	Division consultant and RIE meet to visit sixteen substation sites with planned Asset Condition work.
11	August 4, 2023	RIE provides a preliminary FY 2025 ISR Plan discretionary budget.
12	August 7, 2023	Call to discuss Asset Condition preliminary FY 2025 budget. RIE presented proposed projects and risk analysis.
13	August 8, 2023	Call to discuss System Capacity & Performance preliminary FY 2025 budget.
14	September 8, 2023	RIE provides pre-file information including a revised FY 2025 ISR Plan budget, a Long-Range Plan, Vegetation Management Cost-Benefit Analyses, and Vegetation Management Program Documentation.
15	September 18, 2023	Conference call to discuss 2024 Q1 report and items related to FY 2025 pre-file.
16	September 21, 2023	RIE provided a revised Long-Range Plan.
17	October 1, 2023	Conference call on budgeting and reconciliation framework for future ISR filings (Docket 23-34-EL). RIE presented potential categories and thresholds for general discussion with Division.

FY 2025 ISR Plan Evaluation Actions and Procedures (continued)

Item No.	Date	Actions and Procedures *(Conference calls included the Division, Division consultants, and RIE)*
18	October 3, 2023	Conference call to discuss recloser programs, budgets, justification, and the Division's expectations regarding support for each program. The call was guided by the Division's questions provided to RIE on 6-30-23.
19	October 13, 2023	RIE filed its Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan.
20	October 23, 2023	The Division provided the First Set of Data Requests to the Company.
21	October 26, 2023	The Division provided the Second Set of Data Requests to the Company.
22	November 1, 2023	Conference call to discuss Asset Condition projects, cost estimating processes and Area Study cost estimate/construction completion status.
23	November 2, 2023	The Division provided the Third Set of Data Requests to the Company.
24	November 3, 2023	The Division provided the Fourth Set of Data Requests to the Company.
25	November 7, 2023	Conference call to discuss the ISR Plan Budgetary Framework where RIE presented its preliminary proposals to the PUC's draft budget parameters as they related to the ISR Plan.
26	November 8, 2023	the Division provided the Fifth Set of Data Requests to the Company.
27	November 14, 2023	RIE provided responses to Division Set I.
28	November 16, 2023	RIE provided responses to Division Set II.
29	November 21, 2023	Conference call to discuss reliability programs CEMI-4, ERR and Distribution Automation.
30	November 27-28, 2023	The Division provided and discussed with RIE its position and proposed ISR Plan adjusted budget totaling $136.8 million.
31	November 28, 2023	Conference call was held to discuss Tiverton, Weaver Hill, fiber infrastructure, relays and reclosers. Potential areas ISR Plan adjustments were explored and the budgetary framework was discussed at a high level.
32	November 30, 2023	RIE transmitted a complete set of responses to Division Set II including outstanding and corrected responses.
33	December 1, 2023	The Division provided the Sixth Set of Data Requests to the Company.
34	December 1, 2023	RIE provided responses to Division Set III.
35	December 4, 2023	RIE provided responses to Division Set IV.
36	December 4, 2023	Call to discuss FLISR reclosers.
37	December 7, 2023	RIE put forth further adjustments to the Division's proposed budget reflecting increased costs due to inflation and damaged equipment, savings due to the timing of projects, and a modified recloser implementation plan.
38	December 7, 2023	The Division provided conditional support for recloser installations limited to mainline and FLISR schemes on circuits exceeding CKAIFI of 2.0 identified in the CEMI-4 and ERR programs. The Division's proposed conditions required identification and planned work on all circuits in advance of construction, a budget cap, and the development of tracking mechanisms to measure cost and performance.

FY 2025 ISR Plan Evaluation Actions and Procedures (continued)

Item No.	Date	Actions and Procedures (*Conference calls included the Division, Division consultants, and RIE)*
39	December 8, 2023	RIE agreed with the Division's recloser proposal and conditions but requested that the conditions apply to any circuit with CKAIFI of 2.0 or greater. The Company estimated that the FY 2025 ISR Plan would include 88 recloser installations for a total Plan budget of $140.9 million.
40	December 11, 2023	Call was to discuss the budget and recloser conditions. The Division and RIE came to agreement on a FY 2025 ISR Plan capital budget of $140.9 million, subject to the recloser conditions put forth by the Division.
41	December 20, 2023	RIE provided responses to Division Set VI.
42	December 21, 2023	RIE filed its Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan including AMF capital (subject to Docket 22-49-EL).
43	January 9, 2024	Call to discuss the FY 2024 ISR Plan Q2 report along with information required of RIE to support recloser additions as a part of the Division's conditions.
44	January 10, 2024	The Division provided the Seventh Set of Data Requests to the Company.
45	January 17, 2023	Call to discuss and confirm RIE's planned compliance with the Division's recloser conditions.
46	January 31, 2024	RIE provided responses to the majority of Division Set VII.
47	February 7, 2024	RIE provided the outstanding response to Division Set VII.

APPENDIX 2

Appendix 2
Summary of FY 2025 Capital Outlays by Category with Adjustments

Spending Rationale and Category	ISR Grouping	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
	New Business - Commercial	9,366	-	9,366
	New Business - Residential	7,428	-	7,428
	Public Requirements	3,140	-	3,140
	Transformers and Related Equipment	5,300	2,700	8,000
	Meters and Meter Work	2,533	-	2,533
	Distributed Generation	1,000	-	1,000
	Third Party Attachments	288	-	288
	Land and Land Rights	515	-	515
	Outdoor Lighting	592	-	592
Total Customer Request/Public Requirement		**30,162**	**2,700**	**32,862**
	Damage /Failure	11,268	-	11,268
	RIE16-24 ACNW Vlt 72 Reconstruction		800	800
	Reserves	1,008	-	1,008
	Failed Assets	1,737	-	1,737
	Storms	3,000	-	3,000
Total Damage Failure		**17,013**	**800**	**17,813**
Total Non-Discretionary		**47,175**	**3,500**	**50,675**
Major Projects	Dyer Street Substation	15	-	15
	Providence LT Study Programs	28,395	(2,500)	25,895
	Southeast Substation	-	-	-
Other	Underground Cable Replacement	5,500	-	5,500
	URD Cable Replacement	7,008	(2,008)	5,000
	Blanket Projects	6,177	-	6,177
	I&M	3,000	(1,470)	1,530
	Substation Spares	736	-	736
	Other Area Study Projects - BSVS	1,481	(700)	781
	Other Area Study Projects - CRIE	200	-	200
	Other Area Study Projects - CRIW	1,883	-	1,883
	Other Area Study Projects - East Bay	200	-	200
	Other Area Study Projects - Newport	1,166	-	1,166
	Other Area Study Projects - NWRI	500	-	500
	Other Area Study Projects - Providence	492	-	492
	Other Area Study Projects - SCW	-	-	-
	Tiverton Substation	75	-	75
	Reserve	-	-	-
	Batteries / Chargers	195	-	195
	Recloser Replacements	-	-	-
	UG Improvements and Other	700	-	700
Total Asset Condition		**57,723**	**(6,678)**	**51,045**

Spending Rationale and Category	ISR Grouping	RIE Proposed 10-13-23	Net Adjustments	RIE Proposed 12-21-23
	General Equip & Telecom Blanket	712	-	712
	Verizon Copper to Fiber	1,000	(820)	180
Total Non-Infrastructure		**1,712**	**(820)**	**892**
	Aquidneck Island	0	0	-
	New Lafayette Substation	910	-	910
	Warren Substation	2,800	(1,000)	1,800
	Nasonville Substation	3,674	-	3,674
	East Providence Substation	6,285	-	6,285
	Weaver Hill Road Substation	1,105	-	1,105
	3V0	540	(354)	186
	EMS/RTU	135	-	135
	Overloaded Transformer Replcmts	1,500	-	1,500
	Blanket Projects	2,605	-	2,605
	Other Area Study Projects - BSVS	680	-	680
	Other Area Study Projects - CRIW	1,441	-	1,441
	Other Area Study Projects - East Bay	84	-	84
	Other Area Study Projects - Newport	793	-	793
	Other Area Study Projects - NWRI	-	-	-
	Other Area Study Projects - SCE	1,684	-	1,684
	Other Area Study Projects - SCW	927	-	927
	Tiverton D-Line	328	-	328
	Reserve	-	-	-
	CEMI-4	5,312	(2,693)	2,619
	ERR	4,448	(2,448)	2,000
	Distrib Automation Recloser Program	7,426	(1,469)	5,957
	ADMS/DERMS Advanced	-	-	-
	DER Monitor/Manage	-	-	-
	Electromech RelayUpgrades	1,234	-	1,234
	Fiber Network	200	-	200
	VVO - Smart Capacitors and Regulators	400	-	400
	Mobile Substation	1,278	-	1,278
	Other projects and programs	478	-	478
Total System Capacity & Performance		**46,267**	**(7,964)**	**38,303**
Total Discretionary		**105,702**	**(15,462)**	**90,240**
Total Capital Spending*		**152,877**	**(11,962)**	**140,915**
AMF (Docket 22-49-EL)				**51,725**
Total Capital Spending with AMF*				**192,640**

** Excludes $26.2 million in proposed Reimbursement to DG Customers being considered separately in Dockets 23-37-EL and 23-38-EL*

APPENDIX 3

Appendix 3
Summary of Historical Budgets versus Actual

Spending Rationale	FY 2006 Budget	FY 2006 Actual	FY 2007 Budget	FY 2007 Actual	FY 2008 Budget	FY 2008 Actual
Customer Request/Public Requirements	20,302,000	22,885,193	17,902,500	21,012,048	24,630,000	23,887,492
Damage/Failure	3,250,000	8,264,656	4,550,000	7,442,272	5,660,000	7,642,277
Total Non-Discretionary	***23,552,000***	***31,149,849***	***22,452,500***	***28,454,320***	***30,290,000***	***31,529,769***
Asset Condition	9,323,000	5,828,465	8,641,000	8,342,907	10,020,000	12,559,436
Non-Infrastructure	793,000	(2,196,297)	990,000	3,041,061	75,000	385,109
System Capacity & Performance	10,276,500	10,980,393	12,961,500	11,545,608	12,434,000	13,558,424
Total Discretionary	***20,392,500***	***14,612,561***	***22,592,500***	***22,929,576***	***22,529,000***	***26,502,969***
Grand Total	**43,944,500**	**45,762,410**	**45,045,000**	**51,383,896**	**52,819,000**	**58,032,738**
Vegetation Management	-	-	-	-	-	6,630,000
Inspection & Maintenance Program	-	-	-	-	-	-

Spending Rationale	FY 2009 Budget	FY 2009 Actual	FY 2010 Budget	FY 2010 Actual	FY 2011 Budget	FY 2011 Actual
Customer Request/Public Requirements	24,022,668	21,171,756	23,726,000	19,311,885	21,014,000	14,631,340
Damage/Failure	6,596,000	8,345,442	7,919,000	9,031,133	9,365,000	13,194,101
Total Non-Discretionary	***30,618,668***	***29,517,198***	***31,645,000***	***28,343,018***	***30,379,000***	***27,825,441***
Asset Condition	10,090,732	10,941,238	14,253,000	13,065,303	7,201,000	5,830,800
Non-Infrastructure	242,600	284,808	168,000	(590,138)	685,000	705,603
System Capacity & Performance	16,707,000	14,595,922	22,434,000	17,454,290	8,635,000	10,758,714
Total Discretionary	***27,040,332***	***25,821,968***	***36,855,000***	***29,929,455***	***16,521,000***	***17,295,117***
Grand Total	**57,659,000**	**55,339,166**	**68,500,000**	**58,272,473**	**46,900,000**	**45,120,558**
Vegetation Management	-	7,857,000	-	6,882,000	-	4,829,000
Inspection & Maintenance Program	-	-	-	-	-	-

