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

# Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan

## Book 1 of 3

December 21, 2023

Docket No. 23-48-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™

a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

December 21, 2023

**VIA ELECTRONIC MAIL AND HAND DELIVERY**

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**

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year ("FY") 2025 for review and approval by the Public Utilities Commission ("PUC" or "Commission"). This Electric ISR Plan is being filed in accordance with R.I. Gen. Laws § 39-1-27.7.1(d).[1] The Company respectfully requests that the PUC approve the enclosed Electric ISR Plan as filed.

On October 13, 2023, the Company submitted an earlier version of the enclosed Electric ISR Plan to the Division of Public Utilities and Carriers ("Division"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the Division worked in cooperation with the Company to reach an agreement on a proposed plan to be filed with the Commission. Specifically, the Company consulted with the Division's representatives and received and responded to discovery requests from the Division. As a result of this process, the earlier version of the Plan was refined resulting in the enclosed Electric ISR Plan. The Division has indicated general concurrence with the enclosed Electric ISR Plan.

In support of the Electric ISR Plan, the Company has included joint pre-filed direct testimony of Witnesses Nicole Gooding, Christpher Rooney, Kathy Castro, Ryan Constable, Eric Wiesner, and Daniel Glenning ("Joint Testimony"). As explained in their joint testimony, the Company is proposing spending of $140.9 million for capital investment (approved FY 2024 was $112.3 million); $13.1 million of vegetation management O&M spending (approved FY 2024 was $13.95 million); and $1.1 million of Other O&M spending (approved FY 2024 was $1.16 million).

[1] In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the enclosed Plan addresses (i) capital spending on electric infrastructure; (ii) operation and maintenance ("O&M") expenses on vegetation management; (iii) O&M expenses on system inspection; and (iv) other costs related to maintaining the safety and reliability of the electric distribution system ("Other O&M"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(c)(2), the enclosed Plan also addresses revenue requirement, rate design, and bill impacts.

In addition, the Plan includes a line item for Advanced Metering Functionality ("AMF") capital spending of $51.7 million which, when added to the $140.9 million of capital investment, results in total capital spending contained within the FY 2025 Electric ISR Plan of $192.6 million.[2]

The Company's FY 2025 Electric ISR Plan total net capital investment component of the revenue requirement is $54.2 million (approved FY 2024 was $55.4 million). Separately, the total net capital investment component of the AMF revenue requirement for FY 2025 is $4.7 million; however, that amount is fully offset by deferral balances, and does not have an impact on rates in FY 2025. Please note that, in this case, the revenue requirement calculation also includes an adjustment for the tax hold harmless impact on ISR rate base. The Company has included joint pre-filed direct testimony of Witnesses Stephanie A. Briggs, Jeffrey D. Oliveira, and Natalie Hawk that describes the calculation of the Company's revenue requirement and tax hold harmless impact.

For a residential customer receiving Last Resort Service ("LRS"), and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill decrease of $0.16, or -0.1%. As mentioned above, the inclusion of AMF capital spending in the Plan does not have an impact on the rates this fiscal year. The Company has included pre-filed direct testimony of Witness Tyler Shields to describe the customer bill impacts of the proposed rate changes.

The Company is also enclosing copies of the Company's responses to six sets of discovery issued by the Division pertaining to the Plan. Please be advised that Attachments DIV 1-23; DIV 1-24-2 through DIV 1-24-16; DIV 2-5-4 through DIV 2-5-6; DIV 2-14-1 through DIV 2-14-6; DIV 2-27-3; DIV 2-30-1; and DIV 2-31-1 through DIV 2-31-3 contain confidential and privileged information. For DIV 1-24-2 through DIV 1-24-16, the Company is reviewing the attachments for Critical Energy Infrastructure Information ("CEII"). Following completion of its review, which is anticipated to be by January 31, 2024, the Company will amend the pertinent Motion and provide updated public versions of the attachments.

Pursuant to 810-RICR-00-00-1.3(H)(3), R.I. Gen. Laws § 38-2-2(4)(A)(I)(b), and R.I. Gen. Laws § 38-2-2(4)(B), the Company respectfully requests that the Commission treat the information redacted in the public version as confidential.

In support of this request, the Company has enclosed four (4) Motions for Protective Treatment of Confidential Information. In accordance with 810-RICR-00-00-1.3(H)(2), the Company also respectfully requests that the Commission make a preliminary finding that the information redacted in the public version is exempt from the mandatory public disclosure requirements of the Rhode Island Access to Public Records Act ("APRA").

---

[2] The proposed ISR Plan capital investments, and the forecasts of future years' capital investments contained within the ISR Plan, do not represent the total amount of capital investment anticipated by the Company in this year and future years. In this ISR Plan, the proposed capital investments and forecasts of future capital investments only include those amounts that the Company has proposed, or, with respect to future years, plans to propose, to recover through the ISR mechanism.

Also included in this filing, attached as an exhibit to the Joint Testimony, is the Company's Second Proposed Electric ISR Plan Budgetary and Reconciliation Framework for review by the Commission. This filing stems from Docket No. 23-34-EL. The Company respectfully requests that the Commission approve the proposed framework.

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

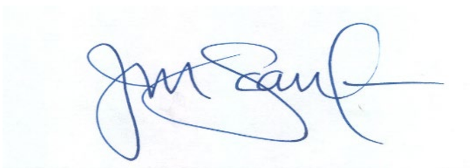
Enclosures

cc: Docket No. 23-48-EL Service List
John Bell, Division (w/confidential information)
Greg Booth, Division (w/confidential information)
Christy Hetherington, Esq.
Al Contente, Division

Certificate of Service

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

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



Joanne M. Scanlon

December 21, 2023
Date

**Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025**
**Service List as of 12/19/23**

| Name/Address | E-mail Distribution | Phone |
|---|---|---|
| **The Narragansett Electric Company d/b/a Rhode Island Energy**<br>Andrew Marcaccio, Esq.<br>280 Melrose St.<br>Providence, RI 02907<br><br>Adam S. Ramos, Esq.<br>**Hinckley Allen**<br>100 Westminster Street, Suite 1500<br>Providence, RI 02903-2319 | amarcaccio@pplweb.com; | 401-784-4263 |
| | cobrien@pplweb.com; | |
| | jscanlon@pplweb.com; | |
| | aramos@hinckleyallen.com; | |
| | sbriggs@pplweb.com; | |
| | NABegnal@RIEnergy.com; | |
| | smtoronto@RIEnergy.com; | |
| | ATLaBarre@RIEnergy.com; | |
| | rconstable@RIEnergy.com; | |
| | krcastro@RIEnergy.com; | |
| | CJRooney@RIEnergy.com; | |
| | joliveira@pplweb.com; | |
| | TGShields@pplweb.com; | |
| | nhawk@pplweb.com; | |
| **Division of Public Utilities (Division)**<br>Gregory Schultz, Esq.<br>Dept. of Attorney General<br>150 South Main St.<br>Providence, RI 02903 | gSchultz@riag.ri.gov; | |
| | Ellen.golde@dpuc.ri.gov; | |
| | John.bell@dpuc.ri.gov; | |
| | Al.contente@dpuc.ri.gov; | |
| | Robert.Bailey@dpuc.ri.gov; | |
| | Christy.Hetherington@dpuc.ri.gov; | |
| | Margaret.l.hogan@dpuc.ri.gov; | |

| | | |
|---|---|---|
| | Paul.roberti@dpuc.ri.gov; | |
| David Effron<br>Berkshire Consulting<br>12 Pond Path<br>North Hampton, NH 03862-2243 | Djeffron@aol.com; | 603-964-6526 |
| Gregory L. Booth, PLLC<br>14460 Falls of Neuse Rd.<br>Suite 149-110<br>Raleigh, N. C. 27614 | gboothpe@gmail.com; | 919-441-6440 |
| Linda Kushner<br>L. Kushner Consulting, LLC<br>514 Daniels St. #254<br>Raleigh, NC 27605 | Lkushner33@gmail.com; | 919-810-1616 |
| **Office of Energy Resources**<br>Al Vitali, Esq. | Albert.vitali@doa.ri.gov;<br>nancy.russolino@doa.ri.gov;<br>Christopher.Kearns@energy.ri.gov;<br>Shauna.Beland@energy.ri.gov;<br>William.Owen@energy.ri.gov;<br>Matthew.Moretta.CTR@energy.ri.gov; | |
| **Office of Attorney General**<br>Nick Vaz, Esq.<br>150 South Main St.<br>Providence, RI 02903 | nvaz@riag.ri.gov;<br>mbedell@riag.ri.gov; | 401-274-4400<br>x 2297 |
| **File an original & five (5) copies w/:**<br>Luly E. Massaro, Commission Clerk<br>Cynthia Wilson-Frias, Esq.<br>Public Utilities Commission<br>89 Jefferson Blvd.<br>Warwick, RI 02888 | Luly.massaro@puc.ri.gov;<br>Cynthia.WilsonFrias@puc.ri.gov;<br>Todd.bianco@puc.ri.gov;<br>Alan.nault@puc.ri.gov;<br>Kristen.L.Masse@puc.ri.gov; | 401-780-2107 |
| Matt Sullivan, Green Development LLC | ms@green-ri.com; | |

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

| | | |
|---|---|---|
| THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY'S FY 2025 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN | ) ) ) ) ) ) | DOCKET NO. 23-48-EL |

**MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION**

The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") hereby respectfully requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein. The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The record that are the subject of this Motion that requires protective treatment from public disclosure is the Company's confidential Attachment DIV 1-23 (the "Confidential Attachment") which was submitted to the Division of Public Utilities and Carriers ("Division") in response to the First Set of Data Requests issued by the Division during the pre-filing stage and then filed by the Company in the above referenced docket on December 21, 2023. The Company requests protective treatment of the Confidential Attachment in accordance with 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(A)(I)(b).

## I. LEGAL STANDARD

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act ("APRA"), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state

or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA. See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

## II. BASIS FOR CONFIDENTIALITY

The Confidential Attachment, which is the subject of this Motion, is exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(A)(I)(b) as "[p]ersonnel and other personal individually identifiable records otherwise deemed confidential by federal or state law or regulation, or the disclosure of which would constitute a clearly unwarranted invasion of personal privacy pursuant to 5 U.S.C. § 552 et seq…" This exemption represents a balancing test between the individual's privacy interests and the public's right to disclosure. See 2016 WL 499007, at *4 (R.I.A.G. Feb. 2, 2016) which states that "[t]he Supreme Court thus determined that the legislative intent represented a balancing test between the individual's privacy interests and the public's right to disclosure."

In this case, the Confidential Attachment consists of the names of private citizens who, at the time the document was created, were employed by National Grid. Releasing the names reveals little or nothing about the utility's performance or official business. As such, the public gains very little, if any, value by knowing the names. The material substance of the document, which consists of sanctioning processes, remains intact without public disclosure of the redacted names. Accordingly, when performing a balancing test, the public's right to disclosure in this case is insignificant.

If the names of the individual private citizens are released, the public would know the citizen's employer or former employer, position that was held at the time, and role in the sanctioning process at the time. While this harm may not be significant, it outweighs the value to the public in this case. Therefore, in this case, this type of information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(A)(I)(b).

## III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of the Confidential Attachment.

Respectfully submitted,

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

By its attorney,

Andrew S. Marcaccio (#8168)
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

## CERTIFICATE OF SERVICE

I hereby certify that on December 21, 2023, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 23-48-EL.

______________________________________

Joanne M. Scanlon

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

| | | |
|---|---|---|
| THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY'S FY 2025 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN | ) ) ) ) ) ) | DOCKET NO. 23-48-EL |

**MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION**

The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") hereby respectfully requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein. The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The records that are the subject of this Motion that require protective treatment from public disclosure are the Company's confidential Attachments DIV 1-24-2 through DIV 1-24-16 (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the First Set of Data Requests issued by the Division during the pre-filing stage and then filed by the Company in the above referenced docket on December 21, 2023. The Company requests protective treatment of the Confidential Attachments in accordance with 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(B).

## I. LEGAL STANDARD

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act ("APRA"), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state

or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA. See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

## II. BASIS FOR CONFIDENTIALITY

The Confidential Attachments, which are the subject of this Motion, are exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(B) as "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information is likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

The Confidential Attachments consist of sanctioning papers which contain financial and commercial information and Critical Energy Infrastructure Information ("CEII").[1] The Company would customarily not release this information to the public. The Company's submission of the Confidential Attachments stem from data requests issued by the Division in the above-referenced

[1] The Company is reviewing the Confidential Attachments for CEII. Following the completion of its review, which is anticipated to be by January 31, 2024, the Company will amend this Motion and provide updated public versions of the Confidential Attachments.

docket. Accordingly, the Company is providing the Confidential Attachments to fulfil its regulatory responsibilities.

Public disclosure of the information identified as CEII in the Confidential Attachments would negatively impact the Company's ability to effectively operate to provide safe and reliable service to its customers as CEII means a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters. As such, the Company would not release this information to the public. Therefore, this information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(B).

## III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of the Confidential Attachments.

Respectfully submitted,

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

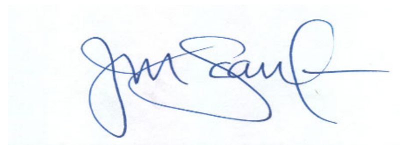
By its attorney,

______________________________
Andrew S. Marcaccio (#8168)
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

Dated: December 21, 2023

## CERTIFICATE OF SERVICE

I hereby certify that on December 21, 2023, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 23-48-EL.



Joanne M. Scanlon

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

| | | |
|---|---|---|
| THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY'S FY 2025 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN | ) | DOCKET NO. 23-48-EL |

**MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION**

The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") hereby respectfully requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein. The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The records that are the subject of this Motion that require protective treatment from public disclosure are the Company's confidential Attachments DIV 2-5-4 through 2-5-6; 2-14-1 through 2-14-6; and 2-31-1 through 2-31-3 (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the Second Set of Data Requests issued by the Division during the pre-filing stage and then filed by the Company in the above referenced docket on December 21, 2023. The Company requests protective treatment of the Confidential Attachments in accordance with 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(B).

**I. LEGAL STANDARD**

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act ("APRA"), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA. See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

## II. BASIS FOR CONFIDENTIALITY

The Confidential Attachments, which are the subject of this Motion, are exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(B) as "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information is likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

The Confidential Attachments consist of financial and commercial information. The Company would customarily not release this information to the public. The Company's submission of the Confidential Attachments stem from data requests issued by the Division in the above-referenced docket. Accordingly, the Company is providing the Confidential Attachments to fulfil its regulatory responsibilities.

In addition, the release of the Confidential Attachments is likely to cause substantial harm to the competitive position of the Company. The Attachments contain commercially sensitive market information, the disclosure of which could affect the Company's ability to negotiate competitive terms with its contractors. Therefore, this information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(B).

## III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of the Confidential Attachments.

Respectfully submitted,

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

By its attorney,

Andrew S. Marcaccio (#8168)
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

Dated: December 21, 2023

## CERTIFICATE OF SERVICE

I hereby certify that on December 21, 2023, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 23-48-EL.

____________________________________
Joanne M. Scanlon

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

| | | |
|---|---|---|
| THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY'S FY 2025 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN | ) | DOCKET NO. 23-48-EL |

**MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION**

The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") hereby respectfully requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein. The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The records that are the subject of this Motion that require protective treatment from public disclosure are the Company's confidential Attachments DIV 2-27-3 and 2-30-1 (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the Second Set of Data Requests issued by the Division during the pre-filing stage and then filed by the Company in the above referenced docket on December 21, 2023. The Company requests protective treatment of the Confidential Attachments in accordance with 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(B).

## I. LEGAL STANDARD

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act ("APRA"), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state

or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA. See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

## II. BASIS FOR CONFIDENTIALITY

The Confidential Attachments, which are the subject of this Motion, are exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(B) as "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information is likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

The Confidential Attachments consist of system information in Pennsylvania (Attachment DIV 2-27-3) and in Rhode Island (Attachment DIV 2-30-1). The Company would customarily not release Attachment DIV 2-30-1 to the public and, for the Pennsylvania jurisdiction, the Company would customarily not release Attachment DIV 2-27-3 to the public. (Rhode Island and Kentucky consider this information public.) The Company's submission of the Confidential Attachments stem from data requests issued by the Division in the above-referenced docket. Accordingly, the Company is providing the Confidential Attachments to fulfil its regulatory responsibilities.

Public disclosure of the information identified in the Confidential Attachments may negatively impact the Company's ability to effectively operate to provide safe and reliable service to its customers in Pennsylvania and Rhode Island. As such, the Company would not release this information to the public. Therefore, this information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(B).

## III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of the Confidential Attachments.

Respectfully submitted,

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

By its attorney,

Andrew S. Marcaccio (#8168)
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

Dated: December 21, 2023

**CERTIFICATE OF SERVICE**

I hereby certify that on December 21, 2023, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 23-48-EL.

____________________________________

Joanne M. Scanlon

# JOINT PRE-FILED DIRECT TESTIMONY

OF

NICOLE GOODING

CHRISTOPHER ROONEY

KATHY CASTRO

RYAN CONSTABLE

ERIC WIESNER

AND

DANIEL GLENNING

# Table of Contents

## I. Introduction

### Nicole Gooding

**Q. Ms. Gooding, please state your name and business address.**

A. My name is Nicole Gooding. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

**Q. 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 ISR Manager. In my position, I am responsible for the filing and reporting of electric infrastructure, safety, and reliability ("ISR") plans, as well as the electric distribution system five-year investment plan.

**Q. Please describe your educational background and professional experience.**

A. In 2017, I graduated from the University of South Carolina with a Bachelor of Science degree in International Business, Finance and Risk Management. In June 2017, I joined National Grid USA Service Company, Inc. ("NGSC") as an Associate Project Manager in the Gas Complex Capital Delivery department, progressing to Project Manager in October 2018.

I managed the execution of liquefied natural gas ("LNG"), regulator station, and leak-prone pipe projects in Rhode Island and Massachusetts. In 2021, I moved to Goulston & Storrs PC as a Project Management Organization ("PMO") Specialist, working on implementing project management practices and policies across the business. I completed my Master of Business Administration degree in December 2021 from the College of William and Mary and Project Management Professional ("PMP") Certification in June 2022 from the Project Management Institute. I joined Rhode Island Energy in July of 2022 and assumed my role as ISR Manager.

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

A. Yes, I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2024 electric ISR plan and FY 2023 electric ISR Annual Reconciliation. I have also participated in technical sessions as part of Docket 23-34-EL.

<u>**Christopher Rooney**</u>

**Q. Mr. Rooney, please state your name and business address.**

A. My name is Christopher Rooney. My business address is 642 George Washington Highway, Lincoln, Rhode Island 02865.

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

A. I am employed by Rhode Island Energy as Manager of Distribution and Transmission Forestry. I am responsible for the day-to-day operations of vegetation management as well as the long-term planning of the vegetation management program.

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

A. In 1998, I graduated from the University of Rhode Island with a Bachelor of Science degree in Horticulture. In 2003, I received a Master of Science in Urban and Community Forestry from the University of Massachusetts Amherst. I joined NGSC as a District Arborist covering the Capital district for distribution vegetation maintenance, covering towns and cities in the northern part of the state. In 2008, I became a Lead Forestry Supervisor covering distribution vegetation maintenance for Southern New England (Rhode Island and Massachusetts). I held that position until 2021 when I became the Manager of Distribution Forestry covering the same area. Upon the close of the Acquisition,[1] I assumed the role of Manager of Forestry for Transmission and Distribution for Rhode Island Energy.

**Q. Have you previously testified before the Commission?**

A. Yes, I have previously testified before the PUC in support of the Company's Fiscal Year FY 2024 electric ISR plan.

__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.

[1] On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation ("PPL"), acquired 100 percent of the outstanding shares of common stock of the Company from National Grid USA ("National Grid")(the "Acquisition").

**Q. Ms. Castro, 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. Ms. Castro, please describe your educational background and professional experience.**

A. In 2003, I graduated from Worcester Polytechnic Institute with a Bachelor of Science Degree in Electrical Engineering. In the same year, I was employed by NGSC as an Associate Distribution Design Engineer responsible for design of new facilities for business and capital improvement projects. In 2005, I earned a graduate-level Certificate of Power Systems Management and Engineering from Worcester Polytechnic Institute. Also in 2005, I joined the Distribution Planning and Engineering department as an Engineer; I was promoted to Senior Engineer in 2008. In this role, I was responsible for identifying asset, capacity, and reliability issues, justifying proposed solutions, and initiating selected projects for the Operations and Substation engineering departments. I also reviewed and recommended solutions to serve customers requiring significant demand. In 2010, I joined a consultant company located in Rockland, Massachusetts, as a Senior Engineer. In this role, I was responsible for completing distribution system impact analyses of distributed generation for utilities across New England and New York. Within one year, I was promoted to Manager of Engineering responsible for building a department that focused on distribution planning short- and long-term studies. In 2017, I was promoted to Director of

Engineering overseeing distribution design and planning functions. In March of 2018, I returned to NGSC and assumed the position of Manager of Distribution Planning and Asset Management, and on May 25, 2022, I became the Director of Asset Management & Engineering for Rhode Island Energy.

**Q. Have you previously testified before the PUC?**

A. Yes. I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2020, FY 2021, and FY 2024 electric ISR plans as well as the FY 2023 electric ISR Annual Reconciliation. I have also participated in technical sessions as part of Docket 23-34-EL.

<u>**Ryan Constable**</u>

**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. Mr. Constable, please describe your educational background and professional experience.**

A. I received a Bachelor of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, New York, in 1993 and a Certificate of Industrial Management and Power Engineering from Worcester Polytechnic Institute in Worcester, Massachusetts, in 2000. I am a Registered Professional Engineer in Massachusetts, number 41632. I worked at NGSC from 1994 to 2000 and again from 2010 to May 24, 2022, after which time I joined Rhode Island Energy in my current position. I have held various positions of increasing responsibility in the area of Distribution Planning. From 1994 to 1998, I was a Project Engineer responsible for the design and maintenance of the electric infrastructure serving commercial and residential customers in southeastern Massachusetts. During the period from 1998 to 2000, I was a Planning Engineer conducting long-range electric system studies. From 2010 to 2011, I worked as a Principal Engineer in the Utility of the Future department developing the Worcester Smart Energy Solution Pilot. In 2011, I became the Manager of Distribution Planning and Asset Management – New England, directing a ten-person team to conduct annual planning activities, perform long-range planning studies, and develop regulatory filings. In 2017, I became the Acting Director of that department.

From 2000 to 2010, I worked for three independent transmission development companies, TransEnergie U.S., Cross Sound Cable Company, and Brookfield Renewable Power.

**Q. Have you previously testified before the Commission?**

A. Yes. I have previously testified before the PUC in support of the Company's FY 2023 electric ISR plan in Docket No. 5209, FY 2022 electric ISR plan in Docket No. 5098, and the Company's FY 2020 and FY 2023 electric ISR reconciliation filings. I have also participated in technical sessions as part of Docket 23-34-EL.

<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 an Engineering Manager for the Regional Engineering department. In my role, I am responsible for oversight of substation and distribution line capital project implementation and field support, transmission line inspection and maintenance support, street lighting, and contact voltage monitoring.

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

A. I received a Bachelor of Science degree in Electric Engineering from Virginia Polytechnic Institute and State University (Virginia Tech) in Blacksburg, Virginia, in 2009 and a Master of Engineering in Electrical and Computer Engineering from Worcester

Polytechnic Institute in Worcester, Massachusetts, in 2015. I am a Registered Professional Engineer in Rhode Island, number 14219. I worked at American Power Conversion from 2009 to 2010, after which time I joined NGSC. From 2010 to 2012, I worked in the Distribution Design department supporting distribution line capital projects and programs. From 2012 to 2015, I worked in the Substation Engineering department supporting capital projects such as substation rebuilds, greenfield substations, and supporting responses to equipment failures. From 2015 to 2016, I joined General Dynamics Electric Boat as an Engineer supporting the electrical power system on various submarines. I returned to NGSC in 2016 and rejoined the Substation Engineering department performing the same type of work as I had performed from 2012 to 2015. From 2016 to 2020, I worked in the Substation Operations and Maintenance department as a field supervisor where I oversaw the day-to-day operations and maintenance of substations in Central Massachusetts. From 2020 to 2022, I rejoined the Substation Engineering department as the Manager where I oversaw the execution of substation capital projects and programs. In 2022, I joined Rhode Island Energy as the Regional Engineering Manager as described above.

**Q. Have you previously testified before the Commission?**

A. No, I have not previously testified before the Commission.

**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. Mr. Glenning, please describe your educational background and professional experience.**

A. I have a Bachelor of Science degree in engineering from Clarkson University and have completed the Naval Postgraduate School Certificate in Project Management/Program Management. I have been managing projects for almost forty years, including sixteen years managing utility projects. I am responsible for initiating, planning, executing, controlling, and closing distribution and transmission projects. As part of this process, my team and I proactively address schedule, technical, and cost risks so the projects can be successfully completed.

Before working for Rhode Island Energy, I worked for NGSC as the Director of Complex Project Management, where I was responsible for major utility projects (electric and gas).

**Q. Have you previously testified before the Commission?**

A. Yes. I have testified in Docket No. 4111 – Review of Proposed Town of New Shoreham Project, Docket No. 5209 - FY 2023 Electric ISR Annual Reconciliation and Docket No. 22-53 EL - FY 2024 Electric ISR. I have also participated in technical sessions as part of Docket 23-34-EL.

## II. Purpose and Structure of Joint Testimony

**Q. What is the purpose of this joint testimony?**

A. The purpose of this joint testimony is to present the FY 2025 Electric Infrastructure, Safety, and Reliability Plan (the "FY 2025 Electric ISR Plan," "Electric ISR Plan," or "Plan"), which the Company developed as part of a collaborative process with the Rhode Island Division of Public Utilities and Carriers (the "Division").[2] Implementation of the Electric ISR Plan will allow the Company to meet its obligation to provide safe and reliable electric distribution service to customers over the short and long term, both efficiently and at reasonable cost. The proposed Electric ISR Plan is attached as Exhibit 1 to this testimony.

[2] The Electric ISR Plan presented in this filing is the fourteenth annual plan submitted to the Commission pursuant to the provisions of R.I. Gen. Laws § 39-1-27.7.1.

**Q. How is the testimony structured?**

A. In addition to the Introduction and Purpose and Structure of Joint Testimony (Sections I and II, respectively), our joint testimony includes the following sections:

- Description of how the Company developed the Electric ISR Plan and FY 2025 capital investment spending levels (Section III).
- Description of the Company's vegetation management program and FY 2025 spending levels (Section IV).
- Description of the Company's inspection and maintenance ("I&M") and other operation and maintenance ("Other O&M") programs and FY 2025 spending levels (Section V).
- Application of the Docket 4600 goals and Framework to certain new or incremental programs in the Electric ISR Plan (Section VI); and
- Conclusion (Section VII).

**Q. Please summarize the categories of infrastructure, safety, and reliability spending covered by the Electric ISR Plan.**

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2025, for the twelve-month period from April 1, 2023, through March 31, 2025: capital spending on electric infrastructure projects; operation and maintenance ("O&M") expenses for vegetation management; O&M for I&M; and O&M for Volt/Var

Optimization and Conservation Voltage Reduction ("VVO/CVR") Expansion. Advanced Metering Functionality ("AMF") capital spend has also been included in the Plan.

**Q. Please explain how the Electric ISR Plan is structured.**

A. The Electric ISR Plan includes the spending plan for FY 2025 and a rate reconciliation mechanism that provides recovery related to capital investments and other spending undertaken pursuant to the pre-approved budget. The Electric ISR Plan itemizes the recommended work activities by general category and provides budgets for capital investment and O&M expenses for the vegetation management, I&M, and VVO/CVR programs. After the end of the fiscal year, the Company trues up the ISR Plan's projected capital and O&M expense levels used to establish the revenue requirement against actual or allowed investment and expenditures on a cumulative basis and reconciles the revenue requirement to the revenue billed from the rate adjustments implemented at the beginning of each fiscal year. The actual AMF ISR plan investments also will be reconciled at the end of each fiscal year in a similar manner.

## III. Capital Investment Plan

### General Questions

**Q. How does the Company prepare its capital investment plan?**

A. In this filing, the Company has proposed a capital spending plan for FY 2025 totaling $140.9 million. The Company developed the proposed capital spending plan by considering the following: (i) work already underway or identified in area studies, which have been advanced by the annual capacity review process, (ii) reliability reviews, and (iii) the Grid Modernization Plan ("GMP"), which was required per the Amended Settlement Agreement ("ASA") approved by the Commission in Docket No. 4770. The project work that is included in the Electric ISR Plan is designed specifically to meet system performance objectives and customer service requirements, which the Company must address as part of its obligation to provide safe and reliable service. In the Electric ISR Plan, the Company has provided a detailed explanation of the categories of investment, the factors motivating the nature and amount of investment, and the specific projects that will be undertaken in Rhode Island.

**Q. Can you explain the annual capacity review process?**

A. Yes. The annual capacity review is a current look at the Company's capacity capabilities. It identifies imminent thermal capacity constraints and assesses the capability of the network to respond to contingencies that might occur. The capacity planning process includes a review of forecasted peak load on each sub-transmission line, substation transformer, and distribution feeder in the entire service territory with a comparison to equipment ratings and consideration of system operational flexibility to respond to various contingency scenarios.

**Q. How are the results from the annual capacity review used?**

A. When capacity reviews highlight an area that has capacity constraints that violate our planning criteria and warrant a detailed and comprehensive review, that area is identified as needing an area planning study. Area study priority is determined by assessing the number and severity of electrical issues, with secondary considerations such as the area statistics (complexity) and the date of previous study efforts. The priority is reviewed and adjusted prior to the start of any new study, but, at a minimum, at least once a year. Other prompts for an area planning study include the identification of asset condition issues, large new customer load requests, or acute reliability issues. The area study planning process is further described in Section 2 of the Plan. The Company has completed all Rhode Island area studies and reviewed results with the Division of Public Utilities and Carriers ("Division").

**Q. Please summarize the significant changes related to reliability targets from the change of Company ownership from National Grid to PPL.**

A. Rhode Island Energy acknowledges that its reliability performance meets regulatory requirements; however, there is an upward trend in both the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") as highlighted by Section 4, Attachment 4, Charts 1 and 2. Based on latest J.D. Power results, overall Customer Satisfaction, which has a direct correlation to reliability, is in the third quartile. All measures indicate a declining reliability performance of the system and underscore the need for course correction, which the Company sees as a priority. The Company has established an internal goal of achieving top first quartile SAIFI performance when compared to peer utilities, which is better performance than required under the PUC's performance penalty threshold of 1.05.

**Q. Is it beneficial to customers for the Company to make investments to achieve its internal goal of top first quartile SAIFI performance**

A. Yes. These comparative system reliability metrics are a key indicator of utility performance. An internal goal to achieve top tier performance helps drive a culture of continuous improvement and can ensure, proactively, that Rhode Island Energy is meeting and exceeding reliability expectations – rather than reactively responding if or when reliability metrics start to decline.

**Q. What process did the Company undertake to prepare its FY 2025 Electric ISR Plan for review by the Commission?**

A. The Company and Division began discussions in May regarding the FY 2025 Electric ISR Plan, with a first view of preliminary budgets in July. The Company submitted a copy of its Long Range Plan to the Division on September 9, 2023 and the first draft of the FY 2025 Electric ISR Plan to the Division on October 13, 2023, for review pursuant to R.I. Gen. Laws § 39-1-27.7.1(d). The Company and the Division met via conference calls to discuss the proposed Plan and completed sixteen substation site visits to review the proposed asset condition work. The Company received and responded to data requests from the Division. These negotiations culminated with an agreement between the Company and the Division on the budget amounts within the Plan being submitted to the Commission.

**Q. Please discuss the conditions the Company and Division agreed to related to recloser installations.**

A. As part of the consensus on the proposed FY 2025 budget, the Company has agreed to provide the Division with information prior to progressing any recloser installations as part of the Customers Experiencing Multiple Interruptions ("CEMI"), Engineering Reliability Review ("ERR") and Distribution Automation Recloser Program ("DARP") Programs. The Company plans to meet with the Division in January to discuss what information will be provided to address this condition. Once the Company and Division agree on what will be provided, the Company will provide the information by circuit and then progress with the installations in an efficient manner. The Company also agreed to provide cost and performance tracking mechanisms and will work on the creation and reporting cadence with the Division in the coming months.

**Q. Please describe the categories of work activities that are included in the Electric ISR Plan to address service reliability.**

A. The Company's overall objective in preparing the Electric ISR Plan is to arrive at a capital spending plan that is the optimal balance in terms of making the investments necessary to improve the performance of discreet aspects of the system, thereby, resulting in maintaining the overall reliability of the system, while also ensuring a cost-effective use of available resources. Therefore, the Plan includes the capital investment needed to: (1) respond to customer requests or city, state, and town requirements; (2) repair failed or damaged equipment; (3) enable DER integration and achieve State Climate Mandates;[3] (4) address load growth/migration; (5) maintain reliable service; and (6) sustain asset viability through targeted investments driven primarily by condition. These categories of investment constitute the core of work required for the Company to meet its public-service obligation in Rhode Island.

**Q. Does the Plan impact the State's ability to achieve its Climate Mandates?**

A. Yes. The investments within the Plan address immediate needs and positively impact the State's ability to meet its mandates. As explained in greater detail in the Plan, the investments proposed are critical to enabling the Company to operate the electric distribution grid safely and reliably while also integrating the level of DER proliferation

[3] The State's "Climate Mandates" include the 2021 Act on Climate, codified as R.I. Gen. Laws § 42-6.2-1 et seq., and the 2022 amendments to the Renewable Energy Standard ("RES"), codified as R.I. Gen. Laws § 39-26-1 et seq.

and increased electric demand necessary to meet the emissions reductions and increased renewable energy generation called for by the Climate Mandates.

**Q. Please provide an update on the Company's IIJA Applications and the impact it could have to upcoming ISR Plans.**

A. Rhode Island Energy's application for Smart Grid was selected to advance to award negotiations. Contingent on successful award negotiations, Rhode Island Energy will apply the federal funding to investments proposed within the annual ISR, which could include advanced reclosers, smart capacitors, regulators, and electromechanical relays, in accordance with the award agreement and subject to annual regulatory review and approval, as appropriate. This federal funding award requires the selected applicant to provide supplemental non-federal funding equivalent to at least 100% of federal funding; however, the exact details of the cost match for Rhode Island Energy's funding proposal have yet to be finalized within the award negotiation process. The award negotiation process is expected to go through the first quarter of 2024, and the Company will provide an update when this is complete.

**Q. Please review the FY 2025 capital investment levels.**

A. The investment levels proposed for recovery through the FY 2025 Electric ISR Plan fall within six key work categories: Non-discretionary work includes (1) Customer

Request/Public Requirement; and (2) Damage/Failure. Discretionary work includes (3) Asset Condition; (4) Non-Infrastructure; (5) System Capacity and Performance and (6) Advanced Metering Functionality ("AMF"). The table below summarizes the proposed spending level for each of these key driver categories.

**Proposed FY 2025 Capital Investment by Key Driver Category**
**($000)**

| Spending Rationale | FY 2025 Proposed Budget | % |
|---|---|---|
| Customer Request/Public Requirement | $32,862 | 23% |
| Damage Failure | 17,813 | 13% |
| Asset Condition | 51,045 | 36% |
| Non-Infrastructure | 892 | 1% |
| System Capacity & Performance | 38,303 | 27% |
| **Capital Spending excluding AMF** | **$140,915** | **100%** |
| Advanced Metering Functionality (AMF) | 51,725 | |
| **Capital Spending including AMF** | **$192,640** | |

As shown in the table above, a significant portion of the investment for capital projects is necessary to meet customer requests or city, state, and town requirements. (*i.e.*, $32.9 million or 23 percent). These investments respond to new customer requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by the Rhode Island Department of Transportation. Overall, the scope and timing of this work is defined by others external to the Company. The need to repair failed and damaged equipment totals approximately $17.8 million, or 13 percent of the Company's investment. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes. The costs associated with the Nasonville substation rebuild are also included in the FY 2025 Damage/Failure category.

The asset condition, system capacity and non-infrastructure projects that the Company will pursue in FY 2025 have been chosen to maintain the overall reliability of the system and collectively total approximately $90.2 million, or 64 percent of the Company's proposed FY 2025 capital investment. Some of the Company's electric infrastructure assets are almost 100 years old and are ready for replacement. Projects necessary due to the condition of infrastructure assets account for approximately $51.0 million, or 36 percent of the Company's proposed FY 2025 capital investment. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company plans these investments to minimize potential reliability issues. One example of a project in the FY 2025 Plan is the replacement of the Admiral Street Substation, which was constructed in 1930.

System capacity and performance projects are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers. Generally, projects in this category address load conditions on substation transformers and distribution feeders recommended by the Company's annual capacity review and Area Planning Studies. System Capacity and Performance projects account for approximately $38.3 million, or 27 percent, of the proposed capital investment in FY 2025.

**Q. Throughout the Plan term, will the Company provide periodic updates regarding the various categories of capital work approved?**

A. Yes. The Company will continue to file quarterly reports on the progress of its Electric ISR Plan programs. Additionally, the Company will provide a report on the fiscal year activity when it submits the reconciliation and rate adjustment filings to the Commission at the end of the Plan, ending March 31, 2025. In executing the approved Electric ISR Plan, circumstances encountered may require reasonable deviations from the original Plan. In such cases, the Company will include an explanation of any significant deviations – both in its quarterly reports and in its fiscal year-end report. The Company will continue to meet quarterly with the Division approximately one month after each quarterly report is filed with the Commission and discuss progress and updates to the Plan and address any questions the Division has.

**Q. Please provide an update on the Distributed Generation review undertaken by the Company.**

A. The Company is finalizing the review of the $10.6 million of plant additions removed from the revenue requirement in the FY 2023 Annual Reconciliation filing. The Company will file the results of this review with the Commission once completed. Any plant additions the Company determines should be included will be incorporated into the ISR FY 2024 and FY 2025 Annual Reconciliation revenue requirement. There will be no impact to the proposed April 1, 2024 rates associated with this review.

**Q. Please provide an update on the settlement between the Division and the Company from the FY 2023 Annual Reconciliation related to the reclosers installed under the reliability blanket.**

A. As part of the Docket No. 5209 - FY 2023 Electric ISR Plan Reconciliation Filing, the Company agreed to remove $1,733,317 of plant additions and removal costs associated with the installation of reclosers in the reliability blanket. The Company discussed with the Division the inclusion of these reclosers in the FY 2025 ISR revenue requirement. DIV 4-38 outlines the benefits seen from reclosers installed during FY 2023.

**IV. Vegetation Management Program**

**Q. Please describe the FY 2025 spending levels for the Company's Vegetation Management Program that the Company has identified as appropriate to maintain safe and reliable distribution service to customers.**

A. For FY 2025, the Company proposes to spend approximately $13.1 million for the Vegetation Management Program. The Company implemented changes to the program in FY 2024, with the goal of maximizing reliability benefits by using data analytics. One example of this includes introducing On-Cycle Outage Risk Reduction work, which aims to address all concerns on a circuit at once. This eliminates risk as well as costs associated with going back to a particular circuit. The Company is also providing additional reporting on the program in quarterly reports. In FY 2025, the Company is introducing a Cycle Trimming Treatment category using tree growth regulators, intending to reduce cycle trimming tree work. The Company plans to start this work in FY 2025 to treat some municipally owned trees.

**V. Inspection and Maintenance Plan and Other O&M**

**Q. Please describe the FY 2025 spending levels for the Company's I&M and Other O&M Program that have been identified as appropriate to maintain safe and reliable distribution service to customers.**

A. The Electric ISR Plan incorporates the implementation of an inspection program for overhead and underground distribution infrastructure to achieve the objective of maintaining safe and reliable service to customers in the short and long term. The I&M Program is designed to provide the Company with comprehensive system-wide information on the condition of overhead and underground system components. The approximately $0.7 million budgeted for the I&M Program include O&M repairs associated with the capital program, inspections, voltage testing, and completion of 20 percent of the Contact Voltage Program ordered in Docket No. 4237. The other O&M expenses includes $0.4 million for O&M expenses for the Volt/Var expansion program,. The Company proposes a total O&M expense budget of approximately $14.2 million.

## VI. <u>Docket 4600 Benefit-Cost Framework Analysis</u>

**Q. Was Docket 4600 Benefit-Cost Framework Analysis completed for proposed investments in the FY 2025 ISR Plan?**

A. Yes, the Company performed a Docket 4600 Benefit-Cost Analysis on two projects. The programs included have proposed capital spending greater than $2 million during the Plan term. The results of the analysis can be found in Attachment 9 of the Plan.

## VII. Budgetary and Reconciliation Framework

**Q. Does this filing include a proposed budgetary and reconciliation framework stemming from Docket No. 23-34-EL?**

A. Yes. Attached as Exhibit 2 to this testimony, is the Company's Second Proposed Electric ISR Plan Budgetary and Reconciliation Framework ("Second Proposed Framework") for review by the Commission.

**Q. What led to the filing of a Second Proposed Electric ISR Plan Budgetary and Reconciliation Framework?**

A. In response to an initial framework drafted by the Commission, the Company submitted a First Proposed ISR Budgetary and Reconciliation Framework ("First Proposed Framework") on November 14, 2023. At a technical session that occurred on November 27, 2023, the Company presented its First Proposed Framework to the Commission, the Division, the Office of Attorney General, and the Office of Energy Resources and received feedback from the parties. This Second Proposed Framework reflects the Company's consideration of the feedback it received from the parties in response to the First Proposed Framework.

**Q. What are the key components of the Second Proposed Framework?**

A. The key components are:

- <u>Separate Treatment for Non-Discretionary and Discretionary</u>: The Company is proposing to exclude Non-Discretionary spend from the budget discipline rules and continue to reconcile on actual costs incurred for investments that strictly meet the definition of "Non-Discretionary," subject to a prudency review.

- <u>For O&M and Discretionary Spend, Impose Budget Discipline with a 2.5% Buffer</u>: The Company is proposing that budget discipline rules are triggered when O&M and spending on Discretionary investments, excluding Separately Tracked Major Projects, exceeds a cap of 2.5% beyond the approved budget.

- <u>Budget Overruns</u>: The Company is proposing that, if the Company exceeds the 2.5% spending threshold in the O&M and/or Discretionary categories, then the Company will make a one-time reduction to the revenue requirement in that year that is equal to one year of revenue requirement dollars associated with the total amount of overspend in excess of the approved budget. In subsequent years, the Company would recover the normal amount on the overspend amount with no adjustment to the revenue requirement.

- <u>Separation of Major Projects</u>: The Company is proposing to exclude major projects from the discretionary budget discipline. These projects would not be subject to an annual budgetary review, but rather a review when the project is complete. The budgetary discipline would be applied when the estimate is refined to a +/-10% accuracy during the Construction Resource Procurement phase. The definition of Separately Tracked Major Projects is outlined in Exhibit 2.

**Q. Does the FY 2025 Electric ISR Plan reflect the proposed budgetary and reconciliation framework?**

A. Yes, for major projects. The Company will continue to review the Plan to see if additional updates are needed. However, at this time, the Company believes the proposed FY 2025 ISR Plan as filed is consistent with the proposed framework.

**Q. What is the Company seeking from the Commission in connection with its proposed budgetary and reconciliation framework?**

A. The Company respectfully requests that the Commission approve the proposed framework. If such approval is granted, subject to modifications and additional directives from the Commission, the Company will submit a tariff advice filing reflecting the detailed terms of the approved framework for review and approval by the Commission as part of this docket, to be applied to the FY 2025 Electric ISR Plan.

## VIII. 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 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 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.

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

# Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan

December 21, 2023

Docket No. 23-48-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

## Table of Contents

# Section 1
# Executive Summary

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

## Section 1: Executive Summary

The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") has developed the proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") in compliance with Rhode Island's Revenue Decoupling statute, which provides for an annual electric "infrastructure, safety, and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget."[1] The FY 2025 period is April 1, 2024 through March 31, 2025 ("ISR Plan Fiscal Year 2025" or " FY 2025"). Through the Plan, the Company proposes both capital and operation and maintenance ("O&M") spending to provide safe and reliable electric service.

The Electric ISR Plan includes an overview of the system planning process that leads to the Company's Long Range Plan; the development of the Work Plan and the estimating process; the proposed FY 2025 Capital and O&M spending plan; a description and calculation of the revenue requirement; a description of the proposed rates; and customer bill impacts. The Company will continue to file quarterly reports with the Rhode Island Division of Public Utilities and Carriers ("Division") and the Rhode Island Public Utilities Commission ("Commission") concerning the progress of its Electric ISR Plan programs. In addition, the Company will file a report on the FY 2025 ISR Plan activities when it submits its reconciliation and rate adjustment filing. In implementing the Plan, the circumstances encountered during the period may require

[1] R.I. Gen. Laws § 39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.

reasonable deviations from the original Plan. In such cases, the Company will include explanations of significant deviations in its quarterly and annual reports.

Through the Plan, the Company will maintain and upgrade its electric distribution system by replacing aging equipment, right-sizing equipment to address load growth or migration, respond to emergency and storm events, and address infrastructure requirements that arise out of state, municipal, and third-party construction projects. In addition, the Company will continue to address poor performing areas of the system to provide improved reliability defined by industry-wide accepted performance metrics in addition to regulatory targets. The Electric ISR Plan proposes a budget as follows:

| Electric ISR Plan Budget | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| Capital Spending - ISR | $112,329 | $140,915 |
| Capital Spending - AMF | $0 | $51,725 |
| Total Capital Spending | $112,329 | $192,640 |
| Vegetation Management O&M | $13,950 | $13,075 |
| Other Programs O&M | $1,163 | $1,065 |

# Section 2
# Electric Capital Plan

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

## Section 2: Electric Capital Plan

The Company developed the FY 2025 Electric ISR Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs. As of September 2023, the Company delivers electricity to 510,237 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 Rhode Island cities and towns. To provide this service, the Company owns and maintains 5,275 miles of overhead and 1,231 miles of underground distribution and sub-transmission circuit that includes 410 distribution feeders, 57 sub-transmission lines and 97 distribution substations.

The Plan includes spending needed to (1) respond to customer requests and city, state, and town requirements; (2) repair failed and damaged equipment; (3) address load growth and migration; (4) maintain reliable service; (5) sustain asset viability through targeted investments driven primarily by asset condition; and (6) implement an affordable strategy for Distributed Energy Resource ("DER") integration.

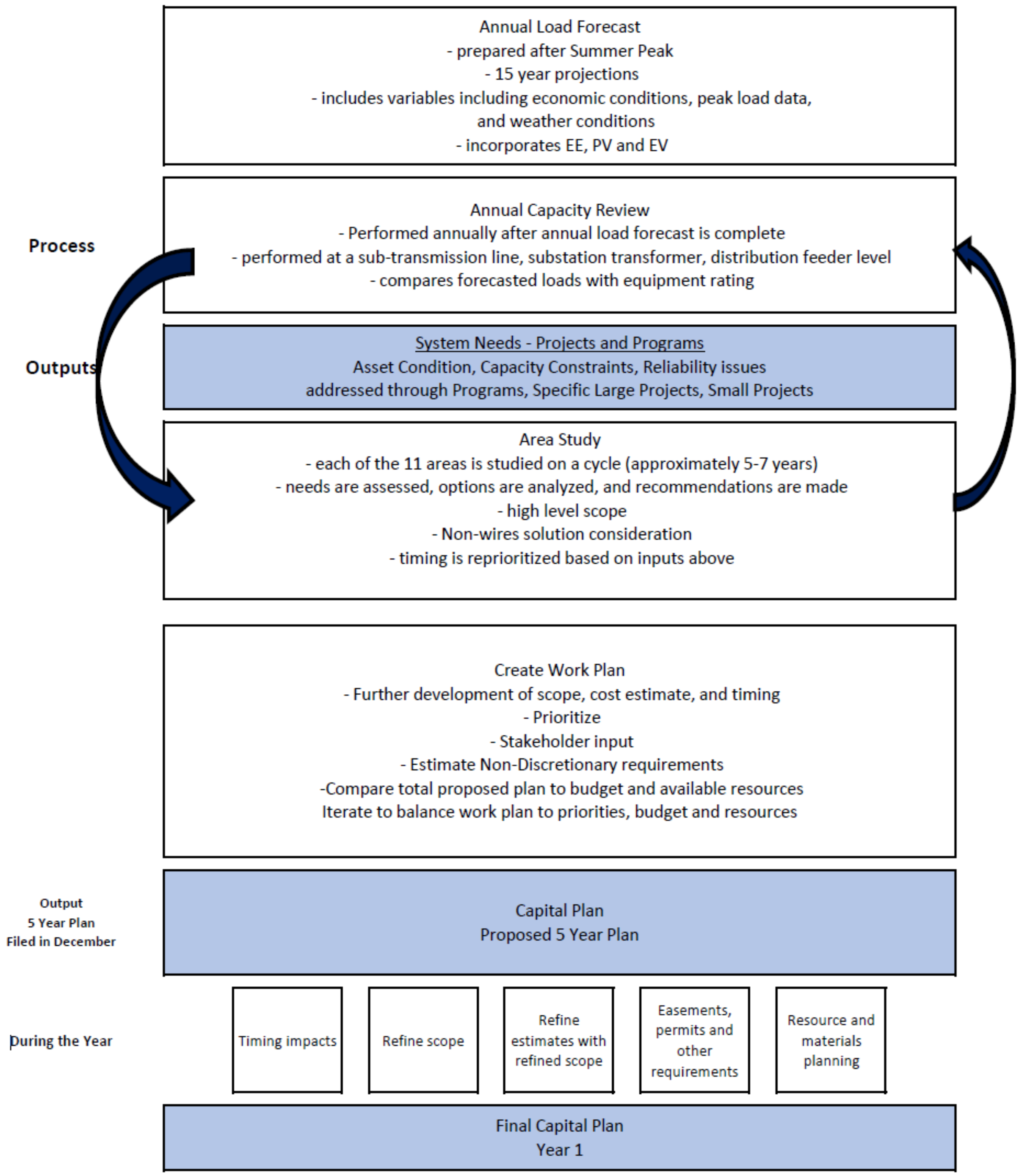
### System Planning

Proposed projects to meet system safety and reliability are developed through a pro-active annual capital work plan process. The Company relies on comprehensive planning guidelines combined with detailed system reviews to determine annual investment requirements. The planning process for the ISR Plan takes place over many months and is a dynamic and iterative process that involves multiple cross-functional teams. The work plan is continually updated for future years based on issues identified on the system, changing circumstances, and outcomes of area studies.

Each year the Company prepares a load forecast and conducts routine system analyses on its distribution system. These include capacity reviews and other integrated planning analyses. The Company uses a study area-based approach for planning and project evaluation. The study process ensures alignment between issues and solutions with incorporation of existing strategies and internal design criteria.

Following, Chart 1 depicts the Company's processes from planning to completion for electric capital work. Additional detail is provided in the following sections.

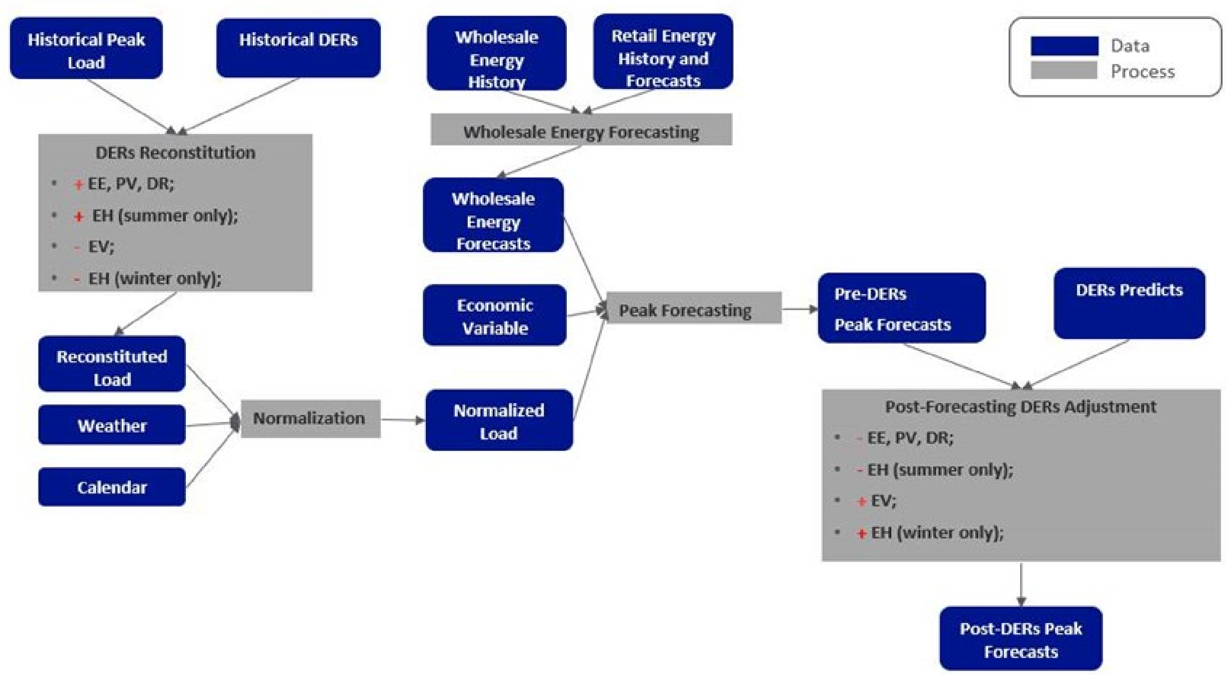
**Chart 1**
**Capital Work Plan Process**



**Load Forecasting**

The Company uses a regression-based core model to forecast summer and winter peak loads. Forecasts are developed annually and have 15-year projections. The explanatory variables being considered and evaluated in this model include historical and forecasted economic conditions specific to Rhode Island, historical peak load data, annual energy sales, and weather conditions based on historical data from the Providence weather station. The chart below shows the data and process flows associated with forecasting load.

**Chart 2**
**Load Forecasting Process**



This model is used to predict the forecasted peak demand for the State under a normal and extreme weather scenario. The normal weather scenario assumes the same normal peak-producing weather for each year of the forecast. The extreme weather scenario assumes an upper bound peak demand under extreme weather conditions. This scenario infers that there is a five percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

The forecast of peak load incorporates distributed energy resources (“DER”), including energy efficiency (“EE”) savings, solar-photovoltaics (“PV”) reductions, electric vehicle (“EV”) increases, electric heat pumps (“EH”) decrease in summer and increase in winter, and demand response (“DR”) reduction achieved through 2022 since these impacts would be reflected in the historical data used by the model. The Company considers these DER impacts cumulative through 2022 and the projected incremental DER impacts in the peak load forecasting. The cumulative EE savings, PV reductions, EH reduction in summer, and DR reduction are subtracted from the forecasted peak, and the EH impacts in winter and EV impacts are added to the peak forecasts. A base case is developed for each DER item using its own recent trend, approved programs, and studies as appropriate. The combination of the base cases from these DER items is considered as the base DER scenario and is considered as the most probable scenario at this time. Scenarios of varying levels and types of DER adoption are also developed to provide additional insights into what loads could look like under different scenarios. System Planning used the load with base DER scenario projections from the most recent load forecast for System Capacity and Area Planning Reviews as well as the Grid Modernization Plan. The Company's 2023 peak forecast report is available on the Rhode Island System Data Portal, and the direct link is:

https://systemdataportal.nationalgrid.com/RI/documents/RI_PEAK_2023_Report.pdf

**Annual Capacity Review**

Actual feeder peak load values from the prior year, along with forecast information described above, are the basis for the capacity reviews. Capacity reviews are completed annually. They identify imminent thermal capacity constraints and assess the capability of the network to respond to contingencies. The capacity planning process includes the following tasks:

- Review historic loading on each sub-transmission line, substation transformer, and distribution feeder.
- Apply and evaluate impacts of the weather adjustment on recent actual peak loads as per the Electric Peak (MW) Forecast.
- Apply and evaluate impacts of the econometric forecast of future peak demand growth as per the Electric Peak (MW) Forecast.
- Analyze forecasted peak loads with comparison to equipment ratings.
- Consider system operational flexibility to respond to various contingency scenarios.

Growth rates are applied to each feeder and sub-transmission line in each area. Specific feeder, sub-transmission line and/or transformer forecasts are adjusted to account for known spot load additions or subtractions, as well as planned load transfers due to system reconfigurations.

Feeder/substation forecasted peak loads under the extreme weather scenario are used to perform planning studies and to determine if the thermal capacity of facilities is adequate for future load level projections.

Individual project proposals are identified to address imminent planning criteria violations. At a conceptual level, the Company prioritizes these small-scale project proposals and submits them for inclusion in future year capital work plans. This is the type of work that could generally arise during the Plan year. In addition, during each year's capacity review, the implementation schedule of projects recommended through Area Planning Studies is assessed and adjusted if conditions indicate an adjustment is needed. This process validates and confirms the need date and implementation schedule of capacity related projects before inclusion in the ISR Plan. The Company anticipates completion of 100% of the annual capacity reviews by February 2024.

**Area Planning Studies**

In addition to identifying imminent issues and corresponding small-scale solutions, annual Capacity Reviews assist in prioritization of addressing system needs as identified in the Company's long-range plan resulting from a series of Area Planning Studies. Area Planning Studies, also known as Area Studies, are more comprehensive technical reviews of the areas within the Company's service territory. Area Study outcomes result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10-to-15-year period. Outcomes are proposed in the ISR Plan or, for system reliability procurement solutions, in System Reliability Procurement Investment Proposals.

Area Planning Studies enhance the ability to meet obligations to provide safe, reliable, and efficient electric service for customers at reasonable costs. The studies typically address issues in a 10- to 15-year window and typically start five to seven years after the last study was completed. Commencement dates may change based on various system conditions and assessments that inform the prioritization of future studies. The Company will appropriately schedule the restudies based on emerging loading, reliability, and system performance issues, new customer interconnections, new asset condition, and operational issues informed by subject matter experts in Engineering and Operations. The study process will continue to be used to develop comprehensive area plans in parallel with existing and emerging program work and other discretionary work the Company considers necessary. For additional information on Area Planning Study efforts, please see the Company's Long Range Plan dated September 8, 2023, in Attachment 5. Completed Area Planning Studies are available in the "Company Reports" section of the Company's Rhode Island System Data Portal using the following link: https://systemdataportal.nationalgrid.com/RI/

The Company's latest portfolio of studies included 11 defined areas with distinct geographical and electrical boundaries. As of December 2021, the Company has completed all 11 Area Studies. The studies reviewed 100% of the State load including 410 Distribution circuits and 97 substations. The studies resulted in a variety of work to address System Capacity violations and Asset Condition issues including 13 station rebuilds, 3 station expansions, and 3 new stations. These projects were factored into the Company's Long Range Plan, see Attachment 5. The Long Range Plan provides the Company's anticipated capital investment spend over a 10-year period. It is intended to give stakeholders a complete view of the Company's proposed strategy to safely, reliably and cost-effectively meet expected load growth, methodically replace aged infrastructure, improve system resiliency, manage increasing distributed energy resource deployment, and implement statutorily or regulatory required programs. The first five years of the Long Range Plan (Years 1-5) include all discretionary and non-discretionary projects, programs, and blanket project cash flows, while the second five years (Years 6 - 10) include large specific projects from area studies, known emerging programs, and inflation adjusted projections of continuing discretionary and non-discretionary cash flows. Please see Attachment 5 for the Company's Long Range Plan.

The Company has developed a standard process for considering the viability of non-wires solutions and system reliability procurement solutions in the distribution planning process.[2] This process is incorporated into Area Planning Studies and detailed in the subsequent subsection. The goal of this process is to develop the optimal combination of wires and non-wires solutions

[2] See the *2024-2026 System Reliability Procurement Three-Year Plan*, submitted to the Rhode Island Energy Efficiency and Resource Management Council on September 21, 2023, and filed with the Rhode Island Public Utilities Commission in Docket No. 23-47-EE on November 17, 2023 in compliance with the Least-Cost Procurement Standards as adopted in Docket No. 23-07-EE. The Company distinguishes between non-wires solutions, which may be owned and operated by either the Company (e.g., utility-owned and operated battery storage, CVR/VVO) or a third-party solution provider (e.g., targeted demand response or energy efficiency, battery storage), and system reliability procurement solutions, which may only be owned and operated by a third-party solution provider. See Section 2 in the *2024-2026 System Reliability Procurement Three-Year Plan* for more information.

via utility reliability procurement and system reliability procurement that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks.

**System Reliability Procurement Process**

During the alternative analysis stage of an Area Planning Study, system needs are screened for their potential for resolution via system reliability procurement, which encompasses a review of both utility-owned and third-party owned non-wires solutions. Screening criteria are proposed and approved within Docket No. 23-47-EE, *2024-2026 System Reliability Procurement Three-Year Plan*. Where an eligible system need has been identified, a system reliability procurement solution may be considered as an option to defer a transmission, sub-transmission, or distribution wires solution indefinitely or for a period of time. This screening is fully integrated into the planning process and is part of the normal course of business, with screening criteria applied by the engineering team to all electric system needs and opportunities for optimizing system performance. System needs that fail any of the screening criteria will be proposed as "wires solutions" through the Company's annual *Electric Infrastructure, Safety, and Reliability ("ISR") Plan* at the appropriate time. System needs that pass the screening criteria advance through the following steps to solicit and evaluate the viability of system reliability procurement solutions.

System engineers always develop their recommendation for the best alternative utility reliability procurement solution. These solutions are described in area studies and annual

*Infrastructure, Safety, and Reliability ("ISR") Plans*. The cost of the best alternative utility reliability procurement solution will be denoted as the cost against which to compare system reliability procurement proposals. The Company will solicit proposals for all possible solutions identified, whether from a third-party vendor or an internal business functional team (i.e., utility-run non-wires solutions). Solicitation will occur via a competitive Request for Proposals. Proposals will be evaluated by the Company using the approved evaluation criteria consistent with Least-Cost Procurement Standards. Results of solicitations, including information about third-party and internally-sourced proposals received, and outcomes of evaluations, including evaluations of third-party and internally-sourced proposals, will be reported annually via *System Reliability Procurement Annual Reports*. If a system reliability procurement solution is selected, the Company will file for regulatory approval of the system reliability procurement solution, such as through a *System Reliability Procurement Investment Proposal*, prior to implementation. Only one solution will be selected and progressed.

