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Rhode Island Energy™
a PPL company

March 7, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-48-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Joint Reply Testimony

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's joint reply testimony responding to the following filings that were submitted in the above-referenced matter:

- Pre-filed direct testimony of Gregory L. Booth, PE on behalf of the Division of Public Utilities and Carriers submitted on February 20, 2024
- Memorandum by John Bell, Chief Accountant for the Division submitted on February 20, 2024
- The Statement of Position filed by Peter F. Neronha, Attorney General of the State of Rhode Island submitted on February 20, 2024; and
- The Statement of Position filed by the Conservation Law Foundation submitted on January 25, 2024

Thank you for your attention to this transmittal. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 23-48-EL Service List

JOINT REPLY TESTIMONY

OF

KATHY CASTRO

RYAN CONSTABLE

ERIC WIESNER

DANIEL GLENNING

PHILIP J. WALNOCK

PARKER CAPWELL

STEPHANIE A. BRIGGS

JEFFREY D. OLIVEIRA

AND

NATALIE HAWK

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I. Introduction

Kathy Castro

Q. Ms. Castro, please state your name and business address.

A. My name is Kathy Castro. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Ms. Castro, by whom are you employed and in what position?

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy") as Vice President of Distribution. In my position, I am responsible for the safe, reliable and cost-effective operation of Rhode Island Energy's electric distribution system, including engineering, field operations, distribution control, investment planning and work management.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

Ryan Constable

Q. Mr. Constable, please state your name and business address.

A. My name is Ryan M. Constable. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Mr. Constable, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as an Engineering Manager in the Distribution Planning and Asset Management Department. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

<u>Eric Wiesner</u>

Q. Mr. Wiesner, please state your name and business address.

A. My name is Eric Wiesner. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Mr. Wiesner, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as the Director of Asset Management and Engineering. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

Daniel Glenning

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

A. My name is Daniel Glenning. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Mr. Glenning, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as the Director of Project and Construction Management. In my role, I am responsible for the delivery of capital projects.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

Philip J. Walnock

Q. Mr. Walnock, please state your name and business address.

A. My name is Philip J. Walnock. My business address is 2 North 9th 4 Street, Allentown, PA 18101.

Q. Mr. Walnock, by whom are you employed and in what position?

A. I am employed by PPL Services Corporation, a subsidiary of PPL Corporation ("PPL"), and I currently hold the position of Director, Product Portfolio – Field Operations.

My responsibilities include supporting the deployment of advanced metering functionality ("AMF") for Rhode Island Energy.

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

A. I hold a Bachelor of Arts degree from East Stroudsburg University of Pennsylvania and a Master of Science degree from Stevens Institute of Technology. I have 15 years of leadership experience at PPL Electric Utilities Corporation ("PPL Electric") across Information Technology, Customer Service, Advanced Metering, and Transmission & Distribution operations and project management. Prior to my current role, I was Director, Customer Service Project Management Office with direct responsibilities for PPL Electric's energy efficiency and low-income programs, along with the planning and implementation of the customer experience portfolio. From 2015-2019, I was responsible for leading the overall implementation of PPL Electric's Smart Meter Implementation Plan ("SMIP"), where approximately 1.45 million automated meter reading ("AMR") meters were exchanged with second-generation AMF meters in Pennsylvania. From 2009 through 2014, I held leadership roles in Attachments, Vegetation Management, Construction Management, and Project and Contract Management. I was employed with Verizon Communications from 1996 – 2009 in various front line and leadership roles in Construction, Installation and Maintenance, Customer Operations, and Strategic Initiatives.

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

A. Yes. I testified in Docket No. 22-49-EL related to the Company's AMF Business Case.

Q. Can you describe your current role in the implementation of the approved AMF plan?

A. I am the lead for the strategy and planning of the AMF plan, which included obtaining regulatory approval of our plan. I have overall leadership responsibilities for implementation, which includes the management of cost, implementation of systems and functionality to be delivered, field deployment installation, and the related business integration and communications activities.

Parker Capwell

Q. Mr. Capwell, please state your name and business address.

A. My name is Parker Capwell. My business address is 1695 Mendon Road, Cumberland, Rhode Island 02864

Q. Mr. Capwell, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as Manager of Advanced Metering Functionality.

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

A. I hold a Bachelor of Science degree in Finance from Bryant College and a Masters of Science in the Business of Energy from Clarkson University. I have 14 years of experience with the utility including roles in finance as a Business Partner, underground operations as a supervisor and in Distribution Operations as a manager of overhead, underground, troubleshooters and customer metering services.

Q. Have you previously testified before the Commission?

A. No.

Q. Can you describe your current role in the implementation of the approved AMF plan?

A. As the Manager of Advanced Metering Functionality, I am responsible for the safe, on time, on budget implementation of Rhode Island Energy's Advanced Metering Functionality Plan. I am responsible for leadership and management of an assigned team of project managers, technical professionals and contractors accountable for all contract management and program management activities throughout the life cycle of the program. These activities include system and network design, field construction, deployment and system stabilization.

Stephanie A. Briggs

Q. Ms. Briggs, please state your name and business address.

A. My name is Stephanie A. Briggs. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Ms. Briggs, by whom are you employed and in what position?