Spending Rationale	FY 2012 Budget	FY 2012 Actual	FY 2013 Budget	FY 2013 Actual	FY 2014 Budget	FY 2014 Actual
Customer Request/Public Requirements	21,636,500	13,075,154	20,006,000	10,410,223	16,509,000	17,137,642
Damage/Failure	9,705,000	12,992,859	10,422,000	17,515,452	10,050,000	14,373,392
Total Non-Discretionary	***31,341,500***	***26,068,013***	***30,428,000***	***27,925,675***	***26,559,000***	***31,511,034***
Asset Condition	12,318,050	11,520,099	11,863,000	8,070,832	20,242,000	20,904,838
Non-Infrastructure	278,000	266,545	336,000	2,269,065	255,000	(346,246)
System Capacity & Performance	17,962,450	13,955,240	13,913,000	11,249,210	12,544,000	25,972,338
Total Discretionary	***30,558,500***	***25,741,884***	***26,112,000***	***21,589,107***	***33,041,000***	***46,530,930***
Grand Total	**61,900,000**	**51,809,897**	**56,540,000**	**49,514,782**	**59,600,000**	**78,041,964**
Vegetation Management	9,826,000	8,176,000	8,256,000	8,248,749	8,476,000	8,529,815
Inspection & Maintenance Program	2,479,230	1,465,884	2,270,900	1,480,205	3,779,000	3,611,958

Spending Rationale	FY 2015 Budget	FY 2015 Actual	FY 2016 Budget	FY 2016 Actual	FY 2017 Budget	FY 2017 Actual
Customer Request/Public Requirements	14,537,000	17,759,797	15,647,000	17,412,295	19,450,550	20,232,661
Damage/Failure	9,816,000	3,044,445	11,177,000	14,531,159	11,467,000	15,614,335
Total Non-Discretionary	***24,353,000***	***20,804,242***	***26,824,000***	***31,943,454***	***30,917,550***	***35,846,996***
Asset Condition	19,511,000	25,140,871	24,053,000	27,178,961	33,280,427	31,274,161
Non-Infrastructure	277,000	1,216,345	275,000	457,389	275,000	621,795
System Capacity & Performance	21,759,000	25,889,850	22,148,000	19,919,705	18,968,000	16,370,536
Total Discretionary	***41,547,000***	***52,247,066***	***46,476,000***	***47,556,055***	***52,523,427***	***48,266,492***
Grand Total	**65,900,000**	**73,051,308**	**73,300,000**	**79,499,509**	**83,440,977**	**84,113,488**
Vegetation Management	7,726,000	8,029,095	8,884,000	8,893,000	8,719,000	8,719,000
Inspection & Maintenance Program	2,995,000	2,022,743	3,333,000	1,196,756	1,611,750	1,611,750

Historical Budgets versus Actual
(Continued)

Spending Rationale	FY 2018 Budget	FY 2018 Actual	FY 2019 Budget	FY 2019 Actual	FY 2020 Budget	FY 2020 Actual
Customer Request/Public Requirements	21,853,000	19,627,243	19,005,000	23,989,000	27,025,000	28,667,288
Damage/Failure	11,379,000	19,184,118	13,674,000	13,998,000	13,505,000	17,028,480
Total Non-Discretionary	***33,232,000***	***38,811,361***	***32,679,000***	***37,987,000***	***40,530,000***	***45,695,768***
Asset Condition	42,744,000	17,241,994	29,768,000	30,708,000	39,675,000	32,877,110
Non-Infrastructure	553,000	362,242	556,000	673,000	550,000	145,367
System Capacity & Performance	24,092,000	50,642,444	39,764,000	41,704,000	21,045,000	24,957,836
Total Discretionary	***67,389,000***	***68,246,680***	***70,088,000***	***73,085,000***	***61,270,000***	***57,980,313***
Grand Total	**100,621,000**	**107,058,041**	**102,767,000**	**111,072,000**	**101,800,000**	**103,676,081**
Vegetation Management	9,400,000	9,515,300	9,800,000	9,800,000	10,400,000	10,400,000
Inspection & Maintenance Program	1,230,800	684,744	1,289,000	1,289,000	1,243,000	1,243,000

Spending Rationale	FY 2021 Budget	FY 2021 Actual	FY 2022 Proposed	FY 2022 Actual	FY 2023 Budget	FY 2023 Actual
Customer Request/Public Requirements	24,540,000	21,989,902	27,237,000	34,339,222	27,183,000	31,799,029
Damage/Failure	12,365,000	19,490,705	12,198,000	20,200,300	14,251,000	17,461,118
Total Non-Discretionary	***36,905,000***	***41,480,607***	***39,435,000***	***54,539,522***	***41,434,000***	***49,260,147***
Asset Condition	41,120,000	41,816,500	40,569,000	35,791,708	48,288,000	44,238,571
Non-Infrastructure	580,000	(57,278)	1,310,000	1,100,074	1,520,000	1,553,685
System Capacity & Performance	25,145,000	17,387,358	20,286,000	15,303,000	13,508,000	13,463,924
Total Discretionary	***66,845,000***	***59,146,580***	***62,165,000***	***52,194,782***	***63,316,000***	***59,256,180***
Grand Total	**103,750,000**	**100,627,187**	**101,600,000**	**106,734,304**	**104,750,000**	**108,516,327**
Vegetation Management	10,600,000	10,600,000	10,800,000	10,800,000	11,875,000	12,748,000
Inspection & Maintenance Program	1,492,000	1,184,000	1,423,000	1,104,000	1,264,000	983,000

Spending Rationale	FY 2024 Proposed	FY 2024 Forecast	FY 2025 Budget
Customer Request/Public Requirements	27,514,000	30,734,596	32,862,000
Damage/Failure	15,192,000	17,181,552	17,813,000
Total Non-Discretionary	***42,706,000***	***47,916,149***	***50,675,000***
Asset Condition	47,725,411	50,402,140	51,044,678
Non-Infrastructure	1,700,000	762,769	892,000
System Capacity & Performance	20,197,471	19,122,240	38,303,250
Total Discretionary	***69,622,883***	***70,287,150***	***90,239,928***
Grand Total	**112,328,883**	**118,203,298**	**140,914,928**
AMF			51,724,655
Grand Total with AMF			**192,639,583**
Vegetation Management	13,950,000	13,950,000	13,075,000
Inspection & Maintenance Program	1,163,000	1,250,000	1,218,000

RESUME OF
GREGORY L. BOOTH, PE, PLS
President
Gregory L. Booth, PLLC

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 60 years. Mr. Booth was inducted into the North Carolina State University Electrical and Computer Engineering Alumni Hall of Fame in November of 2016 based on his accomplishments in the field of engineering.

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 Florida Public Service Commission, the Minnesota Department of Public Service Environmental Quality Board, the Maine Public Utilities Commission, the Massachusetts Department of Public Utilities, 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 Colorado, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Puerto Rico, South Carolina, Texas, Virginia, West Virginia, Virgin Islands, and Wisconsin, and numerous Federal Court jurisdictions. Mr. Booth has provided expert witness services on over 500 tort case matters, and over 50 regulatory matters. 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 Electrical Code and National Electrical Safety Code and Industry Standard compliance.

The following pages provided are the education and experience from 1963 through the present, along with courses taught and publications.

October 2023

RESUME OF
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
PROFESSIONAL HONORS:	Inducted into North Carolina State University Department of Electrical and Computer Engineering Alumni Hall of Fame in November 2016.
REGISTRATIONS:	Registered as Professional Engineer in Alabama, Arizona, Colorado, Connecticut, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas, 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, serving as an expert witness in state and federal regulatory matters and state and federal court.

2005-2019
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, serving as an expert witness in state and federal regulatory matters and state and federal court.

WORK AND EXPERTISE:

ELECTRIC UTILITIES:
(more than 300 clients)

- All aspects of utility planning, design and construction, from generation, transmission, substation and distribution to the end user.
- 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, hydro, microgrid, wind, and solar generation plan analysis, design, and construction observation.
- Transmission line design and construction observation through 230 kV overhead and underground, including interface with DOT and other utilities.
- Switching station and substation design and construction observation through 230 kV.
- Distribution line design and staking, overhead and underground, including interface with DOT and other utilities.
- Design of submarine cable installations. (Transmission and distribution)
- 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 and pole inventories.
- Specialized grounding for abnormal lightning conditions.
- Ground potential rise protection.
- Protective system/relay coordination.
- Grid Modernization Plan development, regulatory testimony, and implementation
- Pole Attachment Agreements, rate design, and testimony

UTILITY OPERATIONS:

- Storm assessment services., including interface with DOT and other utilities
- Regulatory testimony on storm response.
- Storm Response Plan development.
- Operations, including outage management and Call Centers.
- Outage management and operations enhancement services and testimony.

GENERATION DESIGN / FAILURE ANALYSES:

- Intermediate and peaking generation (gas and oil fired through 400 MW).
- Peaking generation (diesel and gas through 10,000 kW)
- Wind generation.
- Solar (PV) generation.
- Hydroelectric generation.
- Microgrid, including energy storage.

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.
- Pole attachment designs and make-ready design.
- Pole Attachment Agreements and rental rates calculations.
- Regulatory testimony.

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.
- Utility Commission testimony (State and Federal)

FORENSIC ENGINEERING:

- Compliance with NESC, NEC, OSHA, IEEE, ANSI, ASTM and other codes and industry standards, including DOT standards.
- Equipment and product failure and analysis and electrical accident investigation (high and low voltage equipment).
- Stray voltage, electrical shocking, and electrocution investigations.
- Building code investigations.
- New product evaluation.
- MCC, MDP failure analysis and arc flash analysis
- Electrical fire analysis

INDUSTRIAL/ELECTRICAL ENGINEERING:

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

INSTRUCTIONAL SEMINARS AND TEXT:

- Seminars taught on arc flash hazards and safety, including National Electrical Safety Code regulations for utilities.
- Courses taught on Distribution System Power Loss Evaluation and Management.
- 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.
- Courses taught on Asset Management.
- Courses taught on OSHA and Construction Safety.

TESTIMONY AS AN EXPERT:

- Concerning rate and other regulatory issues before Federal Energy Regulatory Commission and state commissions in Connecticut, Delaware, Florida, Maine, Maryland, Massachusetts, Minnesota, New Jersey, New Hampshire, North Carolina, Pennsylvania, Rhode Island, and Virginia.
- Concerning property damage or personal injury before courts in Colorado, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Puerto Rico, South Carolina, Texas, Virginia, West Virginia, Virgin Islands, and Wisconsin.