**Additional Planning Analyses**

Annual capacity reviews are the basis for load flow planning models that are used for many different types of planning analysis. Additional planning activities include, but are not limited to

- Distributed Generation ("DG") System Impact Studies ("SIS")
- Large new customer load request reviews
- Acute reliability and/or voltage issue reviews
- Operations and Control Center support
- Arc flash/fault duty customer requests

**Grid Modernization Plan ("GMP") Analysis**

The Company conducted an analysis to understand which investment strategy could best contain long-term costs to operate and maintain the distribution system.[3] The GMP analysis shows that an investment strategy of traditional investments integrated with grid modernization investments, referred to as a 'grid modernization investment strategy', is best-fit, least-cost for a portfolio of electric distribution system issues in Rhode Island. These electric distribution system issues include issues the Company is seeing now, such as interconnection and operation flexibility of distributed energy resources, maintaining reliability, expanding volt/var optimization to save energy, and the continuous effort to improve worker and public safety. Therefore, the insights from the GMP suggest the Company should shift to a grid modernization investment strategy through which traditional investments are integrated with grid modernization investments. In line with this finding, the Company has considered and proposed, where appropriate, grid modernization solutions to system issues throughout this ISR Plan.

**Assessment on Act on Climate**

The 2021 Act on Climate, R.I. Gen. Laws §42-6.2-1 et seq., mandates a statewide, economy-wide 45% reduction in greenhouse gas emissions by 2030 relative to 1990 emissions levels, 80% by 2040, and shall be net-zero emissions by 2050. The Company has assessed that

[3] See Docket No. 22-56-EL for the Company's Grid Modernization Plan, including supplemental testimony further describing the analysis, the findings of the analysis that support a grid modernization investment strategy as being net beneficial in containing long-term costs of the electric distribution system relative to a traditional investment strategy, and discussion of pacing relative to making grid modernization investments.

approval of this ISR Plan promotes the Act on Climate mandates by preparing the electric distribution grid to integrate greater renewable energy generation as discussed in detail throughout the Grid Modernization Plan.

**Docket 4600 Analysis**

The Electric ISR Plan is developed to advance many of the goals for the electric system that the Commission adopted in Docket No. 4600A – Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company, dated October 27, 2017 (the Guidance Document). These goals are:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels).
- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.
- Address the challenge of climate change and other forms of pollution.
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides 8 recognizable net benefits.
- Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.
- Appropriately charge customers for the cost they impose on the grid.
- Appropriately compensate the distribution utility for the services it provides.
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

See Docket 4600 Analysis included in Attachment 9.

**FY 2025 Capital Investment Plan**

The system planning and work development process results in the Company's Capital Investment Plan that will enable it to continue to deliver safe, reliable, and efficient electric service for customers at reasonable costs. As such, the Company presents the following capital spending plan for FY 2025. As shown in Chart 3 below, the Company plans to invest $140.9 million to maintain the safety and reliability of its electric delivery infrastructure. An additional $51.7 million for advanced metering functionality filed under Docket No. 22-49-EL and authorized by the Commission at its Open Meeting on September 27, 2023 is included in the table below for a total capital investment of $192.6 million.

**Chart 3**
**Capital Spending by Category FY 2012 – FY 2025**
**($000)**

| Capial Spending Budget by Spending Rationale | FY12 | FY13 | FY14 | FY15 | FY16 | FY17 | FY18 | FY19 | FY20 | FY21 | FY22 | FY23 | FY24 Budget | FY25 Proposed Budget |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Request/ Public Requirement | $13,075 | $10,410 | $17,138 | $17,760 | $17,412 | $20,233 | $19,627 | $23,989 | $28,667 | $21,990 | $34,335 | $31,727 | $27,514 | $32,862 |
| Damage Failure | 12,993 | 17,515 | 14,374 | 3,044 | 14,531 | 15,614 | 19,184 | 13,999 | 17,028 | 19,491 | 20,200 | 17,461 | $15,192 | 17,813 |
| Asset Condition | 10,320 | 8,071 | 20,905 | 25,141 | 27,179 | 31,274 | 41,978 | 32,897 | 32,878 | 41,816 | 35,792 | 44,239 | $47,726 | 51,045 |
| Non-Infrastructure | 149 | 2,269 | (346) | 1,216 | 457 | 622 | 363 | 673 | 145 | (57) | 1,100 | 1,554 | $1,700 | 892 |
| System Capacity & Performance | 13,995 | 11,249 | 25,972 | 25,890 | 19,920 | 16,371 | 25,906 | 39,515 | 24,958 | 17,387 | 15,303 | 13,464 | $20,197 | 38,303 |
| Advanced Metering Functionalities | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | 51,725 |
| **Capital Spending including AMF** | **$50,532** | **$49,514** | **$78,043** | **$73,051** | **$79,499** | **$84,114** | **$107,058** | **$111,072** | **$103,676** | **$100,627** | **$106,730** | **$108,444** | **$112,329** | **$192,640** |
| **Capital Spending excluding AMF** | **$50,532** | **$49,514** | **$78,043** | **$73,051** | **$79,499** | **$84,114** | **$107,058** | **$111,072** | **$103,676** | **$100,627** | **$106,730** | **$108,444** | **$112,329** | **$140,915** |

Since a portion of the proposed capital spending in this Electric ISR Plan is for projects that will be completed over multiple years, the Company anticipates that only a portion of capital spending will be placed in service in FY 2025. Likewise, a portion of the capital that will be placed in service during FY 2025 will reflect prior years' capital spending for similar multi-year projects. Chart 4 below provides actual and forecasted plant additions for FY 2012 through FY 2025.

**Chart 4**
**Plant in Service FY 2012 – FY 2025**
**($000)**

| Plant in Service Target by Spending Rationale | FY 2012 Actual | FY 2013 Actual | FY 2014 Actual | FY 2015 Actual | FY 2016 Actual | FY 2017 Actual | FY 2018 Actual | FY 2019 Actual | FY 2020 Actual | FY 2021 Actual | FY 2022 Actual | FY 2023 Actual | FY 2024 Target | FY 2025 Proposed Target |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Request/ Public Requirement | $15,144 | $11,285 | $13,809 | $18,325 | $19,697 | $14,860 | $20,923 | $24,272 | $30,113 | $15,900 | $25,258 | $27,619 | $27,353 | $29,747 |
| Damage Failure | 13,628 | 12,173 | 16,928 | 3,804 | 16,371 | 13,635 | 15,085 | 16,172 | 18,035 | 19,684 | 21,246 | 13,452 | 16,387 | 20,285 |
| Asset Condition | 13,019 | 6,638 | 14,640 | 28,094 | 18,533 | 18,726 | 44,645 | 36,599 | 23,870 | 46,730 | 29,872 | 40,972 | 32,298 | 38,401 |
| Non-Infrastructure | 60 | 113 | 1,990 | 346 | 111 | 0 | 3 | 0 | 194 | 197 | 806 | 371 | 1,650 | 830 |
| System Capacity & Performance | 9,799 | 14,145 | 8,727 | 25,970 | 16,845 | 28,170 | 12,103 | 34,461 | 33,081 | 33,114 | 11,522 | 10,244 | 11,187 | 18,816 |
| Advanced Metering Functionality | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 56,821 |
| **Plant Additions including AMF** | **$51,650** | **$44,355** | **$56,094** | **$76,539** | **$71,557** | **$75,391** | **$92,758** | **$111,504** | **$105,293** | **$115,626** | **$88,704** | **$92,657** | **$88,874** | **$164,901** |
| **Plant Additions excluding AMF** | **$51,650** | **$44,355** | **$56,094** | **$76,539** | **$71,557** | **$75,391** | **$92,758** | **$111,504** | **$105,293** | **$115,626** | **$88,704** | **$92,657** | **$88,874** | **$108,080** |

**Development of Work Plan and Estimating**

Each year, the Company develops an Annual Work Plan, which is designed to achieve the Company's overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. The Annual Work Plan represents a compilation of proposed spending for individual capital projects and programs.

Projects and programs are categorized as either Non-Discretionary or Discretionary spending. The Non-Discretionary categories, or Spending Rationales, are Customer Requests/Public Requirements and Damage/Failure. Discretionary work is that which the Company has control over the timing and pacing; however, the Company does not consider discretionary work to be work that is optional. Rather, discretionary work is that which is necessary and over which the Company collaborates with regulators to prioritize given business objectives, state and regulatory policy, and other considerations. The Discretionary categories, or Spending Rationales, are Asset Condition, Non-Infrastructure, and System Capacity and Performance.

The proposed spending is forecasted based on the most recent cost and timing estimates for in-progress projects and initial estimates for newly proposed projects. The Company completes annual workshops with asset management, distribution control center, operations, project management and design departments to evaluate risks associated with projects identified in area studies. The team discusses risks including environmental impacts, equipment availability, construction, permitting, reliability impacts and safety.

Based on the Company's latest proposal for budgetary framework as part of Docket 23-34 EL, the Company will provide additional information in quarterly reporting for substation projects that are valued at greater than $10.0 million and with execution plans longer than two ISR fiscal years. These projects will be referred to "Separately Tracked Major Projects." This information will be provided in Attachment G, which the Company is planning on revising to include additional information that aligns with the framework. The Company, with Division input, will also consider separately tracking other substation projects valued at greater than $5.0 million and having high execution and scope complexity risk. Program work will not be reported on separately in Attachment G to the quarterly reports. For the FY 2025 ISR, the following projects meet the criteria for separate tracking and the Company will provide additional information on the status and spending in Attachment G to the quarterly reports: Kingston #31 Equipment Replacement, Phillipsdale Substation, New Admiral Street 12 KV Substation. The Southeast Substation project and Dyer Street Substation project are essentially complete with the exception of demolition which will occur in FY 2025. The Company will continue to provide updates in quarterly reports on the substation component of these projects until they are complete. In addition to revising Attachment G, the Company is also reviewing the content of Attachment 3 to provide additional information related to project phases and estimates within future ISR filings. The Company plans to discuss these changes with the Division and seek input.

The Company's cost estimates and schedules, specifically for projects, evolve throughout the life of a project. The process is a multi-phase approach which begins with study grade estimates used for alternative analysis and option selection then develops to detailed estimates which are used for execution and construction.

Typically, projects originate from area studies which include multi-stepped comprehensive solutions. At this stage of the process estimates are developed to an accuracy that will allow system area planners to evaluate alternatives and select preferred plans. When the preferred plan is identified the system area planner develops a cashflow for the project based on the system need date and project execution influencing factors that are known at the time, for example material lead times. The Company is now engaging with estimators who have construction experience to further improve the accuracy of these study grade estimates earlier in the process.

The next stages of a project involve preliminary and detailed engineering and construction and material resource procurement. These further refine the scope of a project and improve the accuracy of the estimate. During these stages, the Company engages with the market for large materials and construction contractors, for example, substation transformers and civil construction crews. This process includes real time bids in the construction grade estimates.

Under the FY 2022 ISR Plan, the Company began experiencing impacts in delivery and costs related to materials and services due to supply chain constraints. The Company is continuing to see longer lead times for materials and has adjusted schedules and business practices to ensure the execution and completion of projects in the FY 2025 ISR Plan.

In addition to the narrative descriptions of variances between budgeted and actual spending included in its quarterly reports and Annual Reconciliation, the Company will continue to provide variance explanations for large projects where the costs differ from budget by more than 10% in Attachment E. Large projects are projects with a budget or actual or forecasted spending greater than $1 million.

The FY 2025 Electric ISR Plan is the Company's best information regarding the investments needed to sustain the safe, reliable, and efficient operation of the electric system. The Company continuously reviews and updates the capital plan during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, system operations, performance, safety, updated estimates, and customer-driven needs. In addition to filing quarterly reports with the Commission, the Company has ongoing collaborative discussions with the Division throughout the year to provide updates on execution and risks to the Plan.

Once the mandatory budget level has been established for the Non-Discretionary spending categories, the Company selects necessary projects and programs for inclusion the Discretionary categories of the spending plan. Factors considered in creating the Discretionary Work Plan include, but are not limited to, new project or in-progress status, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is utilized to optimize cost efficiency and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project. Historical and forward-looking checks are made to identify deviations from expected or historical trends.

The portfolio is presented to the Company's senior executives and approved by the President of Rhode Island Energy. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible for managing the approved budget.

**Delegation of Authority and Sanctioning**

Delegation of Authority ("DOA") is a financial control and provides a framework to ensure that business decisions are made at an appropriate level with the right authority. For purposes of capital projects, that framework is the sanctioning process. The sanctioning process establishes DOA approval levels and documentation requirements dependent upon a project's total cost. Projects with estimates between $500,000 to $5 million are documented by Fact Sheets and approved electronically in PowerPlan. Projects with estimates between $5 million and $40 million are documented by Sanction Papers and approved electronically in PowerPlan. Projects above $40 million require are documented by a sanction paper and approved electronically by the Leadership Committee. Project sponsors are required to consult and gain approval of applicable supporters prior to DOA sign-off. Re-sanctioning of a project is required if the project exceeds the estimate. With the Company's new organizational structure, the sanctioning process is more localized and efficient.

**FY 2025 Proposed Capital Spending Plan**

The table below shows the FY 2025 ISR Plan's planned investment to maintain the safety and reliability of its electric delivery infrastructure. The section below summarizes the spending by key drivers. Attachment 1 to this section provides spending detail on major project categories that support the proposed level of capital spending by key driver. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available. Attachment 3 includes a summary of information regarding the major multi-year projects.

**Chart 5**
**Proposed FY 2025 Capital Spending**
**($000)**

| Spending Rationale | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| Customer Request/Public Requirement | $27,514 | $32,862 |
| Damage Failure | 15,192 | 17,813 |
| Asset Condition | 47,726 | 51,045 |
| Non-Infrastructure | 1,700 | 892 |
| System Capacity & Performance | 20,197 | 38,303 |
| **Capital Spending excluding AMF** | **$112,329** | **$140,915** |
| Advanced Metering Functionality (AMF) | - | 51,725 |
| **Capital Spending including AMF** | **$112,329** | **$192,640** |

The Company considers the investment required to comply with customer requests and statutory and regulatory requirements, including meeting State clean energy goals, and to fix damaged or failed equipment as mandatory and non-discretionary in terms of scope and timing. Together, these items total $50.7 million during FY 2025 and represent 36% of the Plan's proposed capital investment, excluding capital spending for AMF of $51.7 million.

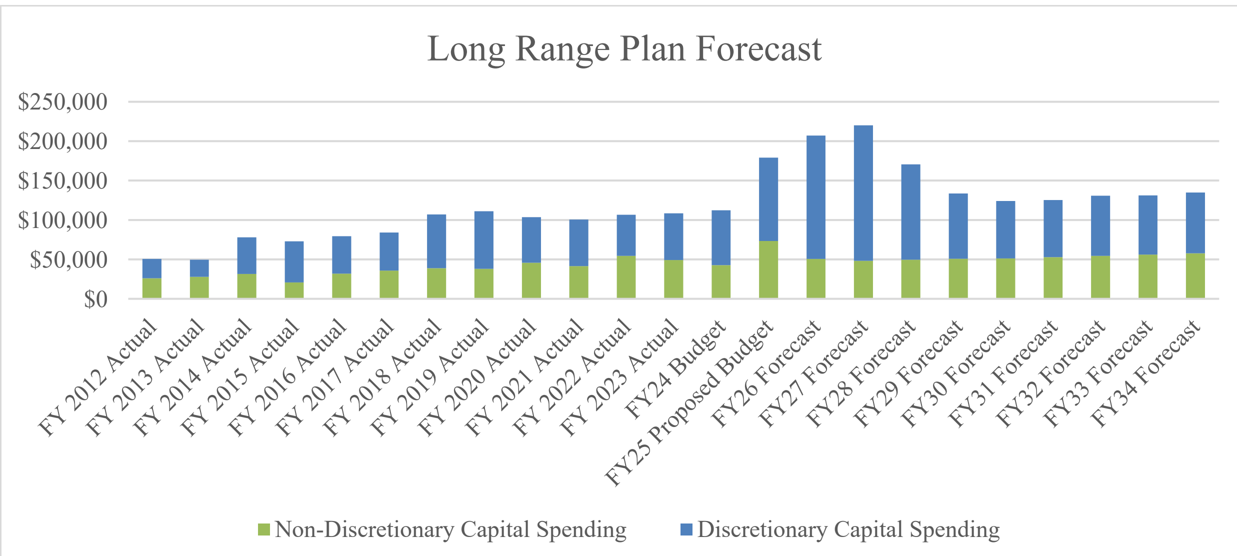
The Company's discretion over spending proposed for Asset Condition and System Capacity and Performance categories pertains only to the timing and pacing of how those projects proceed, and not whether they proceed. The Company closely monitors the risk associated with delaying such projects due to the potential impact and consequences of the failure of equipment or systems. With the completion of the area studies, the Company is now including a backlog of projects in the Plan which if not completed will create greater risk of failure and increased stress on the system. It is the Company's due diligence to propose investments to remedy these system issues and mitigate safety risks in each ISR Plan. These investments are anticipated to be higher in the near-term because of the backlog of system issues identified through Area Studies. Once the backlog is complete, the Company anticipates that this level of investment will be a smaller proportion of the total budget. Please see the Asset Condition and System Capacity & Performance sections for summarized information related to the area study findings and Attachment 5 – Long Range Plan for the specific area study work that is proposed in the FY 2025 Plan. The investments the Company will pursue have been chosen to minimize the likelihood of reliability issues and other problems due to under investment in the system. Together, these items total $89.3 million during FY 2025 and represent 63% of the Plan's proposed capital investment, excluding capital spending for AMF of $51.7 million.

In the FY 2025 Plan, the Company has included a discretionary spending category associated with the deployment of its Advanced Metering Functionality program ("AMF") described in Docket No. 22-49-EL as authorized by the Commission at the Open Meeting on September 27, 2023. The AMF annual spending projections are in line with the project cost cap approved by the Commission. For further information on the program, please refer to Docket No. 22-49-EL - The Narragansett Electric Co. d/b/a Rhode Island Energy's Advanced Metering

Functionality ("AMF") Business Case on the PUC's website. AMF spending totals $51.7 million during FY 2025.

Chart 6 below outlines the past and future projected spend for discretionary and non-discretionary work as outlined in the Long Range Plan.

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



**Customer Request/Public Requirements**

As shown in Attachment 1, the Company has set a FY 2025 budget of $32.9 million to comply with customer requests and statutory and regulatory requirements in the FY 2025 Plan. Overall, the scope and timing of this work is defined by those who are external to the Company. Much of the construction work is variable and requested on short notice to account for emergent projects. The budget is set based on data from previous fiscal years. Since the Company is reimbursed for a portion of this spending, the budget represents the capital the Company expects to spend, net of contributions in aid of construction ("CIAC") and other reimbursements.

The chart below shows a comparison of the FY 2025 proposed capital spending to FY 2024's budgeted capital spending for this category.

**Chart 7**
**Proposed FY 2025 Capital Spending – Customer Request / Public Requirement**
**($000)**

| Customer Request / Public Requirement | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| New Business - Commercial | $9,093 | $9,366 |
| New Business - Residential | 7,212 | 7,428 |
| Public Requirements | 1,249 | 3,140 |
| Transformers & Related Equipment | 5,000 | 8,000 |
| Meters and Meter Work | 2,605 | 2,533 |
| Distributed Generation | 1,000 | 1,000 |
| Other | 1,355 | 1,395 |
| **Total** | **$27,514** | **$32,862** |

The major components in the Customer Request/Public Requirement category are:

- Responding to new customer requests, including establishing electric delivery service to new customers, Third Party Attachment work, and Distributed Generation ("DG") requests.
- Relocating facilities for public works projects requested by cities and towns and the Rhode Island Department of Transportation. As of June 29, 2022, RIDOT will only be reimbursing the Company for 50% of project spending.
- Transformer, capacitor, regulator, network protectors purchases and meter purchases and installations.

**Damage/Failure**

For the FY 2025 Plan, the Company is proposing a budget of $17.8 million to replace assets that either unexpectedly fail or become damaged during the year. The projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes.

Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historical trends. A reserve is budgeted to allow for larger project work due to asset failures that arise during the year. Additionally, the budget includes capital spending to address issues that have been identified for immediate repair as part of the I&M program described in Section 4.

The chart below shows a comparison of the FY 2025 proposed capital spending to FY 2024's budgeted capital spending.

**Chart 8**
**Proposed FY 2025 Capital Spending – Damage/ Failure**
**($000)**

| Damage/Failure | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| Damage/ Failure | $10,940 | $11,268 |
| Failed Assets - specific projects | 1,323 | 2,537 |
| Reserves | 979 | 1,008 |
| Storms and Weather Events | 1,950 | 3,000 |
| **Total** | **$15,192** | **$17,813** |

The Damage/Failure category is made up of the following:

- Blanket projects for substation and line failures for small dollar, frequently occurring items or those projects whose size is unknown at the time of the failure.
- In August 2022, the metal clad switchgear at the Nasonville Substation was damaged beyond repair due to a bus fault. Capital spending of $1.6 million is forecasted and the assets will be placed into service in FY 2025.
- During FY 2023, the Hopkins Hills transformer failed, and a spare transformer was installed. The spare transformer is expected to be received during FY 2026. Minimal spending is anticipated during FY 2025.
- In July 2023, the transformer at Apponaug Substation failed. The Company is investigating the fault. Minimal spending is anticipated during FY 2025.
- Receipt of the Westerly #2 spare transformer is scheduled for June 2024. Minimal spending is anticipated during FY 2025.
- Reconstruction of Vault 72 in Providence due to unsafe conditions and deteriorated equipment.
- Reserves to address larger failures that require capital expenditures in excess of $500,000. The budget for this item is built on recent historical trends of such items and allows the Company to complete unplanned work without having to halt work.
- Storm and weather event activity affects the Company's assets. While the actual spending in this category may vary greatly, this reserve allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required.

**Asset Condition**

The Company is proposing a budget of $51.0 million to replace assets due to condition issues. Asset Condition projects and programs have been identified to reduce the risk and consequences of unplanned asset failures and are identified as part of the System Planning process. The focus is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. This investment is essential and is scheduled to minimize the potential for reliability issues. The recently completed area planning studies have identified a significant number of assets with serious condition issues. The Company has included preliminary engineering and design costs in the FY 2025 Plan to initiate this work. In addition, due to the large number of aged assets in the Company's service area, strategies have been developed to replace assets if the condition impairs reliable and safe service to customers. Examples include the URD and Underground Cable Replacement programs. Experience with assets that have poor operating characteristics in the field has led the Company to develop strategies to remove such equipment. The investments made in these assets are prioritized based on their likelihood of failure along with the consequences of such an event.

The chart below shows a comparison of the FY 2025 Plan proposed capital spending to FY 2024's budgeted capital spending.

**Chart 9**
**Proposed FY 2025 Capital Spending – Asset Condition**
**($000)**

| Asset Condition | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| Separately Tracked Major Projects: | | |
| Dyer Street Substation | $0 | $0 |
| Admiral St. 12 KV Substation | 2,784 | 5,513 |
| Kingston Equipment Replacement | 0 | 400 |
| Phillipsdale Substation | 0 | 100 |
| Southeast Substation | 66 | 0 |
| Other: | | |
| Underground Cable Replacement | 5,500 | 5,500 |
| URD Cable Replacement | 6,276 | 5,000 |
| Blanket projects | 5,220 | 6,177 |
| I&M | 3,000 | 1,530 |
| Substation Breakers & Reclosers | 437 | 736 |
| Other Area Study Projects | 10,373 | 15,709 |
| Other projects and programs | 14,070 | 10,380 |
| **Total** | **$47,726** | **$51,045** |

The Separately Tracked Major Projects in the Asset Condition category are:

- *Dyer Street Replace Indoor Substation* – In the re-scoped Dyer Street Substation project, an external substation within the existing South Street Substation outdoor yard was built. The Company forecasts that all significant capital work will be completed during FY 2024. The removal of the AC building has been pushed into FY 2025. The Dyer Street Substation project is essentially complete with the exception of demolition which will occur in FY 2025. The Company will continue to provide updates in quarterly reports on the substation component of this project until it is complete

- *Providence Long-term Study Projects* – The Providence Area Planning Study identified asset condition issues at five indoor substations and on over 25 miles of underground cable within the study area. The study recommended the expansion of the 12.47 kV distribution system to enable conversion of the majority of 11.5 kV and 4.16 kV load. This allows the elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations and several miles of sub-transmission cable. A large part of the 12.47 kV capacity in the area would be provided by a new 115/12.47 kV station at Admiral Street. This substation will supply the converted load from the Geneva, Harris Avenue, Olneyville, and Rochambeau Avenue substations. The remaining phases to be completed from the Providence Area Planning Study are summarized below:

  - Phase 1B – Convert 4 kV lines currently fed from Olneyville to 12.47 kV. Install manholes and duct banks for new 12.47 kV feeds from Admiral Street station. Remove the 4 kV and 11 kV equipment from Admiral Street building and demolish the building. Install new 12 kV equipment and building at Admiral Street and energize the new 12.47 kV feeders. This phase is currently in construction. The Admiral Street 12 kV Substation project is a Separately Tracked Major Project. The Company will provide updates in quarterly reports on the substation component of this project.

  - Phase 2 – Rebuild and convert sixteen 4 kV and 11 kV feeders at Olneyville, Harris Avenue, Rochambeau, and Geneva substations. Loads will be carried by the new Admiral Street 12 kV substation.

  - Phase 3 – Retire the indoor and outdoor substations at Olneyville, Harris Avenue, Rochambeau, and Geneva substations.

  - Phase 4 – Install a 115 / 12.47 kV substation at Knightsville, convert the station feeds to 12.47 kV. Remove and retire the existing 23 / 4.16 kV substation.

- *Southeast Substation* – This project addressed asset condition and safety concerns at the Pawtucket No. 1 and the Dunnell Park substations as well as improvements to overall capacity. The project is substantially complete and is in service. The building demolition is scheduled for FY 2025. The Company tracks this project separately and reports on its progress quarterly. The Southeast Substation project is essentially complete with the exception of demolition which will occur in FY 2025. The Company will continue to provide updates in quarterly reports on the substation component of this projects until it is complete.

- *Phillipsdale Substation* – The Company proposes to replace the out of phase substation with a new 115/12.47 kV station. For additional information on this project see the Fact Sheet in Attachment 5 – Long Range Plan. This project will be tracked separately in quarterly reports.

- *Kingston Equipment Replacement* – The Company proposes to rebuild the substation. For additional information on this project see the Fact Sheet in Attachment 5 – Long Range Plan. This project will be tracked separately in quarterly reports.

Other work in the Asset Condition category includes:

- *Underground Cable Replacement* – This program implements the strategy to replace primary underground cable that is in poor condition or has poor operating history. This program targets known problematic cable types such as paper and lead insulated cables and certain cross-linked polyethylene ("XLPE") insulated cables. Underground cable is reactively replaced when it fails, and the spending is categorized as non-discretionary spending in the Damage/Failure spending rationale. Proactive replacement of underground cable is included in the Asset Condition spending rationale and prioritized based on type of construction, asset condition, and failure history for a specific or similar asset. Proactive replacement work is justified by the need to eliminate repeated in-service failures, anticipated end-of-life based on historic performance or industry experience, or other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. The underground cable replacement program prioritizes the cables using a risk matrix focused on cable characteristics.

- *URD Cable Replacement* – The replacement of Underground Residential Development ("URD") and Underground Commercial Development ("UCD") cables sized #2 and 1/0. These cables are replaced or rehabilitated through cable injection. This strategy supports the current method for handling cable failures by fixing immediately upon failure and offers options for managing cables that have sustained multiple failures. Although interruptions on #2 and 1/0 cables do not significantly influence Company level service quality metrics, they can have significant localized impacts on effected neighborhoods. For URDs with at least three cable failures within the last three years, two options are considered for replacement. Insulation injection is identified as the preferred solution for direct buried cross-linked polyethylene cables in a loop fed arrangement. The overall condition of the primary and neutral cables and installation specifics determine if insulation injection is a viable option. This strategy does not apply to mainline or supply cables.

- *Blanket Projects* – In addition to specific projects, the Company establishes asset replacement blanket projects to ensure that local field engineering and operations can resolve asset condition issues (i.e., deteriorated equipment) in an efficient and effective manner. The amount of funding in the blanket project is reviewed and approved each year based on historical trends in the volume of work required, input from local Operations, and forecasted impact of inflation on material and labor rates. The individual work requests have a value of less than $500,000. The current year's spending is monitored on a monthly basis.

- *Inspection & Maintenance Program* – Section 4 includes details related to both the capital and O&M components of the I&M program.

- *Substation Spares* – In order to ensure availability, the Company has established projects to procure spare transformers, breakers, and regulators. For additional information on the proposed project, please see Attachment 5 – Long Range Plan.

- *Other Area Study Projects* – Individual projects have been established for Asset Condition work coming out of Area Studies. The majority of the work is engineering, design, and initial procurement of materials. The individual projects are itemized on Attachment 2 – Project Detail for Capital Spending and additional information is provided in Attachment 5 – Long Range Plan.

- *Other Projects and Programs* – Capital spending proposed budgets for the Network Blower Motor Program and Substation Battery Replacement Program are included in this line item. Under the Network Blower Motor Program, network vault blower motors with arc resistant motors, predominantly located in Pawtucket and Providence, are replaced. Approximately half of the locations with blower motors will require civil work to allow installation of the Company's standard arc resistant motor and vent system. The Company anticipates that this program will close by December 2026. The Substation Battery Replacement Program**,** station batteries are identified for replacement as the Company optimizes the replacement schedule with risks and upcoming projects.

**System Capacity and Performance**

The Company is proposing a FY 2025 budget in the Plan of $38.3 million for System Capacity and Performance investments. The Company has minimal discretion to address load constraints caused by the existing and growing and/or shifting demands of customers. Projects in this category are identified through the Company's planning processes that are conducted to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies. Individual project proposals have been identified to address planning criteria violations. The recently completed area planning studies have identified a significant number of assets with serious reliability and performance issues. The Company has included preliminary engineering and design costs in the FY 2025 plan to initiate this work. At a conceptual level, the Company prioritizes these project proposals and submits them for inclusion in future capital work plans. It is important to recognize that these investments may also have asset condition drivers that influence replacement decisions.

The chart below shows a comparison of the proposed budget to FY 2025's capital spending.

**Chart 10**
**Proposed FY 2025 Capital Spending – System Capacity and Performance**
**($000)**

| System Capacity and Performance | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| Aquidneck Island | $1,038 | $0 |
| New Lafayette Substation | 750 | 910 |
| Warren Substation | 1,969 | 1,800 |
| Nasonville Substation | 1,912 | 3,674 |
| East Providence Substation | 1,330 | 6,285 |
| Tiverton D-Line | 109 | 328 |
| Weaver Hill Road Substation | 1,507 | 1,105 |
| 3V0 | 1,095 | 186 |
| EMS/RTU | 658 | 135 |
| Overloaded Transformer Replcmts | 1,500 | 1,500 |
| Blanket Projects | 2,490 | 2,605 |
| Other Area Study Projects | 4,068 | 5,609 |
| CEMI-4 Program | 1,230 | 2,619 |
| ERR Program | 0 | 2,000 |
| Distrib Automation Recloser Program | 0 | 5,957 |
| Electromechanical Relay Upgrades | 0 | 1,234 |
| Fiber Network | 0 | 200 |
| Smart Capacitors and Regulators | 0 | 400 |
| Mobile Substation | 0 | 1,278 |
| Other projects and programs | 541 | 478 |
| **Total** | **$20,197** | **$38,303** |

Summaries for the proposed projects and programs in the FY 2025 System Capacity and Performance category are shown below. For additional information on all newly proposed projects, please see <u>Attachment 5 – Long Range Plan</u>.

- *<u>New Lafayette Substation</u>* – A comprehensive study of the South County East area was performed to identify existing and potential future distribution system performance concerns. The study identified several reliability and asset condition issues. The study recommends building a new open air, low profile, breaker-and-one-half 115/12.47 kV substation at the existing Lafayette substation site. The existing 34.5/12.47 kV station at Lafayette will be retired once the new station is placed into service. The schedule for this project has been adjusted due to transmission outage coordination issues.

- *<u>Warren 115/12.47 kV Substation</u>* – The Warren #5 substation expansion project has been recommended as part of the East Bay Area Study. The project expands the existing substation by adding two new 12.47 kV feeders, a new substation capacitor, and new distribution construction to provide additional capacity to Warren and Barrington. In order to provide additional capacity to the Warren and Barrington area, distribution construction requires the crossing of the Barrington and Palmer Rivers in conjunction with on-going projects with RIDOT along the East Bay Bike Path. Completion of the project facilitates the retirement of the Barrington substation, which has safety and asset condition concerns, and a significant portion of the 23 kV sub-transmission in the area.

- *<u>Nasonville Substation</u>* – The Northwest Rhode Island Area Study recommended bringing a new 115 kV overhead supply line from Woonsocket Substation to Nasonville Substation and adding a second transformer and straight bus to the existing substation.

- *<u>East Providence Substation</u>* – The East Bay Area Study identified asset condition and loading concerns in the East Providence area. The study proposed a new station in the East Providence area that will reduce the loading and dependence on the 23 kV sub-transmission system. This project involves the construction of a new 115/12.47 kV substation adjacent to the 115 kV transmission right-of-way. The project requires a tap structure and easement within the public right of way to the 115kV transmission right-of-way. Construction will consist of a 40 MVA LTC transformer supplying straight-bus metal-clad switchgear with a tie breaker, six feeder positions, and two two-stage capacitor banks.

- *Weaver Hill Road Substation* – The Central Rhode Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder.

- *3V0 Program* – As DG penetration levels continue to increase, the need for zero sequence overvoltage ("3V0") protection is more necessary. The addition of DG to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. To enable a more rapid response to DG interconnections, the Company proactively installs 3V0 protective devices in substations on a priority basis.

- *Substation EMS/RTU (SCADA) Additions Program* – The Company is proposing to continue the EMS/RTU program to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies at Wampanoag and West Greenville Substations.

- *Overloaded Transformer Replacements* – This program proposes to replace or upgrade overloaded transformers to alleviate existing overloads and ensure reliability.

- *Blanket Projects* – In addition to specific projects, the Company also establishes blanket projects to ensure that local field engineering and operations can resolve system and equipment loading and reliability issues in an efficient and effective manner. The amount of funding in the blanket project is reviewed and approved each year based on the results of annual capacity planning and reliability reviews, historical trends in the volume of work required, input from local Operations, and forecasted impacts of inflation. The individual work requests have a value of less than $500,000 in value. The current year's spending is monitored monthly.

  The Company has included $1.7 million of FY 2023 recloser plant additions to FY 2025's Target Plant Additions shown on Chart 11. As noted in the Company's September 22, 2023 Letter titled Settlement Between The Narragansett Electric Company d/b/a Rhode Island Energy and the Division of Public Utilities and Carriers on FY 2023 Spending, the Company removed the plant additions and cost of removal from its FY 2023 revenue requirement and has reviewed the work with the Division.

- *Other Area Study Projects* – Individual projects have been established for System Capacity work coming out of Area Studies. The majority of the work is engineering, design, and initial procurement of materials. The individual projects are itemized on

Attachment 2 – Project Detail for Capital Spending and additional information is provided in Attachment 5 – Long Range Plan.

- *Customers Experiencing Multiple Interruptions (CEMI-4) Program* – The Company is proposing to continue its CEMI-4 program to address areas of poor performance. System and Circuit Average Interruption Frequency Indices measure the experience of the average customer; however, using them exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This leads to uneven reliability performance across the distribution circuits and unhappy customers. Currently, approximately 12% of the Company's customers experience four or more interruptions in a rolling twelve-month period. The CEMI-4 Program will identify and fix reliability issues for customers experiencing significantly poorer service than system or circuit averages. Please see Attachment 7 for the CEMI Program documentation.

- *Engineering Reliability Reviews (ERR)* – After reviewing five-year reliability data for each circuit, the Company proposes capital spending for reliability improvements for the top 5% of the worst performing circuits. Please see Attachment 8 for the ERR Guidance Document.

- *Distribution Automation Recloser Program* – This program uses advanced reclosers to address circuit specific reliability issues focusing on the circuits or portions of the electric system performing below acceptable levels. Feeders in the FY 2025 Plan have been selected based on a CKAIFI level above 2.0. Please see Attachment 6 for the Distribution Automation Recloser Program documentation.

- *Electromechanical Relay Upgrades* – The Company is proposing to upgrade approximately 205 electromechanical relays to digital relays. The upgraded equipment will allow remote access to information and provide greater flexibility for coordination with other devices. The Company plans to initiate work at the following stations in FY 2025: Elmwood, Clark St, Wakefield, Hopkins Hill, Lincoln Ave and Old Baptist Road.

- *Fiber Network* – The Company is proposing to replace cellular services connecting substation with fiber optic cabling to improve data flow and reliability of communications. During FY 2025, the Company proposes to conduct a detailed fiber deployment study that will further develop scope, prioritize deployment, and refine future year execution and spend.

- *Smart Capacitors and Regulators (formerly Volt/VAR Optimization and Conservation Voltage Reduction)* – The Company is proposing initial capital spending for the engineering, design and procurement associated with the installation of smart capacitors and regulators.

- *Mobile Substation* – The Company proposes procuring three mobile substations and one mobile regulator so that it can return service to customers within 24 hours if a power transformer is lost. Expected delivery is FY 2028.

**Non-Infrastructure Spending**

The non-infrastructure category is for those capital expenditures that do not fit into one of the above-mentioned categories. This capital spending is necessary to run the electric system, such as general and telecommunications equipment. The Company has proposed a FY 2025 budget of $0.9 million.

**Advanced Metering Functionality ("AMF")**

The Company has included the capital costs associated with the deployment of its AMF program described in Docket No. 22-49-EL as a separate category in its Discretionary capital spending budget as authorized by the Commission at the Open Meeting on September 27, 2023. Under the AMF program, the Company will replace existing Automatic Meter Reading ("AMR") meters, which are reaching the end of their design life, in accordance with the Commission's motions and votes. The Commission found that there exists a need for the Company to transition its electric distribution operations from the existing AMR-based metering system to a system that utilizes AMF. The AMF budget and annual spend projections are in line with the project cost cap approved by the Commission. Recovery of AMF program costs will be through a separate revenue recovery factor outside of the ISR's revenue requirement. For further information on the program, please refer to Docket No. 22-49-EL - The Narragansett Electric Co. d/b/a Rhode Island Energy's Advanced Metering Functionality ("AMF") Business Case on the PUC's website.

The AMF program includes the following categories:

- **Meter Costs** include the purchase and installation of hardware (i.e., meters), ancillary devices, pre-sweep verifications, and project management costs.

- **Network Costs** include the communications network needed for secure and reliable communications from the Radio Frequency meter to the head-end system. Costs of the installation of the communications network include the network equipment, installation costs, steady state operations after deployment, and project management costs.

- **Systems Costs** include the information technology systems and platforms to enable end-to-end AMF functionality.

- **Program Costs** include project oversight and change management during deployment, implementation, and ongoing operations, specifically for change management.

The chart below shows the FY 2025 Plan proposed capital spending budget.

**Chart 11**
**Proposed FY 2025 Capital Spending – AMF**
**($000's)**

| Advance Metering Functionality | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|
| Meter Costs | $0 | $28,655 |
| Network Costs | 0 | 4,935 |
| System Costs | 0 | 14,356 |
| Program Costs | 0 | 3,779 |
| **Total** | **$0** | **$51,725** |

**Recovery of Electric ISR Plan Capital Investment – Capital Placed in Service**

The Company calculates the revenue requirement based on the projected capital amounts that will be placed into service plus associated Cost of Removal ("COR"). To develop the Plant in Service Target in this filing, the Company estimates the timing that capital spending goes into service. Each year, as part of the Company's annual reconciliation, the revenue requirement related to discretionary in-service amounts is trued-up based on the lesser of allowed discretionary capital spending or actual capital investment placed into service on a cumulative basis since the inception of the Electric ISR Plan. The discretionary categories include the Asset Condition, Non-Infrastructure, and System Capacity and Performance categories. Because of the multi-year nature of certain projects, the Plant in Service amount may include current and prior year(s) capital spending when a project is placed into service. Similarly, the capital spending portion of a project included in the current Plan may be placed into service in future fiscal periods and included in subsequent revenue requirement calculations during that project's in-service year.

The chart below provides details regarding the proposed amounts for Capital Spending, Plant in Service, and Cost of Removal ("COR") that have been used to develop the FY 2025 Electric ISR Plan revenue requirement.

Included in the Plant in Service Target total is $56.8 million for AMF plant additions filed under Docket No. 22-49-EL and authorized by the Commission at its Open Meeting on September 27, 2023. These plant additions are excluded from the Company's FY 2025 ISR Plan revenue requirement calculation proposal in Section 5 as these costs are recovered through a separate revenue recovery mechanism.

The Company's Infrastructure Investment and Jobs Act ("IIJA") application for Smart Grid was selected to advance to award negotiations. Contingent on successful award negotiations, the Company will apply the federal funding to investments proposed within the annual ISR, which could include advanced reclosers, smart capacitors, regulators, and electromechanical relays, in accordance with the award agreement and subject to annual regulatory review and approval, as appropriate. This federal funding award requires the selected applicant to provide supplemental non-federal funding equivalent to at least 100% of federal funding; however, the exact details of the cost match for Rhode Island Energy's funding proposal have yet to be finalized within the award negotiation process. The award negotiation process is expected to go through the first quarter of 2024, and the Company will provide an update when this is complete.

**Chart 12**
**FY 2025 Plan Proposed Capital Spending, Plant in Service, and COR**
**($000)**

| FY 2025 | Capital Spending | Plant in Service | COR | Capital Placed-in-Service + COR |
|---|---|---|---|---|
| Customer Request/Public Requirement | $32,862 | $29,747 | $2,363 | $32,110 |
| Damage Failure | 17,813 | 20,285 | 2,079 | 22,364 |
| **Total Non-Discretionary** | **50,675** | **50,032** | **4,442** | **54,474** |
| Asset Condition | 51,045 | 38,401 | 13,247 | 51,648 |
| Non-Infrastructure | 892 | 830 | 20 | 850 |
| System Capacity & Performance | 38,303 | 18,816 | 2,075 | 20,891 |
| **Discretionary - ISR Revenue Requirement** | **90,240** | **58,047** | **15,342** | **73,389** |
| Advanced Metering Functionality (AMF) | 51,725 | 56,821 | 0 | 56,821 |
| **Total Discretionary** | **141,965** | **114,868** | **15,342** | **130,210** |
| **Total including AMF** | **$192,640** | **$164,901** | **$19,784** | **$184,684** |
| **Total excluding AMF** | **$140,915** | **$108,080** | **$19,784** | **$127,863** |

## Attachment 1 – Capital Spending by Key Driver Category and Budget Classification

| Line Number | Spending Rationale and Budget Class | FY 2011 Actual | FY 2012 Actual | FY 2013 Actual | FY 2014 Actual | FY 2015 Actual | FY 2016 Actual | FY 2017 Actual | FY 2018 Actual | FY 2019 Actual | FY 2020 Actual | FY 2021 Actual | FY 2022 Actual | FY 2023 Actual | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3rd Party Attachments | $ (910) | $ 464 | $ 223 | $ 141 | $ 271 | $ 290 | $ 160 | $ 123 | $ 400 | $ 186 | $ (629) | $ 103 | $ 655 | $ 280 | $ 288 |
| 2 | Distributed Generation | - | - | (675) | 195 | 981 | (933) | 3,760 | 280 | 1,815 | 1,568 | 7,615 | 9,801 | 3,750 | 1,000 | 1,000 |
| 3 | Land and Land Rights | 281 | 185 | 128 | 94 | 165 | 143 | 199 | 305 | 360 | 350 | 404 | 513 | 464 | 500 | 515 |
| 4 | Meters | 2,215 | 1,497 | 1,455 | 835 | 612 | 2,935 | 1,844 | 2,627 | 2,332 | 2,530 | 1,605 | 2,351 | 1,918 | 2,605 | 2,533 |
| 5 | New Business - Commercial | 4,287 | 3,391 | 3,722 | 4,957 | 4,781 | 7,568 | 7,815 | 5,625 | 7,293 | 8,702 | 7,158 | 8,325 | 10,379 | 9,093 | 9,366 |
| 6 | New Business - Residential | 3,530 | 2,833 | 2,886 | 3,593 | 3,769 | 5,085 | 4,598 | 4,618 | 4,337 | 5,186 | 2,536 | 4,691 | 7,695 | 7,212 | 7,428 |
| 7 | Outdoor Lighting | 411 | 495 | 488 | 758 | 479 | 129 | 144 | 185 | 455 | 667 | 509 | 617 | 379 | 575 | 592 |
| 8 | Public Requirements | 1,539 | 1,135 | (1,231) | 4,234 | 4,214 | 770 | (124) | 3,078 | 2,495 | 4,320 | (1,407) | 2,301 | 725 | 1,249 | 3,140 |
| 9 | Transformers & Related Equip | 3,278 | 3,075 | 3,415 | 2,331 | 2,488 | 1,425 | 1,837 | 2,786 | 4,503 | 5,157 | 4,199 | 5,631 | 5,761 | 5,000 | 8,000 |
| 10 | **Customer Requests/ Public Requirements** | **14,631** | **13,075** | **10,410** | **17,138** | **17,760** | **17,412** | **20,233** | **19,627** | **23,989** | **28,667** | **21,990** | **34,335** | **31,727** | **27,514** | **32,862** |
| 11 | Damage/Failure | 8,331 | 9,574 | 7,795 | 11,228 | 12,284 | 11,327 | 13,594 | 11,426 | 10,087 | 12,764 | 11,663 | 12,441 | 14,339 | 13,242 | 14,813 |
| 12 | Major Storms | 4,863 | 3,419 | 9,720 | 3,146 | (9,240) | 3,204 | 2,020 | 7,758 | 3,912 | 4,264 | 7,827 | 7,759 | 3,122 | 1,950 | 3,000 |
| 13 | **Damage/Failure** | **13,194** | **12,993** | **17,515** | **14,374** | **3,044** | **14,531** | **15,614** | **19,184** | **13,999** | **17,028** | **19,491** | **20,200** | **17,461** | **15,192** | **17,813** |
| 14 | **Asset Condition** | **5,831** | **10,320** | **8,070** | **20,905** | **25,140** | **27,179** | **31,274** | **41,980** | **32,896** | **32,878** | **41,816** | **35,792** | **44,239** | **47,726** | **51,045** |
| 15 | **Non-Infrastructure** | **706** | **267** | **2,269** | **(346)** | **1,217** | **457** | **622** | **362** | **673** | **145** | **(57)** | **1,100** | **1,554** | **1,700** | **892** |
| 16 | **System Capacity & Performance** | **10,795** | **13,955** | **11,249** | **25,972** | **25,890** | **19,920** | **16,371** | **25,905** | **39,515** | **24,958** | **17,387** | **15,303** | **13,464** | **20,197** | **38,303** |
| 17 | **Capital Spending excluding AMF** | **$ 45,157** | **$ 50,610** | **$ 49,514** | **$ 78,043** | **$ 73,051** | **$ 79,499** | **$ 84,114** | **$ 107,058** | **$ 111,072** | **$ 103,676** | **$ 100,627** | **$ 106,730** | **$ 108,444** | **$ 112,329** | **$ 140,915** |
| 18 | **Advanced Metering Functionality** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **51,725** |
| 19 | **Capital Spending including AMF** | **$ 45,157** | **$ 50,610** | **$ 49,514** | **$ 78,043** | **$ 73,051** | **$ 79,499** | **$ 84,114** | **$ 107,058** | **$ 111,072** | **$ 103,676** | **$ 100,627** | **$ 106,730** | **$ 108,444** | **$ 112,329** | **$ 192,640** |

## Attachment 2 – Project Detail for Capital Spending

| Line Number | Project # | Project Description | Jurisdictional Spotlight | CAPEX FY 2025 $000's |
|---|---|---|---|---|
| 1 | COS0022 | 3rd Party Attachment Blanket | 3rd Party Attachments | 288 |
| 2 | DG | Distributed Generation Placeholder | Distributed Generation | 1,000 |
| 3 | COS0091 | Land and Land Rights | Land | 515 |
| 4 | CN04904 | Meter Purchases (AMR) | Meters | 1,681 |
| 5 | COS0004 | Meter Blanket | Meters | 852 |
| 6 | C046977 | Reserve for New Business Commercial | New Business Commercial | 3,289 |
| 7 | COS0011 | New Business Commercial Blanket | New Business Commercial | 6,077 |
| 8 | C046978 | Reserve for New Business Residential | New Business Residential | 424 |
| 9 | COS0010 | New Business Residential Blanket | New Business Residential | 7,004 |
| 10 | COS0012 | Streetlighting Blanket | Outdoor Lighting | 592 |
| 11 | C086669 | JO Pole Billing Project - RI | Public Requirements | (1,800) |
| 12 | C046970 | Reserve for Public Requirements | Public Requirements | 2,816 |
| 13 | COS0013 | Public Requirements Blanket | Public Requirements | 2,124 |
| 14 | CN04920 | Transformer Purchases | Transformer Purchases | 8,000 |
| 15 | **Customer Request / Public Requirement Total** | | | **32,862** |
| 16 | CRI3010 | Hopkins Hill - Damage/Failure | Damage/Failure | 50 |
| 17 | CRIAPDF | Apponaug Transformer Failure | Damage/Failure | 50 |
| 18 | C081110 | Westerly Transformer #4 Failure | Damage/Failure | |
| 19 | C091379 | Nasonville Substation Rebuild | Damage/Failure | 1,637 |
| 20 | RIE16-24 | ACNW Vlt 72 Reconstruction, Prov. | Damage/Failure | 800 |
| 21 | COS0002 | Damage Failure Blanket - Substation | Damage/Failure | 659 |
| 22 | COS0014 | Damage/Failure Blanket | Damage/Failure | 10,609 |
| 23 | C022433 | Major Storms | Major Storms | 3,000 |
| 24 | C046986 | Reserve for Damage Failure | Damage/Failure | 212 |
| 25 | C051608 | Reserve for Damage Failure Substation | Damage/Failure | 796 |
| 26 | **Damage/Failure Total** | | | **17,813** |
| 27 | COS0006 | General Equipment Blanket | Blanket | 412 |
| 28 | C040644 | Telecom Small Capital Work | Other | 300 |
| 29 | C086391 | Verizon Copper to Fiber Conversions | Other | 180 |
| 30 | **Non-Infrastructure** | | | **892** |

| Line Number | Project # | Project Description | Jurisdictional Spotlight | CAPEX FY 2025 $000's |
|---|---|---|---|---|
| 1 | CRI3033 | Apponaug Substation(D-Sub) | Other Area Study Projects - CRIE | 150 |
| 2 | CRI3034 | Apponaug Substation (D-Line) | Other Area Study Projects - CRIE | 50 |
| 3 | C051205 | Dyer St Substation | Separately Tracked Major Projects | - |
| 4 | C051211 | Dyer St Substation D-Line | Other Projects | 15 |
| 5 | C078735 | Ph 1B - NEW ADMIRAL ST 12KV D-SUB | Separately Tracked Major Projects | 5,513 |
| 6 | C078803 | Ph 1B - ADMIRAL ST 12KV MH&DUCT | Other Area Studies - Prov | 3,540 |
| 7 | C078804 | Ph 1B - ADMIRAL ST 12KV CABLES | Other Area Studies - Prov | 5,930 |
| 8 | CRI3061 | Ph 2 - HarrisAve 11kV(1129&1137) | Other Area Studies - Prov | 260 |
| 9 | CRI3055 | Ph 2 - Geneva,Olnyvile,Rocham4kV | Other Area Studies - Prov | 1,374 |
| 10 | C078857 | Ph 2 - HARRIS AVE 4&11KV RETIRE | Other Area Studies - Prov | 1,288 |
| 11 | C078805 | Ph 4 - KNIGHTSVILLE 4KV CONVERT | Other Area Studies - Prov | 5,045 |
| 12 | C078806 | Ph 4 - KNIGHTSVILLE 4KV D-SUB | Other Area Studies - Prov | 2,945 |
| 13 | C053657 | SOUTHEAST SUBSTATION (D-SUB) | Separately Tracked Major Projects | - |
| 14 | C053658 | SOUTHEAST SUBSTATION (D-LINE) | Other | - |
| 15 | C055683 | PAWTUCKET NO 1 (D-SUB) | Separately Tracked Major Projects | - |
| 16 | CRI3003 | Tiverton Sub (D-Sub) | Other Area Studies - Tiverton | 75 |
| 17 | C032019 | Batteries/Chargers Replacement | Battery Repl Program | 195 |
| 18 | C026281 | I&M | I&M | 1,530 |
| 19 | COS0017 | Asset Replacement Blanket | Blanket | 5,847 |
| 20 | COS0026 | Substation Asset Repl Blanket | Blanket | 330 |
| 21 | C047829 | IRURD HIGH HAWK | URD Program | 1,500 |
| 22 | C049291 | IRURD WOOD ESTATES PHASE 2 | URD Program | 675 |
| 23 | C049356 | IRURD SILVER MAPLE PHASE 2 | URD Program | 467 |
| 24 | C050070 | IRURD PLACEHOLDER | URD Program | 878 |
| 25 | C057882 | IRURD CHATEAU APTS URD REHAB | URD Program | 171 |
| 26 | C057903 | IRURD WESTERN HILLS VILLAGE URD | URD Program | 156 |
| 27 | C057906 | IRURD WOODVALE ESTATES URD | URD Program | 156 |
| 28 | C057921 | IRURD-ROBIN HILLS ESTATES | URD Program | 208 |
| 29 | C058045 | IRURD-TOCKWOTTON FARM ROAD | URD Program | 156 |
| 30 | NWPT008 | CLX Cable Replacement | URD Program | 633 |
| 31 | CRISPTR | Spare Transformer | Substation Spares | 540 |
| 32 | CRISPRE | Spare Regulators | Substation Spares | 96 |
| 33 | CRISPBU | Spare Bushings | Substation Spares | 100 |
| 34 | C055343 | UG Cable Replacement Placeholder | UG Cable Replacement | 5,500 |
| 35 | BSVS002 | Crossman St #111 Sub (D-Line) | Other Area Study Projects - BSVS | 350 |
| 36 | BSVS004 | Central Falls #104 Sub (D-Line) | Other Area Study Projects - BSVS | 231 |
| 37 | BSVS010 | Valley #102 & Farnum #105 Sub D-Line | Other Area Study Projects - BSVS | 200 |
| 38 | CRI3037 | Division St. 61F2 Reconductoring D Line | Other Area Study Projects - CRIW | 240 |
| 39 | CRI3042 | Hopkins Hill 63F6 Feeder Tie D Line | Other Area Study Projects - CRIW | 184 |
| 40 | CRI3017 | Div St#61 T1 T2 Replacement | Other Area Study Projects - CRIW | 500 |
| 41 | CRI3019 | Anthony #64 Equipment Replacement | Other Area Study Projects - CRIW | 350 |
| 42 | CRI3022 | Natick #29 Equipment Replacement | Other Area Study Projects - CRIW | 50 |
| 43 | CRI3020 | Warwick Mall #28 Equipment Replacement | Other Area Study Projects - CRIW | 150 |
| 44 | CRI3018 | Coventry #54 Sub Relocation | Other Area Study Projects - CRIW | 200 |
| 45 | CRI3021 | Hope #15 Equipment Replacement | Other Area Study Projects - CRIW | 209 |
| 46 | CRI3072 | Dexter #36 Equipment Replacement | Other Area Study Projects - Newport | 83 |
| 47 | NWPT002 | Gate II Equipment Replacement | Other Area Study Projects - Newport | 140 |
| 48 | CRI3073 | Hospital #146 Equipment Replacement | Other Area Study Projects - Newport | 320 |
| 49 | NWPT004 | Kingston #131 Equipment Replacement | Other Area Study Projects - Newport | 400 |
| 50 | NWPT005 | Eldred 45J3 Reconfiguration | Other Area Study Projects - Newport | 53 |
| 51 | NWPT006 | Dexter 36W44 Asset Replacement | Other Area Study Projects - Newport | 170 |
| 52 | CRI3029 | Phillipsdale D-Sub | Separately Tracked Major Projects | 100 |
| 53 | CRI3030 | Phillipsdale D-Line | Other Area Study Projects - East Bay | 100 |
| 54 | CRI3031 | Centredale #50 Sub (D-Sub) | Other Area Study Projects - NWRI | 350 |
| 55 | CRI3032 | Centredale #50 Sub (D-Line) | Other Area Study Projects - NWRI | 150 |
| 56 | PROV001 | Auburn Substation 4kV conversions common | Other Area Study Projects - Providence | 100 |
| 57 | PROV002 | Auburn Substation 4kV conversions (115kV o | Other Area Study Projects - Providence | 100 |
| 58 | PROV003 | Elmwood 7F4 Rebuild Common | Other Area Study Projects - Providence | 152 |
| 59 | PROV004 | Pontiac 27F2 Rebuild Common | Other Area Study Projects - Providence | 136 |
| 60 | PROV005 | Lincoln Ave 72F6 Load Break | Other Area Study Projects - Providence | 4 |
| 61 | C089195 | ACNW Vault Vent Blower Replacement | Other | 700 |
| 62 | **Asset Condition** | | | **51,045** |

| Line Number | Project # | Project Description | Jurisdictional Spotlight | CAPEX FY 2025 $000's |
|---|---|---|---|---|
| 1 | C046726 | East Providence Substation D-Sub | East Providence Substation | 2,685 |
| 2 | C046727 | East Providence Substation D-Line | East Providence Substation | 3,600 |
| 3 | C081675 | New Lafayette 115/12KV D-Sub | New Lafayette Substation | 160 |
| 4 | C081683 | New Lafayette 115/12KV D-Line | New Lafayette Substation | 750 |
| 5 | CRI3035 | Staples #112 Reliability 112W43 | Other Area Study Projects - BSVS | 340 |
| 6 | BSVS013 | Staples #112 Reliability 112W44 | Other Area Study Projects - BSVS | 340 |
| 7 | C065166 | Warren Substation Expansion D-Sub | Warren Substation | 1,050 |
| 8 | C065187 | Warren Substation Expansion D-Line | Warren Substation | 750 |
| 9 | CRI3023 | Weaver Hill Rd DSub | Weaver Hill Rd Substation | 855 |
| 10 | CRI3052 | Weaver Hill Rd. SubT Extension | Weaver Hill Rd Substation | 150 |
| 11 | CRI3025 | Weaver Hill Rd Feeder DLine | Weaver Hill Rd Substation | 100 |
| 12 | CRI3027 | Nasonville #127 Sub (D-Sub) | Nasonville Substation | 3,566 |
| 13 | CRI3028 | Nasonville #127 Sub (D-Line) | Nasonville Substation | 108 |
| 14 | CRI3004 | Tiverton D-Line | Tiverton D-Line | 328 |
| 15 | C088864 | Clarkson St 3V0 | 3V0 | 186 |
| 16 | COS0015 | Reliability Blanket | Blanket | 2,100 |
| 17 | COS0016 | Load Relief Blanket | Blanket | 247 |
| 18 | COS0025 | Substation LR/Reliability Blanket | Blanket | 258 |
| 19 | C074428 | EMS - Wampanoag | EMS | 75 |
| 20 | CRIEMS1 | EMS - W. Greenville | EMS | 60 |
| 21 | CRIADVC | Smart Capacitors & Regulators | VVO | 400 |
| 22 | CRI3041 | Coventry 54F1 Reconductoring | Other Area Study Projects - CRIW | 900 |
| 23 | CRI3039 | 2232 Panto Rd. ERR | Other Area Study Projects - CRIW | 333 |
| 24 | CRI3040 | 2232 Industrial Dr. ERR | Other Area Study Projects - CRIW | 208 |
| 25 | EB00001 | Bristol D Line | Other Area Study Projects - East Bay | 59 |
| 26 | EB00002 | Bristol D-Sub | Other Area Study Projects - East Bay | 25 |
| 27 | NWPT007 | Newport 203WS D Line | Other Area Study Projects - Newport | 64 |
| 28 | NWPT009 | Jamestown Capacitor Bank | Other Area Study Projects - Newport | 100 |
| 29 | NWPT010 | Eldred 45J4 D Line | Other Area Study Projects - Newport | 65 |
| 30 | NWPT015 | 37K22 and 37K33 Reconfiguration | Other Area Study Projects - Newport | 235 |
| 31 | NWPT016 | 65J2 Feeder Upgrade D-Line | Other Area Study Projects - Newport | 329 |
| 32 | SCE001 | Lafayette 30F2 Feeder Tie | Other Area Study Projects - SCE | 285 |
| 33 | SCE002 | Wakefield 17F2 Feeder Upgrade D-Line | Other Area Study Projects - SCE | 286 |
| 34 | SCE003 | Wakefield 17F2 Feeder Upgrade D-Sub | Other Area Study Projects - SCE | 166 |
| 35 | SCE004 | Wakefield 17F3 Feeder Relief | Other Area Study Projects - SCE | 130 |
| 36 | SCE005 | Peacedale 59F3 Feeder Relief | Other Area Study Projects - SCE | 456 |
| 37 | SCE006 | Lafayette 30F2 Feeder Upgrade | Other Area Study Projects - SCE | 361 |
| 38 | SCW0001 | Kenyon Common Items | Other Area Study Projects - SCW | 195 |
| 39 | CRI3043 | Kenyon 68FS Extension | Other Area Study Projects - SCW | 532 |
| 40 | SCW0003 | Chase Hill Common Items | Other Area Study Projects - SCW | 200 |
| 41 | CRI3002 | CEMI 4 Program | CEMI | 2,619 |
| 42 | CRIERR1 | ERR Program | ERR | 2,000 |
| 43 | CRIFIBN | Fiber Network | Fiber Network | 200 |
| 44 | CRIDARP | Distrib Automation Recloser Program | DARP | 5,957 |
| 45 | CRIEMRR | Electromechanical Relay Replacement Progra | Electromech Rlay Rplcmt | 1,234 |
| 46 | C005505 | Transformer Upgrades | Other | 1,500 |
| 47 | C013967 | PS&I Activity | Other | 100 |
| 48 | C091057 | Lafayette 30F4 - Narrow Ln 3-Phase | Other | 378 |
| 49 | CRIMOB1 | Mobile Substation | Mobile Substation | 1,278 |
| 50 | **System Capacity & Performance** | | | **38,303** |

| Line Number | Project # | Project Description | Jurisdictional Spotlight | CAPEX FY 2025 $000's |
|---|---|---|---|---|
| 1 | AMFMETR | Meter Costs | | 28,655 |
| 2 | AMFNTWK | Network Costs | | 4,935 |
| 3 | AMFSYST | System Costs | | 14,356 |
| 4 | AMFPGRM | Program Costs | | 3,779 |
| 5 | **Advanced Metering Functionality (AMF)** | | | **51,725** |
| 6 | **FY 2025 Capital Spending Including AMF** | | | **192,640** |