A. I am employed by PPL Services Corporation as a Senior Manager of Revenue and Rates. The PPL Services Corporation provides administrative, management and support services to PPL and its subsidiary companies, including Rhode Island Energy. My current duties include responsibility for revenue requirement and rates calculations for the Company.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

Jeffrey D. Oliveira

Q. Mr. Oliveira, please state your name and business address.

A. My name is Jeffrey D. Oliveira. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Mr. Oliveira, by whom are you employed and in what position?

A. I am employed by the PPL Services Corporation as a Regulatory Programs Specialist. My current duties include leading the revenue requirement analyses and modeling that support regulatory filings, regulatory strategies, and rate cases for the Company.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

<u>Natalie Hawk</u>

Q. Ms. Hawk, please state your name and business address.

A. My name is Natalie Hawk, and my business address is 2 North Ninth Street, Allentown, Pennsylvania 18101.

Q. Ms. Hawk, by whom are you employed and in what position?

A. I am employed by the PPL Services Corporation as the Director of tax accounting and reporting. My current responsibilities are to oversee the accounting and reporting of income taxes under U.S. Generally Accepted Accounting Principles and the FERC Uniform System of Accounts and support regulatory rate filings from a tax perspective.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 21, 2023.

II. Purpose and Structure of Joint Reply Testimony

Q. What is the purpose of this testimony?

A. The purpose of this testimony is for the Company to respond to the following filings that were submitted in this proceeding: (i) Pre-filed direct testimony of Gregory L. Booth, PE on behalf of the Division of Public Utilities and Carriers ("Division") submitted on February 20, 2024; (ii) Memorandum by John Bell, Chief Accountant for the Division submitted on February 20, 2024; (iii) The Statement of Position filed by Peter F. Neronha, Attorney General ("AG") of the State of Rhode Island submitted on February 20, 2024 ("AG Position"); and (iv) The Statement of Position filed by the Conservation Law Foundation ("CLF") submitted on January 25, 2024 ("CLF Position").

Q. How is this testimony structured?

A. This testimony is broken up by topic. Specifically, through this testimony, the Company responds to the following topics:

- Process, Scope & Standards (Section III)
- Spare Transformers and Mobile Substations (Section IV)
- Reclosers (Section V)
- Electromechanical Relay Upgrades (Section VI)

- Hold Harmless (Section VII)
- Advanced Metering Functionality (Section VIII)
- Conclusion (Section IX)

III. Process, Scope & Standards

Q. When did the Company first begin discussions with the Division about the Company's Proposed Fiscal Year 2025 Electric Infrastructure, Safety, and Reliability Plan ("FY 2025 ISR Plan" or "ISR Plan" or "Plan")?

A. The Company began discussions about the proposed FY 2025 ISR Plan with the Division in May 2023, which was months earlier than in years past. The Company engaged in a series of meetings with the Division between May and August, prior to submitting a Long-Range Plan to the Division on September 8, 2023. The first meeting of the series focused on the adjustments the Company made to the FY 2024 capital plan based on the outcome of the FY 2024 ISR Plan proceedings consistent with the Commission's rulings in Docket No. 22-53-EL. At this meeting the Company and Division discussed a plan to ensure a collaborative approach when reviewing the FY 2025 ISR Plan prior to submittal to the Commission. This collaborative approach included meetings which reviewed specific projects and programs, a dedicated presentation on the Distribution Automation Recloser Program ("DARP"), explanation of project risks and risk workshop process, and a detailed review of the non-discretionary and discretionary categories of the FY 2025 ISR Plan. These meetings also included a line-item budget review of both the asset condition and system capacity and performance projects and programs provided to the Division on August 8, 2023 and August 9, 2023. In addition to these meetings the Company's operations and engineering personnel facilitated 16 substation tours for the Division. The tours allowed the Division to see firsthand the substations that are linked to proposed projects in the FY 2025 ISR Plan.

Q. What were the issues and concerns that were raised by the Division initially?

A. There were a number of issues and questions raised by the Division during these meetings. The following are what the Company considers the two most significant concerns raised during this year's collaboration:

(1) The Company's risk analysis of asset condition work, in the Division's opinion, was not as robust as the Division would have liked to have seen to determine prioritization of projects in the ISR Plan.

(2) In the Division's opinion, the Company did not provide a system wide coordination study providing justification for recloser installations in the DARP.

Additionally, the Division posed other concerns, including:

(3) The inclusion of potential Distributed Generation ("DG") reimbursement of pending Tiverton and Weaver Hill Petitions.

(4) Creation of a non-discretionary category to include emergent system conditions which were being completed under discretionary blankets.

Q. How did the Company respond to those concerns?

A. The Division issued and the Company responded to various sets of data requests leading up to the FY 2025 ISR Plan that was proposed to the Commission.

With respect to the risk analysis concern, the Company provided risk assessments developed via a new process which conducted workshops including operations team members from all disciplines including UG lines, OH lines, Substation, Protection Relay, Telecommunication, engineering, control center leads, and project and construction management. The risk assessments, along with the 16 substation tours, provided support for projects in the ISR to maintain safety and reliability.