FIELD ENGINEERING:

- Transmission line survey and plan and profile.
- Distribution line staking.
- Property surveying.
- DOT highway relocation design.
- Relay and recloser testing.
- Substation start-up testing.
- Generation acceptance and start-up testing.
- Ground resistivity testing.
- Work order inspections.
- Operation and maintenance surveys.
- Building inspection and service facility inspection.
- Construction Management
  - Generation
  - Transmission
  - Substation
  - Distribution
  - Building Electrical Installations
  - GSA construction projects
  - NASA construction projects
  - University construction projects

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) (Life Member) (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)
l. American National Standards Institute (ANSI)

FEDERAL & STATE REGULATORY CASE LIST

As of October 2023

Colorado Public Utility Regulatory Authority
2015
The City of Lamar, Colorado, Colorado Mills LLC, Palace Holdings, LLC, Ports of Plains Travel Plaza and Jeanna Dewitt
2014CV30031

Commonwealth of Virginia State Corporation Commission
1976
Approximately 1976 - 1981 A&N Electric Cooperative Retail Rates Cases
(WT) (HE)

2007
Delmarva Power & Light System Acquisition Purchase by A & N Electric Cooperative, Post Office Box 290, 21275 Cooperative Way, Tasley, VA 23441 and Old Dominion Electric Cooperative, 4201 Dominion Boulevard, Glen Allen, VA 23060
Case Nos. PUE-2007-00060, 00061, 00062, 00063, and 00065
(WT) (HE)

2009
Potomac Edison/Allegheny Power System Acquisition Purchase by Shenandoah Valley Electric Cooperative, 147 Dinkel Ave., Hwy 257, Mt. Crawford, VA 22841
Case No. PUE-2009-00101
(WT) (HE)

2009
Potomac Edison/Allegheny Power System Acquisition Purchase by Rappahannock Electric Cooperative, 247 Industrial Court, Fredericksburg, VA 22408
Case No. PUE-2009-0010
(WT) (HE)

2011
Virginia, Maryland & Delaware Association of Electric Cooperatives Commonwealth of Virginia at the relation of the State Corporation Commission in the Matter of Determining Appropriate Regulation of Pole Attachments and Cost Sharing in Virginia
Case No. PUE-2011-00033
(WT) (HE)

2013
Northern Virginia Electric Cooperative Pole Attachment Dispute with ComCast
PUE-2013-00055
(WT) (HE)

2016
A&N Eastern Shore of Virginia Broadband Authority

Connecticut Public Utilities Regulatory Authority
2017
The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules on behalf of the Connecticut Office of Consumer Counsel
Docket No. 17-10-46
(HE)

2018
PURA Investigation into Distribution System Planning of the Electric Distribution Companies on behalf of the Connecticut Office of Consumer Counsel
Docket No. 17-12-03
(HE)

2020
Phases II and III and IV Subdockets RE02 thruRE09 and RE11 Regarding AMI, Battery Storage, Electric Vehicles, Innovative Technology Applications & Programs, Non-Wires Alternatives, Resilience & Reliability, Clean and Renewable Energy, Interconnection Standards & Practices, Rate Design, RE11
17-12-03

2020
PURA Implementation of Section 3 of Public Act 19-35, Renewable Energy Tariffs and Procurement Plans
20-07-01

2021
Annual Review of Rate Adjustment Mechanism of United Illuminating Company
21-08-02

2021
Annual Non-Residential Renewable Energy Tariff Program Review – Year 1
21-08-03

2021
Annual Review of Storage Program – Year 1
21-08-05

2021
Annual Review of Electric Vehicle Charging Program – Year 1
21-08-06

2021
Application To Install and Operate an Electric Submetering System at 1 Long Wharf Drive, New Haven, CT
21-08-07

2021
Petition to Establish a Docket Pertaining to Public Act 21-162, An Act Concerning the Solicitation of New Fuel Cell Electricity Generation Projects
21-08-08

2021
Application of Aep Onsite Partners, Llc for Qualification of 0 High Street, Willimantic, Ct as a Class I Renewable Energy Source
21-08-11

2021
Investigation into Medium and Heavy-Duty Electric Vehicle Charging
21-09-17

2022
Public Act 22-55, Energy Storage Systems and Electric Distribution on System Reliability
22-06-05

2022
Application of The United Illuminating Company to Amend Its Rate Schedule
22-08-08

Delaware Public Service Commission
1976
Approximately 1976 – 1985 Delaware Electric Cooperative, Inc., Retail Rate Case and Reliability Cases (WT) (HE)

2018
Delaware Distribution Planning Process Phase II
18-0935
(Report)

2018
Delaware Distribution Planning Process, Phase I
18-0935
(Report)

2018
In The Matter of the Petition of the Public Service Commission Staff and Delaware Division of the Public Advocate to Establish a Regulation for Distribution System Investment Plans for Delaware Electric and Natural Gas Utilities
18-0935
(Report)

2020
Delaware Distribution Planning Process Phase III
18-0935
(Report)

2020
Evaluation of the Delmarva Power & Light Company's infrastructure, Safety, and Reliability Plan for the period of July 1, 2020 to June 30,2020
18-0935
(Report)

2020
Application of Delmarva Power & Light Company for an Increase in Electric Base Rates
20-0149
(Report)

2020
Consecutive Estimation Program
20-0226

2022
2022-2024 Electric Infrastructure, Safety and Reliability Plan
22-0320
(Report)

2022
2023-2032 Long Range Distribution Plan
22-0506

2022
2022 Delmarva Power Rate Case
Docket No. 22-0897-04

Federal Energy Regulatory Commission
Public Works Commission of the City of Fayetteville, NC v. Carolina Power & Light Company
ER76-, ER77-, ER78, ER81-344, ER84-
(WT) (HE)

2000
North Carolina Electric Membership Corporation v. Duke Energy Corporation and Duke Electric Transmission
ER01-282-000 and ER01-283-000
(WT) (HE)

2000
North Carolina Electric Membership Corporation v. Virginia Electric Power Company dba North Carolina Power
EL90-26-00-000
(WT) (HE)

2015
Application for Authorization Pursuant to Section 203(a)(1)(A) and 203(a)(2) of the Federal Power Act and Request for Waivers of Certain Filing Requirements on behalf of New Jersey Division of Rate Counsel
Dkt EC15-157-000
(Report)

Florida Public Service Commission (PSC)
2007
Municipal Utility Underground Consortium Pre-Filed Testimony for Storm Hardening and Undergrounding Assessment
Docket Nos. 07023-EI, 080244-EI, and 080522-EI
(WT) (HE)

2007
Gulf Power Company's Storm Hardening Plan Pre-filed Testimony on Behalf of City of Panama City Beach, Florida
Florida PSC Docket No. 070299-EI
(HE)

Georgia Public Service Commission
2020
Notice of Proposed Rulemaking to Adopt Rule 515-12-1-.36, Pole Attachment Agreements
Docket No. 43453
(WT) (HE)

Maine Public Utilities Commission
2016
Efficiency Maine Trust Request for Examination of Voltage Optimization Pilot Program Docket No. 2016-00162 on behalf of Maine Office of Public Advocate
Dkt. 2016-00162
(WT) (HE)

Maine Public Utilities Commission
2017
Investigation into the Designation of Non-Transmission Alternative (NTA) Coordinator on behalf of Maine Office of Public Advocate
Docket No. 2016-00049
(WT) (HE)

2017
Investigation of Inclusion of Acadia Substation Investment in Rates Pertaining to Emera Maine on behalf of Maine Office of Public Advocate
Docket No. 2017-00018
(WT) (HE)

Public Service Commission of Maryland
1976
1976 Approximately 1976 – 1985 A&N Electric Cooperative Retail Rate Cases
(WT) (HE)

Massachusetts Department of Public Utilities
2012
Massachusetts Attorney General's Office Commonwealth of Massachusetts Department of Public Utilities Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid Review for Storm Response and Recovery of 2008 Storm Costs
DPU 11-56
(WT) (HE)

2012
Massachusetts Attorney General's Office Western Massachusetts Electric Company, Northeast Utilities System, Review for Recovery of Storm Costs
DPU 11-102/DPU 11-102A
(WT) (HE)

2013
Massachusetts Attorney General's Office Nstar Review for Recovery of Storm Costs
DPU 13-52
(WT) (HE)

2014
Massachusetts Attorney General's Office National Grid Solar Generation Phase II Program Assessment
D.P.U. 14-01
(WT) (HE)

2014
Massachusetts Attorney General's Office Western Massachusetts Electric Company, Review of Storm Recovery Reserve Cost Adjustment "SRRCA"
D.P.U. 13-135
(WT) (HE)

2016
Massachusetts Attorney General's Office MA Elec. Co. and Nantucket Elec. Co. d/b/a National Grid, Fitchburg Gas and Elec. Light Co. d/a/a Unitil and NSTAR Elec. Co. d/b/a Eversource for Approval by the DPU of their Grid Modernization Plan
DPU 15-120, 15-121, 15-122/15-123
(WT) (HE)

2017
Massachusetts Attorney General's Office Nstar Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy Petition for Approval of a Performance-Based Ratemaking Mechanism and General Distribution Revenue Change
DPU 17-05
(WT) (HE)

2017
Massachusetts Attorney General's Office Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Pre-Approval of Enhanced Vegetation Management Pilot Program
DPU 17-92
(WT) (HE)

2018
Massachusetts Attorney General's Office Massachusetts Eversource Performance Based Ratemaking Mechanism Performance Metrics
DPU 18-50

2018
Massachusetts Attorney General's Office Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid Storm Cost Recovery
DPU 18-94

2019
Massachusetts Attorney General's Office National Grid Rate Case
DPU 18-150

Minnesota Department of Public Service/Environmental Quality Board
Transmission Line Assessment Minnesota Department of Public Service and Minnesota Environmental Quality Board
(HE)

New Hampshire Public Utilities Commission
1985
Approximately 1985 - 1995 Other Cases on Behalf of the New Hampshire Public Utilities Commission Staff

2004
City of Bedford v. Public Service of New Hampshire

New Jersey Board of Public Utilities
1978
Approximately 1978 - 1985 Sussex Rural Electric Cooperative Retail Rate Cases
(WT) (HE)

2004
New Jersey Board of Public Utilities, Focused audit of the planning, operations and maintenance practices, policies and procedures of Jersey Central Power & Light Company
Docket No. EX02120950
(WT) (HE)

2015
Jersey Central Power & Light Company ("JCP&L") and Mid-Atlantic Interstate Transmission, LLC ("MAIT") FERC 7 Factor Test Evaluation on behalf of New Jersey Division of Rate Counsel
BPU Docket No. EM15060733
(WT)

2016
Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges For Electric Service Pursuant to NJSA 48:2-21 and JJSA 48:2-21.1 on behalf of New Jersey Division of Rate Counsel
DPU Docket No. ER16030252 OAL Docket No. PUC 5556-16

North Carolina Utilities Commission
1990
Delora Dennis, et. al. v. Haywood EMC
E-7, Sub 474, EC-10, Sub 37, E013, Sub 151
(WT) (HE)

1990
In Approximately 1990's Larry Eaves, et. al. v. Town of Clayton
(WT) (HE)

North Carolina Utilities Commission
1990
In approximately 1990's Poly-Loc v. Town of Tarboro
(WT) (HE)

2001
Wake EMC Right of Way Acquisition
(TE)

2002
Progress Energy Carolinas, Inc., v. E.M. Harris, Jr. Family Limited Partnership, Edward M. Harris, III and wife Pamela M. Harris, Gene K. Harris and wife Linda Harris, Camille H. Cunnup and husband Timothy J. Cunnup Siler City Transmission Line Issues
General Court of Justice Superior Court Division, File No. 03 CVS SP 251, 252, 253, 254, 255
(WT) (HE)

2004
John Wardlaw, et. al. Interveners v. Progress Energy Carolinas
Docket No. E-2, Sub 855
(WT) (HE)

2011
Frontier Communications of the Carolinas, Inc. v. Blue Ridge Mountain Electric Membership Corporation
11-CVS-17175

2017
Jones-Onslow Electric Membership Corporation; Surry-Yadkin Electric Membership Corporation; Carteret-Craven Electric Membership Corporation; Union Electric Membership Corporation, d/b/a Union Power Cooperative v. Time Warner Cable Southeast, LLC
NCUC Docket Nos. EC-43 5888, EC-49 555, EC55 570 and EC-39 S44
(WT) (HE)

2017
Blue Ridge Electric Membership Corporation v. Charter
Docket No EC-23, SUB 50
(WT) (HE)

Pennsylvania Public Utility Commission
2004
Investigation regarding the Metropolitan Edison Company Pennsylvania Electric Company and Pennsylvania Power Company Reliability Performance on behalf of Allegheny Electric Cooperative and its Member Cooperatives
Docket No. I-00040102
(WT) (HE)

2006
Investigation regarding Pennsylvania Rural Electric Association / Allegheny Electric Cooperative and its Member Cooperatives Rates
Docket Nos. R-00061366, R-0061367, et. al.
(WT) (HE)

2007
Wellsboro Electric Company participants Included C&T Enterprises, Inc., comprised of Wellsboro Electric Company, Claverack Rural Electric Cooperative, Inc., Tri-County Rural Electric Cooperative, Inc., and Citizens Electric
Docket No. P-2008-2020257
(WT) (HE)

2014
Allegheny Electric Cooperative and its Member Cooperatives 2014 Intervention Assistance, Analysis of Service Reliability Concerns Regarding West Pennsylvania Power Company, Pennsylvania Electric Company, Metropolitan Edison Company (First Energy Company)
Docket Nos. R-2014-2428742, -2428743, -2428744, -248745
(WT) (HE)

2015
MAIT and PENELEC for Authorizing the Transfer of Certain Transmission Assets from MET-Ed & PENELEC to MAIT on behalf of Wellsboro Electric Company
A-2015-2488903 (cons.)