## Attachment 3 – Five-Year Budget with Details

| Line Number | Spending Rationale and Category | ISR Grouping | Docket 22-53-EL FY 2024 Budget | 5 Year Investment Plan - Capital Spending FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | Major Project - Details: Major Project - Current Phase | Current Sanction - CAPEX only | Initial Estimate - CAPEX only | Date of Last Sanction | Est'd Constr Start | Est'd Constr End | Capital Spending through FY 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Customer Request/Public Requirement** | | | | | | | | | | | | | | |
| 2 | | New Business - Commercial | 9,093 | 9,366 | 9,647 | 9,937 | 10,235 | 10,542 | | | | | | | |
| 3 | | New Business - Residential | 7,212 | 7,428 | 7,651 | 7,880 | 8,117 | 8,361 | | | | | | | |
| 4 | | Public Requirements | 1,249 | 3,140 | 3,234 | 3,331 | 3,431 | 3,531 | | | | | | | |
| 5 | | Transformers and Related Equipment | 5,000 | 8,000 | 8,000 | 8,000 | 8,000 | 8,000 | | | | | | | |
| 6 | | Meters and Meter Work | 2,605 | 2,533 | 430 | 100 | 100 | 100 | | | | | | | |
| 7 | | Distributed Generation | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | | | | | | | |
| 8 | | Third Party Attachments | 280 | 288 | 297 | 306 | 315 | 324 | | | | | | | |
| 9 | | Land and Land Rights | 500 | 515 | 530 | 546 | 562 | 579 | | | | | | | |
| 10 | | Outdoor Lighting | 575 | 592 | 610 | 628 | 647 | 666 | | | | | | | |
| 11 | **Total Customer Request/Public Requirement** | | **27,514** | **32,862** | **31,399** | **31,728** | **32,407** | **33,103** | | | | | | | |
| 12 | **Damage Failure** | | | | | | | | | | | | | | |
| 13 | | Damage /Failure | 10,940 | 11,268 | 11,606 | 11,954 | 12,313 | 12,682 | | | | | | | |
| 14 | | Reserves | 979 | 1,008 | 1,038 | 1,070 | 1,102 | 1,135 | | | | | | | |
| 15 | | Failed Assets | 1,323 | 2,537 | 1,972 | - | - | - | | | | | | | |
| 16 | | Storms | 1,950 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | | | | | | | |
| 17 | **Total Damage Failure** | | **15,192** | **17,813** | **17,616** | **16,024** | **16,415** | **16,817** | | | | | | | |
| 18 | **Total Non-Discretionary** | | **42,706** | **50,675** | **49,015** | **47,752** | **48,822** | **49,921** | | | | | | | |

| Line Number | Spending Rationale and Category | ISR Grouping | Docket 22-53-EL FY 2024 Budget | 5 Year Investment Plan - Capital Spending FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | Major Project - Details: Major Project - Current Phase | Current Sanction - CAPEX only | Initial Estimate - CAPEX only | Date of Last Sanction | Est'd Constr Start | Est'd Constr End | Capital Spending through FY 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Asset Condition** | | | | | | | | | | | | | | |
| | Separately Tracked | | | | | | | | | | | | | | |
| 2 | Major Projects | Dyer Street Substation | - | 15 | - | - | - | - | Construction | $10,658 | $10,842 | Apr-21 | Sep-21 | FY 2025 | $14,651 |
| 3 | | Admiral St 12kV Substation | 2,784 | 5,513 | 2,500 | - | - | - | Construction | $12,831 | $12,831 | Aug-21 | Sep-21 | FY 2026 | $2,731 |
| 4 | | Kingston Equipment Replacement | - | 400 | 3,361 | 8,403 | 1,681 | 2,961 | Proposal | -- | $16,805 | -- | Oct-25 | FY 2029 | $0 |
| 5 | | Phillipsdale Substation | - | 100 | 5,728 | 7,240 | 1,448 | 324 | Proposal | -- | $6,025 | -- | Oct-25 | FY 2029 | $0 |
| 6 | | Southeast Substation | 66 | - | - | - | - | - | Construction | $11,244 | $9,000 | Jun-19 | Oct-19 | FY 2025 | $15,198 |
| 7 | Other | Underground Cable Replacement | 5,500 | 5,500 | 6,000 | 6,000 | 6,000 | 6,500 | | | | | | | |
| 8 | | URD Cable Replacement | 6,276 | 5,000 | 5,411 | 5,723 | 5,823 | 5,500 | | | | | | | |
| 9 | | Blanket Projects | 5,220 | 6,177 | 6,338 | 6,504 | 6,676 | 6,850 | | | | | | | |
| 10 | | I&M | 3,000 | 1,530 | 1,530 | 1,530 | 1,530 | 1,530 | | | | | | | |
| 11 | | Substation Breakers & Reclosers | 437 | 736 | 2,060 | 3,240 | - | - | | | | | | | |
| 12 | | Other Area Study Projects - BSVS | - | 781 | 1,556 | 2,457 | 2,280 | 1,156 | | | | | | | |
| 13 | | Other Area Study Projects - CRIE | - | 200 | 1,195 | 2,015 | 2,043 | 1,015 | | | | | | | |
| 14 | | Other Area Study Projects - CRIW | - | 1,883 | 6,317 | 10,196 | 3,730 | 390 | | | | | | | |
| 15 | | Other Area Study Projects - East Bay | - | 100 | 505 | 570 | 570 | 190 | | | | | | | |
| 16 | | Other Area Study Projects - Newport | - | 766 | 4,069 | 5,931 | 4,378 | 816 | | | | | | | |
| 17 | | Other Area Study Projects - NWRI | - | 500 | 3,007 | 2,725 | 1,432 | 250 | | | | | | | |
| 18 | | Other Area Study Projects - Providence | - | 492 | 5,396 | 7,407 | 6,293 | 9,619 | | | | | | | |
| 19 | | Other Area Study Projects - SCW | - | - | - | - | 1,029 | 2,297 | | | | | | | |
| 20 | | Tiverton Substation | - | 75 | 393 | 786 | 786 | 393 | | | | | | | |
| 21 | | Providence Area LT Supply & Distrib Study | 21,530 | 20,382 | 10,580 | 7,064 | - | - | | | | | | | |
| 22 | | Reserve | - | - | 1,000 | 1,000 | 1,000 | 1,000 | | | | | | | |
| 23 | | Batteries / Chargers | 230 | 195 | 387 | 319 | 100 | - | | | | | | | |
| 24 | | Recloser Replacements | 1,300 | - | - | - | - | - | | | | | | | |
| 25 | | UG Improvements and Other | 1,383 | 700 | 565 | - | - | - | | | | | | | |
| 26 | **Total Asset Condition** | | **47,726** | **51,045** | **67,898** | **79,109** | **46,798** | **40,792** | | | | | | | |
| 27 | **Non-Infrastructure** | | | | | | | | | | | | | | |
| 28 | | General Equip & Telecom Blanket | 700 | 712 | 724 | 737 | 750 | 764 | | | | | | | |
| 29 | | Verizon Copper to Fiber | 1,000 | 180 | 75 | - | - | - | | | | | | | |
| 30 | **Total Non-Infrastructure** | | **1,700** | **892** | **799** | **737** | **750** | **764** | | | | | | | |

| Line Number | Spending Rationale and Category | ISR Grouping | Docket 22-53-EL FY 2024 Budget | 5 Year Investment Plan - Capital Spending FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | Major Project - Details Major Project - Current Phase | Current Sanction - CAPEX only | Initial Estimate - CAPEX only | Date of Last Sanction | Est'd Constr Start | Est'd Constr End | Capital Spending through FY 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **System Capacity & Performance** | | | | | | | | | | | | | | |
| 2 | | Aquidneck Island | 1,038 | - | - | - | - | - | | | | | | | |
| 3 | | New Lafayette Substation | 750 | 910 | 5,886 | 151 | - | - | | | | | | | |
| 4 | | Warren Substation | 1,969 | 1,800 | 2,943 | 747 | 111 | - | | | | | | | |
| 5 | | Nasonville Substation | 1,912 | 3,674 | 3,228 | 489 | - | - | | | | | | | |
| 6 | | East Providence Substation | 1,330 | 6,285 | 5,009 | 5,003 | - | - | | | | | | | |
| 7 | | Weaver Hill Road Substation | 1,507 | 1,105 | 3,054 | 3,475 | 2,496 | 1,229 | | | | | | | |
| 8 | | 3V0 | 1,095 | 186 | 540 | - | - | - | | | | | | | |
| 9 | | EMS/RTU | 658 | 135 | 1,147 | 2,350 | 750 | - | | | | | | | |
| 10 | | Overloaded Transformer Replcmts | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | | | | | | | |
| 11 | | Blanket Projects | 2,490 | 2,605 | 2,725 | 2,851 | 2,983 | 3,072 | | | | | | | |
| 12 | | Other Area Study Projects - BSVS | 400 | 680 | 681 | 968 | - | - | | | | | | | |
| 13 | | Other Area Study Projects - CRIW | 1,371 | 1,441 | 1,125 | 1,125 | 675 | - | | | | | | | |
| 14 | | Other Area Study Projects - East Bay | - | 84 | 378 | 378 | - | - | | | | | | | |
| 15 | | Other Area Study Projects - Newport | - | 793 | 976 | 461 | - | - | | | | | | | |
| 16 | | Other Area Study Projects - NWRI | 1,933 | - | - | - | - | - | | | | | | | |
| 17 | | Other Area Study Projects - SCE | - | 1,684 | 6,404 | 333 | - | - | | | | | | | |
| 18 | | Other Area Study Projects - SCW | 364 | 927 | 5,107 | 5,921 | 3,582 | 2,153 | | | | | | | |
| 19 | | Tiverton D-Line | 109 | 328 | 656 | 656 | 328 | 440 | | | | | | | |
| 20 | | Reserve | - | - | 1,000 | 1,000 | 1,000 | 1,000 | | | | | | | |
| 21 | | CEMI-4 | 1,230 | 2,619 | 2,698 | 2,779 | 2,862 | - | | | | | | | |
| 22 | | ERR | - | 2,000 | 2,060 | 2,122 | 2,185 | 2,251 | | | | | | | |
| 23 | | Distrib Automation Recloser Program | - | 5,957 | 7,228 | 7,185 | 10,165 | 14,970 | | | | | | | |
| 24 | | ADMS/DERMS Advanced | - | - | - | 3,159 | 1,568 | - | | | | | | | |
| 25 | | DER Monitor/Manage | - | - | - | 2,288 | 4,043 | - | | | | | | | |
| 26 | | Electromech RelayUpgrades | - | 1,234 | 603 | 1,267 | 2,513 | 1,263 | | | | | | | |
| 27 | | Fiber Network | - | 200 | - | - | - | - | | | | | | | |
| 28 | | VVO - Smart Capacitors and Regulators | - | 400 | 8,439 | 6,701 | 6,701 | 6,701 | | | | | | | |
| 29 | | Mobile Substation | - | 1,278 | 3,834 | 7,668 | - | - | | | | | | | |
| 30 | | Other projects and programs | 541 | 478 | 100 | 100 | 100 | 100 | | | | | | | |
| 31 | **Total System Capacity & Performance** | | **20,197** | **38,303** | **67,321** | **60,678** | **43,563** | **34,679** | | | | | | | |
| 32 | **Total Advanced Metering Functionality (AMF)** | | **-** | **51,725** | **87,846** | **8,550** | **-** | **-** | | | | | | | |
| 33 | **Total Discretionary** | | **69,623** | **141,965** | **223,865** | **149,074** | **91,111** | **76,235** | | | | | | | |
| 34 | **Total Capital Spending including AMF** | | **112,329** | **192,640** | **272,880** | **196,826** | **139,933** | **126,155** | | | | | | | |
| 35 | **Total Capital Spending excluding AMF** | | **112,329** | **140,915** | **185,034** | **188,276** | **139,933** | **126,155** | | | | | | | |

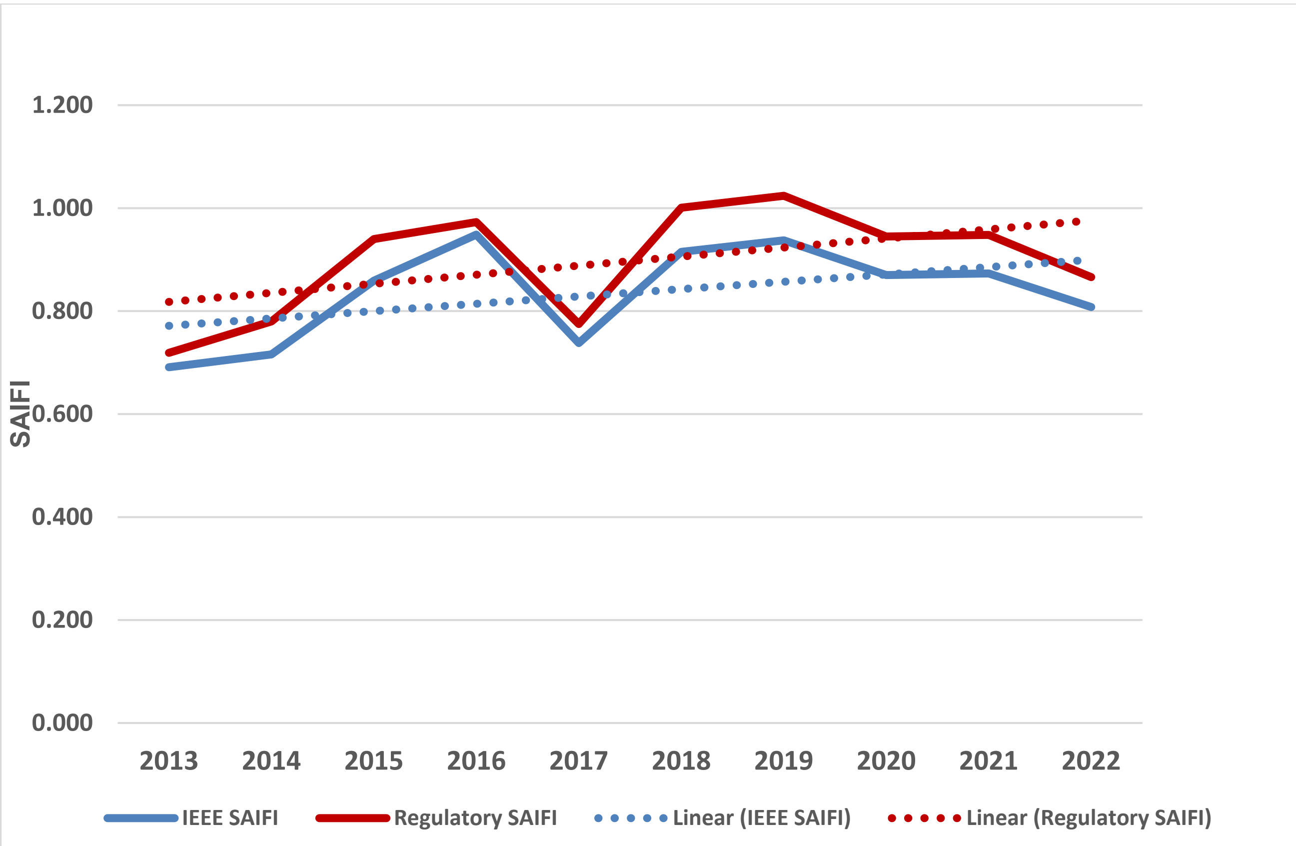
**Attachment 4 – System Reliability Data**

The Company met both its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") regulatory performance metrics in calendar year ("CY") 2022, with SAIFI of 0.866 against a regulatory target of 1.05, and SAIDI of 62.48 minutes, against a regulatory target of 71.9 minutes.

The Company recognizes that regulatory targets for both SAIFI and SAIDI were developed over 20 years ago and customer expectations have changed since then. With the expected widespread adoption of clean energy technologies like electric vehicles and electric heating, the availability of electricity becomes increasingly more important. To further investigate the Company's performance, an effort to review metrics against IEEE SAIDI and SAIFI benchmarks in addition to regulatory targets was conducted. The IEEE Distribution Working Group performs a benchmarking exercise that compares electric distribution reliability performance among North America's electric utility companies. Participating companies use standardized calculation method (IEEE 1366-2003/2012) to report system frequency (SAIFI) and duration (SAIDI) metrics to help reduce reporting variances and equalize results. While the Company met first quartile performance for both SAIFI and SAIDI nationally in CY2022, results indicated that the Company was a fourth quartile performer regionally for SAIFI.

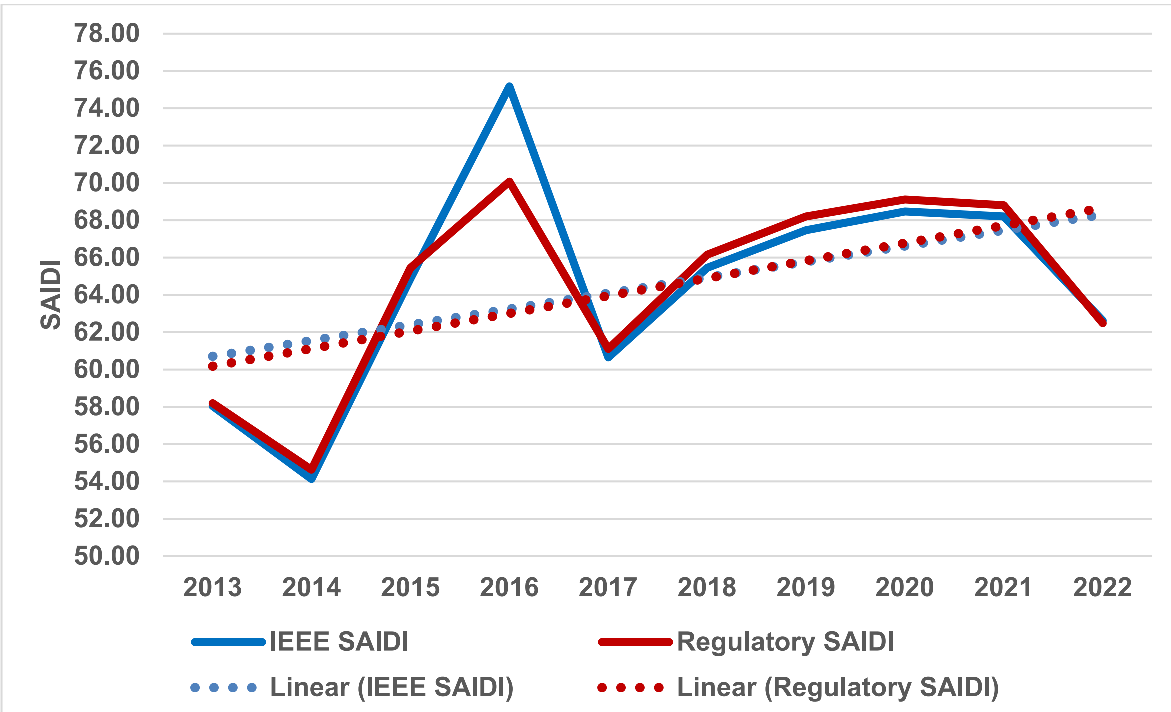
**Attachment 4 – Chart 1**

**Rhode Island Energy CY 2013 – CY 2022**
**IEEE SAIFI and Regulatory SAIFI**



**Attachment 4 – Chart 2**

**Rhode Island Energy CY 2013 – CY 2022**
**IEEE SAIDI and Regulatory SAIDI**




The analysis from CY 2013 to CY 2022 indicates the Company has been experiencing an uptrend for both SAIFI and SAIDI.

In addition to reviewing SAIFI and SAIDI performance metrics the Company used the J.D. Power Electric Utility Residential Customer Satisfaction Study to benchmark itself against similar regional utilities. The study's results for the third quarter of 2023 indicate that the Company falls in the third quartile for overall satisfaction and specifically Power Quality and Reliability. It is critical that the Company continue to invest in its infrastructure and vegetation management programs not only to meet performance targets but to exceed them year over year to provide reliable electric delivery service and improve customer satisfaction.

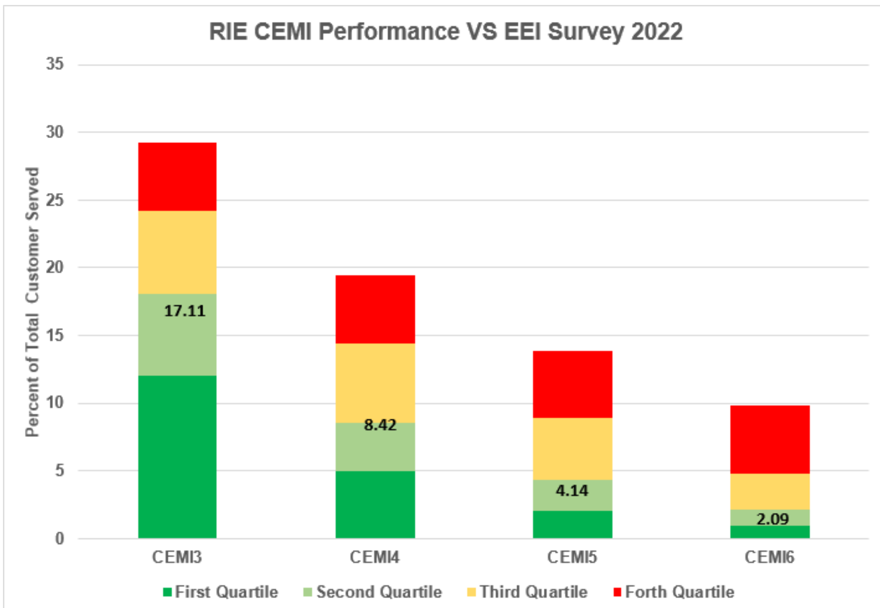
In addition to reviewing system wide metrics, the Company will also increase its focus on areas of the system with minimal customers that have experienced poor performance. The Company performs Engineering Reliability Reviews ("ERRs") on an annual basis, and circuits are selected to be analyzed by reliability metrics which are not heavily impacted by localized issues. This has traditionally been completed under the reliability blanket and other approved programs, for example the cutout mounted recloser program. However, the Company is now creating a separate program for ERRs. Please see Attachment 8 for the ERR Guidance Documentation.

The Company continues to use a CEMI 4 ("Customers Experiencing Multiple Interruptions") index to identify those portions of the system that have experienced reliability challenges. CEMI measures customers who are experiencing the worst reliability in a localized area which may be masked by an acceptable overall system average. Please see Attachment 7 for the CEMI Program documentation.

The chart below shows the Company's performance of CEMI compared to the 2022 EEI performance metrics:

**Attachment 4 – Chart 3**

**RIE CEMI Performance VS EEI Survey 2022**




The chart indicates that the Company falls in the second quartile for CEMI 3, CEMI 5 and CEMI 6 and in between second and third quartile for CEMI 4. Please note, CEMI results are historically volatile considering that major storm outages are included. The Company plans to present rolling three year averages on CEMI circuits to level out spikes based on weather related interruptions. The Company's goal is to rank in the first quartile within five to ten years. This will be achieved by using the CEMI-4 index to implement a targeted set of electric reliability improvement projects to reduce the number of interruptions customers experience in areas of poor performance areas. Three-year quarterly-based CEMI data will be used to prioritize customers that have experienced the most interruptions. The proposed spending for this program has been added to the Plan.

**Annual Reliability Performance**

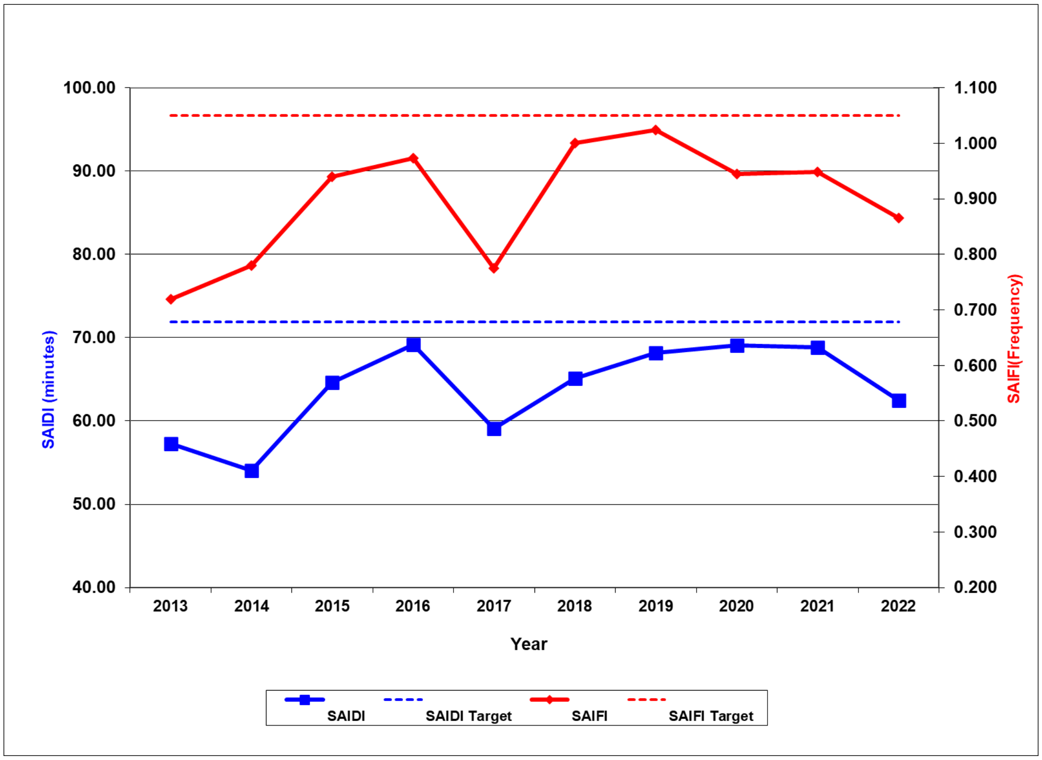
The Company's annual service quality targets are measured by excluding major event days. A Major Event Day ("MED") is defined as a day on which the daily system SAIDI exceeds a MED threshold value. The MED threshold value for CY 2022 was 6.88 minutes. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.[4] The Plan focuses on the underlying drivers of reliability during the entire year. Including major event days would skew that analysis significantly for the small number of days a year that are major event days. For example, including major event days would underestimate the day-to-day drivers of reliability due to substation or underground equipment, because, typically, overhead equipment is most impacted by major event days, which are usually weather driven events. In CY 2022, the Company categorized one day, December 23, 2022, as a major event day. Attachment 4, Chart 4 below provides historical storm details.

**Attachment 4 – Chart 4**
**Historical Storm Data**

| | CY13 | CY14 | CY15 | CY16 | CY17 | CY18 | CY19 | CY20 | CY21 | CY22 |
|---|---|---|---|---|---|---|---|---|---|---|
| SAIFI - Target 1.05 | 0.72 | 0.78 | 0.94 | 0.97 | 0.78 | 1.00 | 1.02 | 0.95 | 0.95 | 0.87 |
| # of Major Event Days | 3 | 0 | 1 | 4 | 4 | 6 | 6 | 6 | 4 | 1 |
| Total Customers Interrupted on major event days | 268,925 | 7,287 | 141,046 | 114,772 | 203,211 | 282,481 | 177,296 | 352,939 | 240,195 | 45,070 |

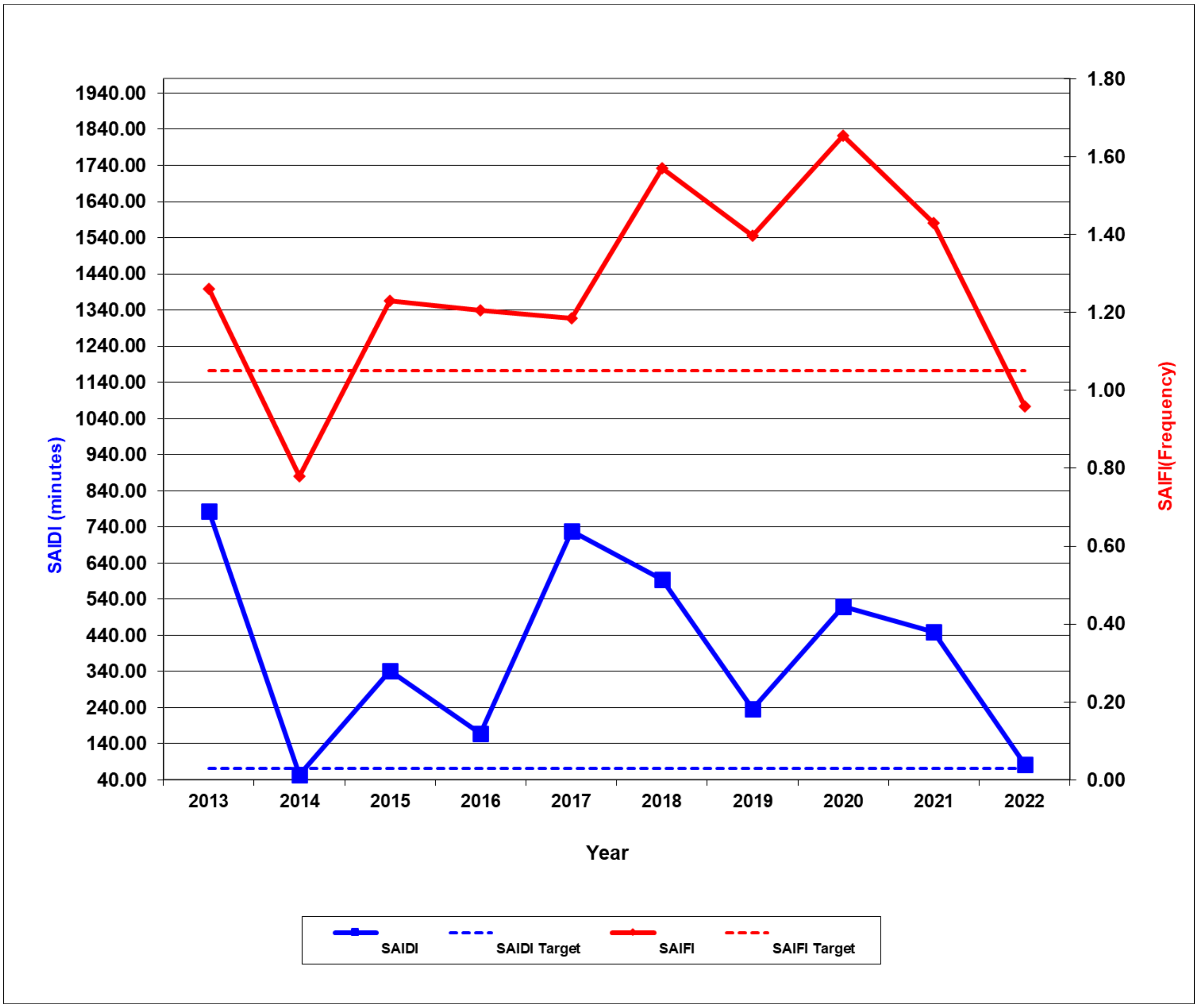
4 For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began.

**Attachment 4 – Chart 5**
**RI Reliability Performance CY 2013 – CY 2022**
**Regulatory Criteria (Excluding Major Event Days)**



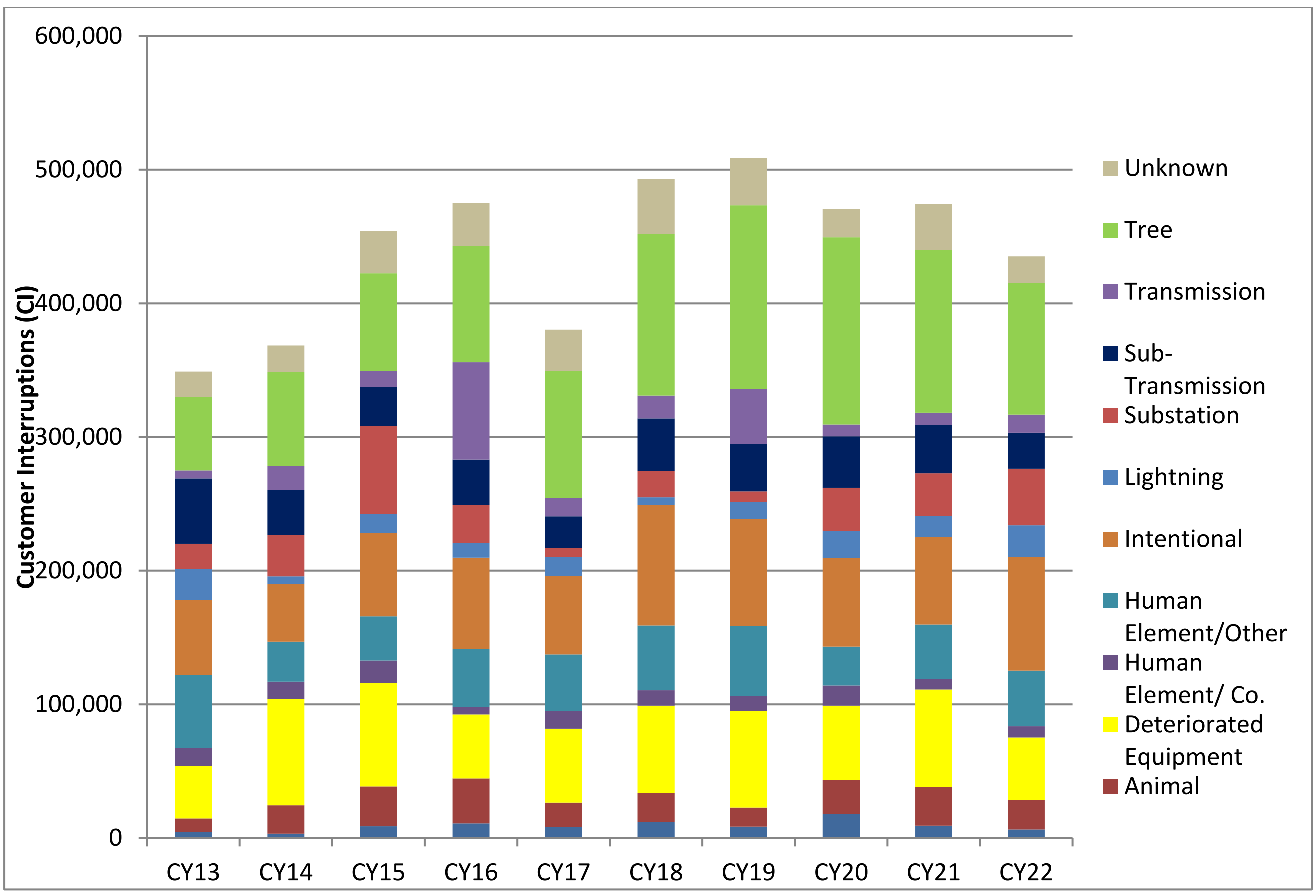

For informational purposes, Attachment 4, Chart 6 below shows reliability performance from CY 2013 to CY 2022, including major event days.

**Attachment 4 – Chart 6**
**RI Reliability Performance CY 2013 – CY 2022**
**Regulatory Criteria (Including Major Event Days)**



Attachment 4, Chart 7 below shows customers interrupted by cause for CY 2013 through CY 2022. Attachment 4, Chart 8 shows the same information in tabular form.

**Attachment 4 – Chart 7**
**Rhode Island Customers Interrupted by Cause**
**Major Event Days Excluded**
**By Calendar Year (2013-2022)**



**Attachment 4 – Chart 8**
**Rhode Island Customers Interrupted by Cause**
**Major Event Days Excluded**
**By Calendar Year (2013-2022)**

| Cause | CY13 | CY14 | CY15 | CY16 | CY17 | CY18 | CY19 | CY20 | CY21 | CY22 |
|---|---|---|---|---|---|---|---|---|---|---|
| Adverse Environment | 4,318 | 3,220 | 8,677 | 10,928 | 8,115 | 11,964 | 8,507 | 17,973 | 9,212 | 6,294 |
| Animal | 10,324 | 21,247 | 29,831 | 33,541 | 18,340 | 21,664 | 14,277 | 25,405 | 28,874 | 22,060 |
| Deteriorated Equipment | 39,131 | 79,260 | 77,575 | 47,966 | 55,316 | 65,386 | 72,114 | 55,603 | 72,996 | 46,819 |
| Human Element/ Co. | 13,481 | 13,259 | 16,619 | 5,489 | 12,995 | 11,462 | 11,392 | 15,066 | 7,801 | 8,319 |
| Human Element/Other | 54,719 | 29,908 | 33,049 | 43,514 | 42,510 | 48,520 | 52,266 | 29,164 | 40,853 | 41,703 |
| Intentional | 55,927 | 43,132 | 62,373 | 68,273 | 58,544 | 90,092 | 80,218 | 66,301 | 65,392 | 84,918 |
| Lightning | 23,310 | 5,745 | 14,374 | 10,832 | 14,505 | 5,766 | 12,648 | 20,127 | 15,801 | 23,748 |
| Substation | 18,882 | 30,888 | 65,932 | 28,525 | 6,616 | 19,802 | 7,830 | 32,413 | 31,896 | 42,464 |
| Sub-Transmission | 48,902 | 33,556 | 29,211 | 33,994 | 23,710 | 39,235 | 35,645 | 38,474 | 36,182 | 26,851 |
| Transmission | 5,958 | 18,284 | 11,594 | 72,808 | 13,786 | 17,106 | 40,969 | 8,856 | 9,232 | 13,628 |
| Tree | 55,056 | 70,277 | 73,248 | 87,036 | 95,025 | 120,812 | 137,437 | 140,002 | 121,540 | 98,260 |
| Unknown | 19,008 | 19,657 | 31,703 | 32,088 | 30,918 | 41,014 | 35,586 | 21,341 | 34,354 | 20,145 |
| **Grand Total** | **349,016** | **368,433** | **454,186** | **474,994** | **380,380** | **492,823** | **508,889** | **470,725** | **474,133** | **435,209** |

Trees, Deteriorated Equipment, and Intentional were the top three drivers affecting customers, accounting for 53 percent of all interruptions in CY 2022. It is, therefore, critical that the Company continue to invest in its infrastructure and vegetation management programs to provide reliable electric delivery service to customers.

**Attachment 5 – Long Range Plan**

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

# Electric Infrastructure, Safety, and Reliability Plan 2025 Proposal

# Long Range Plan

September 8, 2023

**Submitted to:**
Rhode Island Division of Public Utilities & Carriers

Submitted by:

Rhode Island Energy™
a PPL company

**Contents**

## 1. Introduction and Summary

As agreed, The Narragansett Electric Company d/b/a Rhode Island Energy provides the following information in advance of filing its Electric Infrastructure, Safety, and Reliability (Electric ISR) Plan proposal:

- Ten Year Plan to include
  - Investments that are or will be included in the Electric ISR
  - Years 1 through 5 to include all discretionary and non-discretionary projects, programs, and blanket project cash flows
  - Years 6 through 10 to include large specific projects from area studies, known emerging programs, and inflation adjusted projections of continuing discretionary and non-discretionary cash flows.
- Area Study Status
- Asset Condition and System Capacity and Performance Project Summaries, also termed 'Fact Sheets'

## 2. Ten Year Plan

Figure 1 – Ten Year Cash Flow

| Spend Type | Spending Rationale | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| Discretionary | Asset Condition | $60,604 | $69,422 | $82,738 | $47,844 | $42,480 |
| | Non-Infrastructure | $1,712 | $1,724 | $737 | $750 | $764 |
| | System Capacity & Performance | $49,600 | $94,470 | $88,732 | $70,844 | $36,952 |
| **Discretionary Total** | | **$111,916** | **$165,616** | **$172,207** | **$119,437** | **$80,195** |
| Non-Discretionary | Customer Request/Public Requirement | $58,337 | $31,172 | $32,066 | $33,115 | $34,076 |
| | Damage/Failure | $17,013 | $17,616 | $16,024 | $16,415 | $16,817 |
| **Non-Discretionary Total** | | **$75,350** | **$48,788** | **$48,090** | **$49,530** | **$50,893** |
| **Grand Total** | | **$187,266** | **$214,404** | **$220,297** | **$168,967** | **$131,088** |

| Spend Type | Spending Rationale | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|
| **Discretionary** | **Asset Condition** | **$41,586** | **$40,303** | **$43,302** | **$41,163** | **$41,970** |
| | **Non-Infrastructure** | **$786** | **$810** | **$834** | **$859** | **$885** |
| | **System Capacity & Performance** | **$30,374** | **$31,286** | **$32,224** | **$33,191** | **$34,187** |
| **Discretionary Total** | | **$72,747** | **$72,399** | **$76,361** | **$75,213** | **$77,042** |
| **Non-Discretionary** | **Customer Request/Public Requirement** | **$34,008** | **$35,028** | **$36,079** | **$37,161** | **$38,276** |
| | **Damage/Failure** | **$17,322** | **$17,842** | **$18,377** | **$18,928** | **$19,496** |
| **Non-Discretionary Total** | | **$51,330** | **$52,870** | **$54,456** | **$56,090** | **$57,772** |
| **Grand Total** | | **$124,077** | **$125,268** | **$130,817** | **$131,303** | **$134,814** |

The ten year plan was developed in two steps, Long Range Plan Step 1 (LRPS1) which reflects budgeted Capital spend to be proposed in ISR years 1 through 5 and Long Range Plan Step 2 (LRPS2) which reflects Capital Spend to be included in the ISR in years 6 through 10.

LRPS1 includes budgets for specific projects originating from studies such as the Long Range Area Studies, programs like UG cable replacement and URD, blankets like Damage and Failure and Reliability, customer requests, and public requirements.

LRPS2 includes budgets specific for specific projects originating from studies, and inflation projections for years 6 through 10. Inflation is set at 3% for the later year investment projections.

Several factors were taken into consideration while developing the Ten-Year Plan. The following is a breakdown by spending type and rationale.

**Discretionary**

Asset Condition projects are relatively high in years LRPS1 as a result in study-based issue identification and recommendations. This category scales down as various study related projects are completed in later years of LRPS1. Asset Condition spend is expected to continue into LRPS2 in the low to mid $40 million range. This equals approximately $30 million in base asset condition expenditures which includes underground cable work, underground rural development work, inspection and maintenance work, and blanket level efforts plus approximately $12M in specific asset work that may be identified in future study efforts. It is possible that beyond the ten year period, undergound cable and underground rural development work could be reduced as these programs address the majority of assets of concern. However, there is no reduction predicted in the next ten year period.

Like Asset Condition System Capacity and Performance (SC&P) investments are relatively high in LRPS1 as a result of study-based issue identification and recommendations. SC&P levels are expected to continue slightly above $30 million with base investments, which include core blanket work, volt var optimization work, overloaded stepdown and service transformer work, and targeted reliability review work at approximately $14 million and specific projects of $17.5 million per year. The $17.5 million in specific projects was selected as an appropriate estimate for LRPS2 based on the average study based work for LRPS1 and the understanding that loading, voltage, and reliability work will continue to emerge with the current modest growth rates. Although not included in Figure 1, the Company also considered a possible additional increase in SC&P investments as a result of transportation and heating electrification. While advanced sensing and control investments can be used to mitigate the electric vehicle and heat pump impacts, investments may still be necessary. The Company is using an additional $17.5M per year for LRPS2 as a sensitivity to cover possible electrification adoption. This sensitivity level is not intended to represent an upper bound, but to highlight that transportation and heating electrification can significantly impact future investment levels.

Non-infrastructure work, which includes major tools and some telecom investments, are considered to continue at year 5 levels.

**Non-Discretionary**

All non-discretionary projects utilize a specific forecast method for LRPS1 and inflation projections for LRPS2.

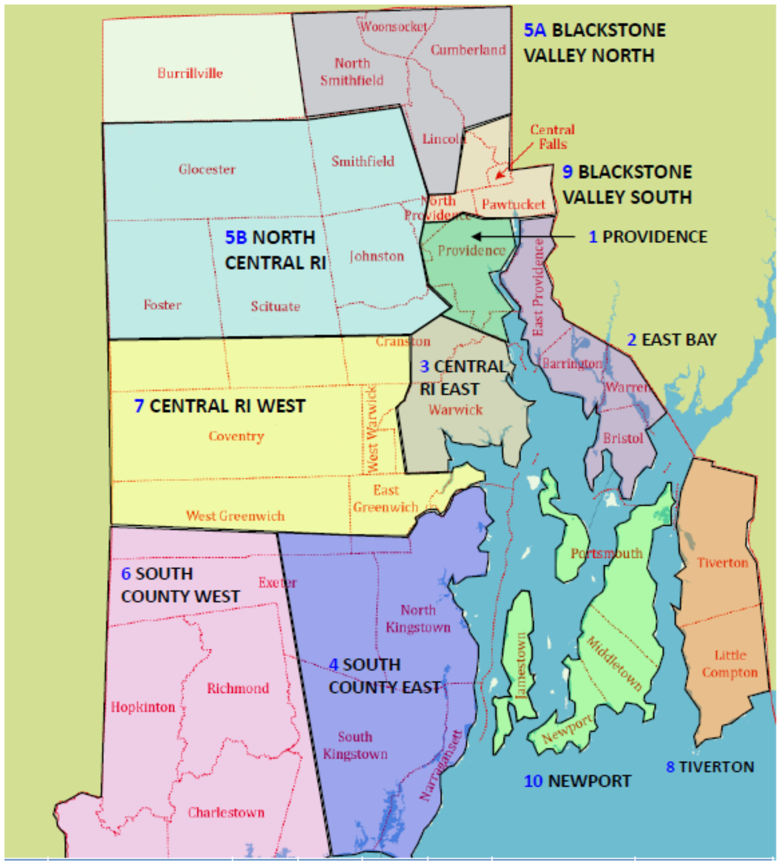
## 3. Area Studies

Area Planning Studies, also known as Area Studies, are more comprehensive technical reviews of the areas within the Company's service territory. Area Study outcomes result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10-to-15- year period.

Areas are defined by distinct geographical and electrical boundaries that have minimal overlap. Studying the system in this manner provides for efficient deployment of engineering resources focused on emerging issues. Should the Company determine that multiple areas have the potential for common system solutions, those areas are combined and/or studied closely together.

An analysis of the state-wide system is only conducted when there is the potential for a fundamental change in the Company's investment strategy. For example, the Company performed a state-wide review to analyze system impacts of load and generation in the Grid Modernization analysis. The analysis is informed by the Area Study solutions and in certain scenarios, identified Area Study solutions may be revised so that the most optimal plan will be executed.

The chart below shows the Company's regional boundaries and study areas.



The chart below shows the statistics by Study area and estimated restudy date.

**Study Area Statistics**

| Study Area | Load (MVA) | % State Load | # Feeders | # Stations | Study Completion Date | Restudy Start |
|---|---|---|---|---|---|---|
| **Providence** | 358 | 19% | 93 | 16 | May 2017 | Tentative 2024 |
| **East Bay** | 147 | 8% | 22 | 7 | August 2015 | Tentative 2024 |
| **Central RI East** | 204 | 11% | 37 | 9 | September 2017 | Tentative 2024 |
| **South County East** | 159 | 9% | 22 | 10 | March 2018 | Tentative 2024 |
| **Blackstone Valley North** | 139 | 8% | 27 | 6 | March 2021 | TBD |
| **North Central RI** | 269 | 15% | 35 | 10 | March 2021 | Aug 2023 |
| **South County West** | 98 | 5% | 14 | 5 | October 2021 | TBD |
| **Central RI West** | 167 | 9% | 29 | 10 | May 2021 | TBD |
| **Tiverton** | 36 | 2% | 4 | 1 | May 2021 | TBD |
| **Blackstone Valley South** | 171 | 9% | 54 | 8 | October 2021 | TBD |
| **Newport** | 105 | 6% | 42 | 11 | December 2021 | Aug 2023 - Partial |
| **Totals** | 1,853 | 100% | 379 | 93 | | |

Restudy start dates may change based on various system assessments that inform the prioritization of future studies.

## 3.1. Future Study Efforts

The Company has explained in past discussion that while the area study process is intended to follow a 5-year restudy timeline, system conditions should ultimately be the deciding factors for restudy. The Company will appropriately schedule the restudies based on emerging loading, reliability, and system performance issues, new customer interconnections, new asset condition and operational issues informed by subject matter experts in Engineering and Operations.

RI Energy is starting study efforts for the following areas:

North Central RI (NCRI)
Although the Northwest RI (NWRI) study was recently completed, the NWRI study was a combination of portions of two other study areas, the western portions of Blackstone Valley North and the northwest portions of North Central RI areas. The southeastern portion of North Central RI includes the town of Johnston which was not included in the NWRI study. Johnston has experienced recent large load and generation applications and interconnections. Furthermore, the Johnston substation has had high utilization (70+% of loading versus ratings) for the recent past. Loading and contingency concerns are emerging for the southeastern portion of the NCRI study area. The recommendations of the NWRI study will be considered to ensure there is no overlap of investments.

Newport
Although recently studied, there are growing concerns about the Gate 2 substation assets within the Newport study area. The Gate 2 substation also has access concerns that significantly affect maintenance

and customer restoration times. Large new customer loads in the southern portion of the study area are putting a strain on limited 4kV capacity.[1]

Providence

The Providence Area Study was last completed in 2017 and the recommendations are still in progress. This effort revisits later period issues identified in the previous study and will build upon the current study recommendations. Specifically, electric facilities located in the East Side of Providence are highly loaded and will likely require wire solutions. A study would be required to determine feasibility of adding a new substation, perhaps from Pawtucket, into the north of the East Side and provide capacity to the area and archive objectives such as the retirement of all overhead 4kV lines.

The Point Street substation, which was noted to remain highly loaded in the previous study, continues to be a concern. Additionally, large load interconnections have occurred /are occurring in the remaining 11kV and 4kV areas placing a strain on those facilities.

The company has identified asset condition issues at the 23kV Admiral Station A study will be required to determine the feasibility of one-for-one replacement, a rebuild of the station for 35kV operation to allow for greater delivery capacity, or other options.

Lastly, there are highly utilized facilities in the western portion of the study area that borders with Johnston and this restudy effort will be coordinated and aligned with the NCRI effort described above.

These issues will be further monitored and could lead to kicking off a new area study potentially in 2024 or 2025.

East Bay

During the East Bay Study an Non-Wires Alternative (NWA) solution was proposed to solve contingency problems at the Bristol Substation. However, after soliciting the market for NWA solutions it was deemed infeasible due to a technically insufficient proposal. Therefore, the Company is choosing to restudy the southern portion of the East Bay area. In addition to the Bristol contingency loading issue, the 23kV assets at the Warren Substation will be reviewed. These issues will be further monitored and could lead to kicking off a new area study potentially in 2024 or 2025.

Central RI East (CRIE)

Drumrock substation asset condition issues raised by Operations need to be reviewed. The Lincoln Ave substation has a high utilization (70+% of loading versus ratings) for the recent past and some feeder contingency issues. The 2222 and 2226 supply lines feeding Warwick substation have contingency issues in the event of an outage of either line. These issues will be further monitored and could lead to kicking off a new area study potentially in 2024 or 2025.

South County East (SCE)

The South County East study area was last studied in 2018. This area is actively being monitored for potential new Quonset Area loads within the next ten years, though the actual loading levels are not confirmed. This coupled with some asset condition/operational concerns with portions of the sub transmission supply system could lead to kicking off a new area study potentially in 2024 or 2025.

[1] The Gate 2 grounding transformer replacement will still be required due to immediate asset needs and the importance of this equipment to the protection system.

### 3.2. Managing Overlap and Avoiding Redundancy

As described above, when the Company determines that multiple areas have the potential for common system solutions, those areas are combined and/or studied closely together. Past examples include: 1) the coordinated study efforts between the Providence and Central RI East study areas in 2017 that resulted in avoidance of a rebuild of the Sockanosett substation to align with the Auburn substation conversion and rebuild; and 2) the Northwest RI Study, which contained the western portions of Blackstone Valley North and the northwest portions of North Central RI areas to sufficiently analyze the Nasonville transformer contingency issue.

Solution redundancy can occur when two separate parallel efforts address the same concern. An example can be a cable replacement program which recommends direct replacement of a cable and a study solution that eliminates the need for that cable. The Company addresses possible redundancy within the study process by gathering program information and aligning the program recommendation with study recommendations and vice versa. The following highlights a number of investments that were avoided as a result on coordinate comprehensive study efforts:

- The Providence Area Study considered the underground cable program and removed a number of cables that were proposed to be reconductored from the program to avoid redundant spending.
- A number of assets at the Sockanosset substation were scheduled to be raised as a result of the March 2010 flood impacts. This rebuild was cancelled with coordination of the Providence Area Study, which recommended the rebuild of the Auburn substation eliminating many of the Sockanosett assets that were to be raised.
- A Phillipsdale transformer was scheduled to be replaced as a result of the former transformer replacement program. This replacement was cancelled as a result of the East Bay Study recommendations which recommended a rebuild of the Phillipsdale substation and changes to the transformer specifications.
- Energy Management System / Remote Terminal Unit (EMS/RTU) work at various 4 kV substations were cancelled as a result of many study area recommendation that converted or eliminated these 4kV stations. Many of these stations would have required significant rebuilds with the EMS/RTU work

### 3.3. Avoiding Early Obsolescence

Early obsolescence can occur when certain devices or technologies are deployed and are replaced by a newer device or technology well before the expected asset life. The focus of this concern is often associated with control and protection systems. As the Company performs each study, subject matter experts are consulted to inform the study of the latest technologies. The technological advancements associated with reclosers and the Companies adoption decisions highlights how early obsolescence is avoided. The Company began the transition to programmable microprocessor recloser controls in early 2010s. Although, the communication details and programming details evolved between 2010 and 2020, the Company was able to install the core recloser and control by the mid 2010s. Many of these were installed as ‘communication ready’, with no actual radio. However, the control cabinet and wiring was setup for various radio plug-ins. Study recommendation through these early years required installation of equipment with the latest sensors, controls, and communication capabilities per standards. As the radio details were determined, the reclosers did not need replacement, simply a radio install in the ready cabinet. Similarly, as programming details evolved, no reclosers needed to be replaced, simply reprogrammed. With diligent consultation and well thought out deployment decisions the Company has avoided early obsolescence with its recloser assets. Similar considerations have occurred for capacitor controls and relays.

Another type of early obsolescence can occur when study efforts do not consider emerging customer trends or public policy programs. For example, the recently completed Newport Study identified asset condition issues at the Merton Substation with a recommendation to rebuild the station. In parallel a grid modernization study, which considered customer adoption of electric vehicles and heating electrification, noted that the Merton Substation should be converted to a higher voltage to accommodate the possible customer adoption. The Company has deferred the Merton project to further investigate this issue. A similar situation arose for the Tiverton substation. The area study identified the need for a new feeder at the Tiverton substation while the grid modernization review indicated two feeders might be required. In this particular example, upon review of the construction details, no change to the current project was necessary. The first new feeder can be installed without compromising the cost or schedule of the future second feeder installation. The second feeder can be installed if and when the customer electrification adoption actually occurs in a cost effective manner.

### 3.4. Process to Identify Opportunities for System Reliability Procurement and Historical Outcomes

The distribution system planning team identifies system needs through area studies, and considers the economic and technical viability of non-wires solutions to each system need identified. The non-wires solution may be considered utility reliability procurement (e.g., conservation voltage reduction, volt-var optimization, utility-owned and operated battery storage) or system reliability procurement (e.g., utility-run or third-party demand response or targeted energy efficiency, third-party owned and operated battery storage). All system reliability procurement solutions are non-wires solutions, but not all non-wires solutions are system reliability procurement solutions.

Engineers screen system needs identified in area studies for the potential viability of a system reliability procurement solution. This screening is fully integrated into the planning process and is part of the normal course of business. Screening criteria have been developed in collaboration with stakeholders and are vetted through regulatory oversight of system reliability procurement.[2] These screening criteria are:

- The system need is not an asset condition issue
    - Electric assets that have reached the end of their lifetimes need to be replaced; a non-wires solution (whether system reliability or utility reliability procurement) cannot resolve an asset condition issue.
- The system need is an eligible system need or optimization

[2] The *2024-2026 System Reliability Procurement Three-Year Plan* will be filed for regulatory review on or before November 21, 2023, in accordance with the Least-Cost Procurement Standards. The Company is not proposing any substantive changes to screening criteria previously approved and applied.

    - Eligible system needs and optimization include load relief, reliability, and supply cost mitigation; if the system need is load relief, the amount of load should not exceed 20% of the total load in the are of the defined need.
- There should be sufficient market interest
    - Rhode Island Energy uses a guideline of the wires solution costing at least $1 million as a proxy for whether a system need is likely to gain sufficient market interest.
- There should be adequate time to implement the system reliability procurement solution
    - Rhode Island Energy uses a guideline of at least 24 months before the start date of the system reliability procurement solution implementation to allow for adequate time to go to market, evaluate proposals, gain necessary approvals, and construct or deploy the system reliability procurement solution.
- Additionally, be the Company's discretion, Rhode Island Energy may pursue a project that does not pass one or more of these screening criteria if there is reason to believe that a viable non-wires solution exists, assuming the benefits of doing so justify the costs.

These screening criteria are applied by the engineering team to all electric system needs and opportunities for optimizing system performance first in area studies and then annually as system needs are considered for action. System needs that pass the screening then advance through steps to solicit and evaluate the viability of system reliability procurement solutions, which would then be proposed via system reliability procurement investment proposals filed alongside but separate from *Electric Infrastructure, Safety, and Reliability Plans* per the Commission's Least-Cost Procurement Standards.

The table below lists previously identified opportunities for system reliability procurement.