With respect to the concerns about the system wide coordination study to support the DARP, the Company provided a detailed program document, which included quantitative and qualitative justification and execution plan for the DARP. In addition, the Company provided a demonstration of a coordination review explaining the Company's robust process and protection criteria. Finally, the Company agreed to provide detailed circuit specific analysis 60 days prior to advancement of recloser installations.

Q. Can you provide an example of something that the Company agreed to adjust after collaborating with the Division?

A. One of the major adjustments in this year's plan was the execution schedule of the DARP. The Company originally proposed the installation of approximately 300 reclosers to address circuits with an average outage frequency greater than the regulatory SAIFI threshold of 1.05. The plan the Company submitted to the Division on October 13, 2023 included a reduction to 88 recloser installations across the DARP, ERR and CEMI programs.

Q. What were the reasons the Company was willing to agree to that adjustments?

A. The Company modified the execution plan for the DARP in response to the Division's concerns about pace and resulting upward pressures on rates.

Q. Can you provide an example of something the Company understands the Division adjusted its position on through the collaborative process?

A. While the Division may prefer the completion of a systemwide protective coordination study, it is the Company's understanding that the Division agreed that a full system protection coordination review would not be required to move forward with recloser installations and, in lieu of a systemwide protective coordination study, the Company will provide detailed circuit analysis to the Division 60 days prior to advancement of recloser installations.

Q. What is your understanding of the reasons that the Division agreed to that?

A. It is our understanding that the Division agreed to adjust its position and agree to the installation of reclosers through the DARP without a full system protection coordination review because of: (a) the program documentation, (b) circuit coordination demonstration, and (c) the Company's agreement to provide specific memos showing the due diligence the Company takes to analyze reliability data and operation characteristic to identify the appropriate number and location of reclosers by circuit.

Q. Is it the Company's understanding that the Division concurs completely with the proposed FY 2025 ISR Plan?

A. Yes, it is the Company's understanding that the Division concurs completely with the proposed FY2025 ISR Plan and that the Company is advancing projects that are reasonably needed to maintain safety and reliability in the short and long term.

Q. Are there capital investments within the proposed ISR Plan that are similar to the investments that previously had been proposed as "grid modernization" investments in the FY 2024 ISR plan? If so, please list the investments.

A. Yes, there are capital investments within the proposed ISR Plan that are similar to the investments that previously had been proposed as "grid modernization" investments in the FY 2024 ISR plan. These investments include the DARP, Electromechanical Relay Replacement Program and the Volt Var Optimization program, which includes the installation of advanced capacitors and regulators. The Company is also proposing a Fiber Network study, but this investment does not include the installation of assets. It is meant to identify the scope of the fiber network that may be needed for grid modernization communication means.

Q. Can you explain why those investments are not categorized as "grid modernization" investments in this year's ISR Plan?

A. Although these proposed investments were included in the overall suite of investments that the Company characterized as "grid modernization" in the FY 2024 Electric ISR Plan, the discreet subset of investments proposed in the FY 2025 Electric ISR Plan are reasonably needed to address issues on the electric distribution system in the short-term and over the long-term. Also, the Company noted the concerns raised by the Commission and the Division regarding the full suite of grid modernization investments proposed during the FY 2024 Electric ISR proceeding, and, in recognition of those concerns, the Company did not include a separate "grid modernization" category as part of the FY2025 Electric ISR Plan. Instead, the Company shifted its focus from a long-term grid modernization strategy, which is more fully addressed in the Company's Grid Modernization Plan ("GMP"), pending before the Commission in Docket No. 22-56-EL, to the important near-term work that is necessary to address the immediate electric distribution system issues, which justifies the projects over the short and long term, while noting long-term alignment with any grid modernization future.

Q. Are each of the investments that may be referred to as "grid modernization" reasonably needed to maintain safe and reliable distribution service over the short and long term? If so, please explain why.

A. Yes.

- Distribution Automation Recloser Program – The FY 2025 investments for this reliability focused strategy target several circuits that have circuit frequency and duration values above the regulatory criteria that establishes the short term reliability needs. Reclosers are considered 25-year assets and provide long term reliability benefits throughout the equipment's useful life. The reclosers enable other long term benefits because each recloser acts as a distribution monitor and remote-controlled switch for system management during situations other than interruptions.
- Electromechanical Relay Replacement - Relays, which monitor and protect the power system, continuously evolve to meet the reliability expectations of customers. Most of the current electromechanical relays in service on the electric distribution system are obsolete and spare parts are difficult to find. In addition, these antiquated relays provide no fault record data that would indicate the fault current, faulted phase, and the time/date of the fault event. This information is important to aid in quickly diagnosing problems and finding faults located on the power system. The obsolete nature of these relays and now standard functionality of the replacement microprocessor relays establishes the short term need. Relays are considered

20 to 25 year assets and will provide long term reliability and operational benefits throughout the equipment's useful life.

- Smart Capacitors & Regulators – These investments are used to establish volt/var optimization schemes that provide immediate short term benefits to customers through energy saving. This investment was approved in previous ISR years but put on hold to avoid obsolescence of a control system which would be replaced with the Company's new Advanced Distribution Management System. These 20 year assets will continue to provide energy savings in the long term through their useful lives.