Rhode Island Public Utilities Commission
1997
1990 - 1997 Other Matters Before the Rhode Island Public Utilities Commission on behalf of Rhode Island Division of Public Utilities and Carriers
(WT) (HE)

1997
Testimony before the Rhode Island Public Utilities Commission, on behalf of Rhode Island Division of Public Utilities and Carriers, May 15, 1997
Docket No. 2489
(WT) (HE)

2003
Testimony before the Rhode Island Public Utilities Commission on behalf of Rhode Island Division of Public Utilities and Carriers December 2003
Docket No. 2930
(WT) (HE)

2004
Issuance of Advisory Opinion to Energy Facility Siting Board Regarding The Narragansett Electric Company's Application to Relocate Transmission Lines Between Providence and East Providence on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 3564
(WT) (HE)

2006
Issuance of Advisory Opinion to Energy Facility Siting Board Regarding the Narragansett Electric Company d/b/a National Grid's Application to Construct and Alter Major Energy Facilities, on behalf of Rhode Island Division of Public Utilities and Carriers, 2004
Docket No. 3732
(WT) (HE)

2007
Issuance of Advisory Opinion to RIDPUC in the Matter of the Joseph Allard Fatality Involving Verizon and National Grid on behalf of Rhode Island Division of Public Utilities and Carriers

2008
Issuance of Advisory Opinion to Energy Facility Siting Board Regarding the Narragansett Electric Company d/b/a
National Grid's Application to Construct and Alter Major Energy Facilities, on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4029
(WT) (HE)

2010
Rhode Island Division of Public Utilities and Carriers Narragansett Tariff Investigation on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. R.I.P.U.C. 4065

2010
National Grid Proposed Electric Infrastructure, Safety and Reliability Plan for FY 2012 Submitted Pursuant to R.I.G.L. § 39-1-27.7.1 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4218
(WT) (HE)

2012
National Grid Electric FY 2013 Electric Infrastructure, Safety and Reliability Plan on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4307
(WT) (HE)

2012
National Grid Hurricane Irene Response Assessment, 2012 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. D-11-94
(WT) (HE)

2012
Public Utilities Commission Review of Storm Contingency Funds of Electric Utilities on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 2509
(WT) (HE)

2012
Commission's Investigation Relating to Stray and Contact Voltage on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4237
(Annual Reports 2012 through 2022)

2012
Rhode Island Public Utilities Commission Interstate Reliability Assessment on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4360
(WT) (HE)

2012
National Grid Electric Infrastructure, Safety, and Reliability Plan for 2014 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4382
(WT) (HE)

2014
National Grid Electric Infrastructure, Safety, and Reliability Plan 2015 Proposal on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4473
(WT) (HE)

2014
National Grid's FY 2016 Electric Infrastructure, Safety and Reliability Plan on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4539
(WT) (HE)

2015
Division's Investigation into Verizon's Vegetation Management Practices on behalf of Rhode Island Division of Public Utilities and Carriers

2015
Wind Energy Development, LLC (WED) and ACP Land, LLC Petition for Dispute Resolution Relating to Interconnection on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4483
(WT)

2015
National Grid Electric Infrastructure, Safety, and Reliability Plan FY 2017 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4592
(WT) (HE)

2016
PUC Advisory Opinion Regarding Need of The Narragansett Electric Co. d/b/a National Grid to Construct and Alter Certain Transmission Components in the Towns of Portsmouth and Middletown (Aquidneck Island Reliability Project) on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4614

2016
National Grid Electric Infrastructure, Safety, and Reliability Plan FY 2018 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4682
(WT) (HE)

2017
National Grid Electric Infrastructure, Safety, and Reliability Plan FY 2019 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4783

2017
Narragansett Electric Company d/b/a National Grid's October 2017 Storm Response on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. D-17-45

2018
National Grid Electric Infrastructure, Safety and Reliability Plan FY 2020 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4915
(WT) (HE)

2018
RIDPUC Streetlight Pilot Metering Program Docket 4513 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4513

2019
Adoption of Performance Incentives for The Narragansett Electric Company d/b/a National Grid Pursuant to R.I. Gen. Laws Section 39-1-27.7.1(e)(3) to Apply to the Electric Infrastructure, Safety, and Reliability Plans on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4857

2019
Capital Efficiency Mechanism - Adoption of Performance Incentives for the Narragansett Electric Company d/b/a National Grid Pursuant to RI Gen. Laws Section 39-1-27.7.1€(3) to Apply to the Electric Infrastructure, Safety, and Reliability Plans on behalf Rhode Island Division of Public Utilities and Carriers
Docket No. 4857

2019
RIDPUC Block Island Transmission Deficiencies Evaluation on behalf of Rhode Island Division of Public Utilities and Carriers

2019
Guidance Document Regarding Principles to Guide the Development and Review of Performance Incentive Mechanisms on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4943

2020
Rhode Island Division of Public Utilities - Least Cost Procurement Standards
Docket No. 5015

2020
National Grid Electric Infrastructure, Safety and Reliability Plan FY 2021 on behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4995
(WT) (HE)

2020
RIDPUC Ngrid Performance Based Incentive Mechanism and Scorecard Metrics
Docket #4770

2020
The Narragansett Electric Company d/b/a National Grid's Electric Proposed Power Sector Transformation (PST) Vision and Implementation Plan on behalf of Rhode Island Division of Public Utilities and Carriers
Docket #4780
(WT) (HE)

2021
Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA and The Narragansett Electric Company for Authority to Transfer Ownership of the Narragansett Electric Company to PPL Rhode Island Holdings, LLC and related approvals.
D-21-09
(WT) (HE)

2021
National Grid Standards for Connecting Distributed Generation - Docket # 5077
Docket # 5077

2021
Rhode Island National Grid AMF 2023 Docket No. 5113 - The Narragansett Electric Co. D/b/a National Grid Updated Advanced Metering Functionality Business Case
Docket No. 5113

2021
Rhode Island The Narragansett Electric Co. D/b/a National Grid - Grid Modernization Plan
Docket No. 5114

2022
National Grid Infrastructure, Safety and Reliability Plan FY 2022 on behalf of RIDPUC and Carriers - Docket # 5098
(WT) (HE)

2022
National Grid Infrastructure, Safety and Reliability Plan FY 2023 on behalf of RIDPUC and Carriers - Docket #5209
(WT) (HE)

2022
Revity Energy LLC Petition for Declaratory Judgment regarding the Rights and Obligations of an Interconnection
Docket # 5235
(WT)

2022
Rhode Island Energy Automated Metering Infrastructure 2022 The Narragansett Electric Co. d/b/a Rhode Island Energy's Advanced Metering Functionality ("AMF") Business Case
Docket No. 22-49-EL

2022
Rhode Island Energy FY2023-2024 Infrastructure Safety and Reliability Plan 2022 Docket No. 22-53-EL The Narragansett Electric Co. d/b/a Rhode Island Energy - FY 2024 Electric Infrastructure, Safety and Reliability (ISR) Plan
Docket No. 22-53-EL

2022
Rhode Island Energy Grid Modernization Plan 2022 Docket No. 22-56-EL The Narragansett Electric Co. d/b/a Rhode Island Energy - Grid Modernization Plan
Docket No. 22-56-EL

The South Carolina Office of Regulatory Staff
2022
2022 Spectrum Southeast, LLC, Complainant v. York Electric Cooperative, Incorporated, Respondent, Petition to Determine Just and Reasonable Terms and Conditions for Pole Attachment Agreement Pursuant to S.C. Code Ann. § 58-9-3030
Case # 2022-188-EC
(WT) (HE)

CURRENT & HISTORICAL CLIENT LISTS

Abramson, Eric M	San Francisco	CA
Abrams & Abrams, P.A.	Raleigh	NC
Adams, Hendon, Carson, Crow & Saenger, P.A.	Asheville	NC
Allegheny Electric Cooperative, Inc.	Harrisburg	PA
Allen & Gooch	Lafayette	LA
Andrews Law Group	Tampa	FL
Arnold & Itkin LLP	Houston	TX
Bailey & Dixon LLP	Raleigh	NC
Baker & Abraham, PC	Boston	MA
Baker Law Firm, PA	Wilmington	NC
Baker, Jenkins, Jones, Murray, Askew & Carter, PA	Ahoskie	NC
Balch & Bingham LLP	Birmingham	AL
Barnes Law Firm, LLC	Kansas City	MO
Barr, Murman, Tonelli, Slother & Sleet	Tampa	FL
Bartimus, Frickleton, Robertson & Gorny	Leawood	KS
Bartimus, Frickleton, Robertson & Goza, P.C.	Leawood	KS
Battle, Winslow, Scott & Wiley, P.A.	Rocky Mount	NC
Beasley Allen	Montgomery	AL
Beaver, Holt, Richardson, Sternlicht, Burge & Glazier, PA	Fayetteville	NC
Berkley Net Underwriters, LLC	Woodbridge	VA

Berman & Simmons	Lewiston	ME
Berman, Sobin, Gross, Feldman & Darby, LLP	Gaithersburgh	MD
Beskind and Rudolph, P.A.	Chapel Hill	NC
Bordas, Bordas & Jividen	Wheeling	WV
Brault Palmer Steinhilver & Robbins, LLP	Fairfax	VA
Breit Drescher Imprevento & Walker	Virginia Beach	VA
Bretz & Young, L.L.C	Hutchinson	KS
Brian G. Miller Co., L.P.A.	Columbus	OH
Britcher, Leone and Roth, LLC	Glen Rock	NJ
Brown & James	St. Louis	MO
Brown, Crump, Vanore & Tierney, LLP	Raleigh	NC
Brunswick Electric Membership Corp.	Whiteville	NC
Buck, Danaher, Ryan & McGlenn	Elmira	NY
Campbell, Campbell, Edwards and Conroy	Boston	MA
Carey Leisure & Neal	Clearwater	FL
Carolina Adjusters	Smithfield	NC
Carolina Power & Light Company	Raleigh	NC
Chappell, Smith and Arden	Columbia	SC
City of Monroe	Monroe	NC

Civille & Tang, PLLC	Hagatna	GU
Cohen, Placitella & Roth	Philadelphia	PA
Coleman, Bernholz, Dickerson, Bernholz, Gledhill, Hargrave	Chapel Hill	NC
Colombo Law	Columbus	OH
Connecticut Office of Consumer Counsel	New Britain	CT
Copeland, Cook, Taylor & Bush, PA	Ridgeland	MS
Couch & Taibi	Durham	NC
Cowan Gates	Richmond	VA
Cozen O' Connor	Charlotte	NC
Crain Brogdon, LLP	Dallas	TX
Cranfill Sumner & Hartzog LLP	Raleigh	NC
Cranfill Sumner & Hartzog LLP	Charlotte	NC
Crisp, Davis, Page & Currin, LLP	Raleigh	NC
Daniel & Daniel	Yanceyville	NC
Daniel, Medley & Kirby, P.C.	Danville	VA
David A. Vukelja, PA	Ormond Beach	FL
David Randolph Smith & Associates	Nashville	TN
Davis & Lumsden PA	Beaufort	NC
Dean Law Firm	Houston	TX
Delaware County Electric Cooperative	Delhi	NY
Delaware Division of the Public Advocate	Dover	DE
Delaware Electric Cooperative, Inc.	Greenwood	DE
Devore, Acton & Stafford, PA	Charlotte	NC