History of System Reliability Procurement

| Naming Convention | Associated Area Study | System Need Identified | Cost of Next Best Alternative Utility Reliability Procurement | Year in which RFP was issued for system reliability procurement solution | Types of technology proposed for non-wires solution | Order of magnitude cost of non-wires solution(s) proposed | Status |
|---|---|---|---|---|---|---|---|
| Bristol 51 | East Bay | Contingency Load Reduction – 3MW | $2M | RFP issued 2020 | Energy Storage | $1.1M | Closed – proposal(s) deemed technically insufficient to meet system need |
| Tiverton New Feeder - NWA Pilot | None – Pilot | Load Reduction 1.0MW | $2.9M | No RFP, Pilot executed 2011-2016 in collaboration with OER | Targeted Energy Efficiency, Solar | $3.6M | Closed[3] |
| Tiverton New Feeder | None | Load Reduction 250kW, 1MWH | $2.9M | 2017 | Energy Storage | $60k to $90k annual budget | Closed – Did not proceed. Equipment Delays and Uneconomical. |
| Bonnet 42F1 Feeder | South County East | Load Reduction 1.2MW, 25 MWH/yr for 12 years | $570k | RFP issued in 2018 and reissued in2019 | Energy Storage , Virtual Power Plant with a mix of solar and backup generators | $1.1M-$5.8M | Closed – proposal(s) more costly than the best alternative utility reliability procurement |
| Narragansett 17F2 and 42F1 Feeder | South County East | Load Reduction 1.8MW, 76 MWH/yr for 10 years | $1.6M | 2018 | Energy Storage | $3.8M | Closed – proposal(s) more costly than the best alternative utility reliability procurement |
| South Kingstown 59F3 and 68F2 Feeders | South County East | Load Reduction 3.1MW, 14+18 MWH/yr for 10 years | $1.7M | 2019 | Energy Storage, Virtual Power Plant with a mix of solar and backup generators | $2.3M to $28M | Closed - proposal(s) more costly than the best alternative utility reliability procurement |
| Staples 112W43 Reliability | Blackstone Valley South | High outage frequency and duration averages | Estimate $1.1M | TBD | TBD | TBD | Pending next steps |

[3] http://rieermc.ri.gov/wp-content/uploads/2019/05/national-grid-ri-srp-pilot-2012-2017-summary-report_final.pdf

## 4. Asset Condition Summaries

**Apponaug Long Term Plan**

| | |
|---|---|
| **Distribution Related Project Number(s):** | C087861 Apponaug Long-Term (D-Sub)<br>C087862 Apponaug Long-Term (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Apponaug: 3F1, 3F2 |
| **Voltage(s):** | 12.47kV |
| **Geographic Area Served:** | Cranston, Warwick |
| **Summary of Issues:** | Apponaug consists of a 23 kV station and two 12.47 kV modular feeders. It supplies 15 MW of peak load. The station has a history of operational challenges and asset condition concerns. The major concerns are:<br>• The control building needs major repairs and much of the 23 kV control equipment in the building is obsolete. The building contains both asbestos wiring and asbestos panels.<br>• The 23 kV auto-transfer scheme is obsolete and has a history of mis-operation. This has resulted in customer outages due to its failure to operate.<br>• The voltage regulators are in poor condition and consist of non-standard installation. This non-standard installation makes it very challenging to replace the regulators.<br>• The 23 kV disconnect switches are obsolete, unreliable, and often fail to latch close.<br>• The station has no remote status, control and monitoring of switching devices, transformers, voltage regulation and battery systems (no EMS). |
| **Risks** | The short-term work has addressed some of the station issues, but risks still remain for the Apponaug assets. The recent #4 transformer failure (July 2023), resulting in approximately 1900 customers interrupted, highlights the ongoing risks. Failure of the #3 transformer, of similar vintage to the #4 transformer, would result in similar impacts. Although not currently overdutied, the temporary 23kV reclosers are near the station fault current levels. As described above, the 23kV air-break scheme is unreliable and does not operate consistently. Additionally, the 23kV switches are on condemned wooden structures. Structure or switch failure can result in the loss of both supplies, interrupting approximately 3500 customers served by this station. Any major equipment issues at Apponaug substation result in transfer of customers to the Warwick substation. The transferred load requires disabling that automatic |

| | |
|---|---|
| | transfer at the Warwick substation placing that station's customers at further risk of interruption. With no supervisory control nor analogue data on the Apponaug 15kV class assets, equipment failures and customer interruptions take additional time to troubleshoot and address. Lastly, the existing control house presents worker safety issues concerning asbestos and lead. The historic designation of the building makes addressing these safety issues more complicated than typical. |
| **Recommended Plan** | The recommended short-term plan for Apponaug was to retire the 23k station, remove all 23kV equipment, and install relayed reclosers for transformer protection. This work has been completed.<br><br>The long-term plan is to rebuild the station with two new 23/12.47 kV modular feeders utilizing standard open air modular feeder construction. |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Central RI East Area Study completed September 2017 |

| **Planned Capital Spend ($000)** | **FY 2025** | **FY 2026** | **FY 2027** | **FY 2028** | **FY 2029** | **FY 2030** | **FY 2031** | **FY 2032** | **FY 2033** | **FY 2034** |
|---|---|---|---|---|---|---|---|---|---|---|
| | $400 | $2,415 | $2,375 | $1,213 | $365 | | | | | |

**Centredale Substation**

| | |
|---|---|
| **Distribution Related Project Number(s):** | C087783 Centredale Sub (D-Sub)<br>C087784 Centredale Sub (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Centredale: 50J1, 50J3, 50F2 |
| **Voltage(s):** | 4.16 kV & 12.47kV |
| **Geographic Area Served:** | Centredale |
| **Summary of Issues:** | Centredale is a 23/12.47/4.16kV substation that consists of one 12.47kV feeder and two 4.16kV feeders. The asset condition report identified the following equipment in need of replacement.<br>• 50F2 voltage regulators (clearance issues)<br>• 50F2 station VSA recloser<br>• 23kV air break control equipment<br>• (4) AB motor mechanisms<br>• (4) 23kV air break switches (501, 502, 503, 504) and replace pole structures<br>• (3) 4.16kV breakers are over duty |
| **Risks** | The 4kV circuits out of the Centredale substation are electrically islanded. As described above the 23kV assets are unreliable. Failure of certain insulators, potential transformers, and reclosers have a history of damaging other nearby parts resulting in major repair requirements. Failure of any major 23kV or 4kV asset would result in the approximately 1100 customers out for an extended duration until repairs are made or mobile assets installed. Mobile or spare assets, specifically transformers, can take 24 to 36 hours to install. With no supervisory control nor analogue data, equipment failures and customer interruptions take additional time to troubleshoot and address. Lastly, there are many clearance issues at the station affecting worker safety. In some cases, walking by certain equipment breaks minimum approach values. |
| **Recommended Plan** | Rebuild the substation with two new modular 23kV/12.47kV transformers and two new 12.47 kV feeder positions. The 4kV distribution loads will be converted and the 4.16kV equipment will be retired. This will eliminate the 4.16KV island and results in approximately 95 kW of peak loss savings and a yearly loss energy savings of approximately 358,000 kWH |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Northwest RI Area Study completed March 2021 |

| **Planned Capital Spend ($000)** | **FY 2025** | **FY 2026** | **FY 2027** | **FY 2028** | **FY 2029** | **FY 2030** | **FY 2031** | **FY 2032** | **FY 2033** | **FY 2034** |
|---|---|---|---|---|---|---|---|---|---|---|
| | $900 | $2,272 | $3,316 | $1,176 | $250 | | | | | |

**Phillipsdale Substation**

| | |
|---|---|
| **Distribution Related Project Number(s):** | C074427 Phillipsdale (D-Sub)<br>C087367 Phillipsdale (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Phillipsdale: 20F1, 20F2 |
| **Voltage(s):** | 12.47kV and 23kV |
| **Geographic Area Served:** | East Providence |
| **Summary of Issues:** | Phillipsdale consists of a two transformer 115/23kV substation that supplies a one transformer 23/12.47kV station and several industrial customers with a combined peak load of approximately 30MW. The following concerns exist at this station:<br>• The power transformers are 1960's vintage. T1 transformer is the only transformer in the system with attached coolers. T2 transformer shows significant signs of aging<br>• The 23kV transformer grounding reactors are concrete encased with small visible cracks. There is no spare grounding reactor to respond to a failure.<br>• Transformer 23kV disconnect switches are non-gang operated and are not readily accessible to operate.<br>• The 23kV breakers are no longer reliable.<br>• A timed scheme at the station prevents bus ties from occurring unless disabled. This scheme is complex to operate and is unreliable.<br><br>The Phillipsdale 23/12.47kV substation consists of non-standard equipment and construction. The following concerns exist at this station:<br>• A single Load-Tap-Changing (LTC) transformer supplies two 12.47kV feeders with pole mounted line reclosers. The LTC is no longer operable and locked in position. The reclosers have a history of poor reliability.<br>• The distribution voltage from this station only phases with Waterman Avenue feeders. This results in a pocket of load being out of phase with the rest of the system and makes maintenance of the station equipment challenging.<br>• The LTC transformer is a delta/zig-zag with no system spare and only a single mobile transformer in the system suitable for this location. A transformer failure would tie up this mobile for an extended period.<br><br>The Waterman 23/12.47kV station consists of two 10/12.5 MVA transformers supplying four feeders. A number of concerns exist at this station:<br>• The 23kV air-break switch is obsolete. |

| | |
|---|---|
| | • The transformers have sacrificial high side air breaks switches which are obsolete.<br>• The 23kV capacitor bank has an obsolete vacuum switch.<br>• The 23kV equipment is mounted on wood poles.<br><br>Significant portions, 7.5 miles, of the 23kV sub-transmission system consists of aged pole plant and small wire installed on rights-of-way and congested public roadways. Portions of the right-of-way are along railroads requiring special permits resulting in additional resources and time for planned and emergency work. |
| **Risks** | Noting the asset issues above, planned or emergency work in and around the Phillipsdale Substation is problematic. First, the out-of-phase configuration makes any planned and emergency work durations longer than typical. Additionally, customer interruptions occur during setup and conclusion of any work. Secondly, there are a number of major components at the Phillipsdale Substation that upon failure result in immediate and long term risks to the system. For example, if either 23kV grounding reactor fails, there is no spare. If the reactor is bypassed, there is a risk of high fault current that could severely damage the surrounding breakers. Alternately, the station can be placed on one transformer while a new reactor is procured and installed. This places all the area customers at an elevated reliability risk for the greater than 1 year procurement period. Another example is failure of the #3 transformer. If this transformer fails, the customers associated with the 20F1 and 20F2 circuits would be transferred to other area circuits. With no spare[4] for the #3 transformer and current procurement lead times approximately 3 years, those customers plus the customers on the transferred feeders would face increased risk to interruptions until the new transformer can be procured and installed. Any other major equipment failure during this 3 year period would result in significant customer interruptions. Planned work and maintenance would be limited in this area and load and generation interconnections may have to wait until the system is restored to its normal configuration. Existing interconnected generation may be required to be offline for extended periods of time. Similarly, failures of the #1 or #2 transformers would place the Narragansett Bay Commission and all the 23kV customers on a single source until the transformer can be repaired. While a spare transformer exists, the spare would be tied up for the 3 year replacement time exposing the rest of the system to risk. Similarly, failure of either of the 23kV lines sourced from this station places the customers at an elevated reliability risk. These lines are difficult to access with portions along railroad rights-of-way that require permits for planned and emergency work. Repair durations are much higher than other lines and as a result, the 23kV lines have reliability statistics higher than regulatory and IEEE targets Finally, there are a |

[4] This is a small spare. The spare would lessen the risk but not eliminate them. The points remain valid.

| | |
|---|---|
| | clearances issues, particularly with the breakers, that increase planned and repair work durations.<br><br>As a specific, recent example to the risks described above, on Wednesday May 24th, 2023 a substation crew reported to Phillipsdale Substation to perform maintenance on the 3TR 2 bus breaker. While the crew was switching the breaker out to establish clearance for the work, an insulator broke on the 3TR 2B-2 disconnect. The crew worked out a plan with the Control Center to expand the worker protection zone[5] to make repairs. One of the new tag points, the 1-2 load break, would not operate properly due to failed load break bottles. The clearance had to be expanded again beyond the 1-2 load break and it was not possible to make repairs. The crew was able to get the switch closed but had to install a hold tag due to broken linkage on one phase. This switch can no longer be operated. The insulator on the 3TR 2B-2 disconnects was repaired and placed back in service. The planned 4 hour job turned into a 14 to 16 hour job with significant overtime hours required. The planned breaker maintenance was not completed. |
| **Recommended Plan** | Replace the out of phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station. Initial construction would consist of a single 40MVA LTC transformer, straight bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a ties breaker, eight feeder positions, and two 7.2 MVAR two-stage capacitor banks. Upon completion of the station rebuild, convert the two remaining 23kV customers to 12.47kV and retire the 23kV station. |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | East Bay Area Study completed August 2015 |

**Planned Capital Spend ($000)**

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| $200 | $6,208 | $7,810 | $2,018 | $514 | | | | | |

[5] When a protection zone is expanded, it includes and deenergizes greater portions of the system with sectionalization and protective devices which places greater strain on the system and increases customer reliability risks.

**Tiverton Substation**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TIV0001 Tiverton Sub (D-Sub) |
| **Substation(s) / Feeder(s) Impacted:** | Tiverton: 33F1, 33F2, 33F3, 33F4 |
| **Voltage(s):** | 12.47 kV |
| **Geographic Area Served:** | Tiverton |
| **Summary of Issues:** | Tiverton is a two transformer 115/12.47kV substation that consists of four feeders. The area is bounded by the ocean on its west and south, by Fall River (MA) to the north, and by non-Rhode Island Energy territory to its east in the town of Westport.<br><br>The Tiverton Substation has the following asset condition concerns:<br>• The T1 transformer has an oil leak present in the area of the oil pump<br>• The 115kV MOABs are sacrificial air break switches. The arcing horns are a weak spot, and these are not an ideal method of protection of the transformers.<br>• The 12.47kV VCB breakers are nearing the end of their designed operational lifecycle and showing rusting issues.<br>• The control house is infested with mice and could use additional rodent proofing. The control house door needs to have push panic bars installed for worker safety.<br>• Animal protection needs to be addressed by adding guards on the UG cable getaways, adding an animal electric fence, and adding transformer 12.47kV bushing guards.<br>• Obsolete relays and transformer protection |
| **Risks** | The greatest risk at the Tiverton substation is with the protection equipment. The relays are obsolete, and the reclosing relays are unreliable. Combined with the rodent issue, if a protection system or relay fails, there is a risk of greater than normal customer impacts. For instance, two feeders in one bay could be affected if the tie breaker protection fails or two feeders off of one bus could be affected if the bus protection fails. Supervisory control of the reclosing relays is currently unreliable. This requires crew dispatch and extends the duration that equipment is in an abnormal configuration. Tiverton also has transformer risks. The transformers have been in service approximately 45 years. Currently one transformer is undersized and the automatic transfer scheme is disabled during the summer months. If the larger transformer fails, approximately 3 to 5 megawatts, 1000 to 1500 customers, could be interrupted until mobile or spare equipment can be deployed. Lastly, Tiverton contains 1980s vintage direct |

| | |
|---|---|
| | buried cross linked polyethylene getaway cables. These cables are in the top 15% of the cables identified within the Underground Cable Replacement Program. |
| **Recommended Plan** | The recommended plan replaces all equipment with asset condition issues. The asset condition replacement work includes the replacement of two (2) 115kV MOAB sacrificial air break switches, Six (6) 12.47kV VCB breakers, three (3) sets of voltage regulators (33F1, 33F2, 33F4), rodent proofing and panic bars for the control house, and the addition of animal protection. (The transformer will be further evaluated and are not scheduled for replacement at this time.) |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Tiverton Area Study completed May 2021 |
| **Planned Capital Spend ($000)** | |

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| $75 | $393 | $786 | $786 | $393 | $187 | | | | |

**Central RI West D-Line Asset Condition Issues**

| | |
|---|---|
| **Distribution Related Project Number(s):** | C088052 Division St 61F2 Reconductoring (D-Line)<br>C088055 Hopkins Hill 63F6 Feeder Tie (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Division St: 61F2<br>Hopkins Hill: 63F6<br>Chase Hill: 155F8 |
| **Voltage(s):** | 12.47kV |
| **Geographic Area Served:** | West Greenwich, East Greenwich, Coventry, Exeter, West Warwick |
| **Summary of Issues:** | The Division St. 61F2 circuit has a 1.6 mile stretch along South Pierce Road and Howland Road in East Greenwich, RI with conductor in poor condition due to many splices.<br><br>The Chase Hill 155F8 tie with the Hopkins Hill 63F6 on New London Turnpike in Exeter, RI consists of approximately 4,700' of difficult to access conductor in poor condition. |
| **Risks** | The 61F2, 155F8, and 63F6 circuits have five year average circuit frequencies of 1.0 , 2.56, and 2.15 respectively, well above Company targets. Circuit durations are 64, 225, and 193 minutes respectively also above Company targets. Reliability is expected to continue at these levels. |
| **Recommended Plan** | The recommended plan to resolve the conductor asset concern on 61F2 is reconductor this 1.6 miles stretch along South Pierce Road and Howland Road with 477 Al SPCR.<br><br>The recommended plan to resolve the tie issue between 155F8 and 63F6 is to remove this conductor and relocate the tie to Nooseneck Hill Road. This requires the installation of a new 2 way duct bank with 6" ducts for 800' of single phase 1000 Cu underground conductor that will then rise up to an additional 4,800' of 477 AL SPCR to the normally open load break switch that serves as the tie to the Hopkins Hill 63F6 feeder. |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Central RI West Area Study completed May 2021 |

**Planned Capital Spend ($000)**

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| $424 | $554 | $1,258 | $650 | $390 | $424 | | | | |

**Central RI West Equipment Replacement**

| | |
|---|---|
| **Distribution Related Project Number(s):** | C088046 Coventry Sub Relocation (D-Sub)<br>C088047 Hope Equipment Replacement (D-Sub)<br>C085405 Division St T1 & T2 Replacement (D-Sub)<br>C088006 Anthony Equipment Replacement (D-Sub)<br>C088007 Natick Equipment Replacement (D-Sub)<br>C088008 Warwick Mall Equipment Replacement (D-Sub) |
| **Substation(s) / Feeder(s) Impacted:** | Coventry: 54F1<br>Hope: 15F1, 15F2<br>Division St: 61F1, 61F2, 61F3, 61F4<br>Anthony: 64F1, 64F2<br>Natick: 29F1, 29F2<br>Warwick Mall: 28F1, 28F2 |
| **Voltage(s):** | 12.47kV |
| **Geographic Area Served:** | West Greenwich, East Greenwich, Coventry, Exeter, West Warwick |
| **Summary of Issues:** | The Central RI West area is made up of six 115kV transmission lines, four 34.5 kV, and three 23kV sub-transmission lines supplying the ten substations in the area.<br><br>A primary area of concern is with the Drumrock 23kV system. Safety and asset conditions issues at the Anthony #64, Warwick Mall #28, and Natick #29 substations exist including the need to replace transformers, air breaks, circuit breakers, regulators, lightning arresters and various other equipment.<br><br>The area also has additional safety and asset conditions issues at Coventry #54, Hope #15, and Division St #61. These concerns include transformers, air breaks, and lightning arrestors. |
| **Risks** | Anthony – The 23kV devices are obsolete and unreliable, including the wooden structures. Failure of certain arrestors and insulators have a history of damaging other nearby parts resulting in major repair requirements. A 23kV equipment event could affect both supply lines, impacting approximately 2300 customers until field switching can be completed or repairs are made. For failure of either transformer, approximately 1000 to 1300 customers will be affected until field switching can be completed or mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Anthony substation contains 1970s vintage direct buried cross linked polyethylene getaway cables. The 64F2 is in the top 10% of the cables identified within the Underground Cable Replacement Program.<br><br>Natick - The 23kV devices are obsolete and unreliable. Failure of certain arrestors and potential transformers have a history of damaging other nearby |

| | |
|---|---|
| | parts resulting in major repair requirements. A 23kV equipment event could affect both supply lines, impacting approximately 2300 customers until field switching can be completed or repairs are made.<br><br>Warwick Mall – The 23kV devices are obsolete and unreliable. A 23kV equipment event could affect both supply lines, impacting approximately 460 customers until field switching can be completed or repairs are made. The Warwick Mall feeders serve an electric island of predominantly commercial customers. Failure of the #1 transformer would require transfer of all customers to the 28F2 circuit with field switching until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Should the regulators fail, they can be bypassed with bus reconstruction. The customers would be without voltage regulation until replacements can be procured which can be up to one year.<br><br>Coventry – The 23kV devices are obsolete and unreliable, including the wooden structures. A 23kV equipment event could affect the single supply line, impacting approximately 2700 customers until field switching can be completed or repairs are made. Failure of the #1 transformer would require transfer of all customers to nearby circuits until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Similar impacts could occur but at a lesser duration for failure of the 12kV load break switch. Switching is limit during peak periods due to distribution line capacity constraints.<br><br>Hope – The 23kV devices are obsolete and unreliable, including the source selector switch. Failure of certain arrestors and potential transformers have a history of damaging other nearby parts resulting in major repair requirements. A 23kV equipment event could affect the single supply line serving each modular feeder, impacting approximately 1200 to 2400 customers until field switching can be completed or repairs are made. Failure of the #1 transformer would require transfer of the 15F1 customers to nearby circuits until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years.<br><br>Division St. – The 34kV devices are obsolete, unreliable, and cannot be used to deenergize the transformer resulting in complex and extended switching. Failure of certain arrestors and potential transformers have a history of damaging other nearby parts resulting in major repair requirements. During peak periods, the automatic transfer is disabled. A 34kV equipment event or transformer failure could affect either bus, impacting approximately 1100 to 2600 customers until field switching can be completed or repairs are made. There are no spare transformers available for the #1 and #2 transformers. For a transformer failure, |

<table>
<tr><td></td><td>the system would remain reconfigured for up to 3 years. The Division St. customers plus the customers on the transferred feeders would face increased risk to interruptions until the new transformer can be procured and installed. Any other major equipment failure during this 3 year period would result in significant customer interruptions. Planned work and maintenance would be limited in this area and load and generation interconnections may have to wait until the system is restored to its normal configuration. Existing interconnected generation may be required to be offline for extended periods of time.</td></tr>
<tr><td>Recommended Plan</td><td>The recommended plan is to address the asset conditions at Anthony #64, Natick #29, and Warwick Mall #28, Coventry #54, Hope # 15, Division St #61. The required replacement work at each station is shown below.<br><br>Anthony #64<br>• Replace the 23 kV bus structures<br>• Replace two (2) OCBs<br>• Replace transformer No. 1 and No. 2<br>• Replace two (2) 23 kV air breaks<br>• Replace 23kV capacitor bank<br>• Replace lightning arresters<br>• Remove all retired 4 kV equipment<br>• Install an animal fence<br><br>Natick #29<br>• Replace the 29F2 regulators<br>• Replace three (3) air breaks - 2266, 2230, and 66-30<br>• Replace the No. 1 and No. 2 station service transformers<br>• Replace the brown porcelain station post insulators and vintage dead-end bells<br><br>Warwick Mall #28<br>• Replace transformer No. 1<br>• Replace three (3) air breaks - 2266, 2230, and 30-66<br>• Replace the 28F2 regulators – all three (3) phases<br>• Replace the 28F1 regulators – B & C phases<br>• Replace five (5) sets of HPL air break disconnects<br>• Replace the No. 1 and No. 2 station service transformers<br>• Replace lightning arresters<br><br>Coventry #54<br>• Replace air breaks/load breaks 541, 542, & 546<br>• Replace all lightning arresters</td></tr>
</table>

| | |
|---|---|
| | • Replace the No. 1 transformer<br><br>Hope #15<br>• Replace the T1 transformer<br>• Replace all lightning arresters and PTs<br><br>Division St. #61<br>• Replace both existing transformers – No. 1 and No. 2<br>• Replace air breaks 3311-2T and 3312-1T<br>• Replace all lightning arresters<br>• Install animal protection |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Central RI West Area Study completed May 2021 |
| **Planned Capital Spend ($000)** | see below |

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| 3,278 | $5,363 | $8,138 | 1,888 | | | | | | |

**Blackstone Valley South 4kV Substation Retirements**

| | |
|---|---|
| **Distribution Related Project Number(s):** | BSVS001 Crossman St #111 Sub (D-Sub)<br>BSVS002 Crossman St #111 Sub (D-Line)<br>BSVS003 Central Falls #104 Sub (D-Sub)<br>BSVS004 Central Falls #104 Sub (D-Line)<br>BSVS005 Centre St #106 Sub (D-Sub)<br>BSVS006 Centre St #106 Sub (D-Line)<br>BSVS007 Pawtucket #148 Sub (D-Sub)<br>BSVS008 Pawtucket #148 Sub (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Crossman: 111J1, 111J3<br>Central Falls: 104J1, 104J5, 104J7<br>Centre St: 106J1, 106J3, 106J7<br>Pawtucket #2: 148J1, 148J3, 148J5<br>Valley: 102W41, 102W50, 102W51, 102W52<br>Pawtucket: 107W62, 107W80, 107W81, 107W85 |
| **Voltage(s):** | 4.16kV and 12.47kV |
| **Geographic Area Served:** | Central Falls, Pawtucket |
| **Summary of Issues:** | Crossman St is a single transformer 13.8/4.16kV substation that consists of two feeders. Central Falls is a two transformer 13.8/4.16kV substation that consists of four feeders. Centre St is a single transformer 13.8/4.16kV substation that consists of three feeders. Pawtucket #2 is a two transformer 13.8/4.16kV substation that consists of four feeders.<br><br>There are numerous concerns with the safety and asset conditions issues at the Crossman St, Central Falls, Centre St, and Pawtucket #2 Substations. The concerns on these 4kV substations include transformers, metal clad switchgears, feeder breakers, and lightning arrestors. There are also asset conditions concerns on the distribution lines. On average, over 55% of the poles are older than 40 years old. |
| **Risks** | The four 4kV stations form an electric island in the Central Falls and Pawtucket area. Although risks are listed separately, the risks can compound for long duration reconfigurations associated with major equipment failures. The distribution lines that tie these stations have a majority of pole plant greater than 40 years.<br><br>Crossman - The 13kV devices are obsolete and unreliable, including the source selector switch and the wooden structures. A 13kV equipment event could affect both supplies to this station, impacting approximately 2600 customers until field switching can be completed or repairs are made. Failure of the #1 transformer would require transfer of the all the customers to nearby circuits until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be |

| | |
|---|---|
| | unavailable for other system needs for approximately 3 years. Similar risks exist for the 4kV metal clad switchgear. For extended duration reconfigurations, emergency conversions may be necessary.<br><br>Central Falls - The #1 and #2 transformers and the 4kV metal clad switchgear are obsolete and unreliable. During peak periods, the automatic transfer is disabled. A transformer failure could affect either bus, impacting approximately 1100 to 1300 customers until field switching can be completed or repairs are made. Metal clad failure could affect all 2400 customers. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. There is no supervisor indication or control at this station, making troubleshooting and repairs more complicated. For extended duration reconfigurations, emergency conversions may be necessary.<br><br>Centre St - The #1 and the 4kV metal clad switchgear are obsolete and unreliable. A transformer or metal clad event could affect the single supply line, impacting approximately 2000 customers until field switching can be completed or repairs are made. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. For extended duration reconfigurations, emergency conversions may be necessary.<br><br>Pawtucket #2 - The #1 and #2 transformers and the 4kV metal clad switchgear are obsolete and unreliable. A transformer failure could affect either bus, impacting approximately 400 to 1300 customers until field switching can be completed or repairs are made. Metal clad failure could affect all 1700 customers. There is a transfer trip scheme for the hydro generator that complicates switching and restoration. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Transformer failures can also result in environmental issues associated with the deluge system. For extended duration reconfigurations, emergency conversions may be necessary. |
| **Recommended Plan** | The recommended plan is to convert the 4.16kV distribution feeder load to 13.8kV and transfer to surrounding 13.8kV feeders. The surrounding 13.8kV feeders are supplied by the Valley and Pawtucket Substations. Once the transfers and conversions are complete, all the equipment at the substation will be retired and removed. These conversions result in approximately 385 kW of peak loss savings and a yearly loss energy savings of approximately 1,444,000 kWH |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Blackstone Valley South Area Study completed October 2021 |

| Planned Capital Spend ($000) | FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| | $1,044 | $2,017 | $2,457 | $2,126 | $386 | | | | | |

**Other Area Study Projects – Asset Condition - Newport**

| | |
|---|---|
| **Distribution Related Project Number(s):** | NWPT001 Dexter #36 Equipment Replacement (D-Sub)<br>NWPT002 Gate II Equipment Replacement (D-Sub)<br>NWPT003 Hospital #146 Equipment Replacement (D-Sub)<br>NWPT005 Eldred 45J3 Reconfiguration (D-Line)<br>NWPT006 Dexter 36W44 Asset Replacement (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Dexter: 36W41, 36W42, 36W43, 36W44<br>Gate II: 38J2, 38J4<br>Hospital: 146J2, 14J4, 146J12, 146J14<br>Eldred: 45J3<br>Merton: 51J2, 51J12, 51J14, 51J16 |
| **Voltage(s):** | 4.16kV and 13.8kV |
| **Geographic Area Served:** | Jamestown, on Conanicut Island, Middletown, Newport, and Portsmouth, on Aquidneck Island, Prudence Island. |
| **Summary of Issues:** | The area has numerous concerns with the safety and asset conditions at Dexter #36, Gate 2 #38, and Hospital #146. These concerns include circuit breakers, transformers, switch gear, and lightning arrestors.<br><br>The Eldred 45J3 and the 4 kV section of the 36W44 on Prudence Island have numerous asset condition and safety concerns. |
| **Risks** | Dexter - Failure of a 13kV circuit breaker will affect the relevant circuit, impacting approximately 1700 to 2100 customers until field switching can be completed or repairs are made. The system would be reconfigured for approximately 6 weeks.<br><br>Gate II – Without the grounding bank, there is no fault current source for ground faults and the protection system will not work as designed. The system would require substantial reconfiguration to put the transformer in sevice without the grounding bank. As a result, this could lead to customer interruptions while the system is rebuilt. After the system is reconfigured, all the area customers will be at an elevated reliability risk for the greater than 1 year procurement period. Additionally, emergency or planned work at this station requires substantially longer durations than typical as a result of Navy access requirements.<br><br>Hospital - The #1 and the 4kV metal clad breakers are obsolete and unreliable. A transformer event could affect one of the supply lines, impacting approximately 600 customers until field switching can be completed or repairs are made. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Failure of a 4kV circuit breaker will affect the |

<table>
<tr><td></td><td>relevant circuit, impacting approximately 600 customers until field switching can be completed or repairs are made. The system would be reconfigured for approximately 6 weeks.<br><br>Eldred – The customers served from the Eldred substation currently experience low voltage issues during peak periods. The voltages issues will continue without this asset work which will improve circuit configurations to imrpove voltage.<br><br>Dexter 36W44 - The customers served from this circuit currently experience low voltage issues during peak periods. The voltages issues will continue without this asset work which will improve voltage.</td></tr>
<tr><td>Recommended Plan</td><td>The recommended plan is to address the asset conditions at Dexter #36, Gate 2 #38, and Hospital #146. The required replacement work at each station is shown below.<br><br>Dexter #36:<ul><li>Replace the existing 13.8 kV, AMCBs, 364T, 36W41, 36W42, 36W43, and 36W44 with VCBs</li></ul>Gate 2 #38:<ul><li>Replace the existing 23 kV zigzag grounding transformer to address asset condition issues.</li></ul>Hospital # 146:<ul><li>Replace the existing 23/4.16 supply transformers, 461 and 462 with two (2) 2.8/35 MVA 23/4.16 kV load-tap-changing transformers. The existing 461 transformer will be rebuilt and refurbished and stored as a spare.</li><li>Replace all the existing air-magnetic circuit breakers, 146J2, 146J12, 146J4, 146J14, and 4600, with VCBs.</li></ul>Eldred 45J3:<ul><li>2,700 circuit feet of single phase overhead primary to be upgraded to 3 phase on Beach Ave</li><li>550 circuit feet of underground single phase primary to be upgraded to 3 phase</li><li>Replace capacitor control with an advanced control to allow voltage override on pole 2 Beach Road</li><li>Rephase several single phase taps on North Road and Sloop Street</li><li>Install 3 single phase 76.2 kVA regulators on pole #135 North Road, Jamestown</li></ul></td></tr>
</table>

<table>
<tr><td></td><td>Dexter 36W44:<ul><li>Reroute the 4 kV overhead primary along the Navy R.O.W. by installing ~1620 circuit feet of 477 Al overhead 3 phase conductor from pole #95 Cliff Road to pole #2-90 Narragansett Pri. Road</li><li>Remove the existing recloser pole #95 Navy R.O.W. and install on Cliff Road</li><li>Reconductor ~3,000 circuit feet of existing #6 Cu overhead 3 phase primary with 3 phase overhead 477 AL from pole # #2-90 Narragansett Pri. Road to pole # 24 Narragansett Pri. Road</li></ul></td></tr>
<tr><td>Alternative Plans</td><td>See area study report for alternative plans.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>Newport Area Study completed December 2021</td></tr>
<tr><td>Planned Capital Spend ($000)</td><td><table><tr><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th><th>FY 2028</th><th>FY 2029</th><th>FY 2030</th><th>FY 2031</th><th>FY 2032</th><th>FY 2033</th><th>FY 2034</th></tr><tr><td>$766</td><td>$3,253</td><td>$3,482</td><td>$296</td><td></td><td></td><td></td><td></td><td></td><td></td></tr></table></td></tr>
</table>

**Kingston Equipment Replacement – Asset Condition - Newport**

| | |
|---|---|
| **Distribution Related Project Number(s):** | NWPT004 Kingston #131 Equipment Replacement (D-Sub) |
| **Substation(s) / Feeder(s) Impacted:** | Kingston: 131J2, 131J4, 131J6, 131J12, 131J14 |
| **Voltage(s):** | 4.16kV |
| **Geographic Area Served:** | Newport |
| **Summary of Issues:** | The Kingston Substation area has numerous concerns with the safety and asset conditions. These concerns include circuit breakers, transformers, switch gear, and lightning arrestors. |
| **Risks** | Kingston - The 23kV devices are obsolete and unreliable. Failure of certain arrestors have a history of damaging other nearby parts resulting in major repair requirements. A 23kV equipment event could affect the single supply line, impacting approximately 3000 customers until field switching can be completed or repairs are made. Failure of the #1 and #2 transformers or #1 and #2 4kV metal clad switchgears would affect approximately 2200 and 800 customers respectively. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. |
| **Recommended Plan** | The recommended plan is to address the asset conditions at Kingston #131 through a station rebuild.<br><br>Kingston #131:<br>• Replace TR 311 and TR 312 transformers<br>• Replace the existing 23 kV switchgear and reclosers with a 10 position, VCB, breaker and a half scheme, switchgear line up (Six (6), 23 kV circuits, two (2) Capacitor banks, and two (2) transformers). Eight (8) - 23 kV circuit positions<br>• Use five (5) initially for 23 kV circuits<br>• 38K21 from Gate 2-Kingston, 38K21 from Kingston-Hospital T2 transformer, will become radial<br>• Replace the existing 4 kV switchgear with a twelve (12) position, vacuum circuit breakers in a breaker and a half scheme switchgear, with two (2) transformers, six (6) feeders, two (2) future capacitor banks, and two (2) spares (Existing Kingston 131J2, 131J4, 131J12 and 131J14) |
| **Alternative Plans** | See area study report for alternative plans. |
| **Long Range Plan Alignment** | Newport Area Study completed December 2021 |

| Planned Capital Spend ($000) | FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| | $400 | $3,361 | $8,403 | $1,681 | $2,961 | | | | | |

**5. System Capacity & Performance Summaries**

**Fault Location Isolation & Service Restoration (FLISR)**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | All |
| **Voltage(s):** | Distribution level voltage |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | One of Rhode Island Energy's primary goals is to ensure a reliable electric system. The main measurement criteria for reliability are System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). These system level criteria can be calculated on a circuit level, CKAIFI and CKAIDI, to find circuits or portions of the electric system performing below acceptable levels. For example, 25% to 30% of the total circuit population have a 5-year average CKAIFI and CKAIDI greater than the regulatory targets of 1.05 and 71.9 respectively. The percent of circuits with poor reliability increases to over 40% when considering a Company frequency target of 0.88. |
| **Recommended Plan** | This program will address the circuit specific reliability issues focusing on the current worst performers. To obtain the greatest opportunity for recloser benefits, the circuit ranking will also be influenced by line exposure distance, existing sectionalization, customers experiencing multiple interruptions (CEMI), distributed generation penetration, and ongoing construction activities. |
| **Current Status and Expected In-Service Date** | This program will begin in FY 2025 and be implemented over five years. |
| **Alternatives:** | Do Nothing: Without this program, the customers on these circuits will continue to experience poor reliability performance. |
| **Long Range Plan Alignment** | This program, which uses advanced reclosers in a FLISR scheme, creates a refined solution opportunity for future study recommendations. This refined use of reclosers will be incorporated into future study efforts as a possible tool. Study recommendations which make use of FLISR techniques will be aligned with this program to avoid redundancy and early obsolescence. |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | This program will be aligned with other reliability based programs such as the CEMI 4+ Program and the ERR program. | | | | | | | | | |
| **Planned Capital Spend ($000)** | **FY 2025** | **FY 2026** | **FY 2027** | **FY 2028** | **FY 2029** | **FY 2030** | **FY 2031** | **FY 2032** | **FY 2033** | **FY 2034** |
| | $7,426 | $22,441 | $17,314 | $17,833 | $18,368 | | | | | |

**Electromechanical Relay Upgrades**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | All |
| **Voltage(s):** | Distribution level voltage |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | Generation, transmission, and distribution systems continuously evolve. The equipment monitoring and protecting the power system must also evolve to meet the reliability expectations of customers. Most electromechanical relays 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 the problem and finding a fault located on the power system. Implementation of digital relays will reduce the amount of relays in the system, provide fault/event record data, allow for remote access to program relays or review fault records, are self-monitoring, and will allow for greater flexibility by offering a wide range of protection settings to help coordinate with other devices. |
| **Recommended Plan** | The proposed investment to upgrade approximately 205 electromechanical relays to digital relays. Electromechanical relays associated with the 34kV, 23kV and 15 kV class distribution system have been inventoried and assigned to one of five categories based upon upgrade complexity and ease of replacement.<br>• Category 1: These relay replacements will utilize the existing PPL standard where the relays come pre-wired within an outdoor enclosure. Using an existing standard will allow for quick implementation.<br>• Category 2: These relay replacements will require a new standard to be developed due to the substation equipment being incompatible with the PPL relay standard described in Category 1. These relays will be installed within the breaker itself as opposed to being in a separate enclosure.<br>• Category 3: These relay replacements will require a new standard to be developed and is expected to be finalized after the Category 2 standard. This new standard will be for substations that have indoor circuit breakers and relay panels where a full relay switchboard panel design is required.<br>• Category 4: These relay replacements will require the station to be |

| | |
|---|---|
| | rebuilt or relocated due to existing space constraints within the substation yard making it not feasible to replace the relays within the same footprint. Due to the complexity of this work, these relays will be replaced after 2028.<br>• Category 5: This category includes all existing digital relays that will need to be reprogrammed to include additional safety and data gathering capabilities. This reprogramming includes, but is not limited to, adding hot line tag and various SCADA indications on why the device tripped for FLISR. |
| **Current Status and Expected In-Service Date** | This program will begin in FY 2025 and be implemented over a five to ten year+ period. |
| **Alternatives:** | Do Nothing: Without this program, the relays will become inaccurate and unreliable. This will lead to additional customer and equipment outages. |
| **Long Range Plan Alignment** | Consideration of this program will be included in future study recommendations and ongoing substation projects. |
| **Planned Capital Spend ($000)** | |

| **FY 2025** | **FY 2026** | **FY 2027** | **FY 2028** | **FY 2029** | **FY 2030** | **FY 2031** | **FY 2032** | **FY 2033** | **FY 2034** |
|---|---|---|---|---|---|---|---|---|---|
| $1,166 | $603 | $1,267 | $2,513 | $1,263 | | | | | |

**Other Area Study Projects – System Capacity & Performance – East Bay**

| | |
|---|---|
| **Distribution Related Project Number(s):** | EB00001 Bristol (D-Sub)<br>EB00002 Bristol (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Bristol 51F1, 51F2, 51F3 |
| **Voltage(s):** | 12.47kV |
| **Geographic Area Served:** | Bristol, Warren |
| **Summary of Issues:** | Bristol is a two transformer substation that consists of three feeders. One of the transformers is supplied by 115kV and the second transformer is supplied by 23kV from the Warren Substation. The Bristol area is electrically isolated from East Providence and Barrington area. There are no feeder ties between these areas because of the Barrington River. The river forms a natural barrier that makes feeder ties between the areas neither practical nor economical.<br><br>There are normal and contingency capacity concerns on the four feeders. The 51F2 and 51F3 feeders are projected to be at the SN rating in 2030 and all three feeders exceed contingency load-at-risk criteria. |
| **Recommended Plan** | The recommended plan is to add a fourth feeder to the Bristol Substation. The addition of a fourth feeder will provide normal and contingency support to the Bristol and Warren feeders. |
| **Alternative Plans** | See area study report for alternative plans. |

**Planned Capital Spend ($000)**

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| $84 | $378 | $378 | | | | | | | |

**Other Area Study Projects – System Capacity & Performance – Newport**

| | |
|---|---|
| **Distribution Related Project Number(s):** | NWPT007 Newport 203W5 (D-Line)<br>NWPT009 Jamestown Capacitor (D-Line)<br>NWPT010 Eldred 45J4 (D-Line)<br>NWPT015 37K22 and 37K33 Reconfiguration (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Newport: 203W5<br>Gate 2: 38K23<br>Eldred: 45J4<br>Kingston: 131J6, 131J12<br>Jespon: 37K22, 37K33 |
| **Voltage(s):** | 4.16kV, 13.8kV, and 23kV |
| **Geographic Area Served:** | Jamestown, on Conanicut Island, Middletown, Newport, and Portsmouth, on Aquidneck Island, Prudence Island. |
| **Summary of Issues:** | Newport is a one transformer 69/13.8kV substation that consists of four feeders. The 203W5 feeders have conductor limiting and voltage concerns<br><br>Gate 2 23kV is a single transformer 69/23kV substation that consists of three feeders. The 38K23 has contingency voltage issues.<br><br>Eldred has two modular 23/4.16kV substations. The 45J4 feeder has a contingency voltage issue.<br><br>Jepson 23kV substation is a two transformer 115/23kV substation that consists of four feeders. The 37K22 has contingency loading issues. |
| **Recommended Plan** | The recommended plan to address the Newport conductor limiting and voltage concerns is as follows:<br>Newport 203W5:<br>• Remove the existing stepdown transformer pole #9 Catherine Street, Newport and convert all the downstream load to 13.8 kV to eliminate the voltage issues.<br>• Reconductor all line sections in the conversion area to 1/0 Al.<br><br>The recommended plan to address the contingency low voltage issues on Gate 2 38K23 is to install a 2700 kVAR, 23 kV switched Capacitor Bank in the vicinity of pole #29 North Road Jamestown.<br><br>The recommended plan to address the contingency low voltage issues on Eldred 45J4 is to install three (3) single phase 76.2 kVA regulators on pole #199 East Shore Road |

<table>
<tr><td></td><td>The recommended option to address the contingency thermal loading issues on 37K22 is to parallel the existing underground cables 37K22 and unused sections of the old 37K33 from P. 1 Adelaide St. to MH 266 at the Hospital #146 substation. This option will increase 37K22 capacity from 7.8/9.1 MVA to 18.5/21.6 MVA vs. 12.8 MVA load.</td></tr>
<tr><td>Alternative Plans</td><td>See area study report for alternative plans.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>Newport Area Study completed December 2021</td></tr>
<tr><td>Planned Capital Spend ($000)</td><td><table>
<tr><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th><th>FY 2028</th><th>FY 2029</th><th>FY 2030</th><th>FY 2031</th><th>FY 2032</th><th>FY 2033</th><th>FY 2034</th></tr>
<tr><td>$580</td><td>$449</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table></td></tr>
</table>

**Other Area Study Projects – System Capacity & Performance – Chase Hill Common Items**

<table>
<tr><td>Distribution Related Project Number(s):</td><td colspan="10">SCW0003 Chase Hill Common Items (D-Line)</td></tr>
<tr><td>Substation(s) / Feeder(s) Impacted:</td><td colspan="10">Chase Hill, 155F2, 155F4, 155F6, 155F8</td></tr>
<tr><td>Voltage(s):</td><td colspan="10">12.47kV</td></tr>
<tr><td>Geographic Area Served:</td><td colspan="10">Hopkington and Westerly, RI</td></tr>
<tr><td>Summary of Issues:</td><td colspan="10">Voltage and reliability issues were identified on all of the Chase Hill feeders. The most significant voltage concerns are on the 155F2 and 155F8 circuits. The three year average reliability statistics are:<br>Circuit CKAIFI CKAIDI<br>155F2 4.50 465<br>155F4 2.77 117<br>155F6 1.34 137<br>155F8 5.83 600<br><br>All the circuits have average reliability statistics greater than the regulatory limits of a frequency of 1.05 and a duration of 71.9 minutes.</td></tr>
<tr><td>Recommended Plan</td><td colspan="10">There are several common items necessary to address voltage, power factor, customer, and reliability issues on the Chase Hill feeders – specifically:<br>• Reconfigure the 155F8 by double circuiting with the 155F6 with new 477 AL spacer cable. (approximately 3.5 miles)<br>• Reconfigure Kenney Hill Road woods construction to Grassy Pond Road (~2,500’).<br>(The 155F8 is also a CEMI priority circuit. The construction work above has been coordinated with the CEMI work to ensure no overlap of scope.)</td></tr>
<tr><td>Alternative Plans</td><td colspan="10">See area study report for alternative plans.</td></tr>
<tr><td>Long Range Plan Alignment</td><td colspan="10">South County West Area Study, completed September 2022</td></tr>
<tr><td rowspan="2">Planned Capital Spend ($000)</td><td>FY 2025</td><td>FY 2026</td><td>FY 2027</td><td>FY 2028</td><td>FY 2029</td><td>FY 2030</td><td>FY 2031</td><td>FY 2032</td><td>FY 2033</td><td>FY 2034</td></tr>
<tr><td>$200</td><td>$2,659</td><td>$1,906</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

**Other Area Study Projects – System Capacity & Performance – South County East**

| | |
|---|---|
| **Distribution Related Project Number(s):** | SCE001 Lafayette 30F2 Feeder Tie (D-Line)<br>SCE002 Wakefield 17F2 Feeder Upgrade (D-Line)<br>SCE003 Wakefield 17F2 Feeder Upgrade (D-Sub)<br>SCE004 Wakefield 17F3 Feeder Relief (D-Line)<br>SCE005 Peacedale 59F3 Feeder Relief (D-Line)<br>SCE006 Lafayette 30F2 Feeder Upgrade (D-Line) |
| **Substation(s) / Feeder(s) Impacted:** | Lafayette – 30F2<br>Wakefield – 17F2, 17F3<br>Peacedale – 59F3<br>Kenyon – 68F5<br>Bonnet - 42F1 |
| **Voltage(s):** | 12.47kV |
| **Geographic Area Served:** | Towns of Narragansett, South Kingston and Exeter |
| **Summary of Issues:** | The Town of Narragansett is supplied mostly by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings.<br><br>The western section of the Town of South Kingston is supplied mostly by (3) 12.47 kV distribution feeders. Two feeders (59F3 and 68F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town.<br><br>The eastern section of the Town of Exeter is supplied mostly by the Lafayette 30F2 feeder. Sections of this feeder are projected to be loaded above summer normal ratings with the limit being 4/0 aluminum conductor. This feeder has no feeder ties suitable to reduce loading below the rating of the 4/0 aluminum. |
| **Recommended Plan** | Town of Narragansett:<br>• Reroute the Peacedale 59F4 feeder along Columbia St, and reconductor ~2,700' with 477 AL Bare and install a normally open recloser with the 17F3.<br>• Modify feeder open points to provide relief to the 42F1 circuit.<br>• To offload the 17F2, reconductor the front end of the circuit along the roadway (Narragansett Ave) with 477 aluminum bare wire.<br>• Replace the 4/0 aluminum bus conductor on the 17F2 feeder with 477 aluminum bus conductor. Replaced the 89-F2 (4T34) 600 Amp air break and transformer fuse with a 1,200 Amp circuit switcher. This will increase the Summer Normal Rating of the feeder. Additionally, a new tie point is created with the 59F4. |

<table>
<tr><td></td><td>Town of South Kingston<ul><li>Create a new feeder tie with the 68F5 (continuing the work proposed in the South County West Area study to offload the 68F2) and the 59F3, with ~13,000’ of 477 aluminum spacer cable, shifting load over to the 68F5 to offload the 59F3.</li></ul><br>Town of Exeter<ul><li>Replaced 4/0 aluminum bare wire on the 30F2 with 477 aluminum bare wire (~10,000’) along Ten Rod Road.</li><li>Create a new feeder tie between the 30F2 and Hopkins Hill 63F6, by reconductoring ~8,000’ of existing 2-phase 4/0 aluminum wire to 477 aluminum spacer cable adding a new pole top recloser at pole 20 on the 63F6 and add a normally open recloser.</li><li>.</li></ul></td></tr>
<tr><td>Alternative Plans</td><td>See area study report for alternative plans.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>South County East Area Study, completed 2018</td></tr>
<tr><td>Planned Capital Spend ($000)</td><td><table><tr><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th><th>FY 2028</th><th>FY 2029</th><th>FY 2030</th><th>FY 2031</th><th>FY 2032</th><th>FY 2033</th><th>FY 2034</th></tr><tr><td>$1,684</td><td>$6,404</td><td>$333</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr></table></td></tr>
</table>

**Engineering Reliability Reviews (ERR)**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | Annual review of 5% of the company's feeders |
| **Voltage(s):** | Distribution level voltage |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | The most commonly used customer-based reliability indices for sustained outages in the electric utility industry are System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index. (SAIDI). SAIFI indicates how frequently the average customer experienced a sustained interruption over a specified time. SAIDI indicates how long (minutes or hours) the average customer was without service over a specific time, typically one year.<br><br>The metrics are commonly used by utility companies and regulators for system planning, benchmarking, and performance-based rate making. While effective in describing overall system performance, using system averages exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This can lead to uneven reliability performance in areas that do not have the customer counts to statistically influence system averages. |
| **Recommended Plan** | The plan is to review the five-year reliability data for each circuit, rank each circuit based on their five-year average number of customers interrupter (CI) and customer minutes interrupted (CMI), and propose reliability improvements for the worst performing 5% of the circuits. Any circuits that have been in the ERR program or the CEMI program in the last three years will be excluded as improvements would have recently been proposed.<br><br>Field Engineers, working closely with Operations Supervisors, will review circuit reliability and event history looking for locations of frequent outages, vegetation issues, a high number of animal contacts, protection concerns, and equipment failures. Field inspections will also be conducted reviewing system construction and reviewing locations for additional sectionalizing, line balancing opportunities, appropriate system hardening locations, and reconfiguration opportunities. Reclosers, crossarm mounted reclosers, tie switches, enhanced hazard tree removal, infrared line surveys, fuse additions, and other reliability improvement tools will be utilized.<br><br>Project developed through the circuit reviews and field inspections will be sent to the Design Group and written into job packets to be constructed. |
| **Alternative Plans** | Continue to utilize the existing reliability blanket and complete improvement projects as they arise. |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Long Range Plan Alignment** | This project looks to enhance reliability for our customers and aligns well with grid modernization and will support area study recommendations. | | | | | | | | | |
| **Planned Capital Spend ($000)** | **FY 2025** | **FY 2026** | **FY 2027** | **FY 2028** | **FY 2029** | **FY 2030** | **FY 2031** | **FY 2032** | **FY 2033** | **FY 2034** |
| | $4,448 | $1,030 | $1,061 | $1,093 | $1,126 | $1,159 | $1,194 | $1,230 | $1,267 | $1,305 |

**Fiber Network**

<table>
<tr><td>Distribution Related Project Number(s):</td><td>TBD</td></tr>
<tr><td>Substation(s) / Feeder(s) Impacted:</td><td>All</td></tr>
<tr><td>Voltage(s):</td><td>Distribution level voltage</td></tr>
<tr><td>Geographic Area Served:</td><td>System Wide</td></tr>
<tr><td>Summary of Issues:</td><td>Currently, leased cellular communications is used to communicate with automated devices in substations and with automated devices that have been installed on the line. Leased cellular service is limited in bandwidth and is subject to greater interference, especially during emergencies when communication is imperative. Cellular limitations do not offer adequate functionality and add reliability and resiliency system risk.</td></tr>
<tr><td>Recommended Plan</td><td>Replace cellular services connecting substations with fiber optic cabling to improve data flow and reliability of communications. The first year amount of $200,000 is to conduct a detailed fiber deployment study that will further develop scope, prioritize deployment, and refine future year execution and spend.</td></tr>
<tr><td>Current Status and Expected In-Service Date</td><td>This program will begin in FY 2025 and be implemented over four to five years.</td></tr>
<tr><td>Alternatives:</td><td>Do Nothing: Without this program, station communications costs will rise greater than the cost of this program.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>Consideration of this program will be included in future study recommendations and ongoing substation projects, however there is expected to be little overlap or impact.</td></tr>
<tr><td>Planned Capital Spend ($000)</td><td><table>
<tr><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th><th>FY 2028</th><th>FY 2029</th><th>FY 2030</th><th>FY 2031</th><th>FY 2032</th><th>FY 2033</th><th>FY 2034</th></tr>
<tr><td>$200</td><td>$12,980</td><td>$17,368</td><td>$17,368</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table></td></tr>
</table>

**IT Infrastructure**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | All |
| **Voltage(s):** | Distribution level voltage |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | The proposed underlying IT infrastructure investments in data management, enterprise integration platform, and corporate PI historian are necessary to enable data gathering, sensing, and control functionalities. The Company considers cybersecurity a necessary capability to operate a safe, reliable and cost-effective electric distribution system. Cybersecurity protects customers and electric grid operations from a vast array of threats. As more intelligent devices, including third-party devices, are interconnected, and integrated with utility operations, the number of potential targets increases, as does the need for a robust cybersecurity program. |
| **Recommended Plan** | Plan includes investments that will build foundational data management capabilities by enabling enhanced data governance across key datasets including an enterprise integration platform that will provide all the necessary integrations between the various applications such as ADMS, VVO/CVR, corporate PI Historian and GIS. The plan includes investments for operational planning and engineering tools necessary to model and evaluate the distribution system under steady-state and dynamic conditions. This includes three phase load flow, stability, contingency analysis, system restoration modeling, relay modeling, waveform analysis and other key tools for system operations and planning. This plan also includes a cyber services component. |
| **Current Status and Expected In-Service Date** | This program will begin in FY 2025 and be implemented over four to five years. |
| **Alternatives:** | Do Nothing: Without these investments, certain functionalities will be unavailable resulting in higher long term costs. |
| **Long Range Plan Alignment** | The IT infrastructure investments will enable new study tools and new alternative methods to help evaluate the increasingly dynamic electric system. As the functionalities are enabled, the study recommendations will adjust to incorporate those functionalities. |

**Planned Capital Spend ($000)**

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| $2,213 | $2,018 | $2,998 | $4,281 | | | | | | |

**Mobile Dispatch**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | All |
| **Voltage(s):** | Distribution level voltage |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | Today dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS to view customers calls and predicted outage locations. They prioritize “trouble calls” and outages and assign them to appropriate field crews based on capability and location as optimally as possible. ADMS-based Mobile Dispatch will interface with OMS and allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews and crew time and shorten “trouble calls” and outage response times. In addition, field crews will be able to update details concerning their time of arrival, incident details once on location, and estimated restoration times rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near-real time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand. In summary, Mobile Dispatch is expected to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety. |
| **Recommended Plan** | These investments establish a mobile dispatch system and functionality. |
| **Current Status and Expected In-Service Date** | This program will begin in FY 2025 and be implemented over four to five years. |
| **Alternatives:** | Do Nothing: Without these investments, certain functionalities will be unavailable resulting in higher long term costs. |
| **Long Range Plan Alignment** | These investments are related to worker efficiencies. There is expected to be little overlap or impact with study efforts or other projects. |

**Planned Capital Spend ($000)**

| FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|
| $107 | $98 | $171 | $196 | | | | | | |

**Spare Transformers**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | All |
| **Voltage(s):** | 115-13.2kV, 35-11.5kV, 69-13.2kV |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | The Rhode Island Energy distribution system is designed for N-1 contingency situations. As such, for the loss of a power transformer, load is expected to be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair/replacement of the failed transformer. Apart from repairing/replacing the failed transformer, the other system restoration options are meant to be a short-term solution to return load to service. System reconfiguration exposes a larger number of customers to outages since feeders will be physically longer. Subsequent failures will result in an outage that impacts a greater number of customers. Temporary equipment is meant to be installed quickly and for short durations. Expecting a mobile substation to be energized for 3-years while a new transformer is being ordered/manufactured will reduce restoration options for ensuing transformer failures at other substations, limit post-fault switching options since mobile substations do not have an overload rating and increase noise pollution since mobile substations are typically louder than standard power transformers. With transformer lead times approaching 3-years, good utility practice drives the need for maintaining an adequate number of spare transformers in the event of a failure to allow the system to return to normal as soon as possible.<br><br>To calculate spare transformer requirements, a Poisson probability distribution (Reliability Criterion Model) is used since transformer failures are random events and can be modeled as stationary random processes. This model uses equipment failure rate (per year), power transformer lead time, and amount of power transformers in service to indicate how many spares are required to meet a certain system reliability metric. In this case, system reliability is defined as the probability that a spare transformer is available when needed.<br><br>Rhode Island Energy has evaluated our spare transformer requirements by grouping transformers by voltage class, capacity, and winding configuration to |

| | |
|---|---|
| | standardize and reduce the number of spares that are required. In total, the Reliability Criterion Model indicates that the company will need thirty (30) spare transformers to meet a .9950 system reliability. The .9950 system reliability benchmark indicates that the company will have a spare available 99.5% of the time. This number has been cited by IEEE to be a common benchmark amongst a wide number of utilities. This system reliability metric introduces a small amount of risk that a spare won't be available, but the number of spares needed drastically increases if the company selected a 1.00 system reliability number. In terms of the actual increase in spares needed, the company would go from thirty (30) to sixty-three (63) spares required to meet a system reliability of 1. This would introduce a large increase in upfront capital costs and ongoing maintenance costs. The existing spare transformer inventory stands at seven (7) spare transformers.<br><br>Understanding that it isn't be feasible to order all twenty-three (23) spare transformers at once, the company has prioritized the spare transformer ordering needs by evaluating the number of in-service transformers (per transformer grouping), load at-risk and transformers serving critical customers. As a result, the company is proposing to order three (3) spare transformers in FY25 with the expectation that they'll be delivered in FY28. The company will then plan on ordering five (5) spare transformers per year for the next four fiscal years (FY26, FY27, FY28 and FY29).<br><br>If the company does not move forward with ordering spare transformers, there will be many feeders that will have load at risk. Out of the three (3) spares that are being proposed in FY25, if any of the in-service transformers fail, the company does not have a mobile or spare transformer to restore customers. There are approximately ten (10) substations where if a transformer fails, there isn't enough capacity on the remaining station transformer or feeder ties to restore all customers. One of the proposed spare transformers will back up two (2) in-service transformers that supply power to a local hospital and not having a spare transformer will expose the hospital to increased reliability risk.<br><br>This project is discretionary and not customer driven. |
| **Recommended Plan** | The plan is to procure 3 spare transformers in FY25, 5 spare transformers in FY26, 5 spare transformers in FY27, 5 spare transformers in FY28 and 5 transformers in FY29.<br><br>The company will use a Poisson Probability Distribution to calculate how many spare transformers are needed to maintain a system reliability of .9950. The company will purchase the spare transformers with a priority on spare transformers that have the greatest amount of spare transformers in-service, supply power to critical customers and have the greatest amount of load at risk. |
| **Alternative Plans** | The company has evaluated a spare/mobile lease agreement with a neighboring utility and an option to build out the distribution system to allow for greater redundancy. However, while the lease agreement is adequate for a temporary solution to shore up the lack of spare inventory, it is not a thorough |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | long-term solution. Neighboring utilities will want to establish a clause to pull back any leased equipment if a failure occurs on their system. This will introduce reliability risks on the company system while other options are considered to restore the system to normal. Building out the system is cost prohibitive and will take much longer to complete. | | | | | | | | | |
| **Long Range Plan Alignment** | The spare transformer calculations have considered long-term projects that add and/or remove transformers. | | | | | | | | | |
| **Planned Capital Spend ($000)** | **FY 2025** | **FY 2026** | **FY 2027** | **FY 2028** | **FY 2029** | **FY 2030** | **FY 2031** | **FY 2032** | **FY 2033** | **FY 2034** |
| | $736 | $2,960 | $6,860 | $8,780 | $8,440 | $7,980 | $4,200 | | | |

**Mobile Substations**

| | |
|---|---|
| **Distribution Related Project Number(s):** | TBD |
| **Substation(s) / Feeder(s) Impacted:** | All |
| **Voltage(s):** | 34.5x23-12.47kV, 115000V-13200Y/7620V, 115000Y/66400Vx115000V-23000Y/13270x34500Y/19920V & 34/23kV mobile regulator |
| **Geographic Area Served:** | System Wide |
| **Summary of Issues:** | The Rhode Island Energy distribution system is designed for N-1 contingency situations. As such, for a loss of a power transformer, load is expected to be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair/replacement of the failed transformer. Apart from transferring customers to an adjacent transformer or feeder ties, installing a mobile substation is the quickest solution to restoring customers and returning the system back to normal operating conditions.<br><br>A mobile substation is a completely self-contained trailer mounted unit and is typically comprised of a transformer, cooling equipment, high voltage and low voltage disconnects, a power circuit breaker, metering, relaying, AC and DC power, and surge protection. Rapid integration into the system and the ability to reuse the mobile substation afterwards at other locations are the most important advantages to maintaining a mobile fleet. In addition, mobile substations can be installed and commissioned in minimal time.<br><br>Mobile substations are key elements for ensuring continued reliability and supporting the system during serious incidents. Mobile substations are typically used in:<br>1. Emergency Response.<br>2. Proactive maintenance.<br>3. Substation capital projects requiring a transformer to be out of service for a prolonged amount of time.<br><br>Rhode Island Energy currently owns and maintains two (2) 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 two hundred (200) in-service distribution transformers in the system, these two mobile substations can only be utilized too fully support approximately eighty (80) transformers in the event of a failure.<br><br>The company is planning to purchase three (3) mobile substations and one (1) mobile regulator to address the gap in coverage. The first mobile substation (along with the mobile regulator) will be able to support twenty-three (23) transformers. At the present time, we have two (2) in-service transformers that would cause 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 fifty-two (52) in-service transformers. There are currently nine (9) substations that will have load at risk if a transformer fails. The third mobile substation will support forty-three (43) in-service transformers. All three mobile substations all cover a different subset of transformer voltages and capacities.<br><br>In addition to supporting restoration efforts, mobile substations are utilized when loading or reliability concerns are introduced because of construction sequencing for capital projects. This typically happens when a transformer is required to be out of service for more than 2 weeks or when the construction is impacting a critical customer or heavily loaded area of the state.<br><br>If the company does not move forward with ordering mobile substations, there will be many feeders with load at risk where the company will not have a solution to restore those customers within a 24-hour timeframe. Planned capital projects will also need to be re-evaluated to determine if scope needs to be added or schedules extended to account for the absence of a mobile substation to support construction activities.<br><br>This project is discretionary and not customer driven. |
| **Recommended Plan** | The plan is to procure 3 mobile substations and 1 mobile regulator starting in FY25 with an expected delivery date of FY28. |
| **Alternative Plans** | The company has evaluated a mobile lease agreement with a neighboring utility and an option to build out the distribution system to allow for greater redundancy. However, while the lease agreement is adequate for a temporary solution to shore up the lack of mobile equipment, it is not a thorough long-term solution. Neighboring utilities will want to establish a clause to pull back any leased equipment if a failure occurs on their system. This will introduce reliability risks on the company system while other options are considered to restore the system to normal. Expanding the system is cost prohibitive and will take much longer to complete. |
| **Long Range Plan Alignment** | The mobile substation plan has taken into consideration the long-term plan by evaluating future transformer inventories and capital projects that will require a mobile substation to complete. This plan could change depending on the spare transformer inventory levels. |

| Planned Capital Spend ($000) | FY 2025 | FY 2026 | FY 2027 | FY 2028 | FY 2029 | FY 2030 | FY 2031 | FY 2032 | FY 2033 | FY 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| | $1,620 | $4,860 | $9,720 | | | | | | | |