Q. Is it fair to say that the reason why the "grid modernization" investments are included in the proposed ISR Plan is because they are reasonably needed to maintain safe and reliable distribution service over the short and long term?

A. Yes, as described above, all the FY 2025 ISR Plan investments are reasonably needed to maintain safe and reliable distribution service over the short and long term.

Q. In addition to being reasonably needed to maintain safe and reliable distribution service over the short and long term, do these investments promote the Rhode Island Act on Climate, R.I. Gen. Laws § 42-6.2-1 et seq. ("Act on Climate")?

A. Yes, as described above not only do the FY 2025 ISR Plan investments serve immediate and long-term needs but they are also aligned with the GMP. The GMP explains how the data, sensing, and control enabled by these investments will be instrumental in helping the State meet the Act on Climate mandates.

Q. Is the Company asserting that any investments in the FY 2025 ISR plan should be approved on the basis of their contribution to meeting the Act on Climate mandates?

A. No.

Q. Can you explain?

A. The FY 2025 ISR Plan investments are justified on their own merits specifically to meet needs for the Company to provide safe and reliable service in the short and long term. As with all investments, the Company takes a thoughtful approach to avoid early obsolescence and redundancy. The actions that will need to be taken in the State to achieve the mandates of the Act on Climate could lead to variety of possible futures for the electric distribution system, but all of them lead to a more complex electric system. The pending complexity is the related intermittency of resources and customer adoption that can occur in both a widespread manner across the State or in an acute localized manner. The current proposed investments can be used to support this growing complexity, whether widespread or localized, while serving their current needs and in doing so avoiding early obsolescence and redundant work.

Q. Is the Company considering alternative funding sources, outside the ISR funding mechanism, to make investments that will promote the Act on Climate? If so, please explain.

A. Yes. The Company is currently in the award negotiation phase for a proposal named *Smart Grid for Smart Decarbonization*. This proposal includes financial support from the federal government (i.e. grant funding) for advanced reclosers, smart capacitors and regulators, digital relays, and fiber communications, along with other grid modernization software. The Company anticipates the award negotiation phase to be completed within the next month. Pending successful completion and the details of the finalized award, the Company intends to include the portion of the award that can be applied to FY 2025 investments within its annual reconciliation of ISR funding. Please see the Company’s response to PUC 9-11 for additional information.

Q. In the Company's Second Proposed Electric ISR Plan Budgetary and Reconciliation Framework ("Second Proposed Framework"), attached as Exhibit 2 to the Joint Pre-Filed Direct Testimony submitted on December 21, 2023, was it the Company's intent to keep Non-Discretionary and Discretionary spend and reconciliation distinct and separate?

A. Yes.

Q. Does that remain the Company's position today? If so, please explain why.

A. Yes, the Company proposes to keep Non-Discretionary spending and reconciliation separate from Discretionary spending and reconciliation.

Non-Discretionary projects are projects over which the Company does not have any control (or discretion) regarding whether to complete them. These Non-Discretionary projects mostly emerge during the year and are, therefore, not defined prior to the start of the year when budgets are established and proposed, and the Company has no ability to control the timing of when these projects arise and must be performed. Discretionary projects are projects that the Company is able to control (the discretion) whether and when to perform them. These Discretionary projects, however, are still identified as needed for the provision of safe and reliable service in the short and long term. The "Discretionary" label does not indicate that they are optional. Rather, the distinction between "Non-Discretionary" projects and "Discretionary" projects is an indication of how the need for the project was identified. Non-Discretionary projects arise from circumstances where the Company is responding to something that has occurred, whether it is a customer request or a damage/failure situation, etc. Discretionary projects arise from circumstances where the Company's system planning and analysis has identified a need to address an emerging problem on the electric system – whether it is currently causing safety and reliability problems or creates an unacceptable risk of doing so in the future. Both types of projects are equally reasonably necessary to provide safe and reliable service in the short and long term.

The Company understands the need to balance the pace of ISR investment with affordability concerns. But, the inability to control the timing of when Non-Discretionary projects will arise and must be performed makes managing the Non-Discretionary and Discretionary categories in totality impractical. Doing so likely would result in the delay and deferral of important Discretionary work when there are greater than anticipated Non-Discretionary projects, such as Customer requests. Doing so would be contrary to the intent of the ISR because the Discretionary projects were identified to ensure the Company is advancing the right work at the right time to maintain system safety and reliability.

Q. The Company currently has two Petitions pending before the Commission in Docket Nos. 23-37-EL (Tiverton) and 23-38-EL (Weaver Hill) related to the acceleration of capital investments due to a distributed generation ("DG") project. In Mr. Booth's testimony, he states 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 Area Study that prompted the need for the project." (Pages 43-44) And, he states "[t]his suggests that both Weaver Hill and Coventry projects could be deferred past the implementation period identified in the study." (Page 44) And, he states "[m]y 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." (Page 46) Does the Company have a response to these comments?

A. The Company disagrees with Mr. Booth's comments about Tiverton and Weaver Hill and reserves its right to reply through Docket Nos. Nos. 23-37-EL (Tiverton) and 23-38-EL (Weaver Hill), which are pending before the Commission.