Dickie, McCamey & Chilcote, P.C.	Charlotte	NC
Dollar Burns & Becker	Kansas City	MO
Dorchak, Kenneth J.	Miami	FL
Dugan, Brinkmann, Maginnis & Pace	Philadelphia	PA
Duke Energy Corporation	Charlotte	NC
Duke Energy Progress	Raleigh	NC
Dull & Heaney, LLC	Clinton	MO
EchardMarquette, P.C.	Allison Park	PA
Edelman & Thompson, LLC	Kansas City	MO
Edmonds Cole Law Firm, PC	Oklahoma City	OK
Edward M. Ricci Law Firm	West Palm Beach	FL
Edwards, Kirby & Holt, LLP	Raleigh	NC
Eichen Crutchlow Zaslow, LLP	Edison	NJ
Electric Insurance Company	Beverly	MA
EnergyUnited EMC	Statesville	NC
Eppes & Plumblee, P.A.	Greenville	SC
Ervin & Gates	Charlotte	NC
Fabian, Sklar, King & Liss	Farmington Hills	MI
Faulkner & Boyce, PC	New London	CT
Federal Reserve Bank of Richmond, VA	Richmond	VA
Federated Rural Electric Insurance Corp.	Lenexa	KS
Ferderigos & Lambe	Winter Park	FL
Fields Law Firm	Kansas City	MO
Fiore, Krause, Crogan & Lopez	Owings Mills	MD
Forensic Engineering, Inc.	Raleigh	NC

Frank M. Wilson, PC	Montgomery	AL
Freeman & Freeman, PC	Rockville	MD
Freidman, Sissman & Heaton	Memphis	TN
French Broad EMC	Marshall	NC
Friday & Cox, LLC	Pittsburgh	PA
Friday, Eldredge & Clark	Little Rock	AR
Frohilich, Gordon & Beason Law Firm	Port Charles	FL
Gallivan, White & Boyd, P.A.	Greenville	SC
Gary Harris Attorneys At Law	Orlando	FL
Glascock, Gardy & Salvage	Suffolk	VA
Glassen, James	Newark	NJ
Godin Geretty & Puntillo	Kenosha	WI
Godwin, Morris, Laurenzi & Bloomfield	Memphis	TN
Gordon & Partners	Palm Beach Gardens	FL
Gough, Skipworth, Summers, Eves & Travett	Rochester	NY
Granger, Santry, Mitchell & Heath PA	Tallahassee	FL
Grossman, Roth & Partridge	Sarasota	FL
Habush Habush & Rottier, SC	Appleton	WI
Habush Habush & Rottier, SC	Milwaukee	WI
Habush, Habush, Davis & Rottier, SC	Rhinelander	WI
Halifax Electric Membership Corp	Enfield	NC
Hall & Bates	San Antonio	TX
Hall Ansley, P.C.	Springfield	MO
Harrison, White, Smtih & Coggins, P.C.	Spartanburg	SC

Haynes Electric Utility Company	Asheville	NC
Haynsworth Sinkler Boyd, P.A.	Greenville	SC
Hedrick & Blackwell, LLP	Wilmington	NC
Hedrick, Eatman, Gardner & Kincheloe	Charlotte	NC
Herzfeld & Rubin, P.C.	New York	NY
Hogue, Hill, Jones, Nash & Lynch	Wilmington	NC
Holden & Carr	Tulsa	OK
Holt Sherlin LLP	Raleigh	NC
Hoover Penrod, PLC	Harrisonburn	VA
Hutchens Law Firm	Fayetteville	NC
Hux, Livermon & Armstrong, LLP	Enfield	NC
Irigonegaray & Associates	Topeka	KS
Jacquart & Lowe, S.C.	Milwaukee	WI
James McElroy & Diehl, P.A.	Charlotte	NC
Jensen, McGrath, & Podgorny, PA	RTP	NC
Jernigan Law Firm	Raleigh	NC
Joel H. Holt, Esq., PC	Christiansted	VI
John Gehlhausen Attorney at Law	Lamar	CO
John Linkowsky & Associates	Carnegie	PA
Johnson & Lambeth	Wilmington	NC
Johnson & Ward	Atlanta	GA
Jose G. Rodriguez, PA	West Palm Beach	FL
Kaplan, Gilpin & Associates, LLC	Charlotte	NC
Kassel Law	Columbia	SC
Katzman, Wasserman, Bennardini & Rubi	Plantation	FL

Kaufman & Canoles	Richmond	VA
Keefe, Keefe & Unsell, P.C.	Belleville	IL
Keller & Heckman, LLP	Washington	DC
Keller, Keller, Caracuzzo, Cox & Bellucci	West Palm Beach	FL
Kenneth J. Allen Law Group	Valparaiso	IN
Key & Tatel	Roanoke	VA
Kilpatrick Stockton LLP	Raleigh	NC
Kline & Specter, PC	Philadelphia	PA
Koskoff Koskoff & Beider, PC	Bridgeport	CT
Kuhlman & Lucas, LLC	Kansas City	MO
Kullman, Klein & Dioneda, PC	Clayton	MO
La Capra Associates, Inc.	Boston	MA
Langdon & Emison	N. Kansas City	MO
Langdon & Emison	Lexington	MO
Lanzotti & Rau LLC	Cape Girardeau	MO
Larry Leake Attorney At Law	Asheville	NC
Law Office of Robert Stranick	Media	PA
Law Offices of Jeffrey G. Scott, PLLC	Charlotte	NC
Law Offices of Peter A. Jouras, Jr.	Overland Park	KS
Law Offices of Rohn and Carpenter, LLC	Christiansted	VI
Law Offices of Rohn and Carpenter, LLC	Memphis	TN
LeClair Ryan	Glen Allen	VI
LeClair Ryan	Washington	DC
LeClair Ryan	Newark	NJ
Levinson Axelrod, P.A.	Edison	NJ

Lewis Brisbois	Raleigh	NC
Lewis Kappes	Indianapolis	IN
Lichtenstein Fishwick PPL	Roanoke	VA
Lucas, Bryant & Denning, PA	Selma	NC
Lyons & Simmons, LLP	Dallas	TX
Lytal, Reiter, Smith, Ivey & Fronrath, LLP	West Palm Beach	FL
MA Attorney General's Office	Boston	MA
Maher & Associates	Townson	MD
Margolis and Velassco	Chicago	IL
Mark C. Tanenbaum, PA	Charleston	SC
Marshall, Williams, Gorham and Brawley	Wilmington	NC
Martin and Jones, PLLC	Raleigh	NC
Martin, Jean & Jackson	Ponca City	OK
Maupin Taylor, PA	Raleigh	NC
MaynardNexsem	Charleston	SC
McAngus Goudelock & Courie, LLC	Raleigh	NC
McCandlish Holton, PC	Richmond	VA
McCoy, Weaver, Wiggins, Cleveland & Raper, PLLC	Fayetteville	NC
McDonald Toole Wiggins, P.A.	Orlando	FL
McGougan, Wright, Worley, Harper & Bullard, LLP	Tabor City	NC
McGuire Woods, LLP	Richmond	VA
McNees Wallace & Nurick LLC	Harrisburg	PA
Michael F. Amezaga, P.A.	West Palm Beach	FL
Michie Hamlett Lowry Rasmussen	Charlottesville	VA

& Tweel PLLC		
Miles & Stockbridge, PC	Baltimore	MD
Montgomery & Larson, LLP	West Palm Beach	FL
Moore & Van Allen, PLLC	Durham	NC
Morgan & Morgan	Orlando	FL
Morris & Morris	Richmond	VA
Morton and Gettys	Rock Hill	SC
Murphy and Landon	Wilmington	DE
Narron, O'Hale, Whittington & Woodruff	Benson	NC
National Benefits America, Inc.	Charlotte	NC
Nationwide Insurance	Durham	NC
Nelson, Mullins, Riley & Scarborough LLP	Raleigh	NC
New Jersey Dividion of Rate Counsel	Trenton	NJ
Newsom Melton	Orlando	FL
Nexsen Pruet	Greensboro	NC
North Carolina League of Municipalities	Raleigh	NC
Northern Virginia Electric Cooperative	Gainesville	VA
Odem & Groves PC	Charlotte	NC
Offices of David B. Mishael, PA	Miami	FL
Offices of Ronald C. Jessamy, PLLC	Washington	DC
O'Malley & Langan, PC	Pittston	PA
Orr & Reno, P.A.	Concord	NH
Panter, Panter & Sampedro	Miami	FL
Parker, Poe, Adams & Bernstein, LLP	Raleigh	NC
Parker, Poe, Adams & Bernstein, LLP	Charlotte	NC

Parker, Poe, Adams & Bernstein, LLP	Spartanburg	SC
Parr Richey Obremskey Frandsen & Patterson	Lebanon	IN
Patla, Staus, Robinson & Moore, P.A.	Asheville	NC
Patrick C. Fire Law Offices	Boardman	OH
Patrick H. Dekle, P.A.	Tampa	FL
Patterson, Dilthey, Clay, Bryson & Anderson, LLP	Raleigh	NC
Patterson, Harkavy & Lawrence LLP	Raleigh	NC
Penry Riemann PLLC	Raleigh	NC
PEPCO	Washington	DC
Peter Perlman Law Offices PSC	Lexington	KY
Peters, Murdaugh, Parker, Eltsroth & Detrick	Hampton	SC
Pitt & Green Electric Membership Corp.	Farmville	NC
Pittman, Germany, Roberts & Welsh LLP	Jackson	MS
Podgorny Law, PA	Durham	NC
Pope & Tart	Dunn	NC
Porter, Wright, Morris & Arthur, LLP	Columbus	OH
Poyner & Spruill, LLP	Rocky Mount	NC
Pulley, Watson, King & Lischer, P.A.	Durham	NC
Ragsdale & Liggett	Raleigh	NC
Rainwater Holt & Sexton, PA	Little Rock	AR
Randles, Mata & Brown, LLC	Kansas City	MO
Reid, Lewis Deese & Nance	Fayetteville	NC
Rhode Island Attorney General	Warwick	RI

Rhode Island Division of Public Utilities	Warwick	RI
Ricci & Leopold, P.A.	Palm Beach Gardens	FL
Richardson, Patrick, Westbrook & Brickman, LLC	Barnwell	SC
Robert D. Douglass Attorney at Law	Indiana	PA
Rogers Mastrangelo Carvalho & Mitchell	Las Vegas	NV
Romano, Eriksen, Cronin & Mullins	Lake Worth	FL
Rountree Losee, LLP	Wilmington	NC
Rourke and Blumenthal	Columbus	OH
Sandler & Marchesini, PC	Philadelphia	PA
Sanford Thompson, PLLC	Raleigh	NC
Saperston & Day, PC	Buffalo	NY
Sasscer, Clagett & Bucher	Upper Marlboro	MD
Scherffius, Ballard, Still & Ayers, LLP	Atlanta	GA
Schoen Walton Teleken & Foster, LLC	Edwardsville	IL
Schultz Law, LLC	Conshohocken	PA
Schwed, Adams, Sobel & McGinley, P.A.	Palm Beach Gardens	FL
Scott T. Kimmel Attorney at Law	Lighthouse Point	FL
Searcy Denney Scarola Barnhart & Shiple	West Palm Beach	FL
Sedgwick Claims Management Services, Inc.	Louisville	KY
Shapiro, Cooper, Lewis & Appleton, PC	Virginia Beach	VA
Shollenberger Januzzi & Wolfe, LLP	Enola	PA
Silverstein, Silverstein & Silverstein, PA	Aventura	FL
Simon & Bocksch	Miami	FL
Simon Passanante, PC	St. Louis	MO