## 6. Attachment 1 – Detailed Long Range Plan

| Spend Type | Spending Rationale | Jurisdictional Spotlight | 2024 ISR Total Budget | 2025 ISR Total Budget | 2026 ISR Total Budget | 2027 ISR Total Budget | 2028 ISR Total Budget | 2029 ISR Total Budget | 2030 ISR Total Budget | 2031 ISR Total Budget | 2032 ISR Total Budget | 2033 ISR Total Budget | 2034 ISR Total Budget |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Discretionary** | **Asset Condition** | Apponaug Sub - CRIE | $0 | $400 | $2,415 | $2,375 | $1,213 | $365 | | | | | |
| | | Batteries | $230 | $195 | $387 | $319 | $100 | | $103 | $0 | $106 | $0 | $109 |
| | | Blanket | $5,220 | $6,177 | $6,338 | $6,504 | $6,676 | $6,480 | $6,675 | $6,875 | $7,081 | $7,294 | $7,513 |
| | | Centredale Sub - NWRI | $0 | $900 | $2,272 | $3,316 | $1,176 | $250 | | | | | |
| | | Dyer St Substation | $0 | $15 | $0 | $0 | $0 | | | | | | |
| | | I&M | $3,000 | $3,000 | $3,000 | $3,000 | $3,000 | $3,000 | $3,090 | $3,183 | $3,278 | $3,377 | $3,478 |
| | | NWRI Study | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Other | $783 | $0 | $0 | $0 | $0 | | | | | | |
| | | Other Area Study Projects - BSVS | $0 | $900 | $0 | $0 | $0 | | | | | | |
| | | Other Area Study Projects - CRIW - D-Line | $0 | $424 | $554 | $1,258 | $650 | $390 | | | | | |
| | | Other Area Study Projects - CRIW - Equipment Repl | $0 | $3,278 | $5,363 | $8,138 | $1,888 | $0 | | | | | |
| | | Other Area Study Projects - EB | $0 | $0 | $25 | $0 | $0 | | | | | | |
| | | Other Area Study Projects - Newport | $0 | $766 | $3,253 | $3,482 | $296 | $0 | | | | | |
| | | Other Area Study Projects - SCW | $0 | $0 | $0 | $0 | $1,029 | $2,297 | $2,536 | $478 | | | |
| | | Phillipsdale Substation | $0 | $200 | $6,208 | $7,810 | $2,018 | $514 | | | | | |
| | | Providence Study | $0 | $492 | $5,396 | $7,407 | $6,293 | $9,619 | $1,567 | $1,516 | $3,738 | $521 | |
| | | ProvSt-Other | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | ProvStudy Ph1A | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | ProvStudy Ph1B | $13,941 | $17,483 | $1,180 | $0 | $0 | | | | | | |
| | | ProvStudy Ph2 | $1,597 | $2,922 | $9,400 | $7,064 | $0 | | | | | | |
| | | ProvStudy Ph3 | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | ProvStudy Ph4 | $8,776 | $7,990 | $0 | $0 | $0 | | | | | | |
| | | Recloser Repl Program | $1,300 | | | | | | | | | | |
| | | Reserve | $0 | $0 | $1,000 | $1,000 | $1,000 | $1,000 | $13,000 | $13,390 | $13,792 | $14,205 | $14,632 |
| | | South St Substation | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Southeast Substation | $66 | $0 | $0 | $0 | $0 | | | | | | |
| | | Substation Breakers & Reclosers | $437 | $0 | $0 | $0 | $0 | | | | | | |
| | | Tiverton Substation | $0 | $75 | $393 | $786 | $786 | $393 | $187 | | | | |
| | | UG Cable Replacement | $5,500 | $5,500 | $6,000 | $6,000 | $6,000 | $6,500 | $6,695 | $6,896 | $7,103 | $7,316 | $7,535 |
| | | URD Program | $6,275 | $7,008 | $7,419 | $7,731 | $7,831 | $7,508 | $7,733 | $7,965 | $8,204 | $8,450 | $8,704 |
| | | UG Improvements | $600 | $700 | $565 | $0 | $0 | | | | | | |
| | | Kingston Equipment Replacement | $0 | $400 | $3,361 | $8,403 | $1,681 | $2,961 | | | | | |
| | | Merton Equipment Replacement | $0 | | $816 | $2,449 | $4,082 | $816 | | | | | |
| | | Substation Power Transformer Spares | $0 | $736 | $2,060 | $3,240 | $0 | $0 | $0 | | | | |
| | | Blackstone Valley South 4kV Conversion Work | $0 | $1,044 | $2,017 | $2,457 | $2,126 | $386 | | | | | |
| | **Asset Condition Total** | | **$47,725** | **$60,604** | **$69,422** | **$82,738** | **$47,844** | **$42,480** | **$41,586** | **$40,303** | **$43,302** | **$41,163** | **$41,970** |
| | | | | | | | | | | | | | |

| Spend Type | Spending Rationale | Jurisdictional Spotlight | 2024 ISR Total Budget | 2025 ISR Total Budget | 2026 ISR Total Budget | 2027 ISR Total Budget | 2028 ISR Total Budget | 2029 ISR Total Budget | 2030 ISR Total Budget | 2031 ISR Total Budget | 2032 ISR Total Budget | 2033 ISR Total Budget | 2034 ISR Total Budget |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Non-Infrastructure** | Blanket | $700 | $712 | $724 | $737 | $750 | $764 | $786 | $810 | $834 | $859 | $885 |
| | | EV Charging Stations | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Infra Red Equipment | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Other | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Overheads | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Verizon Copper to Fiber Conversions | $1,000 | $1,000 | $1,000 | $0 | $0 | | | | | | |
| | **Non-Infrastructure Total** | | **$1,700** | **$1,712** | **$1,724** | **$737** | **$750** | **$764** | **$786** | **$810** | **$834** | **$859** | **$885** |
| | **System Capacity & Performance** | 3V0 | $1,095 | $540 | $0 | $0 | $0 | | | | | | |
| | | Aqudnck Island Projects | $1,038 | $0 | $0 | $0 | $0 | | | | | | |
| | | Blanket | $2,490 | $2,605 | $2,725 | $2,851 | $2,983 | $3,072 | $3,165 | $3,260 | $3,357 | $3,458 | $3,562 |
| | | CEMI 4 | $1,230 | $5,312 | $1,640 | $1,640 | $1,640 | | | | | | |
| | | Chase Hill Common Items | $0 | $200 | $2,659 | $1,906 | $0 | | | | | | |
| | | Chase Hill Second Half of Station | $0 | $0 | $1,006 | $2,012 | $1,006 | $1,006 | | | | | |
| | | East Bay Study | $0 | $84 | $378 | $378 | $0 | | | | | | |
| | | East Providence Sub | $1,330 | $6,865 | $4,429 | $5,003 | $0 | | | | | | |
| | | Electromechanical Relay Replacement Program | $0 | $1,166 | $603 | $1,267 | $2,513 | $1,263 | | | | | |
| | | EMS/RTU | $658 | $135 | $1,147 | $2,350 | $750 | | | | | | |
| | | Mainline Recloser Enhancements | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Nasonville Substation | $1,912 | $3,674 | $3,717 | $0 | $0 | | | | | | |
| | | New Lafayette Sub | $750 | $910 | $5,886 | $151 | $0 | | | | | | |
| | | Other | $2,041 | $1,978 | $1,600 | $1,600 | $1,600 | $1,600 | $1,648 | $1,697 | $1,748 | $1,801 | $1,855 |
| | | Other Area Study Projects - BSVS | | $0 | $0 | $0 | | | | | | | |
| | | Other Area Study Projects - CRIW | $1,372 | $1,550 | $1,261 | $1,261 | $757 | $0 | | | | | |
| | | Other Area Study Projects - Newport | $0 | $909 | $976 | $461 | $0 | | | | | | |
| | | Other Area Study Projects - Northwest Rhode Island | $1,933 | $0 | $0 | $0 | $0 | | | | | | |
| | | Other Area Study Projects - SCW | $364 | $727 | $1,442 | $2,003 | $2,576 | $1,147 | | | | | |
| | | Reserve | $0 | $0 | $1,000 | $1,000 | $1,000 | $1,000 | $17,500 | $18,025 | $18,566 | $19,123 | $19,696 |
| | | RI.GRIDMOD | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Staples #112 Reliability Improvements | $400 | $680 | $681 | $909 | $0 | | | | | | |
| | | VVO | $0 | $100 | $8,439 | $6,701 | $6,701 | $6,701 | $6,902 | $7,110 | $7,323 | $7,542 | $7,769 |
| | | Warren Sub | $1,969 | $3,376 | $2,366 | $747 | $111 | | | | | | |
| | | Weaver Hill Rd Substation | $1,507 | $1,105 | $3,054 | $3,475 | $2,496 | $1,229 | | | | | |
| | | ERR | | $4,448 | $1,030 | $1,061 | $1,093 | $1,126 | $1,159 | $1,194 | $1,230 | $1,267 | $1,305 |
| | | Other Area Study Projects - SCE | | $1,684 | $6,404 | $333 | | | | | | | |
| | | Mobile Substation | | $1,278 | $3,834 | $7,668 | $0 | $0 | $0 | $0 | $0 | $0 | |
| | | FLISR | $0 | $7,426 | $22,441 | $17,314 | $17,833 | $18,368 | | | | | |
| | | Tiverton D-Line Work | $109 | $328 | $656 | $656 | $328 | $440 | | | | | |
| | | ADMS/DERMS Advanced | $0 | $0 | $0 | $3,159 | $1,568 | $0 | | | | | |
| | | DER Monitor/Manage | $0 | $0 | $0 | $2,288 | $4,043 | | | | | | |

| Spend Type | Spending Rationale | Jurisdictional Spotlight | 2024 ISR Total Budget | 2025 ISR Total Budget | 2026 ISR Total Budget | 2027 ISR Total Budget | 2028 ISR Total Budget | 2029 ISR Total Budget | 2030 ISR Total Budget | 2031 ISR Total Budget | 2032 ISR Total Budget | 2033 ISR Total Budget | 2034 ISR Total Budget |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Fiber Network | $0 | $200 | $12,980 | $17,368 | $17,368 | | | | | | |
| | | IT Infrastructure | $0 | $2,213 | $2,018 | $2,998 | $4,281 | | | | | | |
| | | Mobile Dispatch | $0 | $107 | $98 | $171 | $196 | $0 | | | | | |
| | **System Capacity & Performance Total** | | **$20,198** | **$49,600** | **$94,470** | **$88,732** | **$70,844** | **$36,952** | **$30,374** | **$31,286** | **$32,224** | **$33,191** | **$34,187** |
| **Discretionary Total** | | | **$69,622** | **$111,916** | **$165,616** | **$172,207** | **$119,437** | **$80,195** | **$72,747** | **$72,399** | **$76,361** | **$75,213** | **$77,042** |
| **Non-Discretionary** | **Customer Request/Public Requirement** | 3rd Party Attachments | $280 | $288 | $297 | $306 | $315 | $324 | $334 | $344 | $355 | $365 | $376 |
| | | Distributed Generation | $1,000 | $1,000 | $1,000 | $1,000 | $1,000 | $1,000 | | | | | |
| | | Distribution Generation | $0 | | | | | | | | | | |
| | | Land and Land Rights | $500 | $515 | $530 | $546 | $562 | $579 | $596 | $614 | $633 | $652 | $671 |
| | | Meters | $2,605 | $2,533 | $2,603 | $2,638 | $2,708 | $2,789 | $959 | $988 | $1,017 | $1,048 | $1,079 |
| | | New Business - Commercial | $9,093 | $9,366 | $9,647 | $9,937 | $10,235 | $10,542 | $10,858 | $11,184 | $11,520 | $11,865 | $12,221 |
| | | New Business - Residential | $7,212 | $7,428 | $7,651 | $7,880 | $8,117 | $8,361 | $8,611 | $8,870 | $9,136 | $9,410 | $9,692 |
| | | Other | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Outdoor Lighting | $575 | $592 | $610 | $628 | $647 | $666 | $686 | $707 | $728 | $750 | $773 |
| | | Public Requirements | $1,249 | $3,140 | $3,234 | $3,331 | $3,431 | $3,531 | $5,491 | $5,656 | $5,825 | $6,000 | $6,180 |
| | | Regulatory Requirements | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Tiverton Substation | | $14,660 | | | | | | | | | |
| | | Transformers | $5,000 | $5,300 | $5,600 | $5,800 | $6,100 | $6,283 | $6,471 | $6,666 | $6,866 | $7,072 | $7,284 |
| | | Weaver Hill Rd Substation | | $13,515 | $0 | | | | | | | | |
| | **Customer Request/Public Requirement Total** | | **$27,514** | **$58,337** | **$31,172** | **$32,066** | **$33,115** | **$34,076** | **$34,008** | **$35,028** | **$36,079** | **$37,161** | **$38,276** |
| | **Damage/Failure** | Damage/Failure Blanket | $10,940 | $11,268 | $11,606 | $11,954 | $12,313 | $12,682 | $13,063 | $13,455 | $13,858 | $14,274 | $14,702 |
| | | Hopkins Hill Transformer Failure | $0 | $50 | $1,300 | $0 | $0 | $0 | $0 | | | | |
| | | Nasonville Substation Rebuild | $1,092 | $1,637 | $222 | $0 | $0 | | | | | | |
| | | Other Damage/Failure | $0 | $0 | $0 | $0 | $0 | | | | | | |
| | | Reserve | $979 | $1,008 | $1,038 | $1,070 | $1,102 | $1,135 | $1,169 | $1,204 | $1,240 | $1,278 | $1,316 |
| | | Storms | $1,950 | $3,000 | $3,000 | $3,000 | $3,000 | $3,000 | $3,090 | $3,183 | $3,278 | $3,377 | $3,478 |
| | | Westerly T2 Failure | $231 | $0 | $0 | $0 | $0 | | | | | | |
| | | Apponaug Transformer Failure | | $50 | $450 | $0 | | | | | | | |
| | **Damage/Failure Total** | | **$15,192** | **$17,013** | **$17,616** | **$16,024** | **$16,415** | **$16,817** | **$17,322** | **$17,842** | **$18,377** | **$18,928** | **$19,496** |
| **Non-Discretionary Total** | | | **$42,706** | **$75,350** | **$48,788** | **$48,090** | **$49,530** | **$50,893** | **$51,330** | **$52,870** | **$54,456** | **$56,090** | **$57,772** |
| **Grand Total** | | | **$112,329** | **$187,266** | **$214,404** | **$220,297** | **$168,967** | **$131,088** | **$124,077** | **$125,268** | **$130,817** | **$131,303** | **$134,814** |

**Attachment 6 – Distribution Automation Recloser Program Documentation**

# RI Energy

# Distribution Automation Recloser Program

**John Williams**

**September 30, 2023**



| Issue | Date | Summary of Changes | Author(s) | Approved by (include job title) |
|---|---|---|---|---|
| 1 | 9/30/2023 | Initial Issue | JWW | RMC Manager, Dist. Plan. |

## Table of Contents

## 1. Executive Summary

This strategy aims to set forth the general conditions for installing line reclosers on overhead distribution circuits. This is a reliability focused strategy designed to meet both state regulatory targets and support RI Energy's goal of achieving national and regional first quartile reliability performance. It is not intended to cover every situation but provide enough guidance to allow Distribution Field Engineering to make an informed decision.

While the reliability needs and benefits of installing reclosers are immediate, this strategy also enables other benefits as each recloser acts as a distribution monitor and remote controlled switch for system management during situations other than interruptions.

Yearly, this strategy will identify reliability issues and prioritize the circuits by reliability performance (CKAIFI, CKAIDI, CEMI)[1], line exposure, customer counts per sectionalized line, and Distributed Generation (DG) penetration. Alignment with pending construction will also be considered to adjust the prioritization. The mainline outage events for this prioritized list will be reviewed by Engineering and determinations made if reclosers would address the reliability issue and where the reclosers would be most beneficial. The proposed recloser configurations can, and often will, consider automatic sectionalization such as a Fault Location Isolation and Service Restoration (FLISR) capabilities linked to the Company's pending Advanced Distribution Management System (ADMS).

With circuits and preliminary recloser locations identified, Engineering will consult with Operations and the Distribution Control Center to reprioritize circuits if necessary and refine recloser locations.

The program is designed over 5 years with a total of approximately $90M. Ultimate cash flow will be subject to Public Utilities Commission (PUC) review and approval through the Infrastructure, Safety, and Reliability (ISR) Plan process.

This program will be aligned with other programs, such as the CEMI and the Engineering Reliability Review (ERR) programs and ongoing project work to ensure no overlap, redundancy, or early obsolescence of investments.

## 2. Background and Purpose

This strategy document sets forth the conditions for installing advanced line reclosers on overhead distribution feeders. Primarily, line reclosers will be installed on 15 kV class distribution feeders with substandard five-year CKAIFI performance. This is a reliability-focused strategy designed to meet both state regulatory targets and support RI Energy's goal of national and regional first quartile reliability performance. This program will be aligned with other programs, such as the CEMI and the Engineering Reliability Review (ERR) programs and ongoing project work to ensure no overlap, redundancy, or early obsolescence of investments.

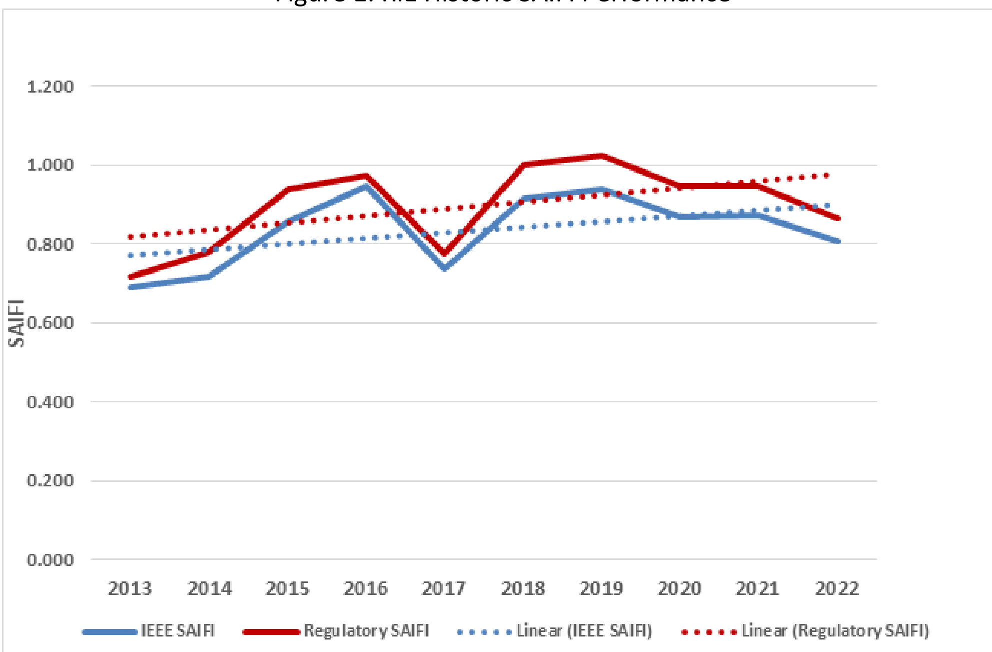
## 3. Justification

Rhode Island Energy has been meeting its state regulatory reliability performance targets as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency

[1] CKAIFI = Circuit Average Interruption Frequency Index, CKAIDI = Circuit Average Interruption Duration Index, CEMI = Customers Experiencing Multiple Interruptions

Index (SAIFI). However, the company's distribution system reliability has been worsening over time. See Figures 1 and 2.[2] Additionally, a subset of circuits have CKAIFI and CKAIDI values above the regulatory criteria (Figure 3). With the near term addition of an ADMS which enables FLISR capabilities, this trend is forecasted to reverse with investment in reclosers to improve sectionalization, by reducing the number of customers initially impacted by the interruption. The Company intends to target circuits with high frequency and duration statistics first.

Figure 1. RIE Historic SAIFI Performance




[2] Charts 1 and 2 show the reliability data using IEEE and regulatory methods.

Figure 2. RIE Historic SAIDI Performance

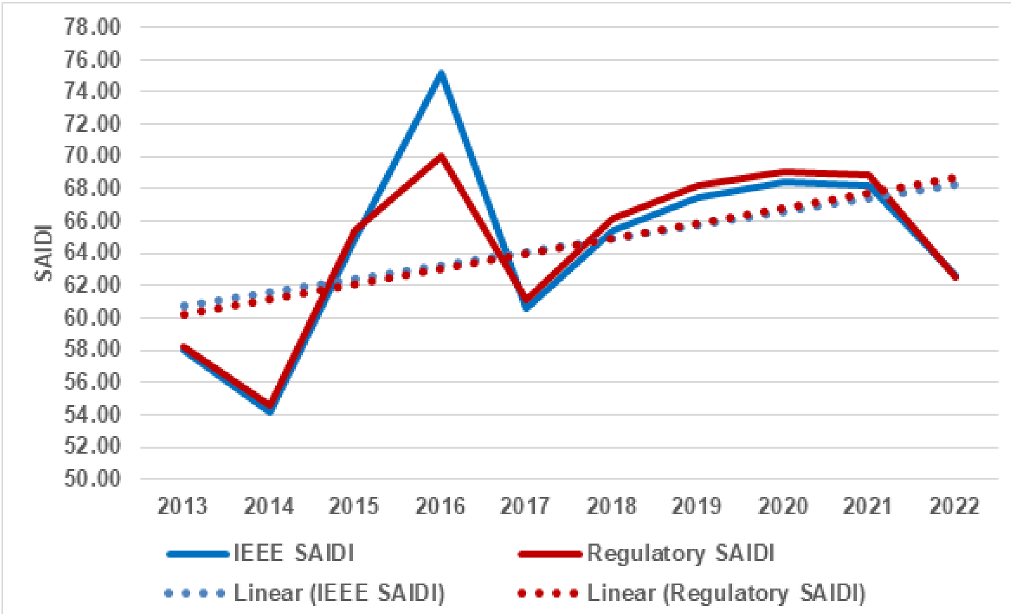



Figure 3 – Sample Feeders with High Frequency Statistics

| Feeder | Year | Customers Interrupted | Customer-Minutes Interrupted | Customers Served | Circuit Frequency (CKAIFI) | Circuit Duration (CKAIDI) |
|---|---|---|---|---|---|---|
| 53-112W44 | 5 Year Average | 6802 | 323708 | 2316 | 2.94 | 139.8 |
| 53-126W41 | 5 Year Average | 6053 | 305765 | 2602 | 2.33 | 117.5 |
| 53-126W50 | 5 Year Average | 6726 | 401928 | 1621 | 4.15 | 248 |
| 53-126W51 | 5 Year Average | 5671 | 326254 | 2466 | 2.3 | 132.3 |
| 53-127W40 | 5 Year Average | 7581 | 516189 | 2929 | 2.59 | 176.2 |
| 53-127W41 | 5 Year Average | 2122 | 227350 | 656 | 3.23 | 346.6 |
| 53-148J5 | 5 Year Average | 1234 | 95255 | 598 | 2.06 | 159.3 |
| 53-34F2 | 5 Year Average | 7763 | 575023 | 2597 | 2.99 | 221.4 |
| 53-34F3 | 5 Year Average | 2663 | 292444 | 852 | 3.13 | 343.2 |
| 53-45F2 | 5 Year Average | 4401 | 300289 | 1867 | 2.36 | 160.8 |
| 56-146J14 | 5 Year Average | 1201 | 28444 | 537 | 2.24 | 53 |
| 56-155F2 | 5 Year Average | 3917 | 292823 | 1311 | 2.99 | 223.4 |
| 56-155F4 | 5 Year Average | 4271 | 196734 | 1485 | 2.88 | 132.5 |
| 56-155F8 | 5 Year Average | 4974 | 437370 | 1942 | 2.56 | 225.2 |
| 56-16F1 | 5 Year Average | 4182 | 135922 | 2040 | 2.05 | 66.6 |
| 56-30F2 | 5 Year Average | 5793 | 512655 | 1851 | 3.13 | 277 |
| 56-33F4 | 5 Year Average | 6831 | 416631 | 2964 | 2.3 | 140.6 |
| 56-54F1 | 5 Year Average | 6482 | 516841 | 2674 | 2.42 | 193.3 |
| 56-63F6 | 5 Year Average | 5656 | 509443 | 2632 | 2.15 | 193.6 |
| 56-85T1 | 5 Year Average | 6811 | 711282 | 2226 | 3.06 | 319.5 |
| 56-86F1 | 5 Year Average | 7495 | 437004 | 3071 | 2.44 | 142.3 |

## 4. Program Development

### 4.1. Definitions

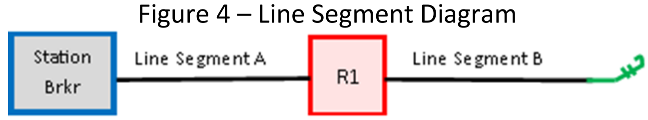
The following definitions are being supplied to ensure a complete understanding of the issues discussed in this strategy.

Distribution Feeder - Typically, distribution feeder voltage levels are between 2.4 kV and 15 kV, but voltages up to 34.5 kV are used for distribution at RI Energy. Distribution feeders can supply between one and several thousand customers using a combination of overhead and underground facilities. Additionally, both three phase and one/two phase sections are present.

Fault Location Isolation and Service Restoration (FLISR) - FLISR automation isolates the effect of outages to small blocks of customers using automated distribution switching so fewer customers experience outages.

Line Segment – sectionalized mainline wire between protective devices (circuit breaker, reclosers) or a three-phase switch.

Figure 4 – Line Segment Diagram




Mainline – Any three-phase primary location that, if faulted, would operate a three-phase, gang-trip device (reclosing or otherwise). This includes sectionalizers, non-reclosing breakers, etc., but excludes three single phase reclosers (CMRs) on the same or adjacent poles.

Normally Open Circuit Tie. A location on the distribution system where two circuits can be tied together by closing a three-phase device. Typically done with a gang operated load break switch or a tie recloser.

Mainline Recloser: a normally closed recloser installed along a distribution circuit with upstream and downstream customers like R1 in the above diagram.

Recloser – An automatic sectionalizing device capable of interrupting a fault and reclosing afterward to restore service. At the time of this strategy the G&W Viper ST with SEL 651R control are the standard RI Energy recloser and control. Reclosers are part of devices on a Distribution Supervisory Control and Data Acquisition (DSCADA) network capable of monitoring actual system conditions such as current, voltage, faults, and device state (Open/Closed).

Tie Recloser – a normally open recloser installed at a tie point between two distributions circuits.

### 4.2. Circuit Selection Criteria

RI Energy removed underground, soon to be converted, or distribution supply circuits that run as redundant pairs from consideration, leaving 336 feeders to be reviewed for eligibility and prioritization.

RI Energy's OH distribution circuits were prioritized by ranking their reliability, line exposure, and distributed generation penetration. Circuits with the highest priority score will be addressed first.

Reliability Rankings.

- CKAIFI (Average Circuit Interruption Frequency Index) Ranking: The circuit with the highest 5-year CKIAFI average was ranked worst (336). The lowest ranked CKAIFI circuit was assigned 1.
- CKAIDI (Average Circuit Interruption Duration Index): The circuit with the highest 5-year CKAIDI average ranked the worst (336). The circuit with the lowest CKAIDI was assigned 1.
- CEMI 4 (Customers Experiencing Multiple interruptions) Ranking: The CEMI ranking was calculating by multiplying the number of consecutive years a circuit appeared on the CEMI 4 list by the average number of CEMI 4 Customers it had. This factor was then ranked highest (336) to lowest. Circuits without a CEMI 4 history were assigned 1.

Line Exposure Ranking:

- The longest circuit, measured by three-phase overhead line miles, scored the worst (336). The shortest scored the lowest (1).

Customer Sectionalization Ranking:

- This is a ranking of the average number of customers per line section. Line sections lie between protective devices. They are derived by dividing the circuits total customers served by the number of ML reclosers plus 1. Circuits are ranked highest customer count per section (336) to lowest (1).

Distributed Generation (DG) Ranking:

- The circuits were ranked from highest penetration of distributed generation (336) to lowest. Circuits with no DG were ranked 1.

Construction Adder:

- Circuits with pending capital projects were given an adder to increase their overall priority score to provide the opportunity to consider recloser installations on circuit with eminent construction projects. This gives the company an opportunity to gain design, material procurement, outage planning, and construction efficiencies. Given that the company's capital construction schedule can be dynamic, the priority score adders will be revised periodically to match the planned work schedule.

Priority Score Equations:
Each of the above criteria were weighted as follows to find an overall priority score.

Figure 5 – Prioritization Weighting

| Category | Weight |
|---|---|
| Circuit Frequency - CKAIFI | 30% |
| Circuit Duration- CKAIDI | 25% |
| CEMI 4 | 15% |
| Line Exposure Ranking | 10% |
| Customer Sectionalization | 15% |
| Distributed Generation Penetration | 5% |
| Construction Adjustment Adder | 250 points |

Figure 6 – Example Prioritization

| Feeder | Cust. Served | Total Priority Score | Line Exposure Rank | Sectionalize Rank | Circuit CKAIFI Rank | Circuit CKAIDI Rank | CEMI Ranking | DG Rank | Construction Adjustment |
|---|---|---|---|---|---|---|---|---|---|
| 30F2 | 1869 | **296** | 317 | 168 | 334 | 331 | 336 | 271 | 250 |
| 34F2 | 2631 | **270** | 327 | 177 | 330 | 327 | 336 | 263 | |
| 127W41 | 661 | **266** | 226 | 180 | 335 | 335 | 336 | 195 | |
| 126W50 | 1608 | **259** | 289 | 121 | 336 | 330 | 336 | 181 | |
| 126W51 | 1748 | **246** | 214 | 126 | 320 | 299 | 336 | 248 | |
| 148J5 | 361 | **235** | 60 | 113 | 317 | 312 | 134 | 75 | 250 |
| 146J14 | 567 | **194** | 24 | 158 | 319 | 193 | 201 | 94 | |

Attachment A shows a preliminary list of circuits with frequencies greater than 1.05. Attachment A also shows a preliminary review of circuit assignment to other programs such as the CEMI and ERR programs.

### 4.3. Determining Recloser Placements on the Circuit.

General guidelines for placement of reclosers on RI Energy circuits are:

- Line segments along the circuit should have approximately the same SAIFI impacts. That is, they should serve about the same number of customers. Exceptions include large loads, critical customers, and line segments with significant exposure.
- Ideally, sectionalized parts of the main line circuit (line segments) will be a minimum of 1 circuit mile long and serve at least 500 customers.
  - For urban circuits with high customer densities, the customers served on each line segment is at the discretion of the engineer.
- Circuits that serve between 500 and 1500 customers and have less than 3 miles of overhead main line wire will typically require only one main line recloser. The recloser should be placed

near the circuit's reliability center where possible. That is, the line segments should serve approximately the same number of customers.

- Normally open tie reclosers will be installed at circuit ties and arranged as part of FLISR schemes.
  - Normally open ties close to the station may be ignored at the engineer's discretion as they often provide limited restoration capability.

### 4.4. Other Considerations:

Area Study Work:
Future area planning studies will consider this program in the study alternatives and recommendations. Feeder construction and reconfiguration projects should incorporate advanced reclosers and FLISR capability at all new midline and normally open tie point recloser locations.

Critical Customers:
Critical customers should be considered when locating reclosers. The reclosers should be placed to limit the critical customer's exposure to the furthest extent possible.

Existing Construction and Customer Interconnection Work:
It is the responsibility of the recommending Field Engineer to review for all concurrent load and generation interconnections and any concurrent or recently recommended area study work before recloser recommendations are determined.

### 4.5. Consultation:

With the prioritized circuit list and preliminary recloser locations, Field Engineering will consult with Operations, Forestry, and Control Center groups prior to implementation. The circuit list and locations may be refined based on this consultation.

Once solutions have been determined all groups described above plus Design, Resource Planning, and Project Management will be consulted for review of the proposed work, impacts to other efforts, alignment with other programs, and resourcing issues.

### 4.6. Benefits:

In the previous 5 years, RI Energy averaged 305 regulatory reportable main line events with an added 135 events during Major Storm days annually. Combined, these events interrupted an average of 1,285 customers. Main Line events accounted for approximately 80% of all RI Energy's reportable SAIFI.

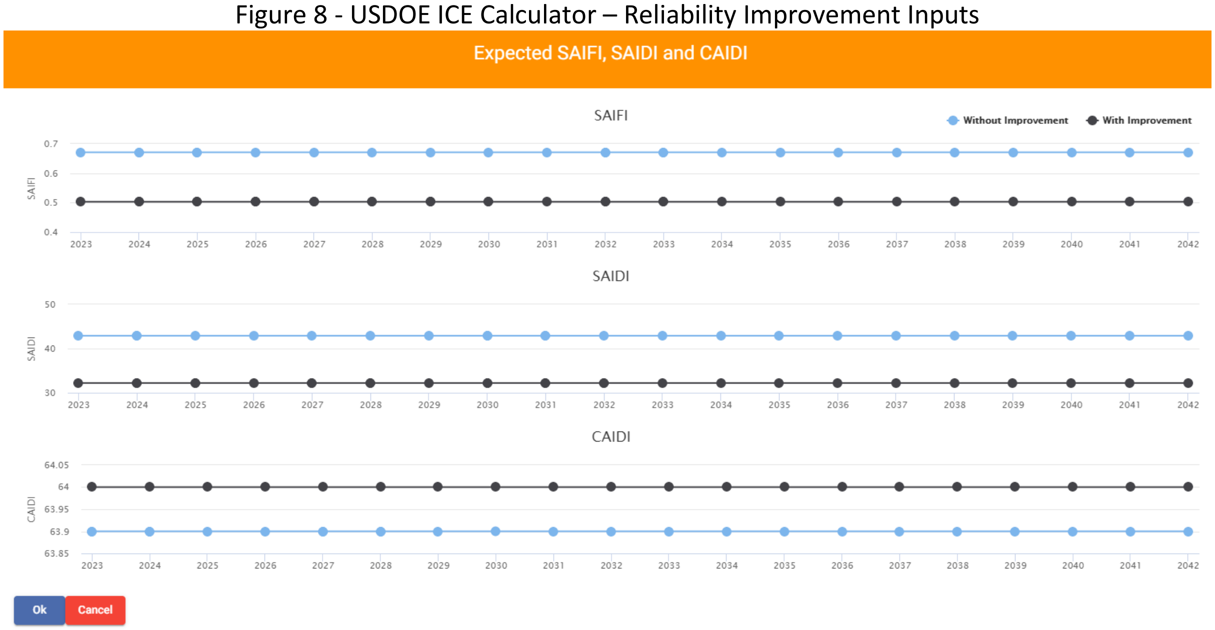
Figure 7 – Main Line Event History

| RI Energy Main Line Events* 2018 Through 2022 | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Regulatory Reportable Events | | | Major Storms | | | |
| YEAR | Events | SAIFI | SAIDI (Min) | Events | SAIFI | SAIDI (Min) | Average. Cs |
| 2018 | 331 | 0.83311 | 43.05 | 175 | 0.46015 | 384.98 | 492418 |
| 2019 | 322 | 0.8506 | 44.78 | 99 | 0.2921 | 105.29 | 496961 |
| 2020 | 312 | 0.75553 | 42.85 | 221 | 0.57319 | 296.72 | 498157 |
| 2021 | 291 | 0.76092 | 42.65 | 145 | 0.40035 | 289.91 | 499886 |
| 2022 | 267 | 0.70182 | 40.30 | 38 | 0.06196 | 7.48 | 500974 |

*Includes Station Breaker, Recloser, Load Break Switch and Disconnect Switch events.*

Of these mainline events approximately 50% can be addressed by sectionalization. Assuming the recloser was located to roughly divide the customers within the existing protection zone, the recloser sectionalization would reduce the frequency by 50%. This results in a net system reduction for mainline events of 25%. For example, if the system average frequency is 0.85, 0.85*80% = portion of the frequency associated with mainline events = 0.68. 0.68-25% reduction = resulting system mainline frequency of 0.51. A quantitative assessment was also conducted using the U.S Department of Energy's Interruption Cost Estimates (ICE) Calculator.[3] Figures 8 and 9 shows the input and results of the reliability improvement analysis.

Figure 8 - USDOE ICE Calculator – Reliability Improvement Inputs




[3] https://www.icecalculator.com/reliability-improvement

Figure 9 - USDOE ICE Calculator – Reliability Improvement Results

| Sector | # of Customers | Total Benefit (2023$) | Benefit Per Customer (2023$) |
|---|---|---|---|
| Residential | 435,486 | $6,098,300.30 | $14.00 |
| Small C&I | 61,640 | $116,841,097.73 | $1,895.54 |
| Medium and Large C&I | 1,701 | $31,783,462.69 | $18,685.16 |
| **All** | **498,827** | **$154,722,860.72** | **$310.17** |

The results from Figures 8 and 9 represent the benefit from saving approximately half of the customers in the average recloser protective zone. However certain FLISR recloser actions will result in an approximate 2 minute momentary interruption. This momentary interruption can be modeled in the USDOE ICE calculator and can have substantial value. The momentary interruption value must be subtracted from the previously calculated benefit to evaluate the complete customer experience. Figure 10 shows the resulting cash flows. Modeling the FLISR benefit less the momentary outage value within the USDOE ICE calculator results in a net present value of $113M and a benefit cost ration of 1.19.

Figure 10 - USDOE ICE Calculator – Reliability Improvement Details

| Year | Without Improvement (Baseline) | With Improvement | Total Benefit* | | Project Costs |
|---|---|---|---|---|---|
| 2023 | $43,540,023 | $32,660,807 | $7,955,540 | | $13,545,600 |
| 2024 | $44,410,823 | $33,314,023 | $8,114,651 | | $14,288,160 |
| 2025 | $45,299,040 | $33,980,304 | $8,276,944 | | $18,958,707 |
| 2026 | $46,205,021 | $34,659,910 | $8,442,483 | | $20,329,967 |
| 2027 | $47,129,121 | $35,353,108 | $8,611,333 | | $18,368,304 |
| 2028 | $48,071,703 | $36,060,170 | $8,783,559 | | $18,919,353 |
| 2029 | $49,033,137 | $36,781,374 | $8,959,231 | | $8,184,512 |
| 2030 | $50,013,800 | $37,517,001 | $9,138,415 | | |
| 2031 | $51,014,076 | $38,267,341 | $9,321,183 | | |
| 2032 | $52,034,358 | $39,032,688 | $9,507,607 | | |
| 2033 | $53,075,045 | $39,813,342 | $9,697,759 | | |
| 2034 | $54,136,546 | $40,609,608 | $9,891,714 | | |
| 2035 | $55,219,277 | $41,421,801 | $10,089,549 | | |
| 2036 | $56,323,662 | $42,250,237 | $10,291,340 | | |
| 2037 | $57,450,135 | $43,095,241 | $10,497,167 | | |
| 2038 | $58,599,138 | $43,957,146 | $10,707,110 | | |
| 2039 | $59,771,121 | $44,836,289 | $10,921,252 | | |
| 2040 | $60,966,543 | $45,733,015 | $11,139,677 | | |
| 2041 | $62,185,874 | $46,647,675 | $11,362,471 | | |
| 2042 | $63,429,592 | $47,580,629 | $11,589,720 | | |
| NPV | | | $113,142,711 | | $95,424,427 |
| Benefit - Cost | | | | | $17,718,284 |
| Benefit/Cost | | | | | 1.19 |

*Total Benefit = Without Improvement -With Improvement – Momentary Outage Value

### 4.7. Quantities and Costs

The number of circuits and potential reclosers are listed by frequency performance. Addressing circuits above RI PUC regulator target of 1.05 would include 94 circuits and about 300 recloser installations. However, RI Energy has included additional high thresholds to facilitate vary cash flow scenarios. Other thresholds include 0.92, which matches RI Energy's three-year system average frequency performance. System SAIFI of 0.8 approaches IEEE first quartile performance. A SAIFI of 0.5 is currently best in class 2021 IEEE performance. Figure 11 below lists the number of circuits and reclosers at the SAIFI thresholds.

Figure 11 - Circuits and Estimated Recloser Quantities

| CKAIFI Threshold | Circuits | Number of Reclosers * |
|---|---|---|
| > 2.0 | 21 | 80 |
| From 1.5 to 2.0 | 25 | 86 |
| From 1.05 to 1.5 | 47 | 170 |
| From 0.92 to 1.05 | 26 | 79 |
| From 0.8 to 0.92 | 30 | 140 |
| From 0.7 to 0.8 | 16 | 69 |
| From 0.5 to 0.7 | 43 | 159 |
| Subtotals | 208 | 783 |

* Includes normally open tie reclosers.

The 2024 estimated capital cost per recloser is $ 80,000. The program's estimated cash flows are shown in Figure 12 and proposed quantities shown in Figure 13. An overlap review has been conducted to check circuits that may be prioritized in other programs similar to this one. Where overlap was found those circuits and the associated reclosers were removed from this program and included in the CEMI and ERR programs. The cash flow and unit transfers between programs is also shown in Figures 12 and 13.

.

Figure 12 - Cash Flows

| Fiscal Year | Unit Costs | Total Capital Budget | Budget Transferred to CEMI Program | Budget Transferred to ERR Program | **Resulting Budget** |
|---|---|---|---|---|---|
| 2025 | $81,600 | $13,545,600 | $3,672,000 | $2,448,000 | **$7,425,600** |
| 2026 | $84,048 | $14,288,160 | $2,857,632 | $2,521,440 | **$8,909,088** |
| 2027 | $86,569 | $18,958,707 | $2,943,361 | $2,597,083 | **$13,418,263** |
| 2028 | $89,167 | $20,329,967 | $3,031,662 | $2,674,996 | **$14,623,310** |
| 2029 | $91,842 | $18,368,304 | $0 | $0 | **$18,368,304** |
| 2030 | $94,597 | $18,919,353 | $0 | $0 | **$18,919,353** |
| 2031 | $97,435 | $8,184,512 | $0 | $0 | **$8,184,512** |
| Total | | $112,594,603 | $12,504,655 | $10,241,519 | **$89,848,430** |

Figure 13 – Equipment Counts After Transfers to Other Programs

| Fiscal Year | # of Units | Units Transferred to CEMI Program | Units Transferred to ERR Program | **Resulting Units** |
|---|---|---|---|---|
| 2025 | 166 | 45 | 30 | **91** |
| 2026 | 170 | 34 | 30 | **106** |
| 2027 | 219 | 34 | 30 | **155** |
| 2028 | 228 | 34 | 30 | **164** |
| 2029 | 200 | 0 | 0 | **200** |
| 2030 | 200 | 0 | 0 | **200** |
| 2031 | 84 | 0 | 0 | **84** |
| Total | 1267 | 147 | 120 | **1000** |

## 5. Attachment A – Preliminary Prioritization List – Circuits with Frequency > 1.05

| Feeder | Substation Name | Cust. Served | ERR FY | CEMI FY | 5 yr Average CKAIFI | 5 yr Average CKAIDI | Sectionalize Rank | Line Exposure Rank | Circuit CKAIFI Rank | Circuit CKAIDI Rank | CEMI Rank | DG Rank | Construction Adjustment | Prority Score | Approx. Reclosers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 53-126W50 | WASHINGTON | 1608 | | | 4.2 | 248 | 121 | 289 | 336 | 330 | 336 | 181 | | 259 | 3 |
| 53-127W41 | NASONVILLE | 661 | | | 3.2 | 347 | 180 | 226 | 335 | 335 | 336 | 195 | | 266 | 2 |
| 56-30F2 | LAFAYETTE | 1869 | | | 3.1 | 277 | 168 | 317 | 334 | 331 | 336 | 271 | 250 | 296 | 3 |
| 53-34F3 | CHOPMIST | 845 | FY25 | | 3.1 | 343 | 80 | 311 | 333 | 334 | 336 | 304 | | 260 | 3 |
| 56-85T1 | WOOD RIVER | 2748 | | FY25 | 3.1 | 320 | 332 | 334 | 332 | 333 | 336 | 325 | | 299 | 6 |
| 53-34F2 | CHOPMIST | 2631 | | | 3.0 | 221 | 177 | 327 | 330 | 327 | 336 | 263 | | 270 | 3 |
| 56-155F2 | CHASE HILL SUBSTATION | 2054 | FY25 | | 3.0 | 223 | 263 | 291 | 331 | 328 | 336 | 300 | | 284 | 3 |
| 53-112W44 | STAPLES | 2344 | | | 2.9 | 140 | 204 | 259 | 329 | 306 | 336 | 231 | | 264 | 3 |
| 56-155F4 | CHASE HILL SUBSTATION | 1773 | FY25 | | 2.9 | 133 | 163 | 304 | 328 | 300 | 336 | 267 | | 260 | 4 |
| 53-127W40 | NASONVILLE | 2946 | | FY24 | 2.6 | 176 | 162 | 326 | 327 | 318 | 336 | 298 | | 267 | 2 |
| 56-155F8 | CHASE HILL SUBSTATION | 1955 | | FY24 | 2.6 | 225 | 99 | 331 | 326 | 329 | 336 | 299 | | 260 | 5 |
| 56-86F1 | LANGWORTHY CORNER | 2735 | | FY25 | 2.4 | 142 | 150 | 297 | 325 | 308 | 336 | 234 | | 257 | 3 |
| 56-54F1 | COVENTRY | 2685 | | FY24 | 2.4 | 193 | 108 | 333 | 324 | 321 | 336 | 280 | | 258 | 5 |
| 53-45F2 | WEST GREENVILLE | 1924 | FY25 | | 2.4 | 161 | 172 | 263 | 323 | 314 | 336 | 329 | | 264 | 6 |
| 53-126W41 | WASHINGTON | 2356 | | FY25 | 2.3 | 118 | 205 | 269 | 322 | 288 | 336 | 253 | | 259 | 7 |
| 53-126W51 | WASHINGTON | 1748 | | | 2.3 | 132 | 126 | 214 | 320 | 299 | 336 | 248 | | 246 | 5 |
| 56-33F4 | TIVERTON | 3095 | | FY25 | 2.3 | 141 | 202 | 330 | 321 | 307 | 336 | 301 | 250 | 294 | 8 |
| 56-146J14 | HOSPITAL | 567 | | | 2.2 | 53 | 158 | 24 | 319 | 193 | 201 | 94 | | 194 | 3 |
| 56-63F6 | HOPKINS HILL | 2605 | | FY24 | 2.2 | 194 | 106 | 335 | 318 | 322 | 336 | 293 | | 257 | 2 |
| 53-148J5 | Pawtucket | 361 | | | 2.1 | 159 | 113 | 60 | 317 | 312 | 134 | 75 | 250 | 235 | 3 |
| 56-16F1 | WESTERLY | 2027 | FY25 | | 2.1 | 67 | 122 | 293 | 316 | 226 | 0 | 223 | | 222 | 1 |
| 53-127W42 | NASONVILLE | 1033 | | | 2.0 | 200 | 264 | 305 | 315 | 324 | 336 | 296 | | 279 | 4 |
| 56-16F2 | WESTERLY | 1817 | | | 2.0 | 54 | 234 | 190 | 314 | 197 | 0 | 187 | | 224 | 4 |
| 56-14F3 | DRUMROCK | 239 | | | 1.9 | 128 | 89 | 95 | 313 | 296 | 201 | 87 | | 210 | 1 |
| 53-107W63 | Pawtucket | 3152 | | | 1.9 | 86 | 207 | 181 | 312 | 262 | 0 | 239 | 250 | 263 | 5 |
| 56-36W44 | DEXTER | 2083 | FY25 | | 1.8 | 140 | 109 | 298 | 310 | 305 | 134 | 320 | | 230 | 4 |
| 56-36W42 | DEXTER | 1861 | | | 1.8 | 126 | 239 | 238 | 309 | 294 | 134 | 305 | | 243 | 4 |

| Feeder | Substation Name | Cust. Served | ERR FY | CEMI FY | 5 yr Average CKAIFI | 5 yr Average CKAIDI | Sectionalize Rank | Line Exposure Rank | Circuit CKAIFI Rank | Circuit CKAIDI Rank | CEMI Rank | DG Rank | Construction Adjustment | Prority Score | Approx. Reclosers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 53-108W53 | RIVERSIDE | 2795 | | FY25 | 1.8 | 89 | 186 | 254 | 308 | 266 | 0 | 249 | | 239 | 3 |
| 56-68F1 | KENYON | 2640 | | FY24 | 1.8 | 217 | 179 | 323 | 307 | 325 | 336 | 308 | | 265 | 3 |
| 56-37W5 | JEPSON | 1946 | | | 1.8 | 151 | 327 | 288 | 306 | 309 | 201 | 63 | | 256 | 7 |
| 56-88F3 | TOWER HILL | 2281 | | | 1.8 | 105 | 198 | 314 | 305 | 283 | 336 | 201 | | 251 | 7 |
| 53-7F2 | ELMWOOD | 2026 | | | 1.7 | 46 | 260 | 167 | 304 | 176 | 134 | 185 | | 205 | 8 |
| 56-32J14 | HARRISON | 552 | | | 1.7 | 40 | 152 | 94 | 303 | 158 | 134 | 108 | | 177 | 2 |
| 53-21F1 | WEST CRANSTON | 2609 | FY25 | | 1.7 | 139 | 148 | 261 | 302 | 304 | 336 | 321 | | 252 | 3 |
| 56-45J4 | ELDERED | 437 | | | 1.6 | 129 | 88 | 176 | 300 | 298 | 0 | 160 | | 221 | 0 |
| 53-26W5 | WOONSOCKET | 2879 | | FY25 | 1.6 | 85 | 191 | 287 | 301 | 261 | 336 | 272 | | 246 | 7 |
| 56-155F6 | CHASE HILL SUBSTATION | 1719 | FY25 | | 1.6 | 164 | 224 | 318 | 299 | 316 | 336 | 330 | | 268 | 3 |
| 53-2243 | PHILLIPSDALE | 1 | | | 1.6 | 283 | 28 | 100 | 298 | 332 | 201 | 171 | 250 | 235 | 3 |
| 56-46F1 | OLD BAPTIST ROAD | 1490 | | | 1.6 | 135 | 141 | 240 | 297 | 302 | 336 | 323 | | 248 | 1 |
| 53-126W40 | WASHINGTON | 154 | | | 1.6 | 85 | 77 | 108 | 296 | 260 | 201 | 125 | | 197 | 0 |
| 53-112W43 | STAPLES | 992 | | Exclude | 1.6 | 117 | 140 | 179 | 295 | 287 | 0 | 250 | | 230 | 1 |
| 53-21F2 | WEST CRANSTON | 1236 | | | 1.6 | 97 | 124 | 306 | 293 | 276 | 336 | 287 | | 239 | 3 |
| 56-17F2 | WAKEFIELD | 2938 | | | 1.6 | 95 | 252 | 312 | 294 | 272 | 0 | 186 | | 246 | 7 |
| 56-30F1 | LAFAYETTE | 1356 | | | 1.5 | 76 | 133 | 228 | 292 | 245 | 336 | 255 | 250 | 252 | 0 |
| 56-51J16 | MERTON | 868 | | | 1.5 | 161 | 228 | 64 | 291 | 315 | 134 | 82 | | 221 | 4 |
| 56-51J2 | MERTON | 321 | | | 1.5 | 81 | 104 | 23 | 290 | 257 | 134 | 66 | | 185 | 2 |
| 56-88F1 | TOWER HILL | 2222 | | FY25 | 1.5 | 113 | 153 | 321 | 289 | 284 | 336 | 310 | | 246 | 3 |
| 53-26W1 | WOONSOCKET | 1547 | | | 1.5 | 118 | 145 | 303 | 287 | 289 | 336 | 311 | | 244 | 1 |
| 56-36W41 | DEXTER | 2069 | | | 1.5 | 104 | 266 | 184 | 288 | 280 | 201 | 254 | | 238 | 3 |
| 53-107W61 | Pawtucket | 2443 | | | 1.5 | 62 | 288 | 163 | 286 | 214 | 201 | 71 | 250 | 239 | 3 |
| 53-34F1 | CHOPMIST | 3331 | | FY24 | 1.4 | 188 | 182 | 336 | 284 | 320 | 336 | 270 | | 256 | 5 |
| 53-4F1 | BARRINGTON | 2342 | FY25 | | 1.4 | 104 | 203 | 262 | 285 | 279 | 336 | 182 | | 242 | 5 |
| 53-112W41 | STAPLES | 1935 | | | 1.4 | 61 | 250 | 122 | 282 | 211 | 0 | 283 | | 222 | 2 |
| 53-148J3 | Pawtucket | 1422 | | | 1.4 | 59 | 302 | 88 | 283 | 205 | 201 | 113 | 250 | 237 | 5 |
| 56-203W7 | NEWPORT SUBSTATION | 2556 | | | 1.4 | 160 | 331 | 172 | 281 | 313 | 67 | 63 | | 231 | 6 |
| 53-18F6 | JOHNSTON | 1555 | | | 1.4 | 95 | 147 | 257 | 279 | 270 | 0 | 318 | | 229 | 3 |
| 53-4F2 | BARRINGTON | 3053 | | | 1.4 | 96 | 199 | 301 | 280 | 274 | 336 | 220 | | 242 | 8 |
| 53-18F13 | JOHNSTON | 2194 | | | 1.4 | 69 | 276 | 199 | 278 | 232 | 0 | 157 | | 227 | 7 |
| 56-203W3 | NEWPORT SUBSTATION | 1419 | | | 1.4 | 54 | 188 | 141 | 277 | 196 | 201 | 63 | | 191 | 2 |
| 53-50F2 | CENTREDALE | 2130 | FY25 | | 1.4 | 95 | 328 | 114 | 276 | 271 | 0 | 156 | 250 | 265 | 8 |

| Feeder | Substation Name | Cust. Served | ERR FY | CEMI FY | 5 yr Average CKAIFI | 5 yr Average CKAIDI | Sectionalize Rank | Line Exposure Rank | Circuit CKAIFI Rank | Circuit CKAIDI Rank | CEMI Rank | DG Rank | Construction Adjustment | Prority Score | Approx. Reclosers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 53-50J2 | CENTREDALE | 18 | | | 1.4 | 85 | 51 | 8 | 275 | 259 | 134 | 63 | 250 | 197 | 0 |
| 53-102W44 | VALLEY | 2572 | | | 1.3 | 67 | 223 | 227 | 274 | 228 | 336 | 217 | | 228 | 3 |
| 53-38F1 | PUTNAM PIKE | 3117 | | | 1.3 | 120 | 169 | 324 | 273 | 290 | 336 | 302 | | 245 | 4 |
| 53-2235 | ELMWOOD | 3 | | | 1.3 | 350 | 37 | 140 | 272 | 336 | 67 | 63 | | 188 | 2 |
| 53-2242 | PHILLIPSDALE | 17 | | | 1.3 | 167 | 50 | 164 | 271 | 317 | 134 | 65 | 250 | 218 | 2 |
| 56-131J2 | Kingston | 1019 | | | 1.3 | 121 | 261 | 42 | 269 | 291 | 134 | 78 | | 212 | 4 |
| 53-26W3 | WOONSOCKET | 2309 | | FY25 | 1.3 | 68 | 284 | 248 | 270 | 229 | 336 | 333 | | 244 | 7 |
| 56-32J12 | HARRISON | 443 | | | 1.2 | 18 | 130 | 125 | 267 | 88 | 134 | 86 | | 146 | 0 |
| 53-111J1 | CROSSMAN STREET | 1488 | | | 1.2 | 92 | 308 | 74 | 268 | 268 | 201 | 119 | | 223 | 3 |
| 53-107W66 | Pawtucket | 3318 | | | 1.2 | 80 | 318 | 221 | 266 | 255 | 201 | 149 | 250 | 255 | 7 |
| 53-5F4 | WARREN | 3587 | | | 1.2 | 96 | 233 | 173 | 265 | 275 | 0 | 192 | 250 | 253 | 9 |
| 56-154J16 | WEST HOWARD | 177 | | | 1.2 | 79 | 81 | 7 | 263 | 251 | 67 | 89 | | 165 | 1 |
| 53-78F4 | WATERMAN AVE | 808 | | | 1.2 | 123 | 213 | 126 | 264 | 292 | 201 | 169 | 250 | 244 | 6 |
| 56-131J14 | Kingston | 317 | | | 1.2 | 76 | 103 | 13 | 262 | 244 | 67 | 63 | | 166 | 0 |
| 56-51J12 | MERTON | 250 | | | 1.2 | 51 | 91 | 27 | 261 | 187 | 67 | 63 | | 150 | 0 |
| 53-127W43 | NASONVILLE | 3 | | | 1.2 | 74 | 36 | 135 | 260 | 241 | 1 | 309 | | 166 | 2 |
| 53-26W7 | WOONSOCKET | 272 | | | 1.2 | 156 | 67 | 218 | 259 | 311 | 201 | 319 | | 212 | 2 |
| 56-17F1 | WAKEFIELD | 2760 | | | 1.2 | 99 | 236 | 279 | 257 | 278 | 0 | 163 | | 231 | 3 |
| 53-111J3 | CROSSMAN STREET | 1092 | | | 1.2 | 81 | 275 | 99 | 258 | 256 | 134 | 127 | | 207 | 3 |
| 56-64F1 | ANTHONY | 1336 | | | 1.2 | 105 | 183 | 197 | 255 | 282 | 0 | 139 | | 218 | 5 |
| 56-68F3 | KENYON | 3191 | | | 1.2 | 58 | 208 | 307 | 256 | 204 | 336 | 240 | | 220 | 4 |
| 56-88F5 | TOWER HILL | 2233 | | | 1.2 | 104 | 195 | 299 | 253 | 281 | 0 | 258 | | 230 | 5 |
| 56-46F2 | OLD BAPTIST ROAD | 1649 | | | 1.2 | 72 | 151 | 258 | 252 | 235 | 336 | 213 | | 214 | 1 |
| 56-61F3 | DIVISION ST | 1041 | | | 1.2 | 129 | 268 | 130 | 254 | 297 | 336 | 202 | | 241 | 5 |
| 56-3F1 | APPONAUG | 1895 | | | 1.1 | 80 | 245 | 196 | 250 | 253 | 67 | 162 | | 200 | 3 |
| 53-102W42 | VALLEY | 3126 | | | 1.1 | 29 | 315 | 209 | 251 | 119 | 0 | 224 | | 201 | 6 |
| 56-52F1 | WARWICK | 1651 | | | 1.1 | 60 | 217 | 143 | 249 | 210 | 134 | 168 | | 189 | 3 |
| 53-2228-ELM | ELMWOOD | 22 | | | 1.1 | 187 | 53 | 152 | 247 | 319 | 1 | 107 | | 175 | 0 |
| 53-5F2 | WARREN | 2559 | FY25 | | 1.1 | 116 | 295 | 286 | 248 | 286 | 336 | 326 | 250 | 279 | 4 |
| 53-50J3 | CENTREDALE | 621 | | | 1.1 | 60 | 167 | 55 | 245 | 209 | 134 | 116 | 250 | 198 | 3 |
| 53-107W80 | Pawtucket | 2009 | | | 1.1 | 46 | 257 | 177 | 246 | 175 | 134 | 276 | 250 | 217 | 8 |
| 53-1125 | FRANKLIN SQUARE | 9 | | | 1.1 | 137 | 47 | 109 | 243 | 303 | 134 | 63 | | 178 | 3 |
| 56-100F1 | TIOGUE AVE | 2273 | FY25 | | 1.1 | 114 | 159 | 207 | 244 | 285 | 336 | 212 | | 223 | 1 |

**Attachment 7 – Customers Experiencing Multiple Interruptions (CEMI) Program Documentation**

# RI Energy

# Customers Experiencing Multiple Interruptions (CEMI) Program

John Williams

September 30, 2023



| Issue | Date | Summary of Changes | Author(s) | Approved by Include Job Title. |
|---|---|---|---|---|
| 1 | 9/30/2023 | First Issue | JWW | RMC Manager, Dist. Plan. |
| 2 | 12/21/2023 | Correction to Table 10 | NG | RMC Manager, Dist. Plan. |

# Table of Contents

## 1. Executive Summary

System reliability metrics are commonly used by utility companies and regulators for system planning, benchmarking, and performance-based rate making. While effective in describing overall system performance, using system averages exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This can lead to uneven reliability performance across the system.

In the previous 3 years[1] the average RI Energy customer experienced 0.98 regulatory reported interruptions and 1.49 interruptions when major storm events are included. However, 11.46 % of the roughly 500,000 customers served, experienced 4 or more events per year over the same period.

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. This CEMI program details the methods to identify and fix reliability issues for customers who are experiencing significantly poorer service than system or circuit averages.

The program's goal is to drive CEMI 4 performance to Electric Edison Institute first quartile level of 4.67 % within 5 years. The program is expected to cost $ 4.5 M annually and reduce the number of customers at CEMI 4 + by approximately 9,000 each year.

Program implementation consists of several steps including data gathering and opportunity prioritization, consultation and design, evaluation of benefits, and cost development. First, historical reliability statistics are gathered to create a draft prioritization list. This list is reviewed with Operations, Forestry, and other personnel to refine and validate. Next, initial scopes are developed and reviewed with the relevant internal departments. Lastly, costs are developed and benefits assigned using the methods described in this document.

This program will be aligned with other programs, such as the Distribution Automation Recloser and the Engineering Reliability Review (ERR) programs and ongoing project work to ensure no overlap, redundancy, or early obsolescence of investments.

## 2. Background and Purpose

The most commonly used customer-based reliability indices for sustained outages in the electric utility industry are System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index. (SAIDI). SAIFI indicates how frequently the average customer experienced a sustained interruption over a specified time. SAIDI indicates how long (minutes or hours) the average customer was without service over a specific time, typically one year.

The metrics are commonly used by utility companies and regulators for system planning, benchmarking, and performance-based rate making. While effective in describing overall system performance, using system averages exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This can lead to uneven reliability performance in areas that do not have the customer counts to statistically influence system averages. As a result, reliability performance

[1] January 1, 2019 through December 31, 2021

experienced by some customers can degrade to a point where the servicing utility company can no longer ignore performance issues.

CEMI $_n$ (Customers Experiencing Multiple Interruptions) measures the percentage of customers that have experienced n or more interruptions. IEEE 1366 – 2003 defines CEMI n as the ratio of individual customers experiencing more than n sustained interruptions to the total number of customers served. Mathematically:

$$CEMI\ n = \frac{total\ number\ of\ customers\ that\ experineced\ n\ interruptions}{Customers\ Served}$$

CEMI is now a relatively commonly collected reliability statistic within the industry. The Edison Electric Institute (EEI) publishes CEMI data from more than 50 of its members in its annual Reliability Survey Report. A number of electric utilities including BC Hydro, Florida Power and Light, and JEA (Jacksonville Florida Electric Association), have active CEMI programs.

The purpose of this document is to develop and implement a 5 year CEMI Program that identifies and fixes reliability issues for customers who are experiencing significantly poorer service than system or circuit averages and identifies the funding requirements to achieve the program goals.

## 3. Justification and Industry Metric Comparisons

While SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index) averages provide a good indication for how the distribution system is performing as a whole, they do not provide information about the reliability experience of a specific customer. Within RI Energy's service area there are a subset of customers who can experience many more interruptions than the average customer. To date, the company's response to addressing this problem is to review a list of protective devices that have multiple interruptions. This method sometimes fails to identify reliability issues of individual customers because more than one protective device can interrupt the same customer. In some cases, issues are only identified by a customer complaint. Development of a CEMI program is a more effective way to proactively identify reliability issues at the customer level.