IV. Spare Transformers and Mobile Substations

Q. What is the Company proposing to spend in FY 2025 on spare transformers and mobile substations?

A. The Company is proposing to spend $1,278,000 on mobile substations and $540,000 on spare transformers in FY 2025. The proposed FY 2025 spend for mobile substation purchases was estimated using historical costs. Recent estimates show that the three proposed mobile substations and one mobile regulator will cost approximately $1,680,000 in FY 2025. However, this cost is expected to fluctuate as market conditions change and the Company will not know the exact costs until firm proposals are received from mobile substation vendors. At that time, the Company will also solidify the payment schedule currently assumed to be 10% upon release of order, 30% upon engineering review, 30% upon delivery, and 30% upon acceptance testing.

Q. Please reiterate why such spending is needed in FY 2025?

A. If the Company does not move forward with ordering mobile substations and spare transformers, there will be feeders that have load at risk and planned capital projects will need to be re-evaluated to determine if scope needs to be added or schedules shifted to account for the absence of a mobile substation to support construction activities.

Out of the three spares that are being proposed in FY 2025, if any of the in-service transformers fail, the Company will not have a mobile or spare transformer to restore customers without utilizing the mobile substation lease agreement with National Grid. There are approximately 15 substations where, if a transformer fails, there is not enough capacity on the remaining transformer or feeder ties to restore all customers. The proposed spare transformer purchases will provide one spare transformer for 13 of the 15 substations. One of the proposed spare transformers will back up two in-service transformers that supply power to a local hospital, and not having a spare transformer will expose the hospital to increased reliability risk.

Rhode Island Energy currently owns and maintains two mobile substations at distribution voltage levels (34kV and below). These two mobile substations have a maximum capacity of 5MVA and 12MVA. Out of the approximately 200 in-service distribution transformers in the system, these two mobile substations can be utilized to fully support only approximately 80 transformers in the event of a failure. The Company is planning to purchase three mobile substations and one mobile regulator to address the gap in coverage. The first mobile substation (along with the mobile regulator) will be able to support 23 transformers. At the present time, the Company has feeders served by two in-service transformers that would result in unserved load in the event of a failure. Procuring this one mobile substation will provide a quick and safe option to restore these customers. The second mobile substation will be able to support 52 in-service transformers. There are currently nine substations that will have load at risk if a transformer fails. The third mobile substation will support 43 in-service transformers. The three mobile substations will cover a different subset of transformer voltages and capacities.

Q. At the time of PPL's acquisition of The Narragansett Electric Company, did National Grid USA ("National Grid") possess spare transformers and mobile substations?

A. Yes. National Grid USA did possess spare transformers and mobile substations at the time of PPL's acquisition of The Narragansett Electric Company.

Q. What purposes do mobile substations and spare transformers serve?

A. Mobile substations and spare transformers serve different purposes. Mobile substations are purchased to be rapidly deployed and energized within 24-72 hours after a substation transformer failure. They are only kept in-service until a spare transformer is delivered to the site and energized. They are also used to support capital substation projects. Spare transformers are purchased to expedite substation transformer replacements resulting from a transformer failure.

Q. What are some of the challenges associated with planning purchases of spare transformers?

A. Substation power transformers are customized for each utility based on company specific specifications. There are a finite number of manufacturers that are approved based on company requirements to ensure only quality transformers are purchased. The customization, limited manufacturer availability, and equipment demand causes lead times to extend beyond what should be considered reasonable to rely on ordering a new transformer after a failure occurs.

Q. While under the ownership of National Grid USA, did Rhode Island customers pay for those spare transformers and mobile substations?

A. While under the ownership of National Grid USA, Rhode Island customers paid for only the spare transformers and mobile substations that were owned and retained by The Narragansett Electric Company upon completion of PPL's acquisition of The Narragansett Electric Company.

Q. Can you explain what the arrangement was under National Grid ownership with respect to the use of spare transformers and mobile substations?

A. Under National Grid ownership, spare transformers were purchased and booked to a specific operating company. If the spare transformer was booked to Massachusetts Electric, the Massachusetts Electric ratepayers would be responsible for paying for the spare transformer. If a failure occurred in Rhode Island, and the identified spare transformer was located in Massachusetts, the remaining spare transformer net book value would be transferred to the Rhode Island project and would be paid for by Rhode Island ratepayers.

Mobile substations followed the same approach. However, if a mobile substation owned by Massachusetts Electric was needed for a failure in Rhode Island, the depreciation would be charged on a monthly rate and charged to the Rhode Island ratepayers for the amount of time the mobile was used in Rhode Island.

Q. Would the spare transformers and mobile substations that the Company proposes to purchase as part of the FY 2025 ISR Plan have been necessary if the Company remained under National Grid ownership?

A. If the Company had remained under National Grid ownership, the Company would not have had to purchase mobile substations proposed under the FY 2025 ISR Plan, but it would have had to purchase the spare transformers proposed under the FY 2025 ISR Plan. The additional spare transformer purchases are being driven by the lead time increase and the lack of existing spare transformers under National Grid ownership.