Simpson Boyd & Powers	Decatur	TX
Smith & Duggan LLC	Lincoln	MA
Smith & Duggan LLP	Boston	MA
Smith, Anderson, Blount, Dorsett, Mitchell & Jernigan, LLP	Raleigh	NC
Smith, Helms, Mulliss & Moore, LLP	Raleigh	NC
Smith, Patterson, Follin, Curtis, James & Haravay	Greensboro	NC
Sommer, Olk, Schroeder & Payant, LLP	Rhinelander	WI
Spivey Law Firm	Ft. Myers	FL
St. Paul Fire and Marine Insurance Co.	Charlotte	NC
Stark & Stark PC	Lawrenceville	NJ
State of Connecticut, Office of Consumer	New Britain	CT
State of Maine, Department of Public Advocate	Augusta	ME
Stites & Hopkins	Kansas City	MO
Stoner, Bowers, Gray & McDonald, P.A.	Lexington	NC
Strassburger McKenna Gutnick & Gefsky	Pittsburgh	PA
Strong Garner Bauer, PC	Springfield	MO
Sumrel ,Sugg, Carmichael, Hicks & Hart	New Bern	NC
Taraska, Grower, Unger & Ketcham, PA	Orlando	FL
Taylor, Day, Grimm, Boyd & Johnson	Jacksonville	FL
The Accurso Law Firm	Kansas City	MO
The Becker Law Firm	Cleveland	OH
The Chandler Law Group	Charlottesville	VA

The Daniel Law Group PLLC	Indiana	PA
The Goss Law Firm, P.C.	Kansas City	MO
The Kuhlman Law Firm, LLC	Kansas City	MO
The Popham Law Firm	Kansas City	MO
The Redfearn Law Firm, P.C.	Independence	MO
The Simon Law Firm, P.C.	St. Louis	MO
The Townsley Law Firm	Lake Charles	LA
The Wilbur C. Smith, III Law Firm, LLC	Fort Myers	FL
Thompson, Smyth & Cioffi, LLP	Raleigh	NC
Throp, Fuller & Slifkin, P.A.	Raleigh	NC
Timothy D. Welbourne Attorney at Law	Wilkesboro	NC
Tomeny Law Firm, APLC	Baton Rouge	LA
Town of Hookerton	Hookerton	NC
Troutman Sanders LLP	Raleigh	NC
Turner & Sweeny	Kansas City	MO
Twiggs, Abrams, Strickland & Trey, PA	Raleigh	NC
United States Department of Justice	Washington	DC
US General Services Administration	Kansas City	MO
Utiliworks Consulting, LLC	Baton Rouge	LA
Vandeventer Black LLP	Raleigh	NC
VML Insurance Programs	Richmond	VA
W. Osmond Smith III Attorney at Law	Yanceyville	NC
Walker & Morgan, LLC	Lexington	SC
Walters Bender Strohbehn & Vaughan, PC	Kansas City	MO

Ward & Smith, PA	Greenville	NC
Warren & Kallianos	Charlotte	NC
Warren & McGraw, LLC	Blue Bell	PA
Warshafsky, Rotter, Tarnoff & Block, S.C	Milwaukee	WI
Warshauer Poe & Thornton, PC	Atlanta	GA
Whitacker, Mudd, Luke & Wells, LLC	Birmingham	AL
Whitesides & Kenny	Gastonia	NC
Wilkins Frohlich, PA	Port Charlotte	FL
Williams & Connolly LLP	Washington	DC
Williams Hart Boundas Easterby, LLP	Houston	TX
Williamson & Lavecchia LC	Richmond	VA
Wilson Elser Moskowitz Edelman & Dick	McClean	VA
Wilson, Frame, Metheney Attorneys & Counselors at Law	Morganton	WV
Wilson, Garber & Small	Orlando	FL
Winner, Wixson & Pernitz	Madison	WI
Womble Bond Dickenson	Winston Salem	NC
Womble Carlyle Sandridge & Rice, LLP	Winston Salem	NC
Wright, Lindsey & Jennings LLP	Little Rock	AR
Wyatt Law Firm	San Antonio	TX
Yates, McLamb & Weyher, LLP	Raleigh	NC
Young & Adams, Attorneys at Law	Boca Raton	FL
Young Moore and Henderson, P.A.	Raleigh	NC
Zurich American Insurance Company	Charlotte	NC
Zurich North America	Charlotte	NC

Partial List of Historical Utility Clients

Client Name	City	State
4 CES/CEEC	Seymour Johnson AFB	NC
A&N Electric Cooperative	Parksley	VA
ACRES International Corporation	Grand Forks	ND
Adams Electric Cooperative	Gettysburg	PA
Adams Rural Electric Cooperative	West Union	OH
AFL Telecommunications		NC
Alabama Power Company	Birmingham	AL
Alachua, City of	Alachua	FL
Alaska 220 Communications	Anchorage	AK
Albemarle Electric Membership Corporation	Hertford	NC
Allegheny Electric Cooperative	Harrisburg	PA
Alleghany Power Energy	Greensburg	PA
Altahama Electric Membership Corporation	Lyons	GA
Alternative Energy Corporation	RTP	NC
American Public Power Association	Washington	DC
American Telecommunications	Raleigh	NC
Apex Communications, LLC	Wynne	AR
Apex, Town of	Apex	NC
Arkansas Electric Cooperative, Inc.	Little Rock	AR
Arlington County		VA
AT&T	Durham	NC
Ayden, Town of	Ayden	NC
BARC Electric Cooperative	Millboro	VA
Bath Electric, Gas & Water	Bath	NC
Bedford, City of	Bedford	VA
Belhaven, Town of	Belhaven	NC
Bellsouth Mobility DCS	Raleigh	NC
Bennettsville, City of	Bennettsville	SC
Benson, Town of	Benson	NC
Black Creek, Town of	Black Creek	NC
Blountstown, City of	Blountstown	FL
Blue Ridge Electric Cooperative	Pickens	SC
Blue Ridge Electric Membership Corporation	Lenoir	NC
Boulder, City of	Boulder	CO
Brazos Electric Power Cooperative		TX
Brunswick Electric Membership Corporation	Shallotte	NC
Burlington-Northern Railroad	St. Paul	MN
Bushnell, City of	Bushnell	FL
Cape Hatteras Electric Membership Corporation	Buxton	NC
Carolina Power & Light	Raleigh	NC
Carroll Electric Cooperative	Carrollton	OH
Carteret Craven Electric Cooperative	Morehead City	NC
Central Electric Cooperative, Inc.	Parker	PA

Client Name	City	State
Central Electric Membership Corporation	Sanford	NC
Central Georgia Electric Membership Corporation	Jackson	GA
Central Virginia Electric Cooperative	Lovingston	VA
Charter Communications	Holly Ridge	NC
Chattahoochee, City of	Chattahoochee	FL
Choptank Electric Cooperative	Denton	MD
Citizens Electric Corporation	Perryville	MO
Claverack Rural Electric Cooperative	Wysox	PA
Clayton, Town of	Clayton	NC
Clemson University	Clemson	SC
Clewiston, City of	Clewiston	FL
Cobb Electric Membership Corporation	Marietta	GA
Coconut Creek, City of	Coconut Creek	FL
Columbus Water Works	Columbus	GA
Community Electric Cooperative	Windsor	VA
Cooperative Energy	Hattiesburg	MS
Cornelius & Huntersville, NC	Huntersville	NC
Continental Cooperative Services	Harrisburg	PA
Craig-Botetourt Electric Cooperative	New Castle	VA
CP&L Area Cooperatives		NC
Crescent Electric Membership Corporation	Statesville	NC
C&T Enterprises		PA
Dalton Utilities	Dalton	GA
Danvers, Town of	Danvers	MA
Danville, City of	Danville	VA
Davidson Water Cooperative	Welcome	NC
Delaware County Electric Cooperative	Delhi	NY
Delaware Division of Parks & Recreation	Dover	DE
Delaware Electric Cooperative	Greenwood	DE
Depcom Power		
Dover, City of	Dover	DE
Drexel, Town of	Drexel	NC
Duke Energy Progress	Raleigh	NC
East Carolina University	Greenville	NC
East Kentucky Power Cooperative	Winchester	KY
Easton Utilities Commission	Easton	MD
Eden, City of	Eden	NC
Edenton, Town of	Edenton	NC
Edgecombe Martin County Electric Membership Corp.	Tarboro	NC
Electric Cooperatives of SC	Cayce	SC
ElectriCities of NC, Inc.	Raleigh	NC
Elizabeth City	Elizabeth City	NC
EnergyUnited	Statesville	NC
Enfield, Town of	Enfield	NC
Enron Wind Corporation	Tehachapi	CA
Farmville Water and Wastewater Systems	Farmville	NC

Client Name	City	State
Farmville, Town of	Farmville	NC
Flint Energies	Warner Robins	GA
Florida Keys Electric Cooperative Association, Inc.	Tavernier	FL
Florida Municipal Electric Association	Tallahassee	FL
Florida Municipal Power Agency	Orlando	FL
Fort-Bragg – USA	Fort Bragg	NC
Fort Lauderdale, City of	Fort Lauderdale	FL
Fort Meade, City of	Fort Meade	FL
Fort Pierce Utilities	Fort Pierce	FL
Four County Electric Membership Corporation	Burgaw	NC
Fox Islands Electric Cooperative	Vinalhaven	ME
French Broad Electric Membership Corporation	Marshall	NC
Fremont, Town of	Fremont	NC
Georgia Consumers Utility Council	Atlanta	GA
Georgia Power	Union City	GA
Gillette, City of	Gillette	WY
Great River Energy	Maple Grove	MN
Green Cove Springs, City of	Green Cove Springs	FL
Greenville Utilities	Greenville	NC
Greer, SC Comm. Of Public Works	Greer	SC
Greystone Power Corporation	Douglasville	GA
Groton Utilities	Groton	CT
Guernsey-Muskingum Electric Cooperative	New Concord	NH
Habersham Electric Membership Corporation	Clarksville	GA
Halifax Electric Membership Corporation	Enfield	NC
Hamilton, Town of	Hamilton	NC
Hancock-Wood Electric Cooperative	N. Baltimore	OH
Harkers Island Electric Membership Corporation	Harkers Island	NC
Harnett County Wastewater	Lillington	NC
Harron Communications	Frazer	PA
Hart Electric Membership Corporation	Hartwell	GA
Havana, Town of	Havana	FL
Haynes Electric Utility Company	Asheville	NC
Haywood Electric Membership Corporation	Waynesville	NC
Hertford, Town of	Hertford	NC
High Point, City of	High Point	NC
Hobgood, Town of	Hobgood	NC
Hookerton, Town of	Hookerton	NC
Jacksonville Beach, City of	Jacksonville Beach	FL
Jefferson Energy Cooperative	Wrens	GA
Joe Wheeler Electric Membership Corporation	Trinity	AL
Jones-Onslow Electric Membership Corporation	Jacksonville	NC
Jupiter Inlet Colony	Jupiter Inlet	FL
Kenergy	Owensboro	KY
Keys Energy Services	Key West	FL
Kinston, City of	Kinston	NC

Client Name	City	State
LaGrange, Town of	LaGrange	NC
Laurinburg, City of	Laurinburg	NC
Lee County Electric Cooperative		FL
Lenior, City of	Lenoir	NC
Lewes, DE Board of Public Works	Lewes	DE
Lewis County Rural Electric Cooperative	Lewiston	MO
Lexington Utilities	Lexington	NC
Lexington, City of	Lexington	NC
Lookout Windpower, LLC		PA
Louisburg, Town of	Louisburg	NC
Lucama, City of	Lucama	NC
Lumbee River MEC	Red Springs	NC
Lumberton, City of	Lumberton	NC
Lynches River Electric Cooperative	Pageland	SC
Madison, Borough of	Madison	NJ
Maine Public Service Company	Presque Isle	ME
Manassas, City of	Manassas	VA
Martinsville, City of	Martinsville	VA
Mebane, City of	Mebane	NC
Mecklenburg Electric Cooperative	Chase City	VA
Middle Georgia Electric Membership Corporation	Rochelle	GA
Milford, City of	Milford	DE
Mississippi Power	Gulfport	MS
Mitchell Electric Membership Corporation	Camilla	GA
MN Planning/Environmental	St. Paul	MN
Monroe, City of	Monroe	NC
Morganton, City of	Morganton	NC
Municipal Gas Group	Wilson	NC
NASA	Wallops Island	VA
National Rural Telecom Cooperative	Herndon	VA
New Bern, City of	New Bern	NC
Newberry, City of	Newberry	NC
New Enterprise Rural Electric Cooperative	New Enterprise	PA
New Hampshire Electric Cooperative	Plymouth	NH
North Carolina AT&T State University	Greensboro	NC
North Carolina Association of Electric Cooperatives	Raleigh	NC
North Carolina Eastern Municipal Power Agency	Raleigh	NC
North Carolina Electric Membership Corporation	Raleigh	NC
North Carolina League of Municipalities	Raleigh	NC
North Carolina Rural Telecommunications Cooperative	Enfield	NC
North Carolina State University	Raleigh	NC
North Georgia Electric Membership Corporation	Dalton	GA
North Miami, City of	Miami	FL
Northern Neck Electric Cooperative	Warsaw	VA
Northern Virginia Electric Cooperative	Gainesville	VA
Northfield Electric Department	Northfield	VT