In the previous 3 years[2] the average RI Energy customer experienced 0.98 regulatory reported interruptions and 1.49 interruptions when major storm events are included (See Table 1). However, 11.46 % of the roughly 500,000 customers served, experienced 4 or more events per year over the same period. (See Table 2).

[2] January 1, 2019 through December 31, 2021

*Table 1. RI Energy SAIFI History with and without Storms.*

| RI Energy SAIFI with and without Major Storms | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Regulatory Reported SAIFI | | | SAIFI Including Major Storms | | |
| Year | Customers Served | No. Of Events | Customers Interrupted | SAIFI | No. Of Events | Customers Interrupted | SAIFI |
| 2019 | 496,961 | 2711 | 508,130 | 1.02 | 4587 | 689,698 | 1.38 |
| 2020 | 498,157 | 2721 | 471,406 | 0.95 | 5427 | 826,935 | 1.66 |
| 2021 | 499,886 | 2911 | 477,691 | 0.96 | 5008 | 720,516 | 1.44 |
| *Averages* | **498,335** | **2781** | **485,742** | **0.98** | **5007** | **745,716** | **1.49** |

*Table 2. RI CEMI n, IEEE calculation, Storms included.*

| Year | Cs | CEMI 3+ | CEMI 4+ | CEMI 5+ | CEMI 6+ | CEMI 7+ |
|---|---|---|---|---|---|---|
| 2019 | 496,961 | 19.81% | 11.09% | 5.63% | 3.71% | 2.25% |
| 2020 | 498,157 | 24.67% | 12.94% | 6.74% | 3.12% | 1.66% |
| 2021 | 499,886 | 20.63% | 10.34% | 4.55% | 2.45% | 1.09% |
| **Averages** | **498,335** | **21.70%** | **11.46%** | **5.64%** | **3.09%** | **1.67%** |

As can be seen comparing RIE's current average CEMI numbers from Table 2 to EEI's CEMI quartile ranges in Table 3, RIE CEMI performance is in the 3rd quartile across all CEMI categories. This lower quartile performance not only indicates an opportunity for RIE to improve its reliability efforts but is believed to be a contributing factor in its current low customer satisfaction.[3] Electrical industry satisfaction surveys consistently show that decreasing the number of interruptions has the propensity to increase customer satisfaction. The goal of RI Energy's CEMI program is to bring CEMI 4+ performance to EEI first quartile levels within 5 years. (See Table 3).

*Table 3. EEI 2020 CEMI quartile results.*

| EEI 2020 Survey With Major Storms | | | | |
|---|---|---|---|---|
| CEMI Values | 1st | 2rd | 3rd | 4th |
| CEMI 3+ | < 10.91 | 10.91- 15.98 | 16.06 - 22.77 | > 22.77 |
| CEMI 4+ | < 4.67 | 4.67- 7.76 | 7.92 - 13.05 | >13.05 |
| CEMI 5+ | < 1.91 | 1.91 - 4.10 | 4.10 - 7.38 | > 7.38 |
| CEMI 6+ | < 0.89 | 0.89- 2.065 | 2.15 - 4.20 | > 4.20 |

## 4. Program Development

Program development consists of several steps to drive CEMI 4+ performance to EEI first quartile levels within 5 years. These steps include data gathering and opportunity prioritization, consultation and design, evaluation of benefits, and cost development.

### 4.1. Data Gathering and Prioritization

RI Energy's Distribution Planning and Asset Management group will compile two datasets to prioritize circuit selection. The first dataset, shown in Table 4, is a list of 3-year CEMI 4+ data on a rolling quarterly

[3] JD Power 2022 3rd quarter results for RI Energy indicate residential customers overall satisfaction trended lower for the third consecutive quarter. The 667 (out of 1000) score is lower than the mean of 709 and ranks in the 4 th quartile when compared to other midsize eastern utilities.

basis. This shows the number of CEMI 4 customers over a three year history. The second dataset lists the circuits that have the highest CEMI n customers for the previous rolling 12 months. See Table 5 for a sample. A weighted evaluation will be used that appropriately balances chronic CEMI 4+ performance and the highest current year CEMI n customers. Once the combine evaluation is complete, circuit selection will be determined with input from RI Energy's Operations group. Final circuit selections will also consider proposed area study work and other pending capital projects to effectively align and balance work across all Company efforts.

*Table 4. Sample of Quarterly rolling 3-year average circuit list*

| CEMI Program Candidate List - Total Number of Customers CEMI 4 + per year | | | | | |
|---|---|---|---|---|---|
| **Row Labels** | **2019** | **2020** | **2021** | **Grand Total** | **3 yr. average** |
| 56-85T1 | 1971 | 734 | 2419 | 8135 | 1708 |
| 56-54F1 | 2595 | 1688 | 820 | 8693 | 1701 |
| 56-33F4 | 1421 | 1068 | 2202 | 7572 | 1564 |
| 53-126W50 | 1582 | 1528 | 1543 | 6619 | 1551 |
| 56-52F1 | | | 1505 | 2609 | 1505 |
| 56-63F6 | 1596 | 1671 | 660 | 7502 | 1309 |
| 56-86F1 | 13 | 1118 | 2689 | 6421 | 1273 |
| 53-78F3 | | 1262 | | 1306 | 1262 |
| 56-155F8 | 745 | 771 | 2194 | 7238 | 1237 |
| 56-33F1 | | 10 | 2444 | 2937 | 1227 |
| 53-126W41 | 1394 | 1956 | 320 | 6738 | 1223 |
| 56-17F2 | | 474 | 1933 | 3740 | 1204 |
| 53-127W40 | 628 | 1388 | 1397 | 6579 | 1138 |
| 56-30F2 | 1808 | 791 | 788 | 6793 | 1129 |
| 56-155F2 | 1796 | 746 | 769 | 5548 | 1104 |
| 53-4F1 | 1035 | 2053 | 213 | 6308 | 1100 |
| 53-34F2 | 1296 | 1411 | 559 | 7190 | 1089 |
| 53-112W41 | | 361 | 1816 | 4024 | 1089 |
| 53-4F2 | 114 | 2933 | 193 | 8035 | 1080 |
| 56-155F4 | 1506 | 1262 | 455 | 6177 | 1074 |
| 56-37W5 | | 927 | 1215 | 2340 | 1071 |
| 53-23F6 | | 1053 | | 3900 | 1053 |
| 53-34F1 | 2042 | 534 | 550 | 7575 | 1042 |
| 53-50F2 | | 2027 | 37 | 2297 | 1032 |
| Total | 21542 | 27766 | 26721 | 136276 | 29764 |

Table 5 *Sample of Circuits with high CEMI n numbers - 2021*

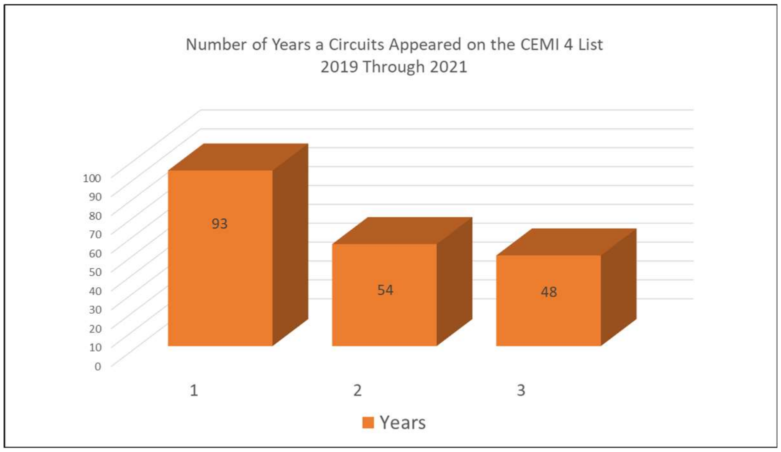
| RI Energy Customers with CEMI 4 + by Circuit | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Rolling 12 months | | CEMI n | | | | | | | |
| | **Circuit** | **4** | **5** | **6** | **7** | **8** | **9** | **10+** | **Grand Total** |
| Jan - Dec '21 | 56-86F1 | 28 | 128 | 1852 | 636 | 44 | 1 | | 2689 |
| Jan - Dec '21 | 56-33F1 | 2313 | 125 | 6 | | | | | 2444 |
| Jan - Dec '21 | 56-85T1 | 1208 | 687 | 375 | 81 | 52 | 16 | | 2419 |
| Jan - Dec '21 | 56-33F4 | 90 | 701 | 367 | 717 | 205 | 68 | 54 | 2202 |
| Jan - Dec '21 | 56-155F8 | 1205 | 687 | 187 | 104 | 9 | 1 | 1 | 2194 |
| Jan - Dec '21 | 56-17F2 | 60 | 1653 | 198 | 21 | 1 | | | 1933 |
| Jan - Dec '21 | 53-112W41 | 1569 | 211 | 36 | | | | | 1816 |
| Jan - Dec '21 | 56-88F3 | 803 | 667 | 160 | 105 | 32 | 13 | 3 | 1783 |
| Jan - Dec '21 | 53-126W50 | 1 | 309 | 230 | 209 | 521 | 139 | 134 | 1543 |
| Jan - Dec '21 | 56-52F1 | 1093 | 397 | 15 | | | | | 1505 |
| Jan - Dec '21 | 56-52F3 | 1431 | 34 | | | | | | 1465 |
| Jan - Dec '21 | 56-42F1 | 392 | 285 | 716 | 62 | | | | 1455 |
| Jan - Dec '21 | 53-127W40 | 622 | 458 | 245 | 72 | | | | 1397 |
| Jan - Dec '21 | 56-88F1 | 235 | 354 | 345 | 237 | 75 | 21 | 1 | 1268 |
| **Jan - Dec '21** | **Total** | **11050** | **6696** | **4732** | **2244** | **939** | **259** | **193** | **26113** |

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.[4] 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.

In addition, from 2019 through 2021, 195 unique circuits appeared on the CEMI 4 + list. Of those, approximately 25 % (48 /195) appeared on the list for 3 consecutive years and 52 % of the circuits appear on the list 2 out of 3 years.

[4] 500,000 customers x 11.45% = 57,250 customers, 500,000 customers x 4.67% = 23,350 customers

*Table 6. Circuits with CEMI 4 + Customers 2019 – 2021*




Also of note, 48 % of the circuits on the list appeared in only one year. Approximately 1/2 of the circuits on the list are new each year.

A common feature of circuits appearing on the CEMI list multiple times is overhead circuit length. Feeders with long overhead line sections appeared more frequently than their shorter counter parts. For this review a 3-year sample of data from 2019 through 2021 was examined. From Table 7, circuits that appeared on the CEMI 4 + list for 5 consecutive years have 3 times the overhead wire length of circuits appearing less often.

Table 7. *CEMI 4 + Circuits by OH circuit length*

| Average Overhead Circuit Length for CEMI 4 + feeders (2017 through 2021) | | | | |
|---|---|---|---|---|
| Number of Years on CEMI 4+ list | No. of Unique Feeders | 1 ph. and 2 ph. (Miles) | 3 PH OH (Miles) | Total OH length (Miles) |
| 1 | 127 | 1.7 | 2.9 | 4.6 |
| 2 | 83 | 4.2 | 4.9 | 9.1 |
| 3 | 59 | 6.3 | 5.9 | 12.2 |
| 4 | 35 | 10.1 | 8.2 | 18.3 |
| 5 | 54 | 30.6 | 14.2 | 44.9 |
| Grand Total | 358 | 8.2 | 6.1 | 14.3 |

A description of these line sections, their customer counts, and overhead line length are listed in the Cost Summary in Appendix A.

## 4.2. Consultation and Design

With the prioritized list determined in Section 4.1, Field Engineering, Operations, Forestry, and Control Center groups will review a list of CEMI 4+ customers on a yearly basis. The circuits and event details will be examined for trends and alignment with Operations, Forestry, and Control Center experience. The list determined in Section 4.1 may be refined based on this consultation.

Engineering and design activities will be conducted on the revised priority list. Distribution Planning and Field Engineering resources will first gather 3-year detailed outage information for the circuits under study. To the furthest extent possible, the damage location should be mapped. With an understanding of the customer, damage location, and protective device locations, solutions will be developed. Due to the specific locational and cause characteristics of the events, this review does not warrant a typical alternative analysis. Instead, the solutions are based on common field engineering knowledge, and advancing lowest cost solutions. For example, if events indicate an animal contact issue, an alternative analysis is not warranted to provide confidence that the low cost of installing animal guards is the best solution. Generally, options can include in order of lowest cost to highest cost:

- Spot Tree Trimming (Expense)
- Lightning Arresters / Animal Guards
- Pole / Transformer Replacements
- New Fuse Location
- Cutout Mounted Recloser
- New Load break Switch
- New Recloser
- Reconductor/Install 1/0 Single Phase Covered Wire Construction
- Reconductor/Install 1/0 Single Phase Spacer Cable Construction
- Reconductor/Install 1/0 Three Phase Covered Wire Construction
- Reconductor/Install 1/0 Three Phase Spacer Cable Construction
- Reconductor/Install 477 Three Phase Covered Wire Construction
- Reconductor/Install 477 Three Phase Spacer Cable Construction

Once solutions have been determined all groups described above plus Design, Resource Planning, and Project Management will be consulted for review of the proposed work, impacts to other efforts, alignment with other programs, and resourcing issues.

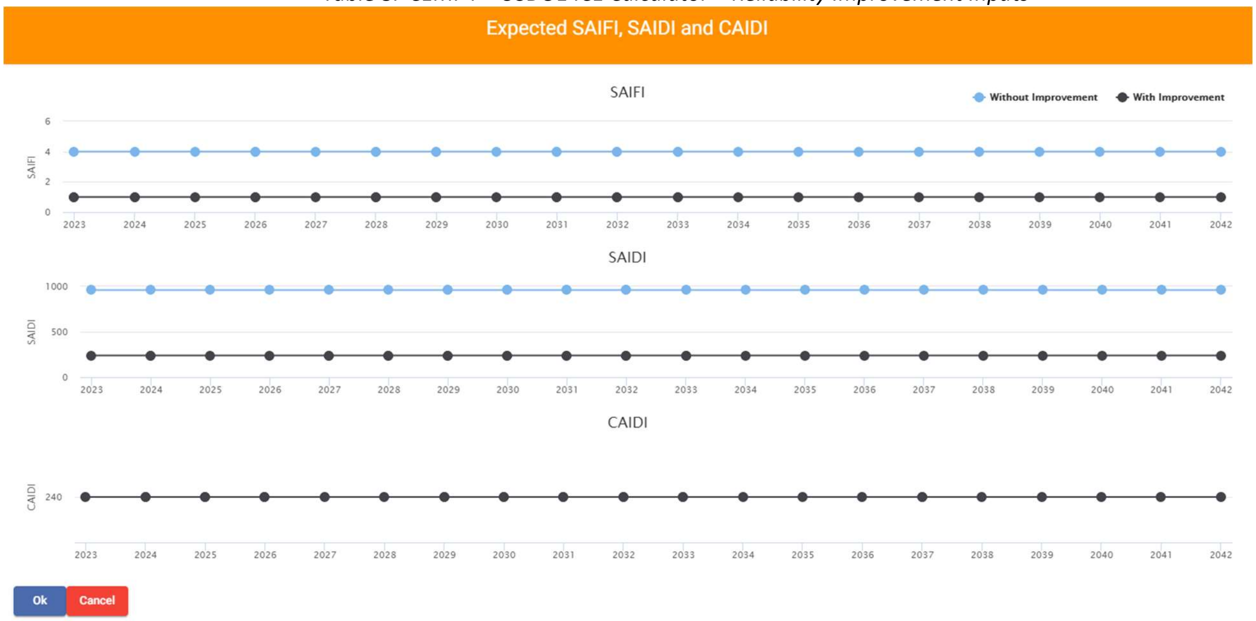
## 4.3. Benefits

Reviewing reliability performance on an individual customer basis provides an opportunity to find and fix issues before customers complain and is expected to improve customer satisfaction. Customer satisfaction improvements result in qualitative reputational benefits.

A quantitative assessment was also conducted using the U.S Department of Energy's Interruption Cost Estimates (ICE) Calculator.[5] Tables 8 and 9 shows the input and results of the reliability improvement analysis.

[5] https://www.icecalculator.com/reliability-improvement

Table 8. *CEMI 4 + USDOE ICE Calculator – Reliability Improvement Inputs*




The inputs, as shown in Table 8, were a frequency per year improvement of 4 to 1 with each interruption assumed to be 4 hours or 240 minutes. Although the CEMI program could impact customers with greater than 4 outages per year, the assumption results in a conservatively low benefit. All customers were considered to be residential, and no small commercial/industrial or large commercial/industrial customers were assumed. This assumption, again, results in a conservatively low benefit.

Table 9. *CEMI 4 + USDOE ICE Calculator – Reliability Improvement Results*

| Sector | # of Customers | Total Benefit (2023$) | Benefit Per Customer (2023$) |
|---|---|---|---|
| Residential | 45,000 | $18,985,881.01 | $421.91 |
| Small C&I | 0 | $0.00 | |
| Medium and Large C&I | 0 | $0.00 | |
| **All** | **45,000** | **$18,985,881.01** | **$421.91** |

To account for additional recloser benefits, a separate analysis was conducted. A review of all events indicated approximately 80% of the total system frequency was associated with mainline issues which can be mitigated by the reclosers. Of these mainline events approximately 50% can be addressed by sectionalization. Assuming the recloser was located to roughly divide the customers within the existing protection zone, the recloser sectionalization would reduce the frequency by 50%. This results in a net system reduction for mainline events of 25%. For example, if the system average frequency is 0.85, 0.85*80% = portion of the frequency associated with mainline events = 0.67. 0.67-25% reduction =

resulting system mainline frequency of 0.50. Modeling this within the ICE calculator results in an additional benefit of $28,000 per year per feeder. This additional value was multiplied by the cumulative CEMI feeders per year and added to the CEMI total benefit in Table 10.

The benefits result in a 20-year net present value in 2023 $s of approximately $33M. Table 10 provides a detailed breakdown of the benefit and cost cash flows showing a benefit to cost ratio of approximately 1.82.

Table 10. *CEMI 4 + USDOE ICE Calculator – Reliability Improvement Details*

| Year | Interruption Costs Without Improvement (Baseline) | Interruptions Costs With Improvement | Total Benefit | | Year | Project Costs |
|---|---|---|---|---|---|---|
| 2023 | $1,779,970 | $444,992 | $1,562,278 | | 2023 | $1,300,000 |
| 2024 | $1,815,569 | $453,892 | $1,825,371 | | 2024 | $5,312,000 |
| 2025 | $1,851,880 | $462,970 | $2,098,363 | | 2025 | $4,546,832 |
| 2026 | $1,888,918 | $472,230 | $2,381,544 | | 2026 | $4,683,237 |
| 2027 | $1,926,696 | $481,674 | $2,675,213 | | 2027 | $4,823,734 |
| 2028 | $1,965,230 | $491,308 | $2,728,717 | | 2028 | |
| 2029 | $2,004,535 | $501,134 | $2,783,291 | | 2029 | |
| 2030 | $2,044,626 | $511,156 | $2,838,957 | | 2030 | |
| 2031 | $2,085,518 | $521,380 | $2,895,736 | | 2031 | |
| 2032 | $2,127,228 | $531,807 | $2,953,651 | | 2032 | |
| 2033 | $2,169,773 | $542,443 | $3,012,724 | | 2033 | |
| 2034 | $2,213,169 | $553,292 | $3,072,978 | | 2034 | |
| 2035 | $2,257,432 | $564,358 | $3,134,438 | | 2035 | |
| 2036 | $2,302,581 | $575,645 | $3,197,127 | | 2036 | |
| 2037 | $2,348,632 | $587,158 | $3,261,069 | | 2037 | |
| 2038 | $2,395,605 | $598,901 | $3,326,291 | | 2038 | |
| 2039 | $2,443,517 | $610,879 | $3,392,817 | | 2039 | |
| 2040 | $2,492,387 | $623,097 | $3,460,673 | | 2040 | |
| 2041 | $2,542,235 | $635,559 | $3,529,886 | | 2041 | |
| 2042 | $2,593,080 | $648,270 | $3,600,484 | | 2042 | |
| NPV | | | $32,960,282 | | | $18,110,970 |
| Benefit - Cost | | | | | | $14,849,311 |
| Benefit/Cost | | | | | | 1.82 |

## 4.4. Costs

Costs associated with work created by the program will be tracked using a work order project code. The project code should include the year of project origination.

Six sample locations were reviewed to estimate annual project costs. The list of remedies to improve circuit reliability includes: FLISR schemes, recloser installations, reconductoring, reducing exposure to long single phase taps by adding line sections from other sources, installation of Cutout Mounted Reclosers (CMR), spot trimming, and animal guard installations. The estimated capital cost of all projects for the sample locations is $ 2.6 M. The work impacted 8,350 customers on the CEMI 4 + list.

When completing the CEMI work, the Company may add other programmatic work, such as FLISR work, to the CEMI feeders for efficiency reasons. This could add 2 to 3 reclosers to each feeder or approximately $1.9M to the yearly cash flow for a total program budget of $4.5M per year. The sample circuits and proposed work can be seen in Appendix A.

*Table 11. Summary of CEMI 4+ Cash Flows*.

| | Cost Type | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 |
|---|---|---|---|---|---|---|
| **CEMI 4+ Program Cash Flows** | Capex | $1,300,000 | $5,312,000 | $4,546,832 | $4,683,237 | $4,823,734 |
| | Opex | $10,600 | $31,212 | $31,836 | $32,473 | $33,122 |
| | Removal | $15,700 | $36,414 | $37,142 | $37,885 | $38,643 |

## 5. Conclusion

The intent of this CEMI 4 + program is to drive performance to EEI first quartile levels through a 5 year investment period. The program is expected to cost $4.5 M annually and reduce the number of customers at CEMI 4 + by approximately 9,000 each year. With benefits approximately equal to costs, the program not only addresses the reliability need but is cost effective. A rolling three-year average CEMI list will be reviewed on a yearly basis to provide an initial list. Detailed reviews and further consultation will revise the list to create the executable work. This refinement will consider other RI Energy initiatives such as FLISR efforts, , Enhanced Hazard Tree program, CMR installations, and Cycle Trimming.

## 6. Appendix A

### 6 Sample Circuits – Proposed work list and estimated costs

| Common Repairs for CEMI work | | | 53 -126W51 (On CEMI list 5 consecutive years) Average Customer Impact 1200, CEMI 6 in 2021 | | | | 53-126W50 ( On CEMI list 5 consecutive years) , Average Customer impact 1320, CEMI 9 in 2021 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CEMI Menu of Potential Repairs | cost / unit | | | Costs | | | | Costs | | |
| Item | Capital | O&M | Item list | Capital | O$M | Rem | Item list | Capital | O&M | Rem. |
| Line Patrol | | $ 170 / hr | 1 day | | $1,360 | | 1 day | | $1,360 | |
| Spot Trimming | | $ 1,250 / day | 3 days along River Rd | | $3,750 | | Louisquissett Pike | | $2,500 | |
| IR Scan | | $1,400 / day | | | | | 1 day (Burnt taps) | | $1,400 | |
| LA or Covering Splices ( Lightning issues) | | $ 170 / hr | 1 day , p 18 to 28 River Rd | | $1,360 | | | | | |
| Animal Guard installations | | $ 500 /pole | 6 locations on Holiday Dr and Timberland Dr | | $3,000 | | Ridge Rock Rd | | $ 500 | |
| Install 3 100 amp in-line fuses | $5,000 | | | | | | | | | |
| 1 Ph Pole Replacements | $5,000 | | | | | | | | | |
| 3 ph pole Replacements | $10,000 | | | | | | | | | |
| OH transformer replacement | $6,200 | | | | | | | | | |
| Install LB switch | $41,000 | | | | | | | | | |
| 1 Ph Cutout mounted recloser installations | $5,000 | | | | | | | | | |
| Line Recloser Installation | $76,000 | | Install a new recloser at p 93 River St, Lincoln | $71,178 | $ 1,000 | $ 1,000 | | | | |
| Three Recloser FLISR Scheme | $250,000 | | | | | | | | | |
| Reconductoring 1 Phase tap with Covered Wire 1 mile | $400 | | | | | | | | | |
| Install 1 Mile of 1/0 SPCA | $656,000 | | | | | | | | | |
| Install 1 Mile of 477 kcmil SPCA | $817,000 | | | | | | | | | |
| Reconductoring 1 mile of 1/0 Alum to 477 SPCA | $1,108,000 | | Reconductor 1/2 mile btwn p 1 and 16 Cullen Hill Rd | $550,000 | $ 15,000 | $ 44,600 | | | | |
| Reconductoring and Convert 1/0 bare alum | $1,117,000 | | | | | | | | | |
| Note all estimates assume 15 kV class construction | | | Cost totals | $ 621,178 | $ 25,470 | $ 45,600 | Cost totals | $0 | $5,760 | 0 |
| | | | | | | | FLISR | $250,000.00 | $ 10,000 | $ 5,000 |

| Common Repairs for CEMI work | | | 56 - 54F1, (On List 5 consecutive years) Customer impact 1740, CEMI 9 in 2021 | | | | 56 -63F6, (On List 5 consecutive years Customer impact 1500, CEMI 9 in 2021 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CEMI Menu of Potential Repairs | cost / unit | | | Costs | | | | Costs | | |
| Item | Capital | O&M | Item List | Capital | O&M | Rem | Item List | Capital | O&M | Rem |
| Line Patrol | | $ 170 / hr | | | | | | | | |
| Spot Triming | | $ 1,250 / day | 1/2 mile spot trim Isaac Fiske Rd and Lionel Person Rd. | | $ 3,000 | | Spot trimming | | $ 1,250 | $ 1,250 |
| IR Scan | | $1,400 / day | | | | | | | | |
| LA or Covering Splices ( Lightning issues) | | $ 170 / hr | | | | | | | | |
| Animal Guard installations | | $ 500 /pole | p 5-4 Lionel Parsons | | $ 500 | | Pole Replacements | $ 10,000 | $ 500 | $ 500 |
| Install 3 100 amp in-line fuses | $5,000 | | | | | | | | | |
| 1 Ph Pole Replcements | $5,000 | | | | | | | | | |
| 3 ph pole Replacemnts | $10,000 | | | | | | | | | |
| OH transformer replacement | $6,200 | | | | | | | | | |
| Install LB switch | $41,000 | | | | | | | | | |
| 1 Ph Cutout mounted recloser installations | $5,000 | | | | | | p 486 Ten Rd Rd. | $ 30,000 | | |
| Line Recloser Installation | $76,000 | | | | | | | | | |
| Three Recloser FLISR Scheme | $250,000 | | | | | | | | | |
| Reconductoring 1 Phase tap with Covered Wire 1 mile | $762,000 | | Reconductor 1 Mile of 1/0 Alum with covered wire on Parts of Sessions Rd, Reduce exposure by extending lines from other streets. | $ 400,000 | $ 10,000 | $ 10,000 | | | | |
| Install 1 Mile of 1/0 SPCA | $656,000 | | | | | | | | | |
| Install 1 Mile of 477 kcmil SPCA | $817,000 | | | | | | | | | |
| Reconductoring 1 mile of 1/0 Alum to 477 SPCA | $1,108,000 | | | | | | | | | |
| Reconductoring and Convert 1/0 bare alum | $1,117,000 | | | | | | | | | |
| Note all estimates assume 15 kV class construction | | | Cost Totals | $ 400,000 | $ 13,500 | $ 10,000 | Cost Totals | $ 40,000 | $ 1,750 | $ 1,750 |
| | | | | | | | FLISR Scheme Ten Rod Rd | $ 250,000 | $ 10,000 | $ 5,000 |

| Common Repairs for CEMI work | | | 56-155F4 ( On CEMI list 5 consecutive years) | | | | 56- 30F2, ( On List 5 consecutive Years) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| CEMI Menu of Potential Repairs | cost / unit | | | Costs | | | | Costs | | |
| Item | Capital | O&M | Item list | Capital | O$M | Removal | Item List | Capital | O&M | Rem |
| Line Patrol | | $ 170 / hr | | | | | | | | |
| Spot Triming | | $ 1,250 / day | 3 days Braford and Oak St | | $ 3,000 | | Spot Trimming Ten Rod rd | | $ 1,500 | |
| IR Scan | | $1,400 / day | | | | | | | | |
| LA or Covering Splices ( Lightning issues) | | $ 170 / hr | | | | | | | | |
| Animal Guard installations | | $ 500 /pole | | | | | p 39 William Reynolds Rd | | $ 1,500 | |
| Install 3 100 amp in-line fuses | $5,000 | | pole Wirk North Granite Ave | $ 10,000 | $ 500 | $ 500 | | | | |
| 1 Ph Pole Replcements | $5,000 | | | | | | | | | |
| 3 ph pole Replacemnts | $10,000 | | | | | | | | | |
| OH transformer replacement | $6,200 | | | | | | | | | |
| Install LB switch | $41,000 | | | | | | | | | |
| 1 Ph Cutout mounted recloser installations | $5,000 | | | | | | P 37 Purgatory Rd | $ 5,000 | | |
| Line Recloser Installation | $76,000 | | 2 PTRs One at Oak St, one Ashaway Rd | $ 152,000 | | | | | | |
| Three Recloser FLISR Scheme | $250,000 | | | | | | | | | |
| Reconductoring 1 Phase tap with Covered Wire 1 mile | $400 | | | | | | Reconductor Long Single phase tap | $ 415,000.00 | $ 8,000.00 | $ 10,500 |
| Install 1 Mile of 1/0 SPCA | $656,000 | | | | | | | | | |
| Install 1 Mile of 477 kcmil SPCA | $817,000 | | | | | | | | | |
| Reconductoring 1 mile of 1/0 Alum to 477 SPCA | $1,108,000 | | | | | | | | | |
| Reconductoring and Convert 1/0 bare alum | $1,117,000 | | | | | | | | | |
| Note all estimates assume 15 kV class construction | | | Cost totals | $ 162,000 | $ 3,500 | $ 500 | Cost Totals | $ 420,000 | $ 11,000 | $ 10,500 |
| | | | | | | | FLISR Scheme Ten Rod Rd | $ 250,000 | $ 10,000 | $ 5,000 |

**Attachment 8 – Engineering Reliability Reviews (ERR) Guidance Documentation**

# RI Energy

# Engineering Reliability Review (ERR) Guidance Document

**Mark Fraser**

**October 11, 2023**



| Issue | Date | Summary of Changes | Author(s) | Approved by Include Job Title. |
|---|---|---|---|---|
| 1.0 | 10/11/2023 | First Issue | Mark Fraser | Eric Wiesner<br>Manager – Regional Engineering |

# Table of Contents

## 1. Executive Summary

Utility performance is commonly scored based on the average system outage frequency (SAIFI) and average system customer outage duration (SAIDI). While these are useful metrics to benchmark the system performance against regulatory metrics and peers, using system averages results in some feeders not meeting reliability standards. The Engineering Reliability Review (ERR) Program will have engineers annually rank the worst performing feeders, select the worst 5% of the feeders, perform an in-depth analysis to determine what caused the outages, and recommend solutions to address and prevent future outages. Feeder rankings will be based on the 5-year average individual circuit interruption frequency (CKAIFI), 5-year average circuit interruption duration (CKAIDI), and operational feedback. Having a systematic approach for improving system reliability is the most cost-effective plan that will benefit the greatest number of customers while reducing the number and duration of customer outages.

The goal of this review is to reduce the frequency and duration of power outages to customers. The projects identified are expected to cost $ 4.5 M annually and reduce the CKAIFI and CKAIDI of the poor performing feeders to or below 1.05 and 71.9 minutes respectfully.

This review will consider other programs, such as the Distribution Automation Recloser and the Customers Experiencing Multiple Interruptions (CEMI) and ongoing project work to ensure no overlap, redundancy, or early obsolescence of investments.

## 2. Background and Purpose

The most commonly used customer-based reliability indices for sustained outages in the electric utility industry are System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). SAIFI indicates how frequently the average customer experienced a sustained interruption over a specified time. SAIDI indicates how long (minutes or hours) the average customer was without service over a specific time, typically one year.

SAIFI and SAIDI defined at the circuit level:

> *'Circuit Average Interruption Frequency Index' (CKAIFI) is calculated by dividing the total number of customers interrupted annually (CI) by the total number of customers served (Cs).*
>
> *CKAIFI = CI / Cs*
>
> *'Circuit Average Interruption Duration Index' (CKAIDI) is calculated by dividing the total number of customers minutes interrupted annually (CMI) by the total number of customers served (Cs).*
>
> *CKAIDI = CMI / Cs*

The aim of this review 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 above our regulatory targets.

## 3. Justification

RI Energy has reviewed historical reliability data and found that approximately 100 feeders have frequency and/or duration statistics greater than the regulatory thresholds, with average yearly frequencies as high as 4 and average yearly durations as high as 350 minutes. Additionally, RI Energy continues to receive customer complaints regarding reliability, including on circuits with statistics better than regulatory criteria. The Company considers this to be unacceptable reliability performance requiring the review in this document.

## 4. Plan

The plan is to review the annual poor performing circuit list and to rank each based on a combination of the Circuit Average Interruption Frequency Index (CKAIFI) and the Circuit Average Interruption Duration Index (CKAIDI). Based on these rankings and feedback from Field Operations and the Control Center, reliability reviews will be initiated for the 5% worst performing circuits. Any circuits that have been in the ERR or the CEMI programs in the last three years will be excluded as improvements would have recently been proposed, in progress, or completed.

Once the feeders are selected, Field Engineers, working closely with Operations Supervisors, will review circuit reliability and event history looking for locations of frequent outages caused by vegetation issues, animal contact, and equipment failures. Field inspections will also include infrared surveys, system pole line construction reviews, line balancing opportunities, system hardening locations, protection coordination concerns, and reviewing locations for additional sectionalizing. Reclosers enabling Fault Location Isolation and Service Restoration, cutout mounted reclosers, tie switches, enhanced hazard tree removal, fuse additions, reconductoring, and other reliability improvement tools will be utilized to improve circuit reliability.

Each proposed project will have a high-level estimated cost along with calculated projected reductions in CKAIFI and CKAIDI. The most favorable projects for each feeder will be forwarded to Design Engineering for job packet creation and an overall projected CKAIFI and CKAIDI value will be created based on the approved projects. Designed jobs will follow the normal workflow and be forwarded on to Operations for construction.

## 5. Timing

To have the greatest reliability impact for this review it is important to have these projects ready to be constructed at the beginning of the fiscal year. The time frame necessary to meet this goal:

- Determine the ERR circuit list by October 1.
- Regional Field Engineering to have all completed ERR project recommendations to the Design group by December 31.
- The Design Group to have all designs completed by April 1.
- Project construction begins in April with emphasis to complete work before the summer season.

## 6. Implementation and Communication

Once the ERR circuits have been selected, Field Engineering will meet weekly to gauge progress and review proposed projects. The list of possible projects will be catalogued on a department SharePoint site providing feeder numbers, project details, cost estimates, and projected CKAIFI and CKAIDI. Any project justification information will also be saved at the SharePoint location.

The ERR lead will forward approved projects onto Design Engineering and enter these into the project database. This representative will attend the regularly scheduled project management meetings held between Design, Project Management, Scheduling, and Field Operations. At these meetings, all field related projects and programs are discussed. This shared knowledge is important to know the full scope of projects underway and how we can either leverage one program to improve another or area to avoid due to pending work.

## 7. Measuring Reliability Improvement

The success of these investments will be based on actual reliability performance achieved. However, a number of years of data is required to reach a conclusion on success. 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.

## 8. Appendix A – Engineering Reliability Review Template

## Memorandum

**To:** Manager's Name

**From:** Engineer's Name

**Date:** Date

**Subject:** Engineering Reliability Review for feeder XX-XXX

---

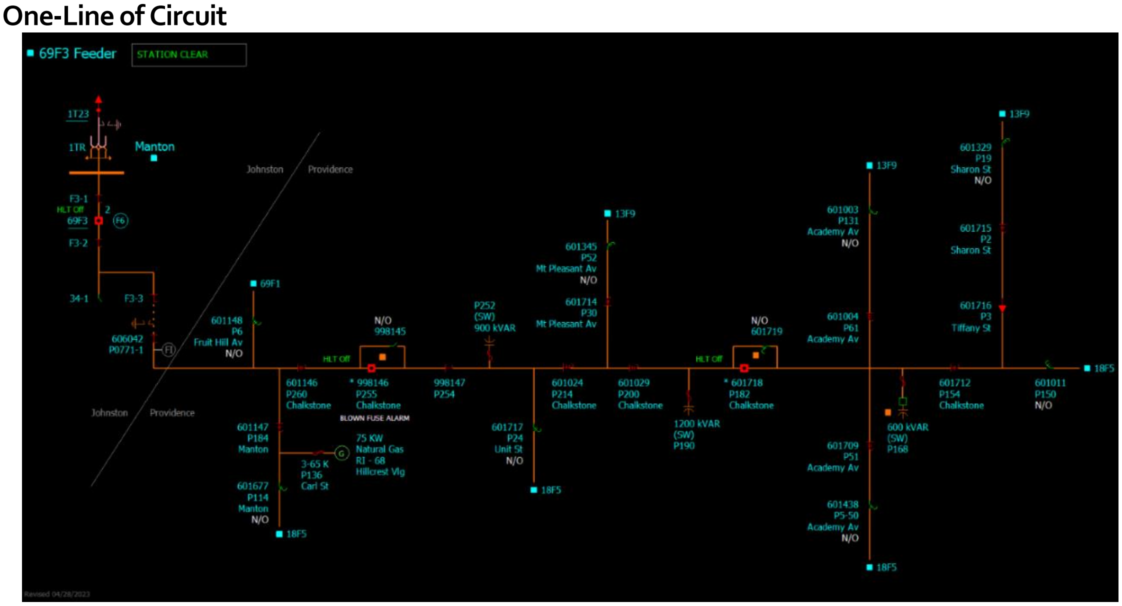
This memo documents the recommendations to improve CKAIFI and / or CKAIDI on the 20XX Engineering Reliability Review for feeder XX-XXX.

### RELIABILITY PERFORMANCE

| Substation | ERR Program Year | Circuit | Events | Customers Interrupted | Customer Minutes Interrupted | Customers Served | CKAIFI (5 year avg.) | CKAIDI (5 year avg.) |
|---|---|---|---|---|---|---|---|---|
| W. Greenville | 2025 | XX-XXFX | 27 | 4,401 | 300,289 | 1,867 | 2.36 | 160.84 |

| | 2019 | 2020 | 2021 | 2022 | 2023 | Average | Targets After Project Implementation |
|---|---|---|---|---|---|---|---|
| **CKAIFI** | 1.51 | 2.00 | 1.30 | 0.79 | 2.30 | 2.36 | |
| **CKAIDI** | 180.0 | 210.0 | 150.0 | 222.0 | 195.0 | 160.8 | |

### One-Line of Circuit



## Summary of Significant Outage Events Major Outages-Over the Last Five Years
## (Significant contribution to CKAIFI is >=.1 and >= 30 min for CKAIDI)

**Circuit ____XXXX___**

| TIME_OFF | UNIQUE_LOCATION | CAUSE | DAY_TYPE | TWN_NAME | Estimated CKAIFI | Estimated CKAIDI Min |
|---|---|---|---|---|---|---|
| 8/23/2022 | 53-127W40: H: GREAT RD (0075) | Lightning | Blue Sky | BURRILLVILLE | 3.40 | 418.60 |
| 3/13/2020 | 53-127W40: D: BRONCO FT14 HWY (0030) | Deterioration | Blue Sky | WOONSOCKET | 2.39 | 18.42 |
| 12/18/2021 | 53-127W40: A: 523 FT14 ROW (0034) | Insulation failure - other | Blue Sky | NORTH SMITHFIELD | 1.57 | 154.00 |
| 12/16/2021 | 53-127W40: H: GREAT RD (0075) | Unknown | Blue Sky | WOONSOCKET | 1.57 | 99.93 |
| 7/18/2022 | 53-127W40: A: 523 FT14 ROW (0034) | Device Failed | Blue Sky | NORTH SMITHFIELD | 1.22 | 54.84 |
| 3/1/2021 | 53-127W40: BAAF: DOUGLAS PIKE (0047) | Device Failed | Blue Sky | BURRILLVILLE | 1.00 | 14.05 |
| 10/7/2019 | 53-127W40: E: VICTORY HWY (0075) | Vehicle | Blue Sky | SMITHFIELD | 0.99 | 64.15 |
| 4/13/2020 | 53-127W40: D: BRONCO FT14 HWY (0030) | Tree - Broken Limb | Major Storm | BURRILLVILLE | 0.90 | 378.40 |
| 10/8/2019 | 53-127W40: D: BRONCO FT14 HWY (0030) | Device Failed | Blue Sky | NORTH SMITHFIELD | 0.68 | 21.08 |
| 2/14/2023 | 53-127W40: F: VICTORY HWY (0075) | Vehicle | Blue Sky | MILLVILLE | 0.68 | 7.45 |
| 4/8/2018 | 53-127W40: D: BRONCO FT14 HWY (0030) | Tree - Broken Limb | Blue Sky | NORTH SMITHFIELD | 0.68 | 1.35 |
| 2/25/2019 | 53-127W40: D: BRONCO FT14 HWY (0030) | Vehicle | Major Storm | BURRILLVILLE | 0.65 | 60.72 |
| 4/12/2023 | 53-127W40: H: GREAT RD (0075) | Vehicle | Blue Sky | NORTH SMITHFIELD | 0.32 | 12.18 |
| 4/15/2019 | 53-127W40: BAA: DOUGLAS PIKE (0034) | Lightning | Major Storm | BURRILLVILLE | 0.21 | 23.23 |
| 7/26/2018 | 53-127W40: BAA: DOUGLAS PIKE (0034) | Tree Fell | Blue Sky | BURRILLVILLE | 0.21 | 2.90 |
| 1/7/2022 | 53-127W40: FH: NORTH MAIN ST (0131) | Vehicle | Blue Sky | NORTH SMITHFIELD | 0.17 | 4.51 |
| 9/9/2019 | 53-127W40: FJ: CARLIN DR (0131) | Vehicle | Blue Sky | NORTH SMITHFIELD | 0.16 | 33.74 |
| 3/31/2023 | 53-127W40: C: DOUGLAS PIKE (0034) | Vehicle | Blue Sky | SMITHFIELD | 0.11 | 18.89 |
| 10/17/2019 | 53-127W40: BAADAGBAA: CLUB LN (0033) | Tree - Broken Limb | Major Storm | BURRILLVILLE | 0.09 | 95.88 |
| 2/7/2020 | 53-127W40: FH: NORTH MAIN ST (0131) | Tree Fell | Major Storm | NORTH SMITHFIELD | 0.09 | 35.90 |
| 2/25/2019 | 53-127W40: FH: NORTH MAIN ST (0131) | Tree Fell | Major Storm | NORTH SMITHFIELD | 0.09 | 38.89 |
| 8/4/2020 | 53-127W40: CD: DOUGLAS PIKE (0034) | Tree Fell | Major Storm | BURRILLVILLE | 0.08 | 30.14 |
| 3/2/2018 | 53-127W40: CD: DOUGLAS PIKE (0034) | Tree Fell | Major Storm | BURRILLVILLE | 0.08 | 120.90 |

**PROPOSED PROJECTS**

These projects are being designed and are to be constructed.

| Title/Description | Category | Est. Cost | Customer Interruptions Saved | Customer Minutes Saved |
|---|---|---|---|---|
| Upgrade distribution plant to tree wire from P6 to P18 Reservoir Road. Trimming required. Cumberland | Line | $120,000 | 150 | 10,957 |
| Install PTR at P118 Nate Whipple Hwy looking east. This will allow better fuse coordination and meet loading requirements. Cumberland. | PTR | $83,000 | 700 | 8,000 |
| Replace 3-100K fuses with 3-100K CMRs at P2 Diamond Hill Road. Cumberland | CMR | $15,000 | 250 | 10,466 |
| Replace 40K fuse with a CMR at P37 Wrentham Road feeding down Sumner Brown Road. Cumberland | CMR | $10,000 | 50 | 4,480 |
| Replace 100K fuse with a CMR at 327 Diamond Hill Road feeding down Reservoir Road. Cumberland | CMR | $10,000 | 80 | 3,936 |
| Replace 65K fuse with a CMR at P65 Reservior Road feeding down Torrey Road. Cumberland | CMR | $10,000 | 72 | 2,592 |
| Upgrade fuse to 100K at P99 Nate Whipple Hwy. Replace fuses at P104 Little Pond Country Road with 65K CMR. Add second 40K fuse at P80 Little Pond Country Road/Longbrook Drive. Cumberland | CMR | $10,000 | 85 | 2,882 |
| Install C/O with 25K Fuse at P27 Sumner Brown Road to slit up the customer count. Cumberland | Fuse | $4,000 | 30 | 2,800 |
| Relocate 3 - 65CMRs to P10 Wrentham Road from P2 Fisher Road. Cumberland | CMR | $4,000 | 180 | 12,267 |

**CONSIDERED PROJECTS**

These projects were reviewed but are not being considered at this time.

| Title/Description | Category | Est. Cost | Customer Interruptions Saved | Customer Minutes Saved |
|---|---|---|---|---|
| Close 3,200' gap along Pine Swamp Road to create loop with 112W43. Will require PTR. Part of IIJA proposed work. Cumberland. | Line | $467,000 | 1,500 | 95,000 |
| Upgrade to tree wire from P8 to P26 Sumner Brown Road. (3,700') Cumberland | Line | $296,000 | 50 | 35,000 |
| Upgrade to tree wire from P26 to P43 Sumner Brown Road. (3,200') Cumberland | Line | $288,000 | 35 | 3,000 |

## COMPLETED WORK

These reliability projects were recently completed.

| Town | Feeder | WR No. | WR Status Code | Work Request Description | Job Type Code |
|---|---|---|---|---|---|
| PROVIDENCE | 53-69F3 | 25622441 | 90 | Install radio antenna for recloser - Distribution Electric Reliability | DRELIABLE |
| PROVIDENCE | 53-69F3 | 28117251 | 90 | Replace broken Pole - Distribution Electric Asset 39.00% EXPENSE | DASSETREPL |
| PROVIDENCE | 53-69F3 | 28208183 | 90 | Replace Pin Insulators 100% EXPENSE | DMAINT-G |
| PROVIDENCE | 53-69F3 | 29951048 | 90 | INSTALL 25KVA TRANSFORMER ON P28 & FUSE @10K dm | DRELIABLE |
| PROVIDENCE | 53-69F3 | 30323664 | 80 | Transfer to new pole dm NJUNS | DPUBLICRQ |
| PROVIDENCE | 53-69F3 | 30336136 | 80 | DOTR - Intersection Safety Improvements Pole 41-50 Mt Pleasant Ave. | DENEDOT |
| PROVIDENCE | 53-69F3 | 30489027 | 90 | Distribution Electric Public Requirements for Distributed Generation Projects | DPUBLICDG |
| PROVIDENCE | 53-69F3 | 30597033 | 90 | Distribution Electric Reliability dm | DRELIABLE |
| PROVIDENCE | 53-69F3 | 30647433 | 80 | Distribution Electric Reliability dm of the 100 recolosers dm | DRELIABLE |
| PROVIDENCE | 53-69F3 | 30657540 | 80 | Distribution Electric Damage/Failure-N/B, Capacitor Replacement dm | DDAMAGE |
| PROVIDENCE | 53-69F3 | 30694922 | 80 | Distribution Electric Load Relief dm | DLOADRELF |
| PROVIDENCE | 53-69F3 | 30697493 | 80 | Voltage Complaint NEEDS DONE ASAP | DLOADRELF |
| PROVIDENCE | 53-69F3 | 30703124 | 80 | See WR 30707883 for Triplex installation - Line Ops - Other | DMAINT-G |
| PROVIDENCE | 53-69F3 | 30707883 | 90 | Replace triplex to P.128 - Distribution Electric Damage/Failure-N/B | DDAMAGE |

## PENDING WORK

These reliability projects are pending.

| Town | Feeder | WR Number | Status | Work Request Description | Job Type |
|---|---|---|---|---|---|
| RI GLOCESTER | 53-34F2 | 29952133 | 10 | 34F2 priority D2C Computapole inspection WR for overhead - 179 locations. | DASSETOH2C |
| GLOCESTER | 53-34F2 | 30427114 | 20 | DER Chopmist - 34F2 - P 576 CAP | DLOADRELF |
| GLOCESTER | 53-34F2 | 30427121 | 20 | DER Chopmist - 34F2 - P452 CAP | DLOADRELF |
| GLOCESTER | 53-34F2 | 30427124 | 20 | DER Chopmist - 34F2 - P393 CAP | DLOADRELF |
| GLOCESTER | 53-34F2 | 30444722 | 20 | DER Chopmist - 34F2 - P16 CAP BANK | DLOADRELF |
| GLOCESTER | 53-34F2 | 30444790 | 20 | DER Chopmist - 34F2 - New P151 Recloser | DLOADRELF |
| GLOCESTER | 53-34F2 | 30445165 | 20 | DER Chopmist - 34F2 - P11 Cap Bank | DLOADRELF |
| GLOCESTER | 53-34F2 | 30594538 | 40 | Distribution Electric Public Requirement | DPUBLICRQ |
| NORTH SCITUATE | 53-34F2 | 30726202 | 40 | Distribution Electric Public Requirements for Distributed Generation Projects | DPUBLICDG |
| GLOCESTER | 53-34F2 | 29291762 | 50 | REPL P12 ON ROW BEHIND PROP # 117 SPRING GROVE dm | DRELIABLE |
| GLOCESTER | 53-34F2 | 30755265 | 50 | I&M Level 9 Computapole - 1ph pole | DASSETREPL |
| GLOCESTER | 53-34F2 | 30703563 | 60 | ASSET REPLACEMENT 12/05/22, 1615 SNAKE HILL RD, N. SCITUATE RI FDR 34F2 | DASSETREPL |
| RI GLOCESTER | 53-34F2 | 17134667 | 60 | 34F2 priority D2C Computapole inspection WR for overhead - VZ locations. | DASSETOH2C |

## ADDITIONAL REVIEWS/RECOMMENDATIONS

### SHORT TERM

**Tree Trimming:** **Recommended (or Not)**
Describe...

**Animal Mitigation:** **Recommended (or Not)**
Describe...

**Fault Indicators:** **Recommended (or Not)**
Describe...

**Load Balancing:** **Recommended (or Not)**
Describe...

**Protective Device Coordination Review:** **Recommended (or Not)**
Describe...

**Cutout Mounted Recloser Installations:** **Recommended (or Not)**
Describe...

**Line Recloser Installations (include Form3s):** **Recommended (or Not)**
Describe...

**Additional Circuit Sectionalizing:** **Recommended (or Not)**
Describe...

**Additional Feeder Ties/Reconfiguration:** **Recommended (or Not)**
Describe...

**Other Recommendations:** **Recommended (or Not)**
Describe...

### LONG TERM SYSTEM IMPROVEMENTS OUTSIDE THE SCOPE OF THE ERR

**Project Description:**
Describe…

**Attachment 9 – Docket 4600 Analysis**

- Attachment 9-1 Distribution Automation Recloser Program
- Attachment 9-2 Engineering Reliability Review Program

**FY2025 New Projects**

**Attachment 9-1 Distribution Automation Recloser Program**

| GOALS FOR "NEW" ELECTRIC SYSTEM | IMPACT | EXPLANATION |
|---|---|---|
| Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels) | Advances | This project will provide substantial reliability benefits. |
| Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures | Neutral | This project does not impact the Rhode Island economy. |
| Address the challenge of climate change and other forms of pollution | Neutral | This reliability project does not impact climate change. |
| Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits | Neutral | This reliability project does create an ability for future system reconfiguration that can be used to optimize renewable generation. |
| Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society | Neutral | This project does not change the compensation distributed energy resources receive. |
| Appropriately charge customers for the cost they impose on the grid. | Neutral | This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid. |
| Appropriately compensate the distribution utility for the services it provides | Advances | This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal. |
| Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive | Neutral | This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives. |

**Docket 4600 Benefit-Cost Framework**

| | |
|---|---|
| **Project Name:** | Distribution Automation Recloser Program |
| **Area Study:** | None |
| **Problem:** | This program aims to set forth the general conditions for installing line reclosers on overhead distribution circuits. This is a reliability focused strategy designed to meet both state regulatory targets and support RI Energy's goal of achieving national and regional first quartile reliability performance. While the reliability needs and benefits of installing reclosers are immediate, this strategy also enables other benefits as each recloser acts as a distribution monitor and remote controlled switch for system management during situations other than interruptions. Specifically, a number of circuits have circuit frequency and duration values above the regulatory criteria. The Company intends to target circuits with high frequency and duration statistics first. |
| **Preferred Plan:** | Install reclosers prioritized based on ranking their interruption frequency, interruption duration, line exposure, customers experiencing multiple interruptions, existing sectionalization, distributed generation penetration, and pending construction activities. The initial group of reclosers is estimated at 166 units with circuit frequencies greater than 1.5. |
| **Alternate Plan:** | None |

**Summary of Benefit - Cost Analysis**

| | |
|---|---|
| **Preferred Plan** | |
| Benefit Cost Ratio | 1.05 |
| Net Benefit/Cost | $ 894,928.11 |
| **Alternate Plan** | |
| Benefit Cost Ratio | |
| Net Benefit/Cost | $ - |

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

**Preferred Plan:**

| Benefit/Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| Cost | Power System | Distribution capacity costs | | $ (16,777,000) | Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment. |
| Cost | Power System | Distribution delivery costs | | $ - | Cost to operate and maintain the project equipment is included in the line item above. |
| Cost | Power System | Electric transmission infrastructure costs for Site Specific Resources | | $ - | This project does not have associated Transmission project costs. |
| Cost | Customer | Program participant / prosumer benefits / costs | | $ - | There are no customer or participant actions or investments (CIAC) involved in this project. |
| Cost | Customer | Participant non-energy costs/benefits: Oil, Gas, Water, Wastewater | | $ - | This project does not impact water or other fuels. |
| Cost | Societal | Non-energy costs/benefits: Economic Development | | $ - | This project does not have societal costs. |
| Benefit | Power System | Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP) | | $ - | This project does not result in any line loss savings or energy savings. |
| Benefit | Power System | Renewable Energy Credit Cost / Value | | $ - | This project does not impact generation capacity or impact REC costs. |
| Benefit | Power System | Retail Supplier Risk Premium | | $ - | This project does not impact generation capacity or impact REC costs. |

| Benefit/Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| Benefit | Power System | Forward Commitment: Capacity Value | | $ - | This project does not result in any line loss savings or capacity savings. |
| Benefit | Power System | Forward Commitment: Avoided Ancillary Services Value | | $ - | This project does not impact transmission ancillary services. |
| Benefit | Power System | Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs | | $ - | This project does not impact generation capacity or impact REC costs. |
| Benefit | Power System | Electric Transmission Capacity Costs / Value | | $ - | This project does not impact transmission costs. |
| Benefit | Power System | Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity | | $ - | This project does not directly provide flexible resources that will impact system operations. |
| Benefit | Power System | Option value of individual resources | | $ - | This project does not impact the option value of individual resources. |
| Benefit | Power System | Investment under Uncertainty: Real Options Cost / Value | | $ - | This project is not categorized as an investment under uncertainty. |
| Benefit | Power System | Energy Demand Reduction Induced Price Effect | | $ - | This project does not impact DRIPE. |

| Benefit/Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| Benefit | Power System | Greenhouse gas compliance costs | | $ - | This project does not result in energy savings that impact GHG Compliance Costs. |
| Benefit | Power System | Criteria air pollutant and other environmental compliance costs | | $ - | This project does not impact environmental compliance costs. |
| Benefit | Power System | Innovation and Learning by Doing | | $ - | This project does not impact innovation or market transformation or provide innovation and learning by doing. |
| Benefit | Power System | Distribution system safety loss/gain |  | $ - | This program allows Control Center personnel to remotely operate devices allowing for faster response during emergency or planned outage work. |
| Benefit | Power System | Distribution system performance |  | $ - | This program allows the Control Center personnel to remotely reconfigure the system to optimize performance for actual conditions. This includes possible future reconfigurations to optimize renewable generation deployment. |
| Benefit | Power System | Utility low income | | $ - | This project does not impact low income participant non-energy benefits. |
| Benefit | Power System | Distribution system and customer reliability / resilience impacts | | $17,671,928 | Reliability benefits were calculated using the USDOE ICE Calculator for this project. The project is estimated to provide an approximate customer benefit of $1.5M per year with a 20-year net present value benefit of approximately $18M. |

| Benefit/Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| | Customer | Program participant / prosumer benefits / costs | | $ - | There are no customer or participant actions or investments (CIAC) involved in this project. |
| | Customer | Participant non-energy costs/benefits: Oil, Gas, Water, Wastewater | | $ - | This project does not impact water or other fuels. |
| | Customer | Low-Income Participant Benefits | | $ - | This project does not impact low income participant non-energy benefits. |
| | Customer | Consumer Empowerment & Choice | | $ - | This project does not directly impact customer empowerment. |
| | Customer | Non-participant (equity) rate and bill impacts | | $ - | This project does not directly impact customer rate and bills. |
| | Societal | Greenhouse gas externality costs | | $ - | GHG savings are associated with loss reductions from this project and avoided bulk energy purchases. |
| | Societal | Criteria air pollutant and other environmental externality costs | | $ - | Criteria air pollutant and other environmental externalist costs are associated with loss reductions from this project and avoided bulk energy purchases. |
| | Societal | Conservation and community benefits | | $ - | This project does not directly reduce Environmental Impacts. |
| | Societal | Non-energy costs/benefits: Economic Development | | $ - | This project does not directly impact economic development. |

| Benefit/Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| | Societal | Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment) | | $ - | This project does not impact innovation or market transformation. |
| | Societal | Societal Low-Income Impacts | | $ - | This project does not impact low income participant non-energy benefits. |
| | Societal | Public Health | | $ - | Public Health benefits are associated with emissions reductions through loss reductions from this project and avoided bulk energy purchases. |
| | Societal | National Security and US international influence | | $ - | This project does not impact National Security. |

**FY2025 New Projects**

## Attachment 9-2 Engineering Reliability Review Program

| GOALS FOR "NEW" ELECTRIC SYSTEM | IMPACT | EXPLANATION |
|---|---|---|
| Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels) | Advances | This project will provide substantial reliability benefits. |
| Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures | Neutral | This project does not impact the Rhode Island economy. |
| Address the challenge of climate change and other forms of pollution | Neutral | This reliability project does not impact climate change. |
| Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits | Neutral | Portions of this reliability project will create an ability for future system reconfiguration that can be used to optimize renewable generation. |
| Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society | Neutral | This project does not change the compensation distributed energy resources receive. |
| Appropriately charge customers for the cost they impose on the grid. | Neutral | This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid. |
| Appropriately compensate the distribution utility for the services it provides | Advances | This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal. |
| Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive | Neutral | This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives. |

**Docket 4600 Benefit-Cost Framework**

| | |
|---|---|
| **Project Name:** | Engineering Reliability Reviews |
| **Area Study:** | None |

**Problem:** The Engineering Reliability Review (ERR) Program goal to address and reduce the frequency and duration of power outages to customers on circuits with poor performance as compared to regulatory targets. This program will have engineers annually rank the worst performing feeders, select the worst 5% of the feeders, perform an in-depth analysis to determine what caused the outages, and recommend solutions to mitigate and prevent future outages. Feeder rankings will be based on the 5-year average individual circuit interruption frequency (CKAIFI), 5-year average circuit interruption duration (CKAIDI), and operational feedback.

**Preferred Plan:** The plan is to review the annual poor performing circuit list and to rank each based on a combination of the Circuit Average Interruption Frequency Index (CKAIFI) and the Circuit Average Interruption Duration Index (CKAIDI). Based on these rankings and feedback from Field Operations and the Control Center, reliability reviews will be initiated for the 5% worst performing circuits. Any circuits that have been in the ERR or the CEMI programs in the last three years will be excluded as improvements would have recently been proposed, in progress, or completed. 16 Circuits have been prioritized for FY2025 with an average CKAIFI of 1.74 and an average CKAIDI of 141 minutes.