That being said, with respect to the proposed purchase of mobile substations, the Company's customers are not being asked to pay again for something they already paid for while under National Grid ownership. The additional mobile substations that were available to the Company under National Grid ownership and would have been available to serve the need that is being addressed by the purchases proposed in the FY 2025 ISR plan, were not paid for by the Company and its customers and were not owned by the Company. Rather, they were owned by other National Grid affiliates. When the Company had the need to deploy them, the Company would have had to pay for that use.

Q. Can you describe how the Company will evaluate the need for spare transformers and mobile substations in future years?

A. The Company will perform an annual evaluation using the proposed Poisson distribution calculation to verify the number of spare transformers required in inventory. Included in this annual evaluation, the Company will survey transformer manufacturers to identify transformer lead times, review transformer failure rates for trends, and update the number of energized transformers resulting from changes made during capital project additions or removals. Once the calculation is complete, the Company will compare the spares required against existing transformer asset condition reports to propose the next round of spare transformers that will be purchased. If the calculation identifies a transformer grouping that has more spare transformers in inventory than required, the Company will look to use the extra spare transformer as part of a capital project, or investigate selling the transformer.

Q. Is it the Company's position that any costs for future spare transformers and mobile substations in subsequent years would not be "transition costs" that arise because the Company is no longer owned by National Grid?

A. The Company's position is that any costs for future spare transformers and mobile substations would not be "transition costs" because these costs will be incurred as part of normal business activity to respond to system contingencies and is not being incurred to integrate operations and assets of Rhode Island Energy and PPL. All spare transformers and mobile substations that were paid for by Rhode Island ratepayers remained with The Narragansett Electric Company and any additional spare transformer or mobile substation that is proposed as a result of the transaction should not be considered duplicative because customers will not be paying for the same equipment twice.

Q. Can you explain that position, particularly in light of the fact that the Company would have continued to have access to National Grid's spare transformers and mobile substations?

A. Even though the Company would have had continued access to National Grid's spare transformers and mobile substations, the Company does not consider the proposed spare or mobile transformer purchases "transition costs" because the Rhode Island ratepayers did not pay for, or own, the spare transformers or mobile substations that remained at National Grid. Historically, the majority of spare transformers and mobile substations were owned, and paid for, by the Massachusetts Electric Company ratepayers. Rhode

Island ratepayers would still have had to pay for this equipment when a failure occurred in Rhode Island. The proposed spare transformers and mobile substations will not be replacing existing equipment, that is currently owned by the Company, prior to the end of its useful life. However, these purchases will be maintaining the same reliability threshold that the Company had planned for while under National Grid ownership.

V. Reclosers

Q. What is the Company proposing to spend in FY 2025 on reclosers? Please breakdown by budgetary classification.

A.

Item	FY25 Capex $k	Estimated Recloser Count	Estimated Recloser Cost $k
CEMI-4	$2,619	11	$898
ERR	$2,000	4	$326
Distribution Automation Recloser Program	$5,957	73	$5,957
Total	**$10,576**	**88**	**$7,181**

Q. What is the rationale behind the deployment of reclosers in FY 2025? Please breakdown by budgetary classification.

A. The table below shows the rationale including the need, prioritization, general scope, schedule, cost, and benefit-cost ratio. Although all the reclosers are part of larger multi-year programs, the recloser investments specific to FY 2025 address the greatest reliability needs of the system.

Program	Distribution Automation Recloser Program	Engineering Reliability Review Program	CEMI-4 Program
Need	Address reliability issues for circuits with frequencies greater than or equal to 2.0 not addressed by the ERR or CEMI-4 programs.	Address reliability issues for circuits with high frequency and duration metrics.	Address reliability issues for a subset of customers who can experience many more interruptions than the average customer.
Prioritization	Reliability performance, circuit characteristics	Worst 5% (approximately 20) feeders per year.	CEMI ranking with 3-year and 12 month rolling data sets.
Scope	80 to 200 reclosers per year subject to alignment and coordination with ERR and CEMI programs	Miscellaneous scope per program document. Typically 3-5 reclosers per year.	Miscellaneous scope per program document. Typically 10-12 reclosers per year.
Schedule	5 to 10 year program	Annual program	5 year program
Cost	$6-$17M	$2-$3M per year	$2-$3M per year
Benefit-Cost Ratio	1.05	8.7	1.8

Q. Did the Company review the caveats expressed by the Division's Consultant, Mr. Booth, related to the deployment of reclosers?

A. Yes. The caveats are:

1. Capping the FY 2025 budget for Advanced Reclosers.
2. 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.
3. Establishing cost and performance tracking mechanisms, including specific measures for circuits with FLISR schemes.

Q. Does the Company agree with Mr. Booth's caveats?

A. Yes. The Company is agreeable to the budget cap. Following substantial discussion between the Company and the Division on sufficient recloser justification, a reasonable compromise was reached to provide detailed circuit specific information satisfying the Division's need for documented justification and the Company's internal engineering efforts. Lastly, the Company is receptive to cost and performance tracking mechanisms on this important work.