Client Name	City	State
Northwest Public Power Association	Vancouver	WA
Northwestern Rural Electric Cooperative Association	Cambridge Springs	PA
NRECA	Arlington	VA
Ohio Rural Electric Cooperative, Inc.	Columbus	OH
Old Dominion Electric Cooperative	Glen Allen	VA
Origis Energy		FL
Ostego Electric Cooperative	Hartwick	NY
Palm Beach, Town of	Palm Beach	FL
Panama City Beach	Panama City	FL
Peace River Electric Cooperative	Wauchula	FL
Pee Dee Electric Cooperative	Darlington	SC
Pee Dee Electric Membership Corporation	Wadesboro	NC
Pennsylvania Rural Electric Association	Harrisburg	PA
Perkasie, Borough of	Perkasie	PA
Piedmont Electric Membership Corporation	Hillsborough	NC
Pineville, Town of	Pineville	NC
Pitt & Greene Electric Membership Corporation	Farmville	NC
Pompano Beach, City of	Pompano Beach	FL
Pope Air Force Base	Pope AFB	NC
Potomac Electric Power Company	Washington	DC
Prince George Electric Cooperative	Waverly	VA
PGEC Enterprise, LLC	Waverly	VA
Progress Energy	Raleigh	NC
PWC of the City of Fayetteville	Fayetteville	NC
Quincy, City of	Quincy	FL
Randolph Electric Membership Corporation	Asheboro	NC
Rappahannock Electric Cooperative	Fredericksburg	VA
REA Energy Cooperative (SW Central)	Indiana	PA
Red Springs, Town of	Red Springs	NC
Roanoke Electric Cooperative	Rich Square	NC
Robersonville, Town of	Robersonville	NC
Rockingham County	Rockingham	NC
Rocky Mount, City of	Rocky Mount	NC
Roxboro, City of	Roxboro	NC
Rutherford Electric Membership Corporation	Forest City	NC
Sacramento Municipal Utility District	Sacramento	CA
Salem, City of	Salem	VA
Sandhills Utility Services, LLC	Red Springs	NC
Santee Cooper	Myrtle Beach	SC
Satilla Rural Electric Membership Corporation	Alma	GA
Sawnee Electric Membership Corporation	Cumming	GA
Scotland Neck, Town of	Scotland Neck	NC
Seaford, Town of	Seaford	DE
SECO Energy	Sumterville	FL
Selma, Town of	Selma	NC
Seneca, City of	Seneca	SC

Client Name	City	State
Seymour-Johnson Air Force Base	Goldsboro	NC
Sharpsburg, Town of	Sharpsburg	NC
Shenandoah Valley Electric Cooperative	Mt. Crawford	VA
SMECO	Hughesville	MD
Smithfield, Town of	Smithfield	NC
Snapping Shoals Electric Membership Corporation	Covington	GA
Somerset Rural Electric Cooperative	Somerset	PA
South Daytona, City of	South Daytona	FL
South Mississippi Electric Power Association	Hattiesburg	MS
South River Electric Membership Corporation	Dunn	NC
Southern Company Services	Atlanta	GA
Southern Maryland Electric Cooperative		MD
Southport, City of	Southport	NC
Southside Electric Cooperative	Crewe	VA
South Carolina Association of Municipal Power Systems	Columbia	SC
Stantonsburg, Town of	Stantonsburg	NC
Starke, City of	Starke	FL
Strata Solar, LLC		
Statesville, City of	Statesville	NC
Steuben Rural Electric Cooperative	Bath	NY
STS Hydro Power Limited	Northbrook	IL
Sullivan County Rural Electric Cooperative	Forksville	PA
Sulphur Springs Valley Electric Membership Corp.	Willcox	AZ
Sumter Electric Cooperative		FL
Surry-Yadkin Electric Membership Corporation	Dobson	NC
Sussex Rural Electric Cooperative	Sussex	NJ
Talquin Electric Cooperative, Inc.	Quincy	FL
Tarboro, Town of	Tarboro	NC
Tarboro Water and Wastewater Systems	Tarboro	NC
Tideland Electric Membership Corporation	Pantego	NC
Time Warner Cable	Newport	NC
Tri-County Electric Membership Corporation	Dudley	NC
Tri-County Electric Membership Corporation	Lafayette	TN
Tri-County Rural Electric Cooperative	Mansfield	PA
TVPPA	Chattanooga	TN
UNC – Asheville	Asheville	NC
UNC – Chapel Hill	Chapel Hill	NC
UNC – Charlotte	Charlotte	NC
UNC – Greensboro	Greensboro	NC
Union Electric Membership Corporation	Monroe	NC
Union Power Cooperative	Monroe	NC
United Electric Cooperative	DuBois	PA
US Generating Company	Bethesda	MD
VA, MD & DE Association of Electric Cooperatives	Glen Allen	VA
Valley Rural Electric Cooperative	Huntington	PA
Vanceburg, City of	Vanceburg	KY

Client Name	City	State
Vero Beach, City of	Vero Beach	FL
Wake County Parks & Recreation	Raleigh	NC
Wake Electric Membership Corporation	Wake Forest	NC
Wake Forest, Town of	Wake Forest	NC
Walstonburg, Town of	Walstonburg	NC
Warren Electric Membership Corporation	Youngsville	PA
Washington Electric Cooperative	E. Montpelier	VT
Washington Electric Membership Corporation	Sandersville	GA
Washington, City of	Washington	NC
Wauchula, City of	Wauchula	FL
Waynesville, Town of	Waynesville	NC
Wellsboro Electric Company	Wellsboro	PA
West Virginia Power Company	Lewisburg	WV
Western Carolina University	Cullowhee	NC
Western North Carolina School for the Deaf	Morganton	NC
Wilmington, City of	Wilmington	NC
Wilson, City of	Wilson	NC
Windsor, Town of	Windsor	NC
Winter Park, City of	Winter Park	FL
Winterville, Town of	Winterville	NC

Partial List of Historical Industrial/Commercial Clients

Client Name	City	State
Action Sensors, Inc.	Wendell	NC
Alcoa Fujikura, Ltd.	Spartanburg	SC
Alliance Development Group, LLC		VA
Atlantic Power Generation	Charlotte	NC
Barnhill Contracting Company	Tarboro	NC
Beckwith Power Systems	North Versailles	PA
Biltmore Dairy Farms, Inc.	Asheville	NC
Black & Decker	Tarboro	NC
Bridgestone/Firestone (BFS)	Wilson	NC
Burroughs Wellcome Company	RTP	NC
CAA Engineers, Inc.		
Calpine Operations Services (Calpine Power)	Houston	TX
Caswell Center	Kinston	NC
Centura Bank	Rocky Mount	NC
Centex Construction	Atlanta	GA
Charter Communications	Surf City	NC
Cherry Hospital – DHR	Goldsboro	NC
Clapp Research Associates	Raleigh	NC
Clark Substations, LLC	Calera	AL
CNA Insurance Companies	Rockville	MD
Cornice Engineering, Inc.	Pagosa Springs	CO
Crawford & Company	Raleigh	NC
Data Comlink, Inc.	Sandersville	GA
Design Dimensions, Inc.	Raleigh	NC
Dolan and Dolan	Newton	NJ
Dupaco	Kinston	NC
Drucker & Falk	Raleigh	NC
E&R Construction	Kinston	NC
East Coast Power & Lighting		
EMC Technologies	Raleigh	NC
Empire of Carolina	Tarboro	NC
Exelon Business Services		
Frigidaire	Kinston	NC
Fontaine Fifth Wheel	Birmingham	AL
Fonville-Morrisey	Raleigh	NC
General Electric	Fairfield	CT
Glenoit Industries	Tarboro	NC
Green Property Advisors, LLC		
Goldsboro, City of	Goldsboro	NC
Cherry Hospital DHR	Goldsboro	NC
Gregory Poole Power Systems	Raleigh	NC
Harris Development Corp.	Wilson	NC
Hesco, Incorporated	Smithfield	NC
High Point Regional Hospital	High Point	NC

Client Name	City	State
Homestead, LLC	Hot Springs	VA
Honeywell	Fort Bragg	NC
Infrastructure Consulting & Engineering		
Jag Management, Inc.	Raleigh	NC
KCI Technologies, Inc.	Raleigh	NC
Kelly Springfield Tire Co.	Fayetteville	NC
Kinston City Hall	Kinston	NC
Larry A. Blattenberger, Inc.	Martinsburg	PA
Lenoir Memorial Hospital	Kinston	NC
Maida Vale, LLC	Raleigh	NC
National Fruit Product Company		VA
National Spinning Co., Inc.	Washington	NC
NC Department of Human Resources	Raleigh	NC
NC Department of Transportation	Raleigh	NC
NC Division of Mental Health	Raleigh	NC
NC Licensing Board – General Contractor	Raleigh	NC
NC School of Deaf	Raleigh	NC
NC State Construction Office	Raleigh	NC
New Hanover County	Wilmington	NC
North Hills PBX	Raleigh	NC
Nucor Steel	Charlotte	NC
Pitt County Memorial Hospital	Greensville	NC
Power Delivery Associates	Smyrna	GA
PS & W Engineering	Cary	NC
Rail-Veyor Global Technologies, Inc.		
Raleigh, City of	Raleigh	NC
Richardson-Wayland Electrical Company		
Rocky Mount City Hall	Rocky Mount	NC
Rural Green Power, LLC		
Sara Lee Corporation	Tarboro	NC
Stanton Barton, LLC		
Still Waters Engineering		
T&D Solutions		
Talisman Partners, Inc. (now Earthtech)	Englewood	CO
Tantalus Systems, Corp.	Burnaby, BC	Canada
Tarboro Elementary School	Tarboro	NC
Tarboro High School	Tarboro	NC
Technical Associates, Inc.		
Teligent, Inc.	Alpharetta	GA
Texfi Industries	Fayetteville	NC
The West Co.	Kinston	NC
Transco	Charlottesville	VA
US Postal Services (GSA)	Raleigh	NC
Utility Engineering Services	Jackson	TN
Volvo Data North America	Greensboro	NC
West Company	Kinston	NC

Client Name	City	State
Williams Energy Group	Tulsa	OK
Zenith Controls, Inc.	Chicago	IL

SEMINARS, PRESENTATIONS & PUBLICATIONS

As of October 2023

Seminars/Presentations and Publications

North Carolina Association of Municipal Electrical Systems (NCAMES)

Date	*Location*	*Presentation/Seminar/Class Title*
1987	Annual Meeting	System Losses Overview
1990	Annual Meeting	NESC – Clearance & Liabilities
1992	Annual Meeting	CL Fuses Presentation
1993	Annual Meeting	NESC Revisions/Partial Review
1996	Annual Meeting May 13, 1996 Greensboro, NC	NESC 1997 Proposals/Partial Review
1997	Annual Meeting Charlotte, NC	Overhead High Voltage Line Safety Act
May 16-18, 2000	39th Annual Conference Raleigh, NC	Protective Relaying Principles Presentation
May 2000	Annual Meeting	Distribution System Protective Coordination Principles
May 2006	Annual Meeting	Asset Management Strategic Planning and Long-Range Planning
May 2007	Annual E & O Conference	Arc Flash Hazard and the NESC (Protection Assessment) Summary Presentation
April 2008	Annual E & O Conference Concord, NC	Long-Range Planning and Distribution Protection
May 2009	Annual Meeting	Economic System Improvements