**Alternate Plan:** None

**Summary of Benefit - Cost Analysis**

| | |
|---|---|
| **Preferred Plan** | |
| Benefit Cost Ratio | 8.69 |
| Net Benefit/Cost | $ 21,565,202.44 |
| **Alternate Plan** | |
| Benefit Cost Ratio | |
| Net Benefit/Cost | $ - |

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

| Benefit/ Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| Cost | Power System | Distribution capacity costs | | $ (2,803,000) | Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment. |
| Cost | Power System | Distribution delivery costs | | $ - | Cost to operate and maintain the project equipment is included in the line item above. |
| Cost | Power System | Electric transmission infrastructure costs for Site Specific Resources | | $ - | This project does not have associated Transmission project costs. |
| Cost | Customer | Program participant / prosumer benefits / costs | | $ - | There are no customer or participant actions or investments (CIAC) involved in this project. |
| Cost | Customer | Participant non-energy costs/benefits: Oil, Gas, Water, Wastewater | | $ - | This project does not impact water or other fuels. |
| Cost | Societal | Non-energy costs/benefits: Economic Development | | $ - | This project does not have societal costs. |
| Benefit | Power System | Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP) | | $ - | This project does not result in any line loss savings or energy savings. |
| Benefit | Power System | Renewable Energy Credit Cost / Value | | $ - | This project does not impact generation capacity or impact REC costs. |
| Benefit | Power System | Retail Supplier Risk Premium | | $ - | This project does not impact generation capacity or impact REC costs. |
| Benefit | Power System | Forward Commitment: Capacity Value | | $ - | This project does not result in any line loss savings or capacity savings. |

| Benefit/ Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| Benefit | Power System | Forward Commitment: Avoided Ancillary Services Value | | $ - | This project does not impact transmission ancillary services. |
| Benefit | Power System | Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs | | $ - | This project does not impact generation capacity or impact REC costs. |
| Benefit | Power System | Electric Transmission Capacity Costs / Value | | $ - | This project does not impact transmission costs. |
| Benefit | Power System | Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity | | $ - | This project does not directly provide flexible resources that will impact system operations. |
| Benefit | Power System | Option value of individual resources | | $ - | This project does not impact the option value of individual resources. |
| Benefit | Power System | Investment under Uncertainty: Real Options Cost / Value | | $ - | This project is not categorized as an investment under uncertainty. |
| Benefit | Power System | Energy Demand Reduction Induced Price Effect | | $ - | This project does not impact DRIPE. |

| Benefit/ Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| Benefit | Power System | Greenhouse gas compliance costs | | $ - | This project does not result in energy savings that impact GHG Compliance Costs. |
| Benefit | Power System | Criteria air pollutant and other environmental compliance costs | | $ - | This project does not impact environmental compliance costs. |
| Benefit | Power System | Innovation and Learning by Doing | | $ - | This project does not impact innovation or market transformation or provide innovation and learning by doing. |
| Benefit | Power System | Distribution system safety loss/gain | ↑ | $ - | Some equipment installed under this program allows Control Center personnel to remotely operate devices allowing for faster response during emergency or planned outage work. |
| Benefit | Power System | Distribution system performance | ↑ | $ - | Some equipment installed under this program allows the Control Center personnel to remotely reconfigure the system to optimize performance for actual conditions. This includes possible future reconfigurations to optimize renewable generation deployment. |
| Benefit | Power System | Utility low income | | $ - | This project does not impact low income participant non-energy benefits. |
| Benefit | Power System | Distribution system and customer reliability / resilience impacts | | $ 24,368,202 | Reliability benefits were calculated using the USDOE ICE Calculator for this project. The project is estimated to provide an approximate customer benefit of $2M per year with a 20-year net present value benefit of approximately $24M. |

| Benefit/ Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| | Customer | Program participant / prosumer benefits / costs | | $ - | There are no customer or participant actions or investments (CIAC) involved in this project. |
| | Customer | Participant non-energy costs/benefits: Oil, Gas, Water, Wastewater | | $ - | This project does not impact water or other fuels. |
| | Customer | Low-Income Participant Benefits | | $ - | This project does not impact low income participant non-energy benefits. |
| | Customer | Consumer Empowerment & Choice | | $ - | This project does not directly impact customer empowerment. |
| | Customer | Non-participant (equity) rate and bill impacts | | $ - | This project does not directly impact customer rate and bills. |
| | Societal | Greenhouse gas externality costs | | $ - | GHG savings are associated with loss reductions from this project and avoided bulk energy purchases. |
| | Societal | Criteria air pollutant and other environmental externality costs | | $ - | Criteria air pollutant and other environmental externalist costs are associated with loss reductions from this project and avoided bulk energy purchases. |
| | Societal | Conservation and community benefits | | $ - | This project does not directly reduce Environmental Impacts. |
| | Societal | Non-energy costs/benefits: Economic Development | | $ - | This project does not directly impact economic development. |
| | Societal | Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment) | | $ - | This project does not impact innovation or market transformation. |

| Benefit/ Cost | Level | Mixed Cost-Benefit, Cost, or Benefit Category | Order of Magnitude | Quantitative Assessment NPV (2023) | Qualitative Assessment: |
|---|---|---|---|---|---|
| | Societal | Societal Low-Income Impacts | | $ - | This project does not impact low income participant non-energy benefits. |
| | Societal | Public Health | | $ - | Public Health benefits are associated with emissions reductions through loss reductions from this project and avoided bulk energy purchases. |
| | Societal | National Security and US international influence | | $ - | This project does not impact National Security. |

# Section 3
# Vegetation Management Plan

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

## Section 3: Vegetation Management

The Company's Vegetation Management ("VM") Program is an essential component to maintain the safety and reliability of the electric distribution network. Trees have a significant impact on reliability. In CY 2022 trees were the leading cause of customer interruptions (23%) with 98,260 customers experiencing outages due to tree conditions. In addition, keeping vegetation clear from conductors increases safety for the workforce and public, provides operational efficiencies, and reduces wildfire risk. The Company is proposing a $13.1 million budget for FY 2025. Chart 1 below shows the categories of spending for FY 2025 and previous years.

**Section 3 – Chart 1**
**Vegetation Management Spending**
**($000)**

| Vegetation Management O&M Spending | FY 2019 Actual | FY 2020 Actual | FY 2021 Actual | FY 2022 Actual | FY 2023 Actual | FY 2024 Budget | FY 2025 Proposed Budget |
|---|---|---|---|---|---|---|---|
| Cycle Pruning (with Enhanced Trimming) | $5,995 | $5,540 | $5,968 | $6,540 | $7,974 | $9,960 | $8,400 |
| Cycle Trimming Treatment (TGR) | 0 | 0 | 0 | 0 | 0 | 0 | 125 |
| Risk Reduction - on cycle | 0 | 0 | 0 | 0 | 0 | 290 | 750 |
| Risk Reduction - off cycle (formerly Hazard Tree – EHTM) | 1,150 | 2,230 | 1,653 | 1,543 | 1,425 | 625 | 400 |
| Risk Reduction - extra | 0 | 0 | 0 | 0 | 427 | 0 | 0 |
| Sub-T (off & on road) | 358 | 616 | 397 | 481 | 184 | 540 | 700 |
| Police/Flaggers | 788 | 746 | 768 | 873 | 1,010 | 860 | 900 |
| Pockets of Poor Performance | 0 | 0 | 200 | 235 | 182 | 120 | 50 |
| Core Crew including interim/spot trim, customer requests, emergency response, worst feeders, etc. | 1,448 | 1,385 | 1,700 | 1,591 | 1,547 | 1,555 | 1,750 |
| **Total** | **$9,739** | **$10,517** | **$10,686** | **$11,262** | **$12,748** | **$13,950** | **$13,075** |

The program includes the following activities:

**Cycle Pruning**

In the FY 2025 ISR Plan, the Company proposes a budget of $8.4 million for its cycle pruning program. This program is designed to ensure that vegetation growth along the overhead portion of the Company's distribution network does not interfere with the safe and reliable performance of the electric network. Cycle pruning includes the scheduling of every distribution circuit for pruning on a fixed timeframe or rotation to maintain acceptable vegetation clearances. A consistent and well thought out cycle pruning program helps maintain service reliability and supports the efficient management of the overhead network. Managing the vegetation clearance reduces interruptions caused by tree contact and increases network accessibility to line crews, greatly aiding in power restoration following an interruption. Lastly, this activity provides the clearance necessary to accurately inspect overhead wires to identify issues or potential issues.

While a traditional four year cycle has been used since 2011, a more prescriptive approach utilizing additional data and tools identifies the exact work needed on each circuit. This helps to better prepare workloads, identify costs, and needed methodologies for future cycles. The Rhode Island Vegetation Risk tool identifies areas where enhancing the cycle trim specification is beneficial. It incorporates many different data sources, including previous outages, land types, and prevailing storm winds, to locate risk on the system. The Company believes that future pruning cycle for circuits will fall into a three to five year window.

**Cycle Trimming Treatment (TGR)**

In the FY 2025 ISR Plan, the Company proposes a budget of $0.1 million to trial a program to apply tree growth regulator treatments to specific fast growing trees to reduce growth. Tree Growth Regulators ("TGR") are an effective tool used in the Utility Arboriculture industry to help regulate regrowth from routine cycle maintenance trimming. TGRs use a compound that decreases vegetative growth by inhibiting the formation of gibberellins, the group of hormones responsible for cell elongation. When applied to a tree growing near power lines, the treatment reduces regrowth that occurs after cycle trim activities. The industry has established maintenance costs of treated trees may be reduced between 35%-60% versus untreated trees. This saving is attributed to either moving feeders to a longer pruning cycle or reducing the amount of tree work upon return. If approved, the Company will work with municipal and state officials to identify candidates for treatment on this year's feeders. During this trial, only municipally owned trees would be treated.

**On-Cycle Outage Risk Reduction work**

In the FY 2025 ISR Plan, the Company proposes a budget of $0.7 million to address specific vegetation and outage risks as needed on each circuit as the circuit is being worked. For this approach, each circuit will be examined prior to scheduled cycle pruning using the Rhode Island Vegetation Risk tool to identify areas where tree-related outage risks are high. Field observations will prescribe the appropriate work required to lower the risk of interruption. These include hazard tree removal, targeted heavy overhang removal, dying trees, structurally deficient trees, and weak wooded species removal. Issues identified will be addressed when the crews are working on the circuit. Once the circuit has been completed, all known risks have been addressed and crews will not need to return to the feeder until it is on schedule again.

**Off-Cycle Outage Risk Reduction work (Hazard tree)**

In the FY 2025 ISR Plan, the Company proposes a budget of $0.4 million to continue proactively identifying and removing hazard trees due to pest infestations or disease. Currently, infestation from the Emerald Ash Borer is creating significant outage risk to the system. The annual budget for this activity is determined by the risks present to the system at the time of the year's budget formation. At the Open Meeting on March 20, 2018 in Docket No. 4783, the Commission directed the Company to include a summary in its quarterly reports of the pest-related damaged trees removed. The Company will continue to tabulate trees removed due to pests.

**Sub-Transmission**

In the FY 2025 ISR Plan, the Company proposes a budget of $0.7 million for activities on the sub-transmission (22kv/33kV) network. Much like distribution cycle pruning, the Sub-T circuits will be on an optimized cycle and will be prescribed in a comparable way. Activities include vegetation management typical for the distribution circuits, as well as herbicide application and mowing floor treatments. The outage risks due to trees on the Sub-T system are quite high and increasing due to large DG customers being added to the Sub-T system. The Company incorporates the use of Lidar technology to determine tree health, quantify risks to the system, and prioritize work. This method of remotely capturing field conditions will allow for more accurate distance and vegetation health measurements.

**Traffic Control Measures**

In the FY 2025 ISR Plan, the Company proposes a budget of $0.9 million for traffic control. To safely perform vegetation management, the Company's tree vendors employ appropriate traffic control measures. These include personnel that flag, police officers, and using crash trucks and arrow boards on busy highways. These costs are often driven by factors outside the Company's control such as municipal requirements, work locations, and hourly rates set by others. Historically, this has been a pass-through cost from the tree vendors to the Company. These costs are now included in the pricing of the cycle trim work to help ensure that each vendor manages them effectively and reduces the risks of a budget overrun. This spending can fluctuate year to year as different areas throughout the state are worked.

**Pockets of Poor Performance**

In the FY 2025 ISR Plan, the Company proposes a budget of $0.1 million to continue to focus on pockets of poor performance. In these areas, customers are experiencing many tree-related outages that the Company's current routine programs have not been able to address. Under this spending category a more prescriptive approach is taken that focuses on trees outside of the normal scope of work. This limited time program is expected to conclude in FY 2028.

**Core Activities**

In the FY 2025 ISR Plan, the Company proposes a budget of $1.7 million for the essential VM activities to efficiently maintain the safety and reliability of the network and to address customer needs. This work includes responding to internal and external customers' requests for vegetation-related work. It also includes responding to emergency calls to remove trees or limbs from wires and performing vegetation work necessary to restore power. The Company has limited discretion over the timing of these activities. Spending for each core activity varies from year-to-year depending on customer calls, weather, and system requirements.

# Section 4
# Inspection and Maintenance and Other O&M

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

## Section 4: FY 2025 Inspection and Maintenance ("I&M") Plan & Other O&M

**Inspection and Maintenance Program**

This program is intended to address deteriorated assets to ensure that the distribution and sub-transmission system is safe, reliable, and environmentally sound. Asset replacement prior to failure provides incremental safety benefits for both the public and our employees. In addition to asset replacement, testing for elevated voltage should minimize potential safety issues related to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. The Company originally introduced spending for the I&M program to achieve a five-year inspection and repair cycle. Through discussions with the Division and with the need to prioritize other projects, the spend for I&M programs decreased throughout the past years. The I&M program was streamlined to continue to inspect on a five-year cycle but focus on the highest priority issues including Level 1s, Level 9s, potted porcelain cutouts and some guying issues. Level 1 maintenance items are repaired or replaced within 30 days. Level 9 priority conditions are targeted for completion within 120 days. Although currently on track, if any Level 9 priority item was not field completed within the targeted 120 days, the Company will perform a repeat site visit to monitor its current field condition. Potted porcelain cutouts and guying issues depend on site specific detail and severity of the condition. This streamlined I&M program allows the Company to repair the most significant items efficiently and on time, while still drawing from the backlog of lower priority work, with discretion. The lower priority finds, formerly called Level 2s and 3s, are now captured as "low priority" and will only be progressed to construction if required to address a specific need, because higher priority work generally exists.

Periodic inspection of equipment also provides for the avoidance of potential environmental problems such as insulating fluid leaks/spills from assets such as transformers and capacitor banks. The program is also intended to satisfy Section 214 of the National Electric Safety Code, which outlines inspection of equipment guidelines for electric utilities.

In addition to addressing deteriorated assets, the data collected during the inspections enhances the Company's Asset Management reviews and the development of projects and programs to maintain reliability performance and customer satisfaction. As discussed in Section 2, deteriorated equipment is one of the top three drivers affecting customers, accounting for 11% of all interruptions in CY 2022. Although the I&M program is not a reliability-based program, the Company believes that the program is an essential component to fulfilling its obligation to provide safe, reliable, and cost-effective electric delivery service to customers in Rhode Island. The Company's proposal for each of the program components is as follows:

- Continue the five-year inspection cycle and repair "high priority" items in the short-term intervals stated and use discretion to determine which lower priority repairs should be pursued.
- Underground I&M inspections will continue to be performed as part of normal working inspections.
- Overhead Manual Contact Voltage testing will be performed as part of the cycle inspections.
- Underground Manual Contact Voltage testing will continue on a five-year cycle.
- Street Light Manual Contact Voltage testing will continue on a three-year cycle.

- Mobile Contact Voltage Testing will test 20 percent of the Designated Contact Voltage Risk Areas ("DCVRA's") designated in Docket No. 4237-A.

**FY 2025 Inspection and Maintenance Budget**

The Company proposes an O&M budget for the I&M program of $0.7 million in the FY 2025 ISR Plan. O&M costs include program spending and OPEX related to Capex, the O&M costs necessary to complete the capital construction and removal. Associated capital costs, which are included in the capital budget in Section 2 of this Electric ISR Plan, are $1.5 million. Removal costs are $0.2 million.

**Section 4 – Chart 1**
**I&M Program Costs**
**($000)**

| FY 2025 | O&M | Capital | Cost of Removal |
|---|---|---|---|
| I&M Program Spending | $500 | $1,530 | $153 |
| I&M Opex Related to Capex | 200 | - | - |
| **Total** | **$700** | **$1,530** | **$153** |

**Other O&M Budget**

As discussed in Section 2, although the Company will no longer deploy VVO/CVR on targeted feeders, for the equipment installed, ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing exist. As shown on the table below, in the FY 2025 ISR Plan the Company has proposed a budget for O&M spending $0.4 million.

No O&M budget is proposed for potential O&M costs associated with the development of the Long Range Plan.

**Section 4 – Chart 2**
**FY 2025 Other O&M Costs**
**($000)**

| Other O&M Spending | FY 2025 |
|---|---|
| VVO/CVR | $365 |
| System Planning & Protection Study | 0 |
| **Total** | **$365** |

The sections listed below are following:

**Section 5: Revenue Requirement**

**Section 6: Rate Design**

**Section 7: Bill Impacts**

# Section 5
# Revenue Requirement

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

## Section 5: Revenue Requirement FY 2025 Proposal

### Introduction

The attached proposed revenue requirement calculations reflect the revenue requirement related to the Company's proposed investment in its Electric ISR Plan for the fiscal year ("FY") ended March 31, 2025.

As shown on Attachment 1, Page 1, Column (b), the Company's FY 2025 Electric ISR Plan cumulative revenue requirement is $55,815,414 and consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, the Company's Inspection and Maintenance ("I&M") program, and other programs, (2) the Company's capital investment in electric utility infrastructure, and (3) the FY 2025 Property Tax Recovery Adjustments. Lines 1, 2, and 3 of Column (b) reflect the forecasted FY 2025 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $13,075,000, $700,000, and $365,000, respectively, which are described in Section 3 and Section 4 of this document.

The FY 2025 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $43,068,815, is shown on Attachment 1, Page 1, Line 16. This amount includes (1) the $3,972,684 revenue requirement on FY 2025 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 26, (2) the FY 2025 revenue requirements on incremental ISR capital investment for FY 2018 through FY 2024 totaling $34,990,722 and (3) the FY 2025 Property Tax Recovery Adjustment of $4.105.409 from Attachment 1, Page 36. Importantly, the incremental capital investment for the FY 2025 Electric ISR revenue requirements exclude capital investment embedded in base rates in Docket No. 4770 for FY 2018 through FY 2025. Incremental electric capital investment for this purpose is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's base rates, net of depreciation expense attributable to general plant. The total annual FY 2025 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $57,208,815, as reflected on Attachment 1, Page 1, Column (b) on Line 17, and is equal to the sum of Lines 4 and 16. The FY 2025 revenue requirement was reduced by $1,393,401, as reflected on Attachment 1, Page 1, Column (b) Line 18, related to the impact of the sale on the ISR rate base as described further below. Finally, Line 20 reflects the incremental FY 2025 revenue requirement adjustment of an increase of $397,356 above the FY 2024 ISR Plan revenue requirement.

**Operation and Maintenance Expenses**

As previously noted, the Company's FY 2025 Electric ISR Plan revenue requirement includes $13,075,000 of VM expenses, $700,000 of I&M expenses, and $365,000 of Other Program O&M expenses as shown on Page 1, Lines 1 through 3 in Column (b) of the Attachment.

**Electric Infrastructure Investment**

Incremental Capital Investment

Page 26 of Attachment 1 to this Section calculates the revenue requirement of incremental capital investment associated with the Company's FY 2025 Electric ISR Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. The proposed capital investment and estimated cost of removal were obtained from Chart 11 of Section 2 in this Plan. The FY 2025 revenue requirements also include the incremental capital investment associated with the Company's FY

2018 through FY 2024 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4770 for FY 2018 through FY 2024. Page 29 of Attachment 1 calculates the incremental FY 2018 through FY 2023 capital investment and the related incremental cost of removal, incremental retirements, and incremental tax net operating loss ("NOL") position for the FY 2025 electric ISR revenue requirement. Docket No. 4770 includes three rate years, and the forecasted rate base embedded in each rate year included an estimate of incremental capital, cost of removal, retirements and NOL/NOL utilization through Rate Year 3 which ended on August 31, 2021. As such no estimate of the incremental non-growth capital investment, cost of removal, retirements, or NOL position to be incurred during FY 2025 were included in Docket No. 4770. Therefore, all FY 2025 ISR-eligible capital is deemed incremental.

For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. This ISR plan limits the amount of eligible discretionary capital investments to the annual movement in the lesser of cumulative discretionary capital additions, cumulative actual discretionary capital spending or cumulative approved discretionary capital spending since April 1, 2011 (the inception date of the ISR). This limitation on discretionary capital investment will be analyzed as a part of the previously mentioned annual reconciliation of the proposed ISR investment to actual investment activity after the conclusion of the fiscal year.

Incremental Capital Investment Calculation

The ISR mechanism was established to allow the Company to recover outside of base rates its costs associated with plant additions incurred to expand its electric infrastructure and improve the reliability and safety of its electric facilities. When new base rates are implemented, as was the case in Docket No. 4770, the costs the Company recovers for pre-rate case ISR plant additions are no longer through a separate ISR factor. Instead, these costs are recovered through base rates, and the underlying ISR plant additions become a component of base distribution rate base from that point forward. The forecast used to develop rate base in the distribution rate case included ISR plant additions levels for FY 2018, FY 2019, and five months of FY 2020 (using the level of plant additions approved in the FY 2018 ISR Plan Proposal as a proxy for FY 2019 and FY 2020). The effective date of new rates in Docket No. 4770 was September 1, 2018. Therefore, recovery of the approved FY 2012 through FY 2019 ISR revenue requirement through the ISR factor stopped on August 31, 2018, and all future recovery of those ISR plant additions are through the Company's base rates.

As a result of the implementation of new base distribution rates established in Docket No. 4770 effective September 1, 2018, the cumulative amount of forecasted ISR plant additions were included in rate base to be recovered through base distribution rates effective as of that date. The FY 2025 revenue requirements for incremental FY 2018 through FY 2025 ISR investments reflect a full year of revenue requirement because none of these incremental investments are included in the Company's rate base. As a result, these incremental vintage amounts must remain in the ISR recovery mechanism as provided for in the terms of the approved amended settlement in Docket No. 4770. This filing is based on the actual ISR plant additions for FY

2018 through FY 2023 and the planned ISR plant additions for FY 2024 and FY 2025, which are incremental to the levels reflected in rate base in Docket No. 4770.

**Electric Infrastructure Revenue Requirement**

The revenue requirement calculation on incremental electric infrastructure investment for vintage year FY 2025 is shown on Page 26 of Attachment 1. The revenue requirement calculation incorporates the incremental Electric ISR Plan capital investment, cost of removal, retirements, and NOL position. The calculations on Page 26 begin with the determination of the depreciable net incremental capital that will be included in the ISR Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in ISR Plan rate base in determining depreciation expense. Retirements, however, do not affect rate base because both plant-in-service and the depreciation reserve are reduced by the installed value of the plant being retired and therefore have no impact on net plant. For purposes of calculating the revenue requirement, incremental plant retirements have been estimated based on the three- year average percentage of retirements to additions during FY 2019 through FY 2023 and have been deducted from the total depreciable capital amount as shown on Page 26, Lines 4 through 6. Incremental book depreciation expense on Line 16 is computed based on the net depreciable additions, from Line 6 at the 3.16 percent composite depreciation rate as approved in Docket No. 4770, and as shown on Line 12. The Company has assumed a half-year convention for the year of installation. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cost of removal, as shown on Line 10, is combined with the incremental depreciable amount from Line 9 (vintage year ISR Plan allowable capital additions less depreciation expense related to non-general plant except for communication equipment included in base distribution rates) to arrive at the incremental investment on Line 11 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 11 and accumulated depreciation and accumulated deferred tax reserves, as shown on Lines 17 and 22, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 18 through 22, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate, net of any incremental tax NOL or NOL Utilization. The calculation of tax depreciation is described below. The average rate base before the adjustment for deferred tax proration is shown on Line 27. This amount is then adjusted for deferred tax proration on Line 28 to derive the average rate base for ISR on Line 29. The average rate base is multiplied by the pre-tax rate of return approved by the PUC in Docket No. 4770, as shown on Line 30, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 31. As reflected on Line 32, incremental depreciation expense is added to this amount. The sum of these amounts reflects the annual revenue requirement associated with the incremental capital investment portion of the Company's Electric ISR Plan on Line 33, which is carried forward to Page 1, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018 through FY 2024 incremental ISR Plan capital investments are shown on Attachment 1 at Pages 2, 5, 10, 13, 17, 20 and 23. These capital investment revenue requirement amounts are added to the total O&M expenses on Attachment 1, Page 1, Line 4, as well as the property tax amount on Page 1, Lines 14 to 15 to derive the total FY 2025 Electric ISR Plan revenue requirements of $57,208,815 as shown on Page 1, Line 17.

Accumulated deferred income tax ("ADIT") included in rate base

As stated above, ADIT is included in the computation of rate base to determine the revenue requirement. Items considered in the computation of deferred taxes are book and tax depreciation, tax repairs deductions, tax gain or loss on retirements, cost of removal, NOL generation or utilization and accumulated deferred tax proration, all of which are discussed further below except for book depreciation. In addition to the usual activity above impacting ADIT, the FY 2025 ISR plan continues to reflect an increased rate base due to the impact of the Acquisition on ADIT for the pre-acquisition vintage years. The increase in the revenue requirement attributable to this increased rate base is offset by a revenue credit reflected on Attachment 1, Page 1, Line 18 in accordance with the commitments PPL made during the acquisition proceeding in Docket No. D-21-09.2.

PPL Corporation ("PPL") and National Grid elected to treat the acquisition as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of the Company at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminated most book/tax timing differences and the related ADIT as of the acquisition date, at which time PPL Corporation began depreciating the new tax basis and started the tracking of book and tax timing differences as if PPL Corporation purchased a new asset in the year of acquisition. The revenue requirement of each pre-acquisition vintage year reflects the elimination of ADIT in the "PPL 5/25/22 – 3/31/23" column of the FY March 2023 sub-period. This includes the elimination of accumulated deferred taxes on any NOL balances that existed prior to PPL Corporation's acquisition date as National Grid utilized all of the Company's NOLs as a result of the sale. In addition, the tax depreciation calculation for each respective pre-acquisition vintage year reflects tax depreciation on the new tax basis that is equivalent to Company's net book basis as of the Acquisition date.

Accumulated Deferred Income Tax Proration Adjustment

The Electric ISR Plan includes a proration calculation with respect to the ADIT balance included in rate base. The calculation fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). This regulation sets forth normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly. The penalty of a normalization violation is the loss of all federal income tax deductions for accelerated depreciation, including bonus depreciation. Any regulatory filing that includes capital expenditures, book depreciation expense and ADIT related to those capital expenditures must follow the normalization requirements. When the regulatory filing is based on a future period, the deferred tax must be prorated to reflect the period of time that the ADIT balances are in rate base. This filing includes the FY 2018 through FY 2025 proration calculations at Attachment 1 on Pages 4, 7, 12, 15, 19, 22, 25, and 28, respectively, the effects of which are included in each year's respective revenue requirement.

Tax Depreciation Calculation

The tax depreciation calculation for FY 2025 is provided on Attachment 1, Page 27. The tax depreciation amount assumes that a portion of the incremental capital investment, as shown on Line 1 of Page 26, will be eligible for immediate deduction on the Company's corresponding

FY federal income tax return. This immediate deductibility is referred to as the capital repairs deduction.[1]

In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Page 27, Lines 5 through 14 for FY 2025. As noted in the Company's previous Electric ISR filings, the Tax Cuts and Jobs Act of 2017 ("Tax Act") went into effect on December 22, 2017. The 2017 Tax Act has many elements, but two particular aspects have an impact on the Electric ISR revenue requirement. The first is the reduction of the federal income tax rate from 35 percent to 21 percent commencing January 1, 2018. The second Tax Act element affecting the Electric ISR revenue requirement is changes to the bonus depreciation rules eliminating bonus depreciation for certain capital investments, including ISR-eligible investments effective September 28, 2017. Based on the 2017 Tax Act, property acquired prior to September 28, 2017 and placed in service during tax years beginning after December 31, 2017 is allowed bonus depreciation. The Company's original interpretation of the 2017 Tax Act was that no deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. Based on bonus rules for long production period property, however, the Company included a deduction for bonus depreciation on its FY 2019 and FY 2020 tax returns. Starting in FY 2021, the Company can no longer take bonus depreciation. The Company's FY 2025

[1] In 2009, the Internal Revenue Service (IRS) issued additional guidance, under Internal Revenue Code Section 162, related to certain work considered to be repair and maintenance expense, and which is eligible for immediate tax deduction for income tax purposes, but capitalized by the Company for book purposes. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in its FY 2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. Since that time, the Company has taken a capital repairs deduction on all subsequent FY tax returns. This has formed the basis for the capital repairs deduction assumed in the Company's revenue requirement. This tax deduction has the effect of increasing deferred taxes and lowering the revenue requirement that customers will pay under the capital investment reconciliation mechanism. The Company's federal income tax returns are subject to audit by the IRS. If it is determined in the future that the Company's position on its tax returns on this matter was incorrect, the Company will reflect any related IRS disallowances, plus any associated interest assessed by the IRS, in a subsequent reconciliation filing under the ISR Plan.

revenue requirements include the above impacts of the 2017 Tax Act on vintage FY 2018 through FY 2025 investment.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRC Modified Accelerated Cost-Recovery System ("MACRS") tax depreciation rate. Also, cost of removal ("COR") is 100% deductible due to the Company's partial disposition election filed with the IRS as part of the tangible property regulations. This election was submitted to the PUC, as required under IRS rules, on December 17, 2015. The vintage FY 2018 through FY 2025 tax depreciation calculations in this filing include an additional tax deduction related to COR. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, MACRS depreciation, the tax loss on retirements, and cost of removal. These annual total tax depreciation amounts are carried over to Page 26 of Attachment 1, Line 14 and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for FY 2018 through FY 2024 on Attachment 1, Pages 3, 6, 11, 14, 18, 21 and 24, respectively.

The Company must file two short-period tax returns for the calendar year 2022, one with National Grid covering the period from March 31, 2022 to May 25, 2022 and one with PPL covering the period from May 26, 2022 to December 31, 2022. To finalize the March FY 2023 vintage year in the FY 2025 ISR plan filing, PPL must also file its calendar year 2023 tax return, expected in October 2024, in order to allocate a portion of the results to the January 1, 2023 through March 31, 2023 period of the March FY 2023 vintage year. In November, National Grid filed its consolidated March 2023 fiscal year tax return and on October 11, 2023, PPL filed its consolidated 2022 calendar year tax return. Both returns included NECO's short-year period results, which are reflected in the March FY 2023 vintage year calculation of ADIT. The January 1 through March 31, 2023 results for the March FY 2023 vintage year calculation of ADIT will not be reflected in an ISR filing until after October of 2024.

Federal Net Operating Loss

Tax NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. This does not mean that the Company is suffering losses in its financial statements; instead, the Company's tax NOLs are the result of the significant tax deductions that were generated by the bonus depreciation and capital repairs tax deductions in various years. In addition to first-year bonus tax depreciation, the US tax code allows the Company to classify certain costs as repairs expense, which the Company takes as an immediate deduction on its income tax return; however, these costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions had exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2018, with the exception of FY 2011 and FY 2017. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future.

As a result of the 2017 Tax Act, the Company originally did not expect to generate new NOLs in FY 2018 or FY 2019 and anticipated it would begin to utilize prior years' NOLs in FY 2020. Therefore, estimated NOL utilization is included in base rates in Docket 4770, and the calculation of ADIT in this filing includes only the incremental amount of forecasted NOL utilization. Any remaining NOLs as of the March FY 2023 vintage year were completely utilized as a result of the Acquisition.

NOL utilization increases the Company's ADIT and results in a credit or reduction in the calculation of rate base.

Property Tax Recovery Adjustment

The Property Tax Recovery Adjustment is shown on Pages 34 through 36 of Attachment 1. The method used to recover property tax expense under the Electric ISR Plan was modified by the rate case settlement agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company includes an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The Property Tax Recovery Adjustment also includes the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative Plan net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery calculation. The FY 2025 revenue requirement includes $4,105,409 for the Net Property Tax Recovery Adjustment, as shown on Page 1, Line 15.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Annual Revenue Requirement Summary**

| Line No. | | Fiscal Year 4/1/23 - 3/31/24 2024 (a) | Fiscal Year 4/1/24 - 3/31/25 2025 (b) |
|---|---|---|---|
| | **Operation and Maintenance (O&M) Expenses:** | | |
| 1 | Current Year Vegetation Management (VM) | $13,950,000 | $13,075,000 |
| 2 | Current Year Inspection & Maintenance (I&M) | $738,000 | $700,000 |
| 3 | Current Year Other Programs | $425,000 | $365,000 |
| 4 | **Total O&M Expense Component of Revenue Requirement** | **$15,113,000** | **$14,140,000** |
| | **Capital Investment:** | | |
| 5 | Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base | $1,898,402 | $1,666,473 |
| 6 | Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base | $4,121,015 | $3,862,929 |
| 7 | Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base | $5,848,269 | $5,195,475 |
| 8 | Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base | $8,572,859 | $8,058,008 |
| 9 | Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base | $5,183,040 | $4,720,533 |
| 10 | Actual Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base | $7,787,883 | $5,507,844 |
| 11 | Forecasted Revenue Requirement on FY 2024 Capital included in ISR Rate Base | $3,069,596 | $6,018,242 |
| 12 | Forecasted Revenue Requirement on FY 2025 Capital included in ISR Rate Base | | $4,020,884 |
| 13 | Subtotal | $36,481,064 | $39,050,389 |
| 14 | Fiscal 2024 Property Tax Recovery Adjustment (Mar-24) | $5,403,526 | |
| 15 | Fiscal Year 2025-PPL Property Tax Recovery Adjustment (Mar-25) | | $4,261,485 |
| 16 | **Total Capital Investment Component of Revenue Requirement** | **$41,884,590** | **$43,311,874** |
| 17 | **Total Revenue Requirement** | **$56,997,590** | **$57,451,874** |
| 18 | Per Tax Hold Harmless Adjustment Section 5, Attachment 2, Pages 1, Line 23 | (1,579,533) | (3,254,068) |
| 19 | **Total Net Capital Investment Component of Revenue Requirement** | **$55,418,057** | **$54,197,806** |
| 20 | **Incremental Rate Adjustment** | | **($1,220,252)** |

Column/Line Notes:

Col (a) Docket No. 22-53-EL, FY 2024 Electric ISR Plan, Section 5: Attachment 1 (C), Page 1 of 35, Column (b)

Col (b)

1 Vegetation Management, Section 3, Chart 1
2 Other Operations and Maintenance, Section 4, Chart 1
3 Other Operations and Maintenance, Section 4, Chart 2
4 Sum of Lines 1 through 3
5 Page 2 of 38, Line 40 column (h)
6 Page 5 of 38, Line 42, Column (g)
7 Page 10 of 38, Line 39, Column (f)
8 Page 13 of 38, Line 40, Column (e)
9 Page 17 of 38, Line 39, Column (d)
10 Page 20 of 38, Line 39, Column (c)
11 Page 23 of 38, Line 35, Column (a)
12 Page 26 of 38, Line 33, Column (a)
13 Sum of Lines 5 through 12
15 Page 36 of 38, Line 91, Column (aa) × 1,000
16 Sum of Lines 13 through 15
17 Line 4 + Line 16
18 Section 5, Attachment 2, Pages 1, Line 23
19 Line 18 + Line 19
20 Column (b) = Line 19 Col (b) - Line 19 Col (a)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2018 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2018 (a) | Fiscal Year 2019 (b) | Fiscal Year 2020 (c) | Fiscal Year 2021 (d) | Fiscal Year 2022 (e) | NG 4/1/22 - 5/24/2022 2023 (f) | PPL 5/25/22 - 3/31/23 2023 (g) | Fiscal Year 2024 (h) | Fiscal Year 2025 (i) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | | | | | | | | |
| 1 | *Non-Discretionary Capital* | | | $1,828,121 | | | | | | | | |
| | *Discretionary Capital* | | | | | | | | | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending | | | $14,638,256 | | | | | | | | |
| 3 | Total Allowed Capital Included in Rate Base | Page 29 of 38, Line 4(a) | | $16,466,377 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | | | | | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $16,466,377 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Retirements | Page 29 of 38 , Line 10 ,Col (a) | | ($5,245,072) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; then = Prior Year Line 6 | | $21,711,449 | $21,711,449 | $21,711,449 | $21,711,449 | $21,711,449 | $21,711,449 | $21,711,449 | $21,711,449 | $21,711,449 |
| | Change in Net Capital Included in Rate Base | | | | | | | | | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $16,466,377 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Depreciation Expense | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; then = Prior Year Line 9 | | $16,466,377 | $16,466,377 | $16,466,377 | $16,466,377 | $16,466,377 | $16,466,377 | $16,466,377 | $16,466,377 | $16,466,377 |
| 10 | Cost of Removal | Page 29 of 38 , Line 7 ,Col (a) | | $1,693,009 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11 | **Total Net Plant in Service** | Year 1 = Line 9 + Line 10, Then = Prior year | | **$18,159,386** | **$18,159,386** | **$18,159,386** | **$18,159,386** | **$18,159,386** | **$18,159,386** | **$18,159,386** | **$18,159,386** | **$18,159,386** |
| | Deferred Tax Calculation: | | | | | | | | | | | |
| 12 | Composite Book Depreciation Rate | | 1/ | 3.40% | 3.26% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% |
| 13 | Number of days | | 2/ | | | | | | 54 | 311 | | |
| 14 | Proration Percentage | | 2/ | | | | | | 14.79% | 85.21% | | |
| 15 | Vintage Year Tax Depreciation: | | | | | | | | | | | |
| 16 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 3 of 38, Line 29; then = Page 3 of 38, Column (e) | | $13,098,604 | $527,752 | $488,128 | $451,575 | $417,654 | $57,161 | $496,115 | $955,055 | $883,350 |
| 17 | Cumulative Tax Depreciation-NG | Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16 | 3/ | $13,098,604 | $13,626,356 | $14,114,484 | $14,566,059 | $14,983,713 | $15,040,874 | | | |
| 18 | Cumulative Tax Depreciation-PPL | Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16 | 3/ | | | | | | | $496,115 | $1,451,170 | $2,334,520 |
| 19 | Book Depreciation | Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12 | 2/ | $369,095 | $707,793 | $686,082 | $686,082 | $686,082 | $101,503 | $584,579 | $686,082 | $686,082 |
| 20 | Cumulative Book Depreciation | Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19 | | $369,095 | $1,076,888 | $1,762,970 | $2,449,051 | $3,135,133 | $3,236,636 | $3,821,215 | $4,507,297 | $5,193,379 |
| 21 | Cumulative Book / Tax Timer | Columns (a) through (f): Line 17 - Line 20, Then Line 18 - Line 20 | | $12,729,509 | $12,549,468 | $12,351,514 | $12,117,008 | $11,848,580 | $11,804,238 | ($3,325,100) | ($3,056,126) | ($2,858,858) |
| 22 | Less: Cumulative Book Depreciation at Acquisition | Line 20 Column (f) | 3/ | | | | | | | $3,236,636 | $3,236,636 | $3,236,636 |
| 23 | Cumulative Book / Tax Timer - PPL | Line 21 + Line 22 | | | | | | | | ($88,464) | $180,509 | $377,777 |
| 24 | Effective Tax Rate | | 4/ | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% |
| 25 | Deferred Tax Reserve | Columns (a) through (f): Line 21 * Line 24, Then Line 23 * Line 24 | | $2,673,197 | $2,635,388 | $2,593,818 | $2,544,572 | $2,488,202 | $2,478,890 | ($18,577) | $37,907 | $79,333 |
| 26 | Less: FY 2018 Federal NOL (Generation) / Utilization | Year 1 = Page 29 of 38 , Line 15 ,Col (a) ; then = Prior Year Line 26 | 3/ | ($2,998,499) | ($2,998,499) | ($2,998,499) | ($2,998,499) | ($2,998,499) | ($2,998,499) | $0 | $0 | $0 |
| 27 | Excess Deferred Tax | Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1 | | $1,342,963 | $1,342,963 | $1,342,963 | $1,342,963 | $1,342,963 | $1,342,963 | $1,342,963 | $1,342,963 | $1,342,963 |
| 28 | Net Deferred Tax Reserve before Proration Adjustment | Sum of Lines 25 through 27 | | $1,017,662 | $979,853 | $938,283 | $889,036 | $832,667 | $823,355 | $1,324,386 | $1,380,870 | $1,422,296 |
| | Rate Base Calculation: | | | | | | | | | | | |
| 29 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $18,159,386 | $18,159,386 | $18,159,386 | $18,159,386 | $18,159,386 | $18,159,386 | $18,159,386 | $18,159,386 | $18,159,386 |
| 30 | Accumulated Depreciation | -Line 20 | | ($369,095) | ($1,076,888) | ($1,762,970) | ($2,449,051) | ($3,135,133) | ($3,236,636) | ($3,821,215) | ($4,507,297) | ($5,193,379) |
| 31 | Deferred Tax Reserve | -Line 28 | | ($1,017,662) | ($979,853) | ($938,283) | ($889,036) | ($832,667) | ($823,355) | ($1,324,386) | ($1,380,870) | ($1,422,296) |
| 32 | Year End Rate Base before Deferred Tax Proration | Sum of Lines 29 through 31 | | $16,772,630 | $16,102,645 | $15,458,134 | $14,821,298 | $14,191,586 | $14,099,396 | $13,013,785 | $12,271,219 | $11,543,711 |
| | Revenue Requirement Calculation: | | | | | | | | | | | |
| 33 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 and 2 = 0; then Average of (Prior + Current Year Line 32) | 5/ | $8,386,315 | $16,437,637 | $15,780,389 | $15,139,716 | $14,506,442 | $13,602,686 | $13,602,686 | $12,642,502 | $11,907,465 |
| 34 | Proration Adjustment | Page 4 of 38, Line 41 | | | | ($1,784) | ($2,114) | ($2,420) | ($1,197) | ($1,197) | $6,745 | $4,947 |
| 35 | Average ISR Rate Base after Deferred Tax Proration | Line 33 + Line 34 | | $8,386,315 | $16,437,637 | $15,778,605 | $15,137,602 | $14,504,023 | $13,601,489 | $13,601,489 | $12,649,247 | $11,912,412 |
| 36 | Pre-Tax ROR | Page 37 of 38, Line 35 | | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% |
| 37 | Proration | Line 14 | 2/ | | | | | | 14.79% | 85.21% | | |
| 38 | Return and Taxes | Cols (a) through (e) and (h): L 35 * L 36; Cols (f) through (g): L 35 * L 36 * L 37 | 2/ | $690,194 | $1,352,818 | $1,298,579 | $1,245,825 | $1,193,681 | $165,610 | $953,792 | $1,041,033 | $980,391 |
| 39 | Book Depreciation | Line 19 | | $369,095 | $707,793 | $686,082 | $686,082 | $686,082 | $101,503 | $584,579 | $686,082 | $686,082 |
| 40 | **Annual Revenue Requirement** | Line 38 + Line 39 | | **$1,059,288** | **$2,060,611** | **$1,984,661** | **$1,931,906** | **$1,879,763** | **$267,113** | **$1,538,372** | **$1,727,115** | **$1,666,473** |

1/ 3.4%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
3.16%, Composite Book Depreciation Rate for ISR plant, approved per RIPUC Docket No. 4770, effective on Sep 1, 2018, per Page 12 of 18
FY 19 Composite Book Depreciation Rate = 3.4% x 5 /12 + 3.16% x 7 / 12

2/ Columns (f) and (g) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ The Federal Income Tax rate changed from 35% to 21% on Janurary 1, 2018 per the Tax Cuts and Jobs Act of 2017

5/ Columns (f) and (g) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 32, Column (e) and the end of the fiscal year on Line 32, Column (g). See note 2.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2018 (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|---|---|
| | Capital Repairs Deduction | | | | | | | | |
| 1 | Plant Additions | Page 2 of 38, Line 3 | | $16,466,377 | | 20 Year MACRS Depreciation | | | |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 9.00% | | | | | |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $1,481,974 | NG MACRS basis: | Line 22, Column (a) | | $7,310,591 | |
| 4 | | ` | | | | | | Annual | Cumulative |
| 5 | Bonus Depreciation | | | | Fiscal Year | | Prorated | MACRS | Tax Depr |
| 6 | Plant Additions | Line 1 | | $16,466,377 | FY Mar-2018 | 3.750% | | $274,147 | $13,098,604 |
| 7 | Less Capital Repairs Deduction | - Line 3 | | ($1,481,974) | FY Mar-2019 | 7.219% | | $527,752 | $13,626,355 |
| 8 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 | | $14,984,403 | FY Mar-2020 | 6.677% | | $488,128 | $14,114,484 |
| 9 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 100.00% | FY Mar-2021 | 6.177% | | $451,575 | $14,566,059 |
| 10 | Plant Eligible for Bonus Depreciation | Line 8 * Line 9 | | $14,984,403 | FY Mar-2022 | 5.713% | | $417,654 | $14,983,713 |
| 11 | Bonus depreciation 100% category | 100% * 16.38% | 2/ | 16.38% | FY Mar-2023 (Apr-May 2022) | 5.285% | 0.782% | $57,161 | $15,040,874 |
| 12 | Bonus depreciation 50% category | 50% * 34.28% | 2/ | 17.14% | | | | | |
| 13 | Bonus depreciation 40% category | 40% * 44.23% | 2/ | 17.69% | PPL Acquisition - May 25, 2022 | | | | |
| 14 | Bonus depreciation 0% category | 0% * 5.11% | 2/ | 0.00% | Book Cost | Line 1, Column (a) | | $16,466,377 | |
| 15 | Total Bonus Depreciation Rate | Line 11 + Line 12 + Line 13 + Line 14 | | 51.21% | Cumulative Book Depreciation | - Page 2 of 38, Line 20, Col (f) | | ($3,236,636) | |
| 16 | Bonus Depreciation | Line 10 * Line 15 | | $7,673,812 | PPL MACRS basis: | Line 14(e) + Line 15(e) | | $13,229,741 | |
| 17 | | | | | | | | | |
| 18 | Remaining Tax Depreciation | | | | Mar-2023 (Jun-Mar 2023) | 3.750% | | $496,115 | $496,115 |
| 19 | Plant Additions | Line 1 | | $16,466,377 | Mar 2024 | 7.219% | | $955,055 | $1,451,170 |
| 20 | Less Capital Repairs Deduction | Line 3 | | $1,481,974 | Mar 2025 | 6.677% | | $883,350 | $2,334,520 |
| 21 | Less Bonus Depreciation | Line 16 | | $7,673,812 | Mar 2026 | 6.177% | | $817,201 | $3,151,721 |
| 22 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 19 - Line 20 - Line 21 | | $7,310,591 | Mar 2027 | 5.713% | | $755,815 | $3,907,536 |
| 23 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% | Mar 2028 | 5.285% | | $699,192 | $4,606,728 |
| 24 | Remaining Tax Depreciation | Line 22 * Line 23 | | $274,147 | Mar 2029 | 4.888% | | $646,670 | $5,253,398 |
| 25 | | | | | Mar 2030 | 4.522% | | $598,249 | $5,851,647 |
| 26 | FY18 Loss incurred due to retirements | Per Tax Department | 3/ | $1,975,662 | Mar 2031 | 4.462% | | $590,311 | $6,441,958 |
| 27 | Cost of Removal | Page 2 of 38, Line 10 | | $1,693,009 | Mar 2032 | 4.461% | | $590,179 | $7,032,137 |
| 28 | | | | | Mar 2033 | 4.462% | | $590,311 | $7,622,448 |
| 29 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 16, 24, 26, and 27 | | $13,098,604 | Mar 2034 | 4.461% | | $590,179 | $8,212,627 |
| 30 | | | | | Mar 2035 | 4.462% | | $590,311 | $8,802,938 |
| 31 | | | | | Mar 2036 | 4.461% | | $590,179 | $9,393,116 |
| 32 | | | | | Mar 2037 | 4.462% | | $590,311 | $9,983,427 |
| 33 | | | | | Mar 2038 | 4.461% | | $590,179 | $10,573,606 |
| 34 | | | | | Mar 2039 | 4.462% | | $590,311 | $11,163,917 |
| 35 | | | | | Mar 2040 | 4.461% | | $590,179 | $11,754,096 |
| 36 | | | | | Mar 2041 | 4.462% | | $590,311 | $12,344,407 |
| 37 | | | | | Mar 2042 | 4.461% | | $590,179 | $12,934,586 |
| 38 | | | | | Mar 2043 | 2.231% | | $295,156 | $13,229,741 |
| 39 | | | | | | 92.78% | | $13,229,741 | |
| 40 | | | | | | | | | |

1/ Capital Repairs percentage is based on the actual results of the FY 2018 tax return.
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY2018 tax return
3/ Actual Loss for FY2018
Column (d), Line 11 = MACRS Rate 5.285% / 365 days x 54 days

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment**

| Line No. | Deferred Tax Subject to Proration | | FY22 (a) | FY23 (b) | FY24 (c) | FY25 (d) |
|---|---|---|---|---|---|---|
| 1 | Book Depreciation | See the corresponding Fiscal Year on Page 2 of 38, Line 19. Note there are 2 columns to sum for FY23. | $686,082 | $686,082 | $686,082 | $686,082 |
| 2 | Bonus Depreciation | | $0 | $0 | $0 | $0 |
| 3 | Remaining MACRS Tax Depreciation | See the corresponding Fiscal Year on Page 2 of 38, Line 16. Note there are 2 columns to sum for FY23. | ($417,654) | ($553,276) | ($955,055) | ($883,350) |
| 4 | FY18 tax (gain)/loss on retirements | | $0 | $0 | $0 | $0 |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | $268,428 | $132,806 | ($268,973) | ($197,268) |
| 6 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | $56,370 | $27,889 | ($56,484) | ($41,426) |
| | **Deferred Tax Not Subject to Proration** | | | | | |
| 8 | Capital Repairs Deduction | | | | | |
| 9 | Cost of Removal | | | | | |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2017 | | | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | $0 | $0 | $0 | $0 |
| 12 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 13 | Deferred Tax Reserve | Line 11 × Line 12 | $0 | $0 | $0 | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | $56,370 | $27,889 | ($56,484) | ($41,426) |
| 15 | Net Operating Loss | | $0 | $0 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | $56,370 | $27,889 | ($56,484) | ($41,426) |
| | **Allocation of FY 2018 Estimated Federal NOL** | | | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Line 5 | $268,428 | $132,806 | ($268,973) | ($197,268) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | $0 | $0 | $0 | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | $268,428 | $132,806 | ($268,973) | ($197,268) |
| 20 | Total FY 2018 Federal NOL | | | | | |
| 21 | Allocated FY 2018 Federal NOL Not Subject to Proration | (Line 18 ÷ Line 19 ) × Line 20 | $0 | $0 | $0 | $0 |
| 22 | Allocated FY 2018 Federal NOL Subject to Proration | (Line 17 ÷ Line 19 ) × Line 20 | $0 | $0 | $0 | $0 |
| 23 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 × Line 23 | $0 | $0 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | $56,370 | $27,889 | ($56,484) | ($41,426) |

| Line No. | Proration Calculation | Number of Days in Month (e) | Proration Percentage (f) | FY22 (g) | FY23 (h) | FY24 (i) | FY25 (j) |
|---|---|---|---|---|---|---|---|
| 26 | April | 30 | 91.78% | $4,311 | $2,133 | ($4,320) | ($3,168) |
| 27 | May | 31 | 83.29% | $3,912 | $1,936 | ($3,920) | ($2,875) |
| 28 | June | 30 | 75.07% | $3,526 | $1,745 | ($3,533) | ($2,592) |
| 29 | July | 31 | 66.58% | $3,127 | $1,547 | ($3,134) | ($2,298) |
| 30 | August | 31 | 58.08% | $2,728 | $1,350 | ($2,734) | ($2,005) |
| 31 | September | 30 | 49.86% | $2,342 | $1,159 | ($2,347) | ($1,721) |
| 32 | October | 31 | 41.37% | $1,943 | $961 | ($1,947) | ($1,428) |
| 33 | November | 30 | 33.15% | $1,557 | $770 | ($1,560) | ($1,144) |
| 34 | December | 31 | 24.66% | $1,158 | $573 | ($1,161) | ($851) |
| 35 | January | 31 | 16.16% | $759 | $376 | ($761) | ($558) |
| 36 | February | 28 | 8.49% | $399 | $197 | ($400) | ($293) |
| 37 | March | 31 | 0.00% | $0 | $0 | $0 | $0 |
| 38 | Total | 365 | | $25,765 | $12,748 | ($21,498) | ($15,767) |
| 39 | Deferred Tax Without Proration | Line 25 | | $56,370 | $27,889 | ($56,484) | ($41,426) |
| 40 | Average Deferred Tax without Proration | Line 25 * 50% | | $28,185 | $13,945 | ($28,242) | ($20,713) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | ($2,420) | ($1,197) | $6,745 | $4,947 |

**Column Notes:**
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2019 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2019 (a) | Fiscal Year 2020 (b) | Fiscal Year 2021 (c) | Fiscal Year 2022 (d) | NG 4/1/22 - 5/24/22 2023 (e) | PPL 5/25/22 - 3/31/23 2023 (f) | Fiscal Year 2024 (g) | Fiscal Year 2025 (h) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | | | | | | | |
| 1 | *Non-Discretionary Capital* | | | $6,261,278 | | | | | | | |
| | *Discretionary Capital* | | | | | | | | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending | | | $25,486,776 | | | | | | | |
| 3 | Total Allowed Capital Included in Rate Base (non-intangible) | Page 29 of 38, Line 4(b) | | $31,748,054 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | | | | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3, Column (a) | | $31,748,054 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Retirements | Page 29 of 38 , Line 10 ,Col (b) | | ($10,649,479) | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $42,397,533 | $42,397,533 | $42,397,533 | $42,397,533 | $42,397,533 | $42,397,533 | $42,397,533 | $42,397,533 |
| | Change in Net Capital Included in Rate Base | | | | | | | | | | |
| 7 | Capital Included in Rate Base | Line 3, Column (a) | | $31,748,054 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Depreciation Expense | | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Incremental Capital Amount | Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9 | | $31,748,054 | $31,748,054 | $31,748,054 | $31,748,054 | $31,748,054 | $31,748,054 | $31,748,054 | $31,748,054 |
| 10 | Cost of Removal | Page 29 of 38 , Line 7 ,Col (b) | | $361,723 | | | | | | | |
| 11 | **Total Net Plant in Service** | Year 1 = Line 9 + Line 10, Then = Prior year | | **$32,109,777** | **$32,109,777** | **$32,109,777** | **$32,109,777** | **$32,109,777** | **$32,109,777** | **$32,109,777** | **$32,109,777** |
| | Deferred Tax Calculation: | | | | | | | | | | |
| 12 | Composite Book Depreciation Rate | As approved per RIPUC Docket No. 4323 and Docket No. 4770 | 1/ | 3.26% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% |
| 13 | Number of days | | 2/ | | | | | 54 | 311 | | |
| 14 | Proration Percentage | | 2/ | | | | | 14.79% | 85.21% | | |
| 15 | Vintage Year Tax Depreciation: | | | | | | | | | | |
| 16 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 6 of 38, Line 28 Then = Page 6 of 38 Column (e) | | $9,877,791 | $1,776,194 | $1,642,838 | $1,519,816 | $207,959 | $1,006,480 | $1,937,542 | $1,792,072 |
| 17 | Cumulative Tax Depreciation-NG | Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16 | 3/ | $9,877,791 | $11,653,985 | $13,296,823 | $14,816,638 | $15,024,597 | | | |
| 18 | Cumulative Tax Depreciation-PPL | Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16 | 3/ | | | | | | $1,006,480 | $2,944,022 | $4,736,094 |
| 19 | Book Depreciation | Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12 | 2/ | $691,080 | $1,339,762 | $1,339,762 | $1,339,762 | $198,211 | $1,141,551 | $1,339,762 | $1,339,762 |
| 20 | Cumulative Book Depreciation | Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19 | | $691,080 | $2,030,842 | $3,370,604 | $4,710,366 | $4,908,577 | $6,050,128 | $7,389,890 | $8,729,652 |
| 21 | Cumulative Book / Tax Timer | Columns (a) through(e): Line 17 - Line 20, Then Line 18 - Line 20 | | $9,186,711 | $9,623,143 | $9,926,219 | $10,106,272 | $10,116,020 | ($5,043,648) | ($4,445,868) | ($3,993,558) |
| 22 | Less: Cumulative Book Depreciation at Acquisition | Line 20 Column (e) | 3/ | | | | | | $4,908,577 | $4,908,577 | $4,908,577 |
| 23 | Cumulative Book / Tax Timer - PPL | Line 21 + Line 22 | | | | | | | ($135,070) | $462,709 | $915,019 |
| 24 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% |
| 25 | Deferred Tax Reserve | Columns (a) through (e): Line 21 * Line 24, Then Line 23 * Line 24 | | $1,929,209 | $2,020,860 | $2,084,506 | $2,122,317 | $2,124,364 | ($28,365) | $97,169 | $192,154 |
| 26 | Add: FY 2019 Federal NOL (Generation) / Utilization | Page 29 of 38 , Line 15 ,Col (b) | 3/ | $991,622 | $991,622 | $991,622 | $991,622 | $991,622 | $0 | $0 | $0 |
| 27 | Net Deferred Tax Reserve before Proration Adjustment | Sum of Lines 25 through 26 | | $2,920,831 | $3,012,482 | $3,076,128 | $3,113,939 | $3,115,986 | ($28,365) | $97,169 | $192,154 |
| | Rate Base Calculation: | | | | | | | | | | |
| 28 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $32,109,777 | $32,109,777 | $32,109,777 | $32,109,777 | $32,109,777 | $32,109,777 | $32,109,777 | $32,109,777 |
| 29 | Accumulated Depreciation | -Line 20 | | ($691,080) | ($2,030,842) | ($3,370,604) | ($4,710,366) | ($4,908,577) | ($6,050,128) | ($7,389,890) | ($8,729,652) |
| 30 | Deferred Tax Reserve | -Line 27 | | ($2,920,831) | ($3,012,482) | ($3,076,128) | ($3,113,939) | ($3,115,986) | $28,365 | ($97,169) | ($192,154) |
| 31 | Year End Rate Base before Deferred Tax Proration | Sum of Lines 28 through 30 | | $28,497,866 | $27,066,453 | $25,663,045 | $24,285,472 | $24,085,214 | $26,088,014 | $24,622,718 | $23,187,971 |
| | Revenue Requirement Calculation: | | | | | | | | | | |
| 32 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 = Current Year Line 31 ÷ 2; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2 | 4/ | $14,248,933 | $27,782,160 | $26,364,749 | $24,974,259 | $25,186,743 | $25,186,743 | $25,355,366 | $23,905,345 |
| 33 | Proration Adjustment | Page 7 of 38, Line 43 | | $0 | $0 | $0 | ($522) | ($959) | ($959) | $7,102 | $1,677 |
| 34 | Average ISR Rate Base after Deferred Tax Proration | Line 32 + Line 33 | | $14,248,933 | $27,782,160 | $26,364,749 | $24,973,737 | $25,185,784 | $25,185,784 | $25,362,468 | $23,907,021 |
| 35 | Pre-Tax ROR | Page 37 of 38, Line 35 | | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% |
| 36 | Proration Percentage | Line 14 | 2/ | | | | | 14.79% | 85.21% | | |
| 37 | Return and Taxes | Cols (a) through (d) and (g): L 34 * L 35; Cols (e) and (f): L 34 * L 35 * L 36 | 2/ | $1,172,687 | $2,286,472 | $2,169,819 | $2,055,339 | $306,659 | $1,766,131 | $2,087,331 | $1,967,548 |
| 38 | Book Depreciation | Line 19 | | $691,080 | $1,339,762 | $1,339,762 | $1,339,762 | $198,211 | $1,141,551 | $1,339,762 | $1,339,762 |
| 39 | Annual Revenue Requirement | Line 37 + Line 38 | | $1,863,767 | $3,626,234 | $3,509,581 | $3,395,101 | $504,871 | $2,907,681 | $3,427,093 | $3,307,310 |
| 40 | Revenue Requirement of Plant | Year 1 = Line 39*7/12, Then = Line 39 | | $1,087,197 | $3,626,234 | $3,509,581 | $3,395,101 | $504,871 | $2,907,681 | $3,427,093 | $3,307,310 |
| 41 | Revenue Requirement of Intangible | Page 8 of 38, Line 34, Column (l) ~ (aa) | | $434,302 | $705,779 | $655,914 | $617,127 | $81,808 | $548,352 | $595,648 | $555,619 |
| 42 | **Revenue Requirement** | Line 40 + Line 41 | | **$1,521,500** | **$4,332,013** | **$4,165,495** | **$4,012,227** | **$586,679** | **$3,456,033** | **$4,022,741** | **$3,862,929** |

1/ 3.4%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
3.16%, Composite Book Depreciation Rate for ISR plant, approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.4% x 5 /12 + 3.16% x 7 / 12

2/ Columns (e) and (f) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ Columns (e) and (f) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (d) and the end of the fiscal year on Line 31, Column (f). See note 2.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2019 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2019 (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|---|---|
| | Capital Repairs Deduction | | | | | | | | |
| 1 | Plant Additions | Page 5 of 38, Line 3 | | $31,748,054 | | 20 Year MACRS Depreciation | | | |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 9.68% | | | | | |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $3,073,236 | MACRS basis: | Line 22, Column (a) | | $24,604,428 | |
| 4 | | | | | | | | Annual | Cumulative |
| 5 | Bonus Depreciation | | | | Fiscal Year | | Prorated | MACRS | Tax Depr |
| 6 | Plant Additions | Line 1 | | $31,748,054 | FY Mar-2019 | 3.750% | | $922,666 | $9,877,791 |
| 7 | Plant Additions | | | $0 | FY Mar-2020 | 7.219% | | $1,776,194 | $11,653,985 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $3,073,236 | FY Mar-2021 | 6.677% | | $1,642,838 | $13,296,822 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $28,674,818 | FY Mar-2022 | 6.177% | | $1,519,816 | $14,816,638 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 100.00% | FY Mar-2023 (Apr-May 2022) | 5.713% | 0.85% | $207,959 | $15,024,597 |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $28,674,818 | | | | | |
| 12 | Bonus Depreciation Rate | 1 * 11.65% * 30% | 2/ | 3.50% | PPL Acquisition - May 25, 2022 | | | | |
| 13 | Bonus Depreciation Rate | 1 * 26.75% * 40% | 2/ | 10.70% | Book Cost | Line 1, Column (a) | | $31,748,054 | |
| 14 | Total Bonus Depreciation Rate | Line 12 + Line 13 | | 14.20% | Cumulative Book Depreciation | - Page 5 of 38, Line 20, Col (e) | | ($4,908,577) | |
| 15 | Bonus Depreciation | Line 11 * Line 14 | | $4,070,390 | PPL MACRS basis: | Line 13(e) + Line 14(e) | | $26,839,477 | |
| 16 | | | | | | | | | |
| 17 | Remaining Tax Depreciation | | | | FY Mar-2023 (Jun-Mar 2023) | 3.750% | | $1,006,480 | $1,006,480 |
| 18 | Plant Additions | Line 1 | | $31,748,054 | Mar-2024 | 7.219% | | $1,937,542 | $2,944,022 |
| 19 | Less Capital Repairs Deduction | Line 3 | | $3,073,236 | Mar-2025 | 6.677% | | $1,792,072 | $4,736,094 |
| 20 | Less Bonus Depreciation | Line 15 | | $4,070,390 | Mar-2026 | 6.177% | | $1,657,874 | $6,393,969 |
| 21 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 18 - Line 19 - Line 20 | | $24,604,428 | Mar-2027 | 5.713% | | $1,533,339 | $7,927,308 |
| 22 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% | Mar-2028 | 5.285% | | $1,418,466 | $9,345,774 |
| 23 | Remaining Tax Depreciation | Line 21 * Line 22 | | $922,666 | Mar-2029 | 4.888% | | $1,311,914 | $10,657,688 |
| 24 | | | | | Mar-2030 | 4.522% | | $1,213,681 | $11,871,369 |
| 25 | FY19 (Gain)/Loss incurred due to retirements | Per Tax Department | 3/ | $1,449,776 | Mar-2031 | 4.462% | | $1,197,577 | $13,068,946 |
| 26 | Cost of Removal | Page 5 of 38, Line 10 | | $361,723 | Mar-2032 | 4.461% | | $1,197,309 | $14,266,255 |
| 27 | | | | | Mar-2033 | 4.462% | | $1,197,577 | $15,463,833 |
| 28 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 15, 23, 25, and 26 | | $9,877,791 | Mar-2034 | 4.461% | | $1,197,309 | $16,661,142 |
| 29 | | | | | Mar-2035 | 4.462% | | $1,197,577 | $17,858,719 |
| 30 | | | | | Mar-2036 | 4.461% | | $1,197,309 | $19,056,028 |
| 31 | | | | | Mar-2037 | 4.462% | | $1,197,577 | $20,253,606 |
| 32 | | | | | Mar-2038 | 4.461% | | $1,197,309 | $21,450,915 |
| 33 | | | | | Mar-2039 | 4.462% | | $1,197,577 | $22,648,492 |
| 34 | | | | | Mar-2040 | 4.461% | | $1,197,309 | $23,845,801 |
| 35 | | | | | Mar-2041 | 4.462% | | $1,197,577 | $25,043,379 |
| 36 | | | | | Mar-2042 | 4.461% | | $1,197,309 | $26,240,688 |
| 37 | | | | | Mar-2043 | 2.231% | | $598,789 | $26,839,477 |
| 38 | | | | | | 100.000% | | $26,839,477 | |
| 39 | | | | | | | | | |