VI. Electromechanical Relay Upgrades

Q. What is the Company proposing to spend in FY 2025 on electromechanical relay upgrades?

A. The Company is proposing to spend $1,234,000 in FY 2025 on electromechanical relay upgrades.

Q. Does the Company agree with Mr. Booth's evaluation and support of the electromechanical relay upgrades?

A. The Company does agree with Mr. Booth's evaluation and support of the electromechanical relay upgrades.

Q. Please explain why programmatic budget line item for electromechanical relay upgrades is justified?

A. A programmatic budget line item for electromechanical relay upgrades is justified because all electromechanical relay replacements have the same project driver and overall solution. Electromechanical relays are at the end of their life and replacement parts are difficult to locate. These vintage relays provide minimal fault event information and introduce accuracy errors over time. All electromechanical relays will be replaced with microprocessor relays, which will assist with quickly identifying faults by providing fault current amplitude, the time of the fault, and event records to accurately understand the sequence of events. Additionally, microprocessor relays will allow remote access for relay setting programming and monitoring, reduce the number of relays on the system, and will allow for greater flexibility by offering a wide range of protection settings and features.

VII. Hold Harmless

Q. Please explain the origins of the hold harmless adjustment?

A. PPL Corporation ("PPL") and National Grid elected to treat the acquisition of the Company as an asset purchase for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). One of the impacts of this election, among other things, is an increase in rate base due to the elimination of accumulated deferred income taxes ("ADIT"). During the acquisition proceeding in Docket No. D-21-09, PPL committed to holding customers harmless from the increase in rate base and revenue requirement that resulted from the tax impacts of the acquisition of the Company.

Q. In general, how does the hold harmless adjustment impact rates in this ISR docket?

A. The hold harmless adjustment is reflected as a revenue credit to offset the increase in rates from the higher rate base resulting from the elimination of ADIT.

Q. The Division's Chief Accountant, Mr. Bell, referenced an ongoing review of the hold harmless adjustment. Please provide the current status of the ongoing review.

A. The Company worked with the Division to determine the appropriate number of years it would take the Company to utilize its net operating loss ("NOL") in the FY2023 revenue requirement calculation reflecting the scenario in which an acquisition never occurred ("No Acquisition Scenario"). The revenue requirement calculation in the No Acquisition Scenario is compared to the revenue requirement calculation that uses actual results based on the acquisition occurring to determine the hold harmless revenue credit. The Division and the Company agreed to utilize 7 years.

Q. Please describe the rationale behind the changes to the hold harmless adjustment.

A. Mr. Bell discovered a formula issue with the FY2023 revenue requirement calculation in the No Acquisition Scenario of the Gas ISR filing. Upon review of this discovery, the Company realized that FY2023 reflected the utilization of its entire NOL balance in one year in the No Acquisition Scenario in both the Gas and Electric ISR filings. Had the acquisition never occurred, it would have taken the Company several years to utilize its NOL balance. The proposed change is to reflect the utilization of the FY2023 NOL over 7 of years to demonstrate a more accurate representation of the No Acquisition Scenario used to develop the hold harmless revenue credit.

Q. Will the Company be filing updated proposed FY 2025 ISR Factors and bill impacts stemming from the agreement described above?

A. Yes, the Company will file prior to the hearing.

VIII. <u>Advanced Metering Functionality</u>

Q. Please summarize the procedural background on AMF.

A. Rhode Island Energy's Advanced Metering Functionality Plan, Docket No. 22-49-EL, was approved on September 27, 2023. On this date the Commission authorized the Company to deploy an AMF based metering system for the electric distribution business subject to conditions. On December 22, 2023, the Company filed its certification agreeing to the terms set forth in the PUC approval.

Q. What is the Company proposing to spend in FY 2025 on AMF?

A. The Company is proposing a total spend of $48,192,432 in FY 2025. This spend is inclusive of the meter data management system ("MDMS"). The MDMS spend in FY 2025 is $888,085.

Q. What is the resulting revenue requirement stemming from the proposed AMF spend that will be placed in service through FY 2025?

A. The resulting revenue requirements in FY 2025 specific to AMF capital placed in service is $3,808,934.

Q. Is the Company committed to tracking AMF expenses and providing documentation so that the Commission, Division, and all interested stakeholders can clearly monitor the progress that the Company is making?

A. Yes, the Company is committed to providing documentation so that the Commission, Division, and interested stakeholders can clearly monitor the Company's progress.

Q. What steps is the Company taking to ensure it effectuates such a commitment?

A. The Company intends to follow the current processes and requirements in place to provide financial updates for ISR-AMF, along with the commitments made in the Company's Docket No. 22-49-EL filing to conduct an annual in-person review at the Commission and a detailed annual report submission. The in-person review and annual update will be approximately 6 months apart. Additionally, the Company intends to provide an update on AMF at the quarterly Power Sector Transformation Advisory Group meetings. Specifically, the Company intends to provide financial status updates, as provided in the Company's response to PUC Supplemental 3-4 and 4-1 including Attachments PUC 3-4-1, 3-4-2, 3-4-3, 3-4-4, 4-1-1, 4-1-2, 4-1-3, and 4-1-4, as part of the quarterly updates, the annual report, and the annual in-person review.

Q. In the Company's responses to PUC Set 9, it indicated that the AMF timeline shifted slightly. What caused the shift in timing?