National Rural Electric Cooperative Association (NRECA)

Date	*Location*	*Presentation/Seminar/Class Title*
July 18-20, 1983	St. Louis, MI	Store, Deter, Delay or Interrupt
Nov. 16, 1989		Report on Distribution Improvements that pay off through Lower Power Loss
1991	Annual Meeting	Distribution System Loss Management
1992		Distribution Loss Seminar
June 24-26, 1992	San Antonio, TX	Distribution System Loss Workshop
Sept. 23-24, 1993	Herndon, VA	Cost Effective Management of System Planning & Purchasing
January 2000		Recloser Actuator Engineering Analysis Update
February 2001	TechAdvantage Meeting	ABCs of System Planning
February 2002	TechAdvantage Meeting	Economic Conductor Sizing
August 15, 2006	CRN Member Summit - Cooperative Research Council Meeting	Asset Management Strategic Planning Reliability and Trends

American Public Power Association (APPA)

Date	*Location*	*Presentation/Seminar/Class Title*
October 6-7, 1986	Kansas City, MI	Distribution Line Loss Seminar & Manual
Sept. 28-30, 1987	Raleigh, NC	Distribution Line Loss Seminar & Manual
April 11-13, 1988	Colorado Springs, CO	Distribution Line Loss Seminar & Manual
June 24, 1988		National Distribution Improvements Pay Off through Power Losses
October 12-14, 1988	Minneapolis, MN	Distribution Line Loss Guide

North Carolina Electric Membership Corporation & North Carolina Association of Electric Cooperatives (NCEMC & NCAEC)

Date	*Location*	*Presentation/Seminar/Class Title*
October 1986		NCAEC – Distribution System Loss Evaluation
October 30, 1986	Greenville Utilities Commissions	NCAEC – Reduce Losses in Distribution Systems
November 13, 1986	Crescent UMC Statesville, NC	NCAEC – Reduce Losses in Distribution Systems
1993	Operations Conference	1993 NESC Revisions Partial Review
December 12, 1996	Nash Community College, Rocky Mount, NC	NCAEC – Advanced Lineman Training NESC Introduction
June 1999	E & O Conference	Distribution Protective Coordination Workshop
June 2000	E & O Conference	NCAEC – Proposed changes to 1997 NESC
June 2001	E & O Conference	NCAEC – The NESC
December 5-6, 2001	System Engineer's Workshop	NCAEC -- The NESC
June 2002	E & O Conference	NCAEC – Overview of 2002 NESC Changes
September 2002	NCEMC Manager’s Conference, Sunset Beach, NC	NCEMC – Overview 2002 NESC Changes

Date	*Location*	*Presentation/Seminar/Class Title*
June 2007	2007 E & O Conference	NCAEC - Arc Flash Hazard and the NESC (Protection Assessment) Summary Presentation
December 6, 2007	System Engineers Workshop	NCAEC - Arc Flash Hazard and the NESC (Protection Assessment) 7 Hour Seminar and Manual
June 2008	2008 E & O Conference	NCAEC - Two Presentations: Arc Flash Hazard Update and The National Electrical Code and How it Applies to Utilities
August 2008	2008 Safety Coordinator's Workshop	NCEMC - Arc Flash Hazard Update
December 2008	2008 System Engineers' Workshop	NCAEC - Arc Flash Hazard Assessment Findings
December 2010	2010 System Engineers’ Workshop	NCAEC – Power Quality
December 2011	2011 System Engineers’ Workshop	NCAEC - National Electrical Safety Code Update
June 2013	2013 E&O Conference	Stray Voltage and Contact Voltage
December 2014	2014 System Engineers’ Workshop	NCAEC-Pole Attachment – Joint Use
March 14-15, 2017	Rocky Mount, NC	Incident Investigation Training for Utility Professionals
November 16, 2018	NCEMC Counsel Association Counsel Meeting	Joint Use Contracts: From the Electrical Engineer Perspective

North Carolina Electric Municipal Power Association (NCEMPA)
& ElectriCities of North Carolina, Inc.

Date	*Location*	*Presentation/Seminar/Class Title*
1983	Wake Tech. College Raleigh, NC	Distribution System Protective Coordination School and Manual
1985	Wake Tech. College Raleigh, NC	Distribution System Protection School
June 17, 1987	ElectriCities	NESC & Municipal Electric System Safety Seminar
Sept. 28-30, 1988	Raleigh, NC	Distribution System Loss Evaluation Manual
November 1990	ElectriCities	NESC Course Manual
Dec. 11-12, 1991	ElectriCities	NESC
November 1992	ElectriCities	NESC Course Manual
Nov. 17-18, 1993	Raleigh, NC	NESC School
Nov. 16-17, 1994	ElectriCities	NESC Seminar
November 13, 1996	ElectriCities	1997 NESC Course

Other

Date	*Location*	*Presentation/Seminar/Class Title*
May 1988	SC Public Service Authority-Santee Cooper	NESC Training Guide
November 14, 1989	City of Bennettsville, SC	Value of System Planning
1990	Joe Wheeler EMC Hartselle, AL	NESC
May 1990	Northeast Assoc. of Electric Cooperatives	Power Quality Presentation & Distribution Cost Trends Presentation
May 22-24, 1990	New England Statewide	NARC
Dec. 10-11, 1990	Lexington, NC	NESC School
Dec. 26, 1990	City of Kinston, NC	NESC Course
1993	Davidson Electric Membership Cooperative Lexington, NC	NESC Course Manual Partial Review
Jan. 12-14, 1993	Rappahannock Electric Cooperative Fredericksburg, VA	Distribution System Loss Management Workshop
June 18-19, 1993	Joe Wheeler EMC Hartselle, AL	NESC School
June 2000	SCAMPS Annual Meeting	Distribution System Protective Coordination Principles
July 2000	CP&L Raleigh, NC	CP&L Accident Investigation Workshop

Date	*Location*	*Presentation/Seminar/Class Title*
June 2001	SCAMPS Annual Meeting	Accident Investigation and Avoidance Issues
February 2002	SCAMPS Columbia, SC	2002 NESC Workshop and Manual
July 2002	Florida Municipal Electric Association Orlando, FL	2002 NESC and Manual
April 2003	Old Dominion Electric Cooperative	Load Research Relevance to Distribution Planning
April 2004	Virginia, Maryland & Delaware Association of Electric Cooperatives	• System Grounding Presentation • Capacitor Placement & Power Factor Correction • System Planning
May 2004	Virginia, Maryland & Delaware Association of Electric Cooperatives	Interval Data and Construction Work Plan Design
October 23, 2007	PREA Fall 2007 Engineering Meeting State College, PA	Arc Flash Hazard and the NESC (Protection Assessment) Summary Presentation
December 11, 2007	City of Wilson, North Carolina	Arc Flash Hazard and the NESC (Protection Assessment) 4 Hour Workshop for Municipalities
December 13, 2007	City of Lexington, NC	Arc Flash Hazard Assessment and the NESC 8 hour Workshop and Manual
January 2008	PREA State College, PA	Arc Flash Hazard Assessment and the NESC 8 hour Workshop and Manual

Date	*Location*	*Presentation/Seminar/Class Title*
April 15, 2008	Virginia, Maryland & Delaware Association of Electric Cooperatives	Arc Flash Hazard and the NESC (Protection Assessment) 7 Hour Workshop and Manuals
July 13, 2009	SCAMPS Annual Meeting	Maximizing Utility Resources Through Best Practices
April 29, 2010	PREA CEO Meeting, State College, PA	NERC Compliance Monitoring & Enforcement Presentation (Summary)
June 24, 2010	PREA 2010 Manager's Workshop, State College, PA	NERC Compliance Monitoring & Enforcement Presentation (Detailed)
May 5, 2011	Virginia, Maryland & Delaware Association of Electric Cooperatives	Pole Attachment Review
August 29, 2012	LeClair Ryan Webinar	Energy Audits
November 20, 2012	Schultz Law Webinar	Subrogation of Workers' Comp. Claims Involving Electrical Contact Injuries
December 7, 2012	PWC of the City of Fayetteville, NC	Why Follow Engineering Design and the NESC Linemen Presentation
August 20, 2013	RESMA Lobbying Clinic, Virginia	Pole Attachment Dispute Discussion
January 19, 2015	PWC of the City of Fayetteville, NC	Arc Flash Risk Assessment – Industrial and Commercial Facilities
April 30, 2015	Northwestern Rural Electric Cooperative Association	Joint Use Pole Attachment – PA & Regional Issues
May 6-7, 2015	Virginia, Maryland & Delaware Association of Electric Cooperatives	Joint Use Pole Attachment – VA & Regional Issues

Date	*Location*	*Presentation/Seminar/Class Title*
July 2016	Sussex Rural Electric Cooperative, Sussex, NJ	Arc Flash Hazard Assessment Update
November 30, 2016	Rappahannock Electric Cooperative, VA	2017 NESC Update
July 2019	NRECA Legal 59 Seminar	Practical Considerations in Pole Attachment Negotiations
August 29, 2019	Rappahannock Electric Cooperative, VA	Storm Hardening Assessment Presentation
February 23, 2023	Wake Electric, Youngsville, NC	Incident Investigation Training for Utility Professionals

Distribution System Loss Evaluation Seminars

Date	*Location*
September 30 – October 2, 1991	Marco Island, FL
November 15, 1991	Albuquerque, NM
November 18, 1991	St. Louis, MI
November 22, 1991	Charlotte, NC
January 15, 1992	Jones Onslow EMC Jacksonville, NC
May 11-13, 1992	Nashville, TN
September 30 – October 2, 1992	Northwest Public Power Association Seattle, WA
October 4-7, 1992	District Manager's Conference San Antonio, TX
November 12, 1992	Four County EMC Burgaw, NC
July 18-21, 1993	Materials Management Conference Hilton Head, SC
October 13-16, 1993	Northwest Public Power Authority Portland, OR
June 15-17, 1994	North Carolina Association of Electric Cooperatives E&O Conference Sunset Beach, NC
October 18, 1994	North Carolina Electric Membership Cooperative Raleigh, NC

Date	*Location*
October 23-26, 1994	NRECA E&O Conference Jacksonville, FL
January 17, 1995	United EC Dubois, PA
November 20 – December 1, 1995	Minneapolis, MN
December 14-15, 1995	Nashville, TN
May 22-24, 1996	San Antonio, TX
June 12-14, 1996	Denver, CO
April 22-23, 1997	Minneapolis, MN
1999	North Carolina Alternative Energy Corporation Distribution System Loss Reduction Manual and Courses
May 9, 2000	Lewis County REC Lewistown, MI

National and State Publications

Date	*Publications*
1983	North Carolina Alternative Energy Corporation Distribution System Loss Reduction Manual and Courses
1983	Distribution System Protective Coordination Manual ElectriCities of North Carolina
1986	Distribution System Loss Evaluation Manual American Public Power Association
1991	Distribution System Loss Management Manual – NRECA (2 manuals, 6 National Workshops and Manuals)
1994	Distribution System Loss Reduction Manual Tennessee Valley Public Power Association, Research & Development
1998	Distribution Protective Coordination Workshop and Manual ElectriCities of North Carolina
June 1999	Distribution Protective Coordination Workshop and Manual
2000	Improving Distribution System Performance
2001	National Electrical Safety Code Workshop Materials
2001	Evaluation of Recloser Actuators – NRECA
2003	Power Loss Management Manual for the Deregulated Utility Environment NRECA-CRN
2004	Power Loss Management Manual for the Deregulated Utility Environment NRECA-CRN Computer Based Training CD and Power Loss Management Interactive CD Publication

Date	***Publications***
2004	Virginia, Maryland & Delaware Association of Electric Cooperatives • System Grounding Materials • Capacitor Placement & Power Factor Correction Materials • System Planning Materials
2004	Interval Data and Construction Work Plan Design Materials
2007	Arc Flash Hazard and the NESC (Protection Assessment) Seminar Materials