A. The primary reason for the AMF updates is the schedule shift of the final Transition Services Agreement ("TSA") exit date from National Grid USA's systems to PPL's systems moving from May 2024 to August 2024. The shift of the TSA exit date results in a shift of AMF timing and approach. Along with a needed update in the systems functionality release approach and schedule, meter deployment start will move from January 2025 to March 2025. There is no change to the timing of pre-sweeps and network deployment. The secondary reason for the AMF updates is a result of finalizing or near finalization of vendor contracts, resulting in firm cost estimates. There is no change to the overall AMF program cost, yet the update does reduce FY2025 forecasted spend and increases FY2026 and FY2027. Additional details on timing can be found in the Company's supplemental response to PUC 3-3.

Q. Can you provide an update on what has been done to date to implement the AMF program?

A. To date, the Company has finalized the strategy and plan for deploying pre-sweeps, field area network installations and meter deployments. Vendor management activities have been focused on finalizing contracts and ramping up the internal project team and vendor resources to execute and support implementation. Our systems activities have been focused on completing detailed design, development and coding work, along with finalizing the testing environments to commence and perform necessary testing of the software and system used to collect and use the data from the AMF meters.

The following are key activities that have been completed to date:

- Functional designs, technical designs, and test cases approved for the software used to create a file to be sent to the deployment vendor.
- Foundational systems have stood up the testing versions of the meter reading system, the customer information system, and the software used to automatically move data and information between different computer systems. System testing and validation has progressed to meet program planned milestones. Systems testing kick-offs for all approved test cases and on-boarded vendors. Internal project team staffing.
- The network vendor contract to provide network communication devices, AMF meters, and network installation services has been signed.
- The PMO vendor contract to provide needed external support services has been executed.

- The network vendor has onboarded initial team members responsible for coordinated planning efforts and network program oversight.
- The network vendor has completed a tabletop design to locate the network device installation locations in Rhode Island for network communications.
- Engineering designs for network device installations has been created and approved by the Rhode Island Energy standards group.
- A purchase order for network devices required for initial installations in Westerly has been executed.
- AMF meters have been provided to meter engineering to conduct meter First Article testing. First article testing is done by RIE prior to approving Landis+Gyr's mass build production of AMF meters. This is technical testing is done to ensure the specifications and programming of our AMF meters meet the expected requirements and functionality for Rhode Island Energy.

Q. Can you provide a description of the expected activities between now and the commencement of meter installation in March 2025?

A For FY 2025 the Company's focus is on completing the necessary activities to begin pre-sweeps and physical network deployment in September 2024 and start meter deployment solution validation in March 2025. Below are the key milestones that are planned for FY 2025:

- Meter installation vendor contract finalized and signed.
- First Article production meter testing completed prior to final ordering confirmation.
- Head-End system operational and ready for network deployment.
- Rhode Island Energy AMF Website is live with FAQs and interactive map.
- Call Center is stood up and operational.
- Customer and stakeholder communications occur, per the communications plan, to provide notification of pending pre-sweep, network installations and meter deployment activities.
- Vendor logistics cross dock, which is the AMF warehouse and distribution hub for meter equipment, is operational.
- Initial network equipment deliveries are received as planned.
- Network deployment begins.
- Pre-sweeps commence as planned.
- Initial meter deliveries are received, and successfully sample tested, as planned.
- MDMS, CSS, Customer Portal, and the Deployment Meter Exchange systems are ready for the installation of AMF meters via Solution Validation.
- Solution Validation meter deployment begins as planned.

Q. Can you provide an update regarding the status of the deferrals being used to offset AMF revenue requirement if the FY 2025 ISR plan is approved as requested?

A. If the updated revenue requirement provided as Attachment PUC 9-19-5 is approved as requested, that revenue requirement in FY 2025 would be completely offset by the designated deferrals and there would be no bill impact to ratepayers related to AMF capital costs in FY 2025.

Q. Does the Company have an estimate of when the deferral balances will be exhausted and the AMF investments will begin having a rate impact? If so, what is that estimate?

A. Based on the estimated revenue requirements related to AMF capital costs provided in Attachment PUC 2-2-1 Supplemental, the Company estimates that the deferral balances will be exhausted during the FY 2027 ISR plan year and the AMF investments will begin having a rate impact during the FY 2027 ISR plan year.

IX. Conclusion

Q. In your opinion does the Electric ISR Plan fulfill the requirements established in relation to the safety and reliability of the Company's electric distribution system in Rhode Island?

A. Yes. The Electric ISR Plan is designed to establish the capital investment, vegetation management, and inspection and maintenance ("I&M") activities in Rhode Island that are necessary to meet the needs of Rhode Island customers and maintain the overall safety and reliability of the Company's electric distribution system. The proposed Plan accomplishes these objectives. Each and every proposed investment, including the operation and maintenance ("O&M") activities, is reasonably needed to maintain safe and reliable distribution service over the short and long term. Therefore, the Commission's approval of the proposed Electric ISR Plan is essential for the Company to continue maintaining a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

Certificate of Service

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

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

__________________________________ March 7, 2024
Joanne M. Scanlon Date

Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025
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