1/ Capital Repairs percentage is the actual result of FY 2019 tax return
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY 2019 tax return
3/ Actual Loss for FY 2019
Column (d), Line 10 = MACRS Rate 5.713% / 365 days x 54 days

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment**

| Line No. | **Deferred Tax Subject to Proration** | | FY22 (a) | FY23 (b) | FY24 (c) | FY25 (d) |
|---|---|---|---|---|---|---|
| 1 | Book Depreciation - Excl. Intangibles | See the corresponding Fiscal Year on Page 5 of 38, Line 19. Note there are 2 columns to sum for FY23. | $1,339,762 | $1,339,762 | $1,339,762 | $1,339,762 |
| 2 | Book Depreciation - Intangibles | See the corresponding Fiscal Year on Page 8 of 38, Line 21 - Line 20. Note there are 2 columns to sum for FY23. | $494,375 | $494,375 | $494,375 | $494,375 |
| 3 | Bonus Depreciation | | $0 | $0 | $0 | $0 |
| 4 | Remaining MACRS Tax Depreciation - Excl. Intangibles | See the corresponding Fiscal Year on Page 5 of 38, Line 16. Note there are 2 columns to sum for FY23. | ($1,519,816) | ($1,214,440) | ($1,937,542) | ($1,792,072) |
| 5 | Remaining MACRS Tax Depreciation - Intangibles | See the corresponding Fiscal Year on Page 8 of 38, Line 18 - Line 17. Note there are 2 columns to sum for FY23. | ($256,432) | ($513,297) | ($684,550) | ($228,081) |
| 6 | FY 2019 tax (gain)/loss on retirements | | $0 | $0 | $0 | $0 |
| 7 | Cumulative Book / Tax Timer | Sum of Lines 1 through 6 | $57,889 | $106,400 | ($787,955) | ($186,015) |
| 8 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 9 | Deferred Tax Reserve | Line 7 * Line 8 | $12,157 | $22,344 | ($165,470) | ($39,063) |
| | **Deferred Tax Not Subject to Proration** | | | | | |
| 10 | Capital Repairs Deduction | | | | | |
| 11 | Cost of Removal | | | | | |
| 12 | Book/Tax Depreciation Timing Difference at 3/31/2018 | | | | | |
| 13 | Cumulative Book / Tax Timer | Line 10 + Line 11 + Line 12 | $0 | $0 | $0 | $0 |
| 14 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 15 | Deferred Tax Reserve | Line 13 × Line 14 | $0 | $0 | $0 | $0 |
| 16 | Total Deferred Tax Reserve | Line 9 + Line 15 | $12,157 | $22,344 | ($165,470) | ($39,063) |
| 17 | Net Operating Loss | | $0 | $0 | $0 | $0 |
| 18 | Net Deferred Tax Reserve | Line 16 + Line 17 | $12,157 | $22,344 | ($165,470) | ($39,063) |
| | **Allocation of FY 2019 Estimated Federal NOL** | | | | | |
| 19 | Cumulative Book/Tax Timer Subject to Proration | Line 7 | $57,889 | $106,400 | ($787,955) | ($186,015) |
| 20 | Cumulative Book/Tax Timer Not Subject to Proration | Line 13 | $0 | $0 | $0 | $0 |
| 21 | Total Cumulative Book/Tax Timer | Line 19 + Line 20 | $57,889 | $106,400 | ($787,955) | ($186,015) |
| 22 | Total FY 2019 Federal NOL | | $0 | $0 | $0 | $0 |
| 23 | Allocated FY 2019 Federal NOL Not Subject to Proration | (Line 20 ÷ Line 21 ) × Line 22 | $0 | $0 | $0 | $0 |
| 24 | Allocated FY 2019 Federal NOL Subject to Proration | (Line 19 ÷ Line 21 ) × Line 22 | $0 | $0 | $0 | $0 |
| 25 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 26 | Deferred Tax Benefit subject to proration | Line 24 × Line 25 | $0 | $0 | $0 | $0 |
| 27 | Net Deferred Tax Reserve subject to proration | Line 9 + Line 26 | $12,157 | $22,344 | ($165,470) | ($39,063) |

| | **Proration Calculation** | (e) Number of Days in Month | (f) Proration Percentage | (g) FY22 | (h) FY23 | (i) FY24 | (j) FY25 |
|---|---|---|---|---|---|---|---|
| 28 | April | 30 | 91.78% | $930 | $1,709 | ($12,656) | ($2,988) |
| 29 | May | 31 | 83.29% | $844 | $1,551 | ($11,485) | ($2,711) |
| 30 | June | 30 | 75.07% | $760 | $1,398 | ($10,351) | ($2,444) |
| 31 | July | 31 | 66.58% | $674 | $1,240 | ($9,180) | ($2,167) |
| 32 | August | 31 | 58.08% | $588 | $1,081 | ($8,009) | ($1,891) |
| 33 | September | 30 | 49.86% | $505 | $928 | ($6,876) | ($1,623) |
| 34 | October | 31 | 41.37% | $419 | $770 | ($5,705) | ($1,347) |
| 35 | November | 30 | 33.15% | $336 | $617 | ($4,571) | ($1,079) |
| 36 | December | 31 | 24.66% | $250 | $459 | ($3,400) | ($803) |
| 37 | January | 31 | 16.16% | $164 | $301 | ($2,229) | ($526) |
| 38 | February | 28 | 8.49% | $86 | $158 | ($1,171) | ($276) |
| 39 | March | 31 | 0.00% | $0 | $0 | $0 | $0 |
| 40 | Total | 365 | | $5,557 | $10,213 | ($75,633) | ($17,855) |
| 41 | Deferred Tax Without Proration | Line 27 | | $12,157 | $22,344 | ($165,470) | ($39,063) |
| 42 | Average Deferred Tax without Proration | Line 39 * 50% | | $6,078 | $11,172 | ($82,735) | ($19,532) |
| 43 | Proration Adjustment | Line 40 - Line 42 | | ($522) | ($959) | $7,102 | $1,677 |

**Column Notes:**
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 27 ÷ 12 × Current Month Col (f)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2019 Intangible Investment**

| Line No. | | Reference | FY19 Total (c) = (a) + (b) | FY 20 Total (f) = (d) + (e) | FY 21 Total (i) = (g) + (h) | FY 22 Total (l) = (j) + (k) | FY Mar-2023 (Apr-May 2022) (o) = (m) + (n) NG | FY Mar-2023 (Jun 2022 -Mar 2023) (r) = (p) + (q) PPL | FY 24 Total (u) = (s) + (t) PPL | FY 25 Total (x) = (v) + (w) PPL |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capital Investment | | | | | | | | | |
| 1 | Start of Rev. Req. Period | | 09/01/18 | 04/01/19 | 04/01/20 | 04/01/21 | 04/01/22 | 05/25/22 | 04/01/23 | 04/01/24 |
| 2 | End of Rev. Req. Period | | 03/31/19 | 03/31/20 | 03/31/21 | 03/31/22 | 05/24/22 | 03/31/23 | 03/31/24 | 03/31/25 |
| 3 | Investment Name | Per Company's Book | | | | | | | | |
| 4 | Work Order | Per Company's Book | | | | | | | | |
| 5 | Total Spend | | $3,460,626 | $3,460,626 | $3,460,626 | $3,460,626 | $3,460,626 | $3,460,626 | $3,460,626 | $3,460,626 |
| 6 | In ServiceDate | Per Company's Book | | | | | | | | |
| 7 | Book AmortizationPeriod | Per Company's Book | | | | | | | | |
| 8 | Beginning Book Balance | Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021 | $3,378,230 | $3,089,845 | $2,595,470 | $2,101,094 | $1,606,719 | $1,540,045 | $1,112,344 | $617,969 |
| 9 | Ending Book Balance | Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022 | $3,089,845 | $2,595,470 | $2,101,094 | $1,606,719 | $1,540,045 | $1,112,344 | $617,969 | $123,594 |
| 10 | Average Book Balance | (Line 8 + Line 9) ÷ 2 | $3,234,038 | $2,842,657 | $2,348,282 | $1,853,907 | $1,573,382 | $1,326,195 | $865,157 | $370,781 |
| | Deferred Tax Calculation: | | | | | | | | | |
| 11 | Total Spend | | | | | | | | | |
| 12 | In Service Date | | | | | | | | | |
| 13 | Tax Amortizaton Period | Page 9 of 38 | | | | | | | | |
| 14 | Tax Expensing | Per Tax Department | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15 | Tax Bonus Rate | Per Tax Department | | | | | | | | |
| 16 | Bonus Depreciation | Year 1 = (L. 5 - L. 14) × L.15, Then = 0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 17 | Beginning Acc. Tax Balance | (L. 5 - L. 14- L.16)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%) | $1,153,427 | $1,153,427 | $2,691,675 | $3,204,194 | $3,460,626 | $0 | $513,297 | $1,197,847 |
| 18 | Ending Acc. Tax Balance | (L. 5 - L. 14- L.16) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%) | $1,153,427 | $2,691,675 | $3,204,194 | $3,460,626 | $3,460,626 | $513,297 | $1,197,847 | $1,425,928 |
| 19 | Average Acc. Tax Balance | (Line 17 + Line 18) ÷ 2 | $1,153,427 | $1,922,551 | $2,947,934 | $3,332,410 | $3,460,626 | $256,649 | $855,572 | $1,311,887 |
| 20 | Beginning Acc. Dep. Balance | Line 5 - Line 8 | $82,396 | $370,781 | $865,157 | $1,359,532 | $1,853,907 | $1,920,581 | $2,348,282 | $2,842,657 |
| 21 | Ending Acc. Dep. Balance | Line 5 - Line 9 | $370,781 | $865,157 | $1,359,532 | $1,853,907 | $1,920,581 | $2,348,282 | $2,842,657 | $3,337,032 |
| 22 | Average Acc. Dep. Balance | (Line 20 + Line 21) ÷ 2 | $226,589 | $617,969 | $1,112,344 | $1,606,719 | $1,887,244 | $2,134,432 | $2,595,470 | $3,089,845 |
| 23 | Number of days | | | | | | | | | |
| 24 | Proration Percentage | | | | | | | | | |
| 25 | Average Book / Tax Timer | Line 19 - Line 22 | $926,838 | $1,304,582 | $1,835,590 | $1,725,691 | $232,774 | ($1,599,974) | ($1,739,898) | ($1,777,957) |
| 26 | Effective Tax Rate | | | | | | | | | |
| 27 | Deferred Tax Reserve | Line 25 × Line 26 | $194,636 | $273,962 | $385,474 | $362,395 | $48,883 | ($335,995) | ($365,378) | ($373,371) |
| | Rate Base Calculation: | | | | | | | | | |
| 28 | Average Book Balance | Line 10 | $3,234,038 | $2,842,657 | $2,348,282 | $1,853,907 | $232,774 | $1,129,991 | $865,157 | $370,781 |
| 29 | Deferred Tax Reserve | Line 27 | $194,636 | $273,962 | $385,474 | $362,395 | $48,883 | ($335,995) | ($365,378) | ($373,371) |
| 30 | Average Rate Base | Line 28 - Line 29 | $3,039,402 | $2,568,695 | $1,962,808 | $1,491,512 | $183,892 | $1,465,985 | $1,230,535 | $744,152 |
| | Revenue Requirement Calculation: | | | | | | | | | |
| 31 | Pre-Tax ROR | year 1 = Page 37 of 38, Line 27, column (e)×7÷12 Then = Page 37 of 38, Line 27(e) | | | | | | | | |
| 32 | Return and Taxes | Line 30 × Line 31 | $145,917 | $211,404 | $161,539 | $122,751 | $15,134 | $120,651 | $101,273 | $61,244 |
| 33 | Book Depreciation | Line 9 - Line 8 | $288,386 | $494,375 | $494,375 | $494,375 | $66,674 | $427,701 | $494,375 | $494,375 |
| 34 | Annual Revenue Requirement | Line 32 + Line 33 | $434,302 | $705,779 | $655,914 | $617,127 | $81,808 | $548,352 | $595,648 | $555,619 |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**MACRS Tables For Information Systems**

| Line | Annual Rate | | | Monthly Cumulative Rate | | | | |
|---|---|---|---|---|---|---|---|---|
| No. | Year | | | Year | Period | Cumulative Rate | | |
| 1 | Yr 1 | 33.33% | 33.33% | 1 | 1 | 33.33% | 2.78% | Yr 1 - Monthly rate |
| 2 | Yr 2 | 44.45% | 77.78% | 1 | 2 | 33.33% | | |
| 3 | Yr 3 | 14.81% | 92.59% | 1 | 3 | 33.33% | | |
| 4 | Net Salvage Value | 7.41% | 100.00% | 1 | 4 | 33.33% | | |
| 11 | | | | 1 | 11 | 33.33% | | |
| 12 | | | | 1 | 12 | 33.33% | | |
| 13 | | | | 2 | 13 | 77.78% | 3.70% | Yr 2 - Monthly rate |
| 25 | | | | 3 | 25 | 92.59% | 1.23% | Yr 3 - Monthly rate |
| 36 | | | | 3 | 36 | 92.59% | 0.62% | Yr 3 - Monthly rate |
| 48 | | | | 4 | 48 | 100.00% | | |
| 60 | | | | 5 | 60 | 100.00% | | |
| 72 | | | | 6 | 72 | 100.00% | | |
| 84 | | | | 7 | 84 | 100.00% | | |
| 96 | | | | 8 | 96 | 100.00% | | |
| 108 | | | | 9 | 108 | 100.00% | | |
| 120 | | | | 10 | 120 | 100.00% | | |
| 132 | | | | 11 | 132 | 100.00% | | |
| 144 | | | | 12 | 144 | 100.00% | | |
| 156 | | | | 13 | 156 | 100.00% | | |
| 168 | | | | 14 | 168 | 100.00% | | |
| 180 | | | | 15 | 180 | 100.00% | | |
| 192 | | | | 16 | 192 | 100.00% | | |
| 204 | | | | 17 | 204 | 100.00% | | |
| 216 | | | | 18 | 216 | 100.00% | | |
| 228 | | | | 19 | 228 | 100.00% | | |
| 240 | | | | 20 | 240 | 100.00% | | |
| 252 | | | | 21 | 252 | 100.00% | | |
| 264 | | | | 22 | 264 | 100.00% | | |
| 276 | | | | 23 | 276 | 100.00% | | |
| 288 | | | | 24 | 288 | 100.00% | | |
| 300 | | | | 25 | 300 | 100.00% | | |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2020 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2020 (a) | Fiscal Year 2021 (b) | Fiscal Year 2022 (c) | NG 4/1/22 - 5/24/22 2023 (d) | PPL 5/25/22 - 3/31/23 2023 (e) | Fiscal Year 2024 (f) | Fiscal Year 2025 (g) |
|---|---|---|---|---|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | | | | | | |
| 1 | *Non-Discretionary Capital* | | | $27,837,942 | | | | | | |
| 2 | *Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending | | | $39,597,335 | | | | | | |
| 3 | Total Allowed Capital Included in Rate Base | Page 29 of 38, Line 4(c) | | $67,435,277 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | | | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $67,435,277 | $0 | $0 | $0 | $0 | $0 | $0 |
| 5 | Retirements | Page 29 of 38 , Line 10 ,Col (c) | | $4,015,632 | $0 | $0 | $0 | $0 | $0 | $0 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $63,419,645 | $63,419,645 | $63,419,645 | $63,419,645 | $63,419,645 | $63,419,645 | $63,419,645 |
| | Change in Net Capital Included in Rate Base | | | | | | | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $67,435,277 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Depreciation Expense | Page 33 of 38, Line 41, Col (d) ×7 ÷12 | | $29,112,370 | $0 | $0 | $0 | $0 | $0 | $0 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; then = Prior Year Line 9 | | $38,322,907 | $38,322,907 | $38,322,907 | $38,322,907 | $38,322,907 | $38,322,907 | $38,322,907 |
| 10 | Cost of Removal | Page 29 of 38 , Line 7 ,Col (c) | | $11,332,719 | | | | | | |
| 11 | **Total Net Plant in Service** | Year 1 = Line 9 + Line 10, Then = Prior year | | **$49,655,625** | **$49,655,625** | **$49,655,625** | **$49,655,625** | **$49,655,625** | **$49,655,625** | **$49,655,625** |
| | Deferred Tax Calculation: | | | | | | | | | |
| 12 | Composite Book Depreciation Rate | Page 31 of 38, Line 3, Col ( e) | 1/ | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% |
| 13 | Number of days | | 2/ | | | | 54 | 311 | | |
| 14 | Proration Percentage | | 2/ | | | | 14.79% | 85.21% | | |
| 15 | Vintage Year Tax Depreciation: | | | | | | | | | |
| 16 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 11 of 38, Line 28, Then = Page 11 of 38, Column (e) | | $23,504,007 | $4,305,759 | $3,982,484 | $545,069 | $2,329,824 | $4,485,066 | $4,148,329 |
| 17 | Cumulative Tax Depreciation-NG | Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16 | 3/ | $23,504,007 | $27,809,766 | $31,792,250 | $32,337,319 | | | |
| 18 | Cumulative Tax Depreciation-PPL | Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16 | 3/ | | | | | $2,329,824 | $6,814,890 | $10,963,219 |
| 19 | Book Depreciation | Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12 | 2/ | $1,002,030 | $2,004,061 | $2,004,061 | $296,491 | $1,707,570 | $2,004,061 | $2,004,061 |
| 20 | Cumulative Book Depreciation | Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16 | | $1,002,030 | $3,006,091 | $5,010,152 | $5,306,643 | $7,014,213 | $9,018,274 | $11,022,334 |
| 21 | Cumulative Book / Tax Timer | Columns (c) & (d): Line 17 - Line 20, Then Line 18 - Line 20 | | $22,501,976 | $24,803,674 | $26,782,098 | $27,030,675 | ($4,684,389) | ($2,203,384) | ($59,116) |
| 22 | Less: Cumulative Book Depreciation at Acquisition | Line 20 Column (d) | 3/ | | | | | $5,306,643 | $5,306,643 | $5,306,643 |
| 23 | Cumulative Book / Tax Timer - PPL | Line 21 + Line 22 | | | | | | $622,254 | $3,103,259 | $5,247,528 |
| 24 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% |
| 25 | Deferred Tax Reserve | Columns (c) & (d): Line 21 * Line 24, Then Line 23 * Line 24 | | $4,725,415 | $5,208,772 | $5,624,241 | $5,676,442 | $130,673 | $651,684 | $1,101,981 |
| 26 | Add: FY 2020 Federal NOL (Generation) / Utilization | Page 29 of 38, Line 15, Col (c) | 3/ | ($1,462,980) | ($1,462,980) | ($1,462,980) | ($1,462,980) | $0 | $0 | $0 |
| 27 | Net Deferred Tax Reserve before Proration Adjustment | Sum of Lines 25 through 26 | | $3,262,435 | $3,745,791 | $4,161,260 | $4,213,461 | $130,673 | $651,684 | $1,101,981 |
| | Rate Base Calculation: | | | | | | | | | |
| 28 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $49,655,625 | $49,655,625 | $49,655,625 | $49,655,625 | $49,655,625 | $49,655,625 | $49,655,625 |
| 29 | Accumulated Depreciation | -Line 20 | | ($1,002,030) | ($3,006,091) | ($5,010,152) | ($5,306,643) | ($7,014,213) | ($9,018,274) | ($11,022,334) |
| 30 | Deferred Tax Reserve | -Line 27 | | ($3,262,435) | ($3,745,791) | ($4,161,260) | ($4,213,461) | ($130,673) | ($651,684) | ($1,101,981) |
| 31 | Year End Rate Base before Deferred Tax Proration | Sum of Lines 28 through 30 | | $45,391,160 | $42,903,743 | $40,484,213 | $40,135,521 | $42,510,739 | $39,985,667 | $37,531,310 |
| | Revenue Requirement Calculation: | | | | | | | | | |
| 32 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 = Current Year Line 31 * Page 16 of 38, Line 16, Col(e); Then =(Prior Year Line 31 + Current Year Line 31) ÷ 2 | 4/ | $16,573,333 | $44,147,452 | $41,693,978 | $41,497,476 | $41,497,476 | $41,248,203 | $38,758,489 |
| 33 | Proration Adjustment | Page 12 of 38, Line 41 | | $30,912 | $18,700 | $17,833 | $7,849 | $7,849 | $22,363 | $19,328 |
| 34 | Average ISR Rate Base after Deferred Tax Proration | Line 33 + Line 34 | | $16,604,245 | $44,166,151 | $41,711,811 | $41,505,326 | $41,505,326 | $41,270,566 | $38,777,816 |
| 35 | Pre-Tax ROR | Page 37 of 38, Line 35 | | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% |
| 36 | Proration | Line 14 | 2/ | | | | 14.79% | 85.21% | | |
| 37 | Return and Taxes | Cols (a) through (c) and (f): L 34 * L 35; Cols (d) and (e): L 34 * L 35 * L 36 | 2/ | $1,366,529 | $3,634,874 | $3,432,882 | $505,364 | $2,910,524 | $3,396,568 | $3,191,414 |
| 38 | Book Depreciation | Line 19 | | $1,002,030 | $2,004,061 | $2,004,061 | $296,491 | $1,707,570 | $2,004,061 | $2,004,061 |
| 39 | **Annual Revenue Requirement** | Line 37 + Line 38 | | **$2,368,560** | **$5,638,935** | **$5,436,943** | **$801,855** | **$4,618,094** | **$5,400,628** | **$5,195,475** |

40 Docket No. 4915, FY 2020 Electric ISR Reconciliation, Page 9, Line 29
41 2020 Tax True Up

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))
2/ Columns (d) and (e) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.
3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.
4/ Columns (d) and (e) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (c) and the end of the fiscal year on Line 31, Column (e). See note 2.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2020 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2020 (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|---|---|
| | Capital Repairs Deduction | | | | | | | | |
| 1 | Plant Additions | Page 10 of 38, Line 3 | | $67,435,277 | 20 Year MACRS Depreciation | | | | |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 8.51% | | | | | |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $5,738,742 | NG MACRS basis: | Line 22, Column (a) | | $59,644,817 | |
| 4 | | | | | | | | Annual | Cumulative |
| 5 | Bonus Depreciation | | | | Fiscal Year | | Proration | MACRS | Tax Depr |
| 6 | Plant Additions | Line 1 | | $67,435,277 | FY Mar-2020 | 3.750% | | $2,236,681 | $23,504,007 |
| 7 | Plant Additions | | | $0 | FY Mar-2021 | 7.219% | | $4,305,759 | $27,809,766 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $5,738,742 | FY Mar-2022 | 6.677% | | $3,982,484 | $31,792,250 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $61,696,535 | FY Mar-2023 (Apr-May 2022) | 6.177% | 0.914% | $545,069 | $32,337,319 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 100.00% | | | | | |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $61,696,535 | PPL Acquisition - May 25, 2022 | | | | |
| 12 | Bonus Depreciation Rate | 1 * 14.78% * 30% * 75% | 2/ | 3.33% | Book Cost | Line 1, Column (a) | | $67,435,277 | |
| 13 | Bonus Depreciation Rate | 1 * 0% * 25% | | 0.00% | Cumulative Book Depreciation | - Page 10 of 38, Line 20, Col (d) | | ($5,306,643) | |
| 14 | Total Bonus Depreciation Rate | Line 12 + Line 13 | | 3.33% | PPL MACRS basis: | Line 12(e) + Line 13(e) | | $62,128,634 | |
| 15 | Bonus Depreciation | Line 11 * Line 14 | | $2,051,718 | | | | | |
| 16 | | | | | FY Mar-2023 (Jun-Mar 2023) | 3.750% | | $2,329,824 | $2,329,824 |
| 17 | Remaining Tax Depreciation | | | | Mar-2024 | 7.219% | | $4,485,066 | $6,814,890 |
| 18 | Plant Additions | Line 1 | | $67,435,277 | Mar-2025 | 6.677% | | $4,148,329 | $10,963,219 |
| 19 | Less Capital Repairs Deduction | Line 3 | | $5,738,742 | Mar-2026 | 6.177% | | $3,837,686 | $14,800,904 |
| 20 | Less Bonus Depreciation | Line 15 | | $2,051,718 | Mar-2027 | 5.713% | | $3,549,409 | $18,350,313 |
| 21 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 18 - Line 19 - Line 20 | | $59,644,817 | Mar-2028 | 5.285% | | $3,283,498 | $21,633,812 |
| 22 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% | Mar-2029 | 4.888% | | $3,036,848 | $24,670,659 |
| 23 | Remaining Tax Depreciation | Line 21 * Line 22 | | $2,236,681 | Mar-2030 | 4.522% | | $2,809,457 | $27,480,116 |
| 24 | | | | | Mar-2031 | 4.462% | | $2,772,180 | $30,252,296 |
| 25 | FY20 Loss incurred due to retirements | Per Tax Department | 3/ | $2,144,147 | Mar-2032 | 4.461% | | $2,771,558 | $33,023,854 |
| 26 | Cost of Removal | Page 10 of 38, Line 10 | | $11,332,719 | Mar-2033 | 4.462% | | $2,772,180 | $35,796,034 |
| 27 | | | | | Mar-2034 | 4.461% | | $2,771,558 | $38,567,592 |
| 28 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 15, 23, 25, and 26 | | $23,504,007 | Mar-2035 | 4.462% | | $2,772,180 | $41,339,772 |
| 29 | | | | | Mar-2036 | 4.461% | | $2,771,558 | $44,111,330 |
| 30 | | | | | Mar-2037 | 4.462% | | $2,772,180 | $46,883,510 |
| 31 | | | | | Mar-2038 | 4.461% | | $2,771,558 | $49,655,068 |
| 32 | | | | | Mar-2039 | 4.462% | | $2,772,180 | $52,427,248 |
| 33 | | | | | Mar-2040 | 4.461% | | $2,771,558 | $55,198,806 |
| 34 | | | | | Mar-2041 | 4.462% | | $2,772,180 | $57,970,986 |
| 35 | | | | | Mar-2042 | 4.461% | | $2,771,558 | $60,742,544 |
| 36 | | | | | Mar-2043 | 2.231% | | $1,386,090 | $62,128,634 |
| 37 | | | | | | 100.000% | | $62,128,634 | |
| 38 | | | | | | | | | |

1/ Per Tax Department
2/ Per Tax Department
3/ Per Tax Department
Column (d), Line 9 = MACRS Rate 6.177% / 365 days x 54 days

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investment**

| Line No. | | | | FY22 (a) | FY23 (b) | FY24 (c) | FY25 (d) |
|---|---|---|---|---|---|---|---|
| | **Deferred Tax Subject to Proration** | | | | | | |
| 1 | Book Depreciation | See the corresponding Fiscal Year on Page 10 of 38, Line 19. Note there are 2 columns to sum for FY23. | | $2,004,061 | $2,004,061 | $2,004,061 | $2,004,061 |
| 2 | Bonus Depreciation | | | $0 | $0 | $0 | $0 |
| 3 | Remaining MACRS Tax Depreciation | See the corresponding Fiscal Year on Page 10 of 38, Line 16. Note there are 2 columns to sum for FY23. | | ($3,982,484) | ($2,874,892) | ($4,485,066) | ($4,148,329) |
| 4 | FY 2020 tax (gain)/loss on retirements | Year 1 = Docket No. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0 | | | | | |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | | ($1,978,424) | ($870,832) | ($2,481,005) | ($2,144,268) |
| 6 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | | ($415,469) | ($182,875) | ($521,011) | ($450,296) |
| | **Deferred Tax Not Subject to Proration** | | | | | | |
| 8 | Capital Repairs Deduction | Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0 | | | | | |
| 9 | Cost of Removal | Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0 | | | | | |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2020 | | | | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | | $0 | $0 | $0 | $0 |
| 12 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | | $0 | $0 | $0 | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | | ($415,469) | ($182,875) | ($521,011) | ($450,296) |
| 15 | Net Operating Loss | Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a) | | $0 | $0 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | | ($415,469) | ($182,875) | ($521,011) | ($450,296) |
| | **Allocation of FY 2020 Estimated Federal NOL** | | | | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (a) = Line 5 | | ($1,978,424) | ($870,832) | ($2,481,005) | ($2,144,268) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | | $0 | $0 | $0 | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | | ($1,978,424) | ($870,832) | ($2,481,005) | ($2,144,268) |
| 20 | Total FY 2020 Federal NOL (Utilization) | Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a) | | $0 | $0 | $0 | $0 |
| 21 | Allocated FY 2020 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | | $0 | $0 | $0 | $0 |
| 22 | Allocated FY 2020 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | | $0 | $0 | $0 | $0 |
| 23 | Effective Tax Rate | | | 21% | 21% | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | | $0 | $0 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | | ($415,469) | ($182,875) | ($521,011) | ($450,296) |
| | | (e) | (f) | (g) | (h) | (i) | (j) |
| | **Proration Calculation** | Number of Days in Month | Proration Percentage | FY22 | FY23 | FY24 | FY25 |
| 26 | April | 30 | 91.78% | ($31,777) | ($13,987) | ($39,849) | ($34,440) |
| 27 | May | 31 | 83.29% | ($28,836) | ($12,693) | ($36,162) | ($31,253) |
| 28 | June | 30 | 75.07% | ($25,991) | ($11,440) | ($32,593) | ($28,169) |
| 29 | July | 31 | 66.58% | ($23,050) | ($10,146) | ($28,905) | ($24,982) |
| 30 | August | 31 | 58.08% | ($20,109) | ($8,851) | ($25,218) | ($21,795) |
| 31 | September | 30 | 49.86% | ($17,264) | ($7,599) | ($21,649) | ($18,711) |
| 32 | October | 31 | 41.37% | ($14,323) | ($6,305) | ($17,962) | ($15,524) |
| 33 | November | 30 | 33.15% | ($11,478) | ($5,052) | ($14,393) | ($12,440) |
| 34 | December | 31 | 24.66% | ($8,537) | ($3,758) | ($10,706) | ($9,253) |
| 35 | January | 31 | 16.16% | ($5,596) | ($2,463) | ($7,018) | ($6,066) |
| 36 | February | 28 | 8.49% | ($2,941) | ($1,294) | ($3,688) | ($3,187) |
| 37 | March | 31 | 0.00% | $0 | $0 | $0 | $0 |
| 38 | Total | 365 | | ($189,902) | ($83,588) | ($238,143) | ($205,820) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($415,469) | ($182,875) | ($521,011) | ($450,296) |
| 40 | Average Deferred Tax without Proration | Year 1=Line 39 * Page 16 of 38, Line 16, Col (e); then = Line 39 * 50% | | ($207,734) | ($91,437) | ($260,506) | ($225,148) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $17,833 | $7,849 | $22,363 | $19,328 |

**Column Notes:**

| | |
|---|---|
| (f) | Sum of remaining days in the year (Col (e)) ÷ 365 |
| (g) & (j) | Current Year Line 25 ÷ 12 × Current Month Col (f) |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2021 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2021 (a) | Fiscal Year 2022 (b) | NG 4/1/22 - 5/24/22 2023 (c) | PPL 5/25/22 - 3/31/23 2023 (d) | Fiscal Year 2024 (e) | Fiscal Year 2025 (f) |
|---|---|---|---|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | | | | | |
| 1 | *Non-Discretionary Capital* | | | $35,318,912 | | | | | |
| | *Discretionary Capital* | | | | | | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible) | | | $80,041,254 | | | | | |
| 3 | Total Allowed Capital Included in Rate Base (non-intangible) | Page 29 of 38, Line 4(d) | | $115,360,166 | $0 | $0 | $0 | $0 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $115,360,166 | $0 | $0 | $0 | $0 | $0 |
| 5 | Retirements | Page 29 of 38 , Line 10 ,Col (d) | | $21,996,026 | $0 | $0 | $0 | $0 | $0 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $93,364,140 | $93,364,140 | $93,364,140 | $93,364,140 | $93,364,140 | $93,364,140 |
| | Change in Net Capital Included in Rate Base | | | | | | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $115,360,166 | $0 | $0 | $0 | $0 | $0 |
| 8 | Depreciation Expense | Page 33 of 38, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12 | | $49,906,920 | $0 | $0 | $0 | $0 | $0 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; Then = Prior Year Line 9 | | $65,453,245 | $65,453,245 | $65,453,245 | $65,453,245 | $65,453,245 | $65,453,245 |
| 10 | Cost of Removal | Page 29 of 38 , Line 7 ,Col (d) | | $10,232,810 | | | | | |
| 11 | **Total Net Plant in Service** | **Line 9 + Line 10** | | **$75,686,055** | **$75,686,055** | **$75,686,055** | **$75,686,055** | **$75,686,055** | **$75,686,055** |
| | Deferred Tax Calculation: | | | | | | | | |
| 12 | Composite Book Depreciation Rate | Page 31 of 38, Line 3, Col ( e) | 1/ | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% |
| 13 | Number of days | | 2/ | | | 54 | 311 | | |
| 14 | Proration Percentage | | 2/ | | | 14.79% | 85.21% | | |
| 15 | Vintage Year Tax Depreciation: | | | | | | | | |
| 16 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 14 of 38, Line 28, Column (a), Then = Line Page 14 of 38 , Column (e) | | $44,175,121 | $6,372,048 | $871,935 | $4,143,683 | $7,976,867 | $7,377,966 |
| 17 | Cumulative Tax Depreciation-NG | Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16 | 3/ | $44,175,121 | $50,547,169 | $51,419,105 | | | |
| 18 | Cumulative Tax Depreciation-PPL | Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16 | 3/ | | | | $4,143,683 | $12,120,550 | $19,498,516 |
| 19 | Book Depreciation | year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line | | $1,475,153 | $2,950,307 | $436,484 | $2,513,823 | $2,950,307 | $2,950,307 |
| 20 | Cumulative Book Depreciation | Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19 | | $1,475,153 | $4,425,460 | $4,861,944 | $7,375,767 | $10,326,074 | $13,276,381 |
| 21 | Cumulative Book / Tax Timer | Columns (a) through (c): Line 17 - Line 20, Then Line 18 - Line 20 | | $42,699,968 | $46,121,709 | $46,557,161 | ($3,232,084) | $1,794,476 | $6,222,136 |
| 22 | Less: Cumulative Book Depreciation at Acquisition | Line 20 Column (c) | 3/ | | | | $4,861,944 | $4,861,944 | $4,861,944 |
| 23 | Cumulative Book / Tax Timer - PPL | Line 21 + Line 22 | | | | | $1,629,860 | $6,656,420 | $11,084,080 |
| 24 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% |
| 25 | Deferred Tax Reserve | Columns (a) through (c): Line 21 * Line 24, Then Line 23 * Line 24 | | $8,966,993 | $9,685,559 | $9,777,004 | $342,271 | $1,397,848 | $2,327,657 |
| 26 | Add: FY 2021 Federal NOL (Generation) / Utilization | Page 29 of 38, Line 15, Col (d) | 3/ | ($5,639,147) | ($5,639,147) | ($5,639,147) | $0 | $0 | $0 |
| 27 | Net Deferred Tax Reserve beforee Proration Adjustment | Sum of Lines 25 through 26 | | $3,327,846 | $4,046,411 | $4,137,856 | $342,271 | $1,397,848 | $2,327,657 |
| | Rate Base Calculation: | | | | | | | | |
| 28 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $75,686,055 | $75,686,055 | $75,686,055 | $75,686,055 | $75,686,055 | $75,686,055 |
| 29 | Accumulated Depreciation | -Line 20 | | ($1,475,153) | ($4,425,460) | ($4,861,944) | ($7,375,767) | ($10,326,074) | ($13,276,381) |
| 30 | Deferred Tax Reserve | -Line 27 | | ($3,327,846) | ($4,046,411) | ($4,137,856) | ($342,271) | ($1,397,848) | ($2,327,657) |
| 31 | Year End Rate Base before Deferred Tax Proration | Sum of Lines 28 through 30 | | $70,883,056 | $67,214,184 | $66,686,255 | $67,968,018 | $63,962,133 | $60,082,018 |
| | Revenue Requirement Calculation: | | | | | | | | |
| 32 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2 | 4/ | $35,441,528 | $69,048,620 | $67,591,101 | $67,591,101 | $65,965,075 | $62,022,076 |
| 33 | Proration Adjustment | Page 15 of 38, Line 41 | | $16,539 | $30,843 | $18,616 | $18,616 | $45,308 | $39,910 |
| 34 | Average ISR Rate Base after Deferred Tax Proration | Line 32 + Line 33 | | $35,458,067 | $69,079,462 | $67,609,717 | $67,609,717 | $66,010,383 | $62,061,985 |
| 35 | Pre-Tax ROR | Page 37 of 38, Line 35 | | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% |
| 36 | Proration | Line 14 | 2/ | | | 14.79% | 85.21% | | |
| 37 | Return and Taxes | Cols (a),(b) and (e): L 34 * L 35; Cols (c) and (d): L 34 * L 35 * L 36 | 2/ | $2,918,199 | $5,685,240 | $823,209 | $4,741,071 | $5,432,655 | $5,107,701 |
| 38 | Book Depreciation | Line 19 | | $1,475,153 | $2,950,307 | $436,484 | $2,513,823 | $2,950,307 | $2,950,307 |
| 39 | Revenue Requirement of Intangible Assets | | | | | | | | |
| 40 | **Annual Revenue Requirement** | **Line 37 + Line 38 + Line 39** | | **$4,393,352** | **$8,635,547** | **$1,259,692** | **$7,254,894** | **$8,382,961** | **$8,058,008** |

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

2/ Columns (c) and (d) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ Columns (c) and (d) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (b) and the end of the fiscal year on Line 31, Column (d). See note 2.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2021 (a) |
|---|---|---|---|---|
| | Capital Repairs Deduction | | | |
| 1 | Plant Additions | Page 13 of 38, Line 3(a) | | $115,360,166 |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 23.49% |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $27,092,422 |
| 4 | | | | |
| 5 | Bonus Depreciation | | | |
| 6 | Plant Additions | Line 1 | | $115,360,166 |
| 7 | Plant Additions | | | $0 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $27,092,422 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $88,267,744 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 |
| 12 | Bonus Depreciation Rate | 1 * 14.78% * 75% * 30% | | 0.00% |
| 13 | Bonus Depreciation Rate | 1 * 25% * 0% | | 0.00% |
| 14 | Total Bonus Depreciation Rate | Line 12 + Line 13 | | 0.00% |
| 15 | Bonus Depreciation | Line 11 * Line 14 | | $0 |
| 16 | | | | |
| 17 | Remaining Tax Depreciation | | | |
| 18 | Plant Additions | Line 1 | | $115,360,166 |
| 19 | Less Capital Repairs Deduction | Line 3 | | $27,092,422 |
| 20 | Less Bonus Depreciation | Line 15 | | $0 |
| 21 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 18 - Line 19 - Line 20 | | $88,267,744 |
| 22 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% |
| 23 | Remaining Tax Depreciation | Line 21 * Line 22 | | $3,310,040 |
| 24 | | | | |
| 25 | FY21 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $3,539,849 |
| 26 | Cost of Removal | Page 13 of 38, Line 10 | | $10,232,810 |
| 27 | | | | |
| 28 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 15, 23, 25, and 26 | | $44,175,121 |

| Line No. | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|
| 1 | | 20 Year MACRS Depreciation | | | |
| 2 | | | | | |
| 3 | MACRS basis: | Line 21, Column (a) | | $88,267,744 | |
| 4 | | | | Annual | Cumulative |
| 5 | Fiscal Year | | Prorated | MACRS | Tax Depr |
| 6 | FY Mar-2021 | 3.750% | | $3,310,040 | $44,175,121 |
| 7 | FY Mar-2022 | 7.219% | | $6,372,048 | $50,547,169 |
| 8 | FY Mar-2023 (Apr-May 2022) | 6.677% | 0.988% | $871,935 | $51,419,105 |
| 9 | | | | | |
| 10 | PPL Acquisition - May 25, 2022 | | | | |
| 11 | Book Cost | Line 1, Column (a) | | $115,360,166 | |
| 12 | Cumulative Book Depreciation | - Page 13 of 38, Line 20, Col (c) | | ($4,861,944) | |
| 13 | PPL MACRS basis: | Line 11(e) + Line 12(e) | | $110,498,222 | |
| 14 | | | | | |
| 15 | FY Mar-2023 (Jun-Mar 2023) | 3.750% | | $4,143,683 | $4,143,683 |
| 16 | Mar-2024 | 7.219% | | $7,976,867 | $12,120,550 |
| 17 | Mar-2025 | 6.677% | | $7,377,966 | $19,498,516 |
| 18 | Mar-2026 | 6.177% | | $6,825,475 | $26,323,991 |
| 19 | Mar-2027 | 5.713% | | $6,312,763 | $32,636,755 |
| 20 | Mar-2028 | 5.285% | | $5,839,831 | $38,476,586 |
| 21 | Mar-2029 | 4.888% | | $5,401,153 | $43,877,739 |
| 22 | Mar-2030 | 4.522% | | $4,996,730 | $48,874,469 |
| 23 | Mar-2031 | 4.462% | | $4,930,431 | $53,804,899 |
| 24 | Mar-2032 | 4.461% | | $4,929,326 | $58,734,225 |
| 25 | Mar-2033 | 4.462% | | $4,930,431 | $63,664,656 |
| 26 | Mar-2034 | 4.461% | | $4,929,326 | $68,593,981 |
| 27 | Mar-2035 | 4.462% | | $4,930,431 | $73,524,412 |
| 28 | Mar-2036 | 4.461% | | $4,929,326 | $78,453,738 |
| 29 | Mar-2037 | 4.462% | | $4,930,431 | $83,384,168 |
| 30 | Mar-2038 | 4.461% | | $4,929,326 | $88,313,494 |
| 31 | Mar-2039 | 4.462% | | $4,930,431 | $93,243,925 |
| 32 | Mar-2040 | 4.461% | | $4,929,326 | $98,173,250 |
| 33 | Mar-2041 | 4.462% | | $4,930,431 | $103,103,681 |
| 34 | Mar-2042 | 4.461% | | $4,929,326 | $108,033,007 |
| 35 | Mar-2043 | 2.231% | | $2,465,215 | $110,498,222 |
| 36 | | 100.00% | | $110,498,222 | |
| 37 | | | | | |

1/ Per Tax Department
2/ Per Tax Department
Column (d), Line 8 = MACRS Rate 6.677% / 365 days x 54 days

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investment**

| Line No. | **Deferred Tax Subject to Proration** | | FY22 (a) | FY23 (b) | FY24 (c) | FY25 (d) |
|---|---|---|---|---|---|---|
| 1 | Book Depreciation | See the corresponding Fiscal Year on Page 13 of 38, Line 19. Note there are 2 columns to sum for FY23. | $2,950,307 | $2,950,307 | $2,950,307 | $2,950,307 |
| 2 | Bonus Depreciation | Page 14 of 38, Line 20 | $0 | $0 | $0 | $0 |
| 3 | Remaining MACRS Tax Depreciation | See the corresponding Fiscal Year on Page 13 of 38, Line 16. Note there are 2 columns to sum for FY23. | ($6,372,048) | ($5,015,619) | ($7,976,867) | ($7,377,966) |
| 4 | FY 2021 tax (gain)/loss on retirements | - Page 14 of 38, Line 25 | | | | |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | ($3,421,742) | ($2,065,312) | ($5,026,560) | ($4,427,659) |
| 6 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | ($718,566) | ($433,715) | ($1,055,578) | ($929,808) |
| | **Deferred Tax Not Subject to Proration** | | | | | |
| 8 | Capital Repairs Deduction | - Page 14 of 38, Line 3 | | | | |
| 9 | Cost of Removal | - Page 14 of 38, Line 26 | | | | |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2021 | | | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | $0 | $0 | $0 | $0 |
| 12 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | | $0 | $0 | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | ($718,566) | ($433,715) | ($1,055,578) | ($929,808) |
| 15 | Net Operating Loss | Page 13 of 38, Line 26 | $0 | $0 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | ($718,566) | ($433,715) | ($1,055,578) | ($929,808) |
| | **Allocation of FY 2021 Estimated Federal NOL** | | | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (b) = Line 5 | ($3,421,742) | ($2,065,312) | ($5,026,560) | ($4,427,659) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | $0 | $0 | $0 | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | ($3,421,742) | ($2,065,312) | ($5,026,560) | ($4,427,659) |
| 20 | Total FY 2021 Federal NOL (Utilization) | - Page 13 of 38, Line 26 / 21% | $0 | $0 | $0 | $0 |
| 21 | Allocated FY 2021 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | $0 | $0 | $0 | $0 |
| 22 | Allocated FY 2021 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | $0 | $0 | $0 | $0 |
| 23 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | $0 | $0 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | ($718,566) | ($433,715) | ($1,055,578) | ($929,808) |

| Line No. | **Proration Calculation** | Number of Days in Month (e) | Proration Percentage (f) | FY22 (g) | FY23 (h) | FY24 (i) | FY25 (j) |
|---|---|---|---|---|---|---|---|
| 26 | April | 30 | 91.78% | ($54,959) | ($33,172) | ($80,735) | ($71,115) |
| 27 | May | 31 | 83.29% | ($49,873) | ($30,103) | ($73,264) | ($64,535) |
| 28 | June | 30 | 75.07% | ($44,951) | ($27,132) | ($66,034) | ($58,166) |
| 29 | July | 31 | 66.58% | ($39,866) | ($24,062) | ($58,563) | ($51,585) |
| 30 | August | 31 | 58.08% | ($34,780) | ($20,993) | ($51,092) | ($45,004) |
| 31 | September | 30 | 49.86% | ($29,858) | ($18,022) | ($43,862) | ($38,636) |
| 32 | October | 31 | 41.37% | ($24,772) | ($14,952) | ($36,391) | ($32,055) |
| 33 | November | 30 | 33.15% | ($19,851) | ($11,982) | ($29,161) | ($25,686) |
| 34 | December | 31 | 24.66% | ($14,765) | ($8,912) | ($21,690) | ($19,106) |
| 35 | January | 31 | 16.16% | ($9,679) | ($5,842) | ($14,219) | ($12,525) |
| 36 | February | 28 | 8.49% | ($5,086) | ($3,070) | ($7,471) | ($6,581) |
| 37 | March | 31 | 0.00% | $0 | $0 | $0 | $0 |
| 38 | Total | 365 | | ($328,440) | ($198,242) | ($482,481) | ($424,995) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($718,566) | ($433,715) | ($1,055,578) | ($929,808) |
| 40 | Average Deferred Tax without Proration | Line 39 × 0.5 | | ($359,283) | ($216,858) | ($527,789) | ($464,904) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $30,843 | $18,616 | $45,308 | $39,910 |

**Column Notes:**

(f) Sum of remaining days in the year (Col (e)) ÷ 365

(g) through (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**ISR Additions April 2020 through March 2021**

| Line No. | Month No. | Month | FY 2021 Plant Additions | In Rates | Not In Rates | Weight for Days | Weighted Average | Weight for Not in Rates |
|---|---|---|---|---|---|---|---|---|
| | | | (a) | (b) | (c) = (a) - (b) | (d) | (e) = (d) * (c) | (f)=(c)/Total(c) |
| 1 | | | | | | | | |
| 2 | 1 | Apr-20 | 8,218,322 | 6,236,917 | 1,981,405 | 0.958 | 1,898,846 | 2.94% |
| 3 | 2 | May-20 | 8,218,322 | 6,236,917 | 1,981,405 | 0.875 | 1,733,729 | 2.94% |
| 4 | 3 | Jun-20 | 8,218,322 | 6,236,917 | 1,981,405 | 0.792 | 1,568,612 | 2.94% |
| 5 | 4 | Jul-20 | 8,218,322 | 6,236,917 | 1,981,405 | 0.708 | 1,403,495 | 2.94% |
| 6 | 5 | Aug-20 | 8,218,322 | 6,236,917 | 1,981,405 | 0.625 | 1,238,378 | 2.94% |
| 7 | 6 | Sep-20 | 8,218,322 | - | 8,218,322 | 0.542 | 4,451,591 | 12.19% |
| 8 | 7 | Oct-20 | 8,218,322 | - | 8,218,322 | 0.458 | 3,766,731 | 12.19% |
| 9 | 8 | Nov-20 | 8,218,322 | - | 8,218,322 | 0.375 | 3,081,871 | 12.19% |
| 10 | 9 | Dec-20 | 8,218,322 | - | 8,218,322 | 0.292 | 2,397,010 | 12.19% |
| 11 | 10 | Jan-21 | 8,218,322 | - | 8,218,322 | 0.208 | 1,712,150 | 12.19% |
| 12 | 11 | Feb-21 | 8,218,322 | - | 8,218,322 | 0.125 | 1,027,290 | 12.19% |
| 13 | 12 | Mar-21 | 8,218,322 | - | 8,218,322 | 0.042 | 342,430 | 12.19% |
| 14 | | Total | $98,619,860 | $31,184,583 | $67,435,277 | | $24,622,135 | 100.00% |
| 15 | **Total September 2020 through March 2021** | | | **$** | **57,528,252** | | | |
| 16 | **FY 2020 Weighted Average Incremental Rate Base Percentage** | | | | | | **36.51%** | |

Column (a)=Page 29 of 38, Line 1(c)
Column(b)=Page 29 of 38, Line 3(c)
Line 15 = sum of Line 7(c) through Line 13(c)
Line 16 = Line 14(f)/Line 14(c)

**The Narragansett Electric Company**
**d/b/a National Grid**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2022 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2022 (a) | NG 4/1/22 - 5/24/2022 2023 (b) | PPL 5/25/22 - 3/31/23 2023 (c) | Fiscal Year 2024 (d) | Fiscal Year 2025 (e) |
|---|---|---|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | | | | |
| 1 | *Non-Discretionary Capital* | Docket 5098, P 29 of 29. Line 1(a) | | $44,263,589 | | | | |
| | *Discretionary Capital* | | | | | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible) | Docket 5098, P 29 of 29. Line 2(a) | | $42,200,430 | | | | |
| 3 | Total Allowed Capital Included in Rate Base (non-intangible) | Page 29 of 38, Line 4(e) | | $86,464,019 | $0 | $0 | $0 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $86,464,019 | $0 | $0 | $0 | $0 |
| 5 | Retirements | Page 29 of 38 , Line 10 ,Col (e) | | $34,853,004 | $0 | $0 | $0 | $0 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $51,611,015 | $51,611,015 | $51,611,015 | $51,611,015 | $51,611,015 |
| | Change in Net Capital Included in Rate Base | | | | | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $86,464,019 | $0 | $0 | $0 | $0 |
| 8 | Depreciation Expense | Page 33 of 38, Line 62, Col (d) | | $49,906,920 | $0 | $0 | $0 | $0 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; Then = Prior Year Line 9 | | $36,557,099 | $36,557,099 | $36,557,099 | $36,557,099 | $36,557,099 |
| 10 | Cost of Removal | Page 29 of 38 , Line 7 ,Col (e) | | $7,600,505 | $0 | $0 | $0 | $0 |
| 11 | **Total Net Plant in Service** | **Line 9 + Line 10** | | **$44,157,603** | **$44,157,603** | **$44,157,603** | **$44,157,603** | **$44,157,603** |
| | Deferred Tax Calculation: | | | | | | | |
| 12 | Composite Book Depreciation Rate | Page 31 of 38, Line 3, Col ( e) | 1/ | 3.16% | 3.16% | 3.16% | 3.16% | 3.16% |
| 13 | Number of days | | 2/ | | 54 | 311 | | |
| 14 | Proration Percentage | | 2/ | | 14.79% | 85.21% | | |
| 15 | Vintage Year Tax Depreciation: | | | | | | | |
| 16 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 18 of 38, Line 27, Column (a), Then = Line Page 18 of 38 , Column (e) | | $41,638,714 | $649,462 | $3,202,773 | $6,165,552 | $5,702,644 |
| 17 | Cumulative Tax Depreciation-NG | Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16 | 3/ | $41,638,714 | $42,288,176 | | | |
| 18 | Cumulative Tax Depreciation-PPL | Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16 | 3/ | | | $3,202,773 | $9,368,325 | $15,070,969 |
| 19 | Book Depreciation | year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12 | 2/ | $815,454 | $241,285 | $1,389,623 | $1,630,908 | $1,630,908 |
| 20 | Cumulative Book Depreciation | Prior Year Line 20 + Current Year Line 19 | | $815,454 | $1,056,739 | $2,446,362 | $4,077,270 | $5,708,178 |
| 21 | Cumulative Book / Tax Timer | Columns (a) & (b): Line 17 - Line 20, Then Line 18 - Line 20 | | $40,823,260 | $41,231,437 | $756,411 | $5,291,054 | $9,362,790 |
| 22 | Less: Cumulative Book Depreciation at Acquisition | Line 20 Column (b) | 3/ | | | $1,056,739 | $1,056,739 | $1,056,739 |
| 23 | Cumulative Book / Tax Timer - PPL | Line 21 + Line 22 | | | | $1,813,150 | $6,347,793 | $10,419,529 |
| 24 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% | 21.00% |
| 25 | Deferred Tax Reserve | Cols (a) and (b): Line 21 * Line 24, Then Line 23 * Line 24 | | $8,572,885 | $8,658,602 | $380,761 | $1,333,037 | $2,188,101 |
| 26 | Add: FY 2022 Federal NOL (Generation) / Utilization | Page 29 of 38, Line 15, Col (e) | 3/ | ($3,602,966) | ($3,602,966) | $0 | $0 | $0 |
| 27 | Net Deferred Tax Reserve before Proration Adjustmer | Sum of Lines 25 through 26 | | $4,969,918 | $5,055,636 | $380,761 | $1,333,037 | $2,188,101 |
| | Rate Base Calculation: | | | | | | | |
| 28 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $44,157,603 | $44,157,603 | $44,157,603 | $44,157,603 | $44,157,603 |
| 29 | Accumulated Depreciation | -Line 20 | | ($815,454) | ($1,056,739) | ($2,446,362) | ($4,077,270) | ($5,708,178) |
| 30 | Deferred Tax Reserve | -Line 27 | | ($4,969,918) | ($5,055,636) | ($380,761) | ($1,333,037) | ($2,188,101) |
| 31 | Year End Rate Base before Deferred Tax Proratioı | Sum of Lines 28 through 30 | | $38,372,231 | $38,045,228 | $41,330,480 | $38,747,296 | $36,261,324 |
| | Revenue Requirement Calculation: | | | | | | | |
| 32 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2 | 4/ | $19,186,115 | $39,851,355 | $39,851,355 | $40,038,888 | $37,504,310 |
| 33 | Proration Adjustment | Page 19 of 38, Line 41 | | $13,204 | $20,022 | $20,022 | $40,874 | $36,701 |
| 34 | Average ISR Rate Base after Deferred Tax Proration | Line 33 + Line 34 | | $19,199,320 | $39,871,378 | $39,871,378 | $40,079,762 | $37,541,011 |
| 35 | Pre-Tax ROR | Page 37 of 38, Line 35 | | 8.23% | 8.23% | 8.23% | 8.23% | 8.23% |
| 36 | Proration | Line 14 | 2/ | | 14.79% | 85.21% | | |
| 37 | Return and Taxes | Col (a) and (d): L 34 * L 35; Cols (b) through (c): L 34 * L 35 * L 36 | 2/ | $1,580,104 | $485,470 | $2,795,945 | $3,298,564 | $3,089,625 |
| 38 | Book Depreciation | Line 19 | | $815,454 | $241,285 | $1,389,623 | $1,630,908 | $1,630,908 |
| 39 | **Annual Revenue Requirement** | **Line 37 + Line 38** | | **$2,395,558** | **$726,755** | **$4,185,568** | **$4,929,472** | **$4,720,533** |

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

2/ Columns (b) and (c) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ Columns (b) and (c) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (a) and the end of the fiscal year on Line 31, Column (c). See note 2.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2022 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2022 (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|---|---|
| | Capital Repairs Deduction | | | | | | | | |
| 1 | Plant Additions | Page 17 of 38, Line 3 | | $86,464,019 | 20 Year MACRS Depreciation | | | | |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 29.67% | | | | | |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $25,653,874 | NG MACRS basis: | Line 22, Column (a) | | $60,810,145 | |
| 4 | | | | | | | | Annual | Cumulative |
| 5 | Bonus Depreciation | | | | Fiscal Year | | Prorated | MACRS | Tax Depr |
| 6 | Plant Additions | Line 1 | | $86,464,019 | FY Mar-2022 | 3.750% | | $2,280,380 | $41,638,714 |
| 7 | Plant Additions | | | $0 | FY Mar-2023 (Apr-May 2022) | 7.219% | 1.068% | $649,462 | $42,288,176 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $25,653,874 | | | | | |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $60,810,145 | PPL Acquisition - May 25, 2022 | | | | |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% | Book Cost | Line 1, Column (a) | | $86,464,019 | |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 | Cumulative Book Depreciation | - Page 17 of 38, Line 20, Col (b) | | ($1,056,739) | |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% | PPL MACRS basis: | Line 10(e) + Line 11(e) | | $85,407,280 | |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% | | | | | |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 | FY Mar-2023 (Jun-Mar 2023) | 3.750% | | $3,202,773 | $3,202,773 |
| 15 | | | | | Mar-2024 | 7.219% | | $6,165,552 | $9,368,325 |
| 16 | Remaining Tax Depreciation | | | | Mar-2025 | 6.677% | | $5,702,644 | $15,070,969 |
| 17 | Plant Additions | Line 1 | | $86,464,019 | Mar-2026 | 6.177% | | $5,275,608 | $20,346,576 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $25,653,874 | Mar-2027 | 5.713% | | $4,879,318 | $25,225,894 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 | Mar-2028 | 5.285% | | $4,513,775 | $29,739,669 |
| 20 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 17 - Line 18 - Line 19 | | $60,810,145 | Mar-2029 | 4.888% | | $4,174,708 | $33,914,377 |
| 21 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% | Mar-2030 | 4.522% | | $3,862,117 | $37,776,494 |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $2,280,380 | Mar-2031 | 4.462% | | $3,810,873 | $41,587,367 |
| 23 | | | | | Mar-2032 | 4.461% | | $3,810,019 | $45,397,386 |
| 24 | FY22 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $6,103,955 | Mar-2033 | 4.462% | | $3,810,873 | $49,208,258 |
| 25 | Cost of Removal | Page 17 of 38, Line 10 | | $7,600,505 | Mar-2034 | 4.461% | | $3,810,019 | $53,018,277 |
| 26 | | | | | Mar-2035 | 4.462% | | $3,810,873 | $56,829,150 |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $41,638,714 | Mar-2036 | 4.461% | | $3,810,019 | $60,639,169 |
| 28 | | | | | Mar-2037 | 4.462% | | $3,810,873 | $64,450,042 |
| 29 | | | | | Mar-2038 | 4.461% | | $3,810,019 | $68,260,060 |
| 30 | | | | | Mar-2039 | 4.462% | | $3,810,873 | $72,070,933 |
| 31 | | | | | Mar-2040 | 4.461% | | $3,810,019 | $75,880,952 |
| 32 | | | | | Mar-2041 | 4.462% | | $3,810,873 | $79,691,825 |
| 33 | | | | | Mar-2042 | 4.461% | | $3,810,019 | $83,501,844 |
| 34 | | | | | Mar-2043 | 2.231% | | $1,905,436 | $85,407,280 |
| 35 | | | | | | 100.000% | | $85,407,280 | |
| 36 | | | | | | | | | |

1/ Per Tax Department
2/ Per Tax Department
Column (d), Line 7 = MACRS Rate 7.219% / 365 days x 54 days

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investment**

| Line No. | Deferred Tax Subject to Proration | | FY22 (a) | FY23 (b) | FY24 (c) | FY25 (d) |
|---|---|---|---|---|---|---|
| 1 | Book Depreciation | See the corresponding Fiscal Year on Page 17 of 38, Line 19. Note there are 2 columns to sum for FY23. | $815,454 | $1,630,908 | $1,630,908 | $1,630,908 |
| 2 | Bonus Depreciation | Page 14 of 38, Line 20 | $0 | $0 | $0 | $0 |
| 3 | Remaining MACRS Tax Depreciation | Col (a): - Page 18 of 38, Line 22, column (a), thereafter, see the corresponding Fiscal Year on Page 17 of 38, Line 16. Note there are 2 columns to sum for FY23. | ($2,280,380) | ($3,852,235) | ($6,165,552) | ($5,702,644) |
| 4 | FY 2022 tax (gain)/loss on retirements | - Page 18 of 38, Line 24 | | | | |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | ($1,464,926) | ($2,221,327) | ($4,534,643) | ($4,071,736) |
| 6 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | ($307,635) | ($466,479) | ($952,275) | ($855,065) |
| | **Deferred Tax Not Subject to Proration** | | | | | |
| 8 | Capital Repairs Deduction | - Page 18 of 38, Line 3 | ($25,653,874) | | | |
| 9 | Cost of Removal | - Page 18 of 38, Line 25 | ($7,600,505) | | | |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2022 | | | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | ($33,254,379) | $0 | $0 | $0 |
| 12 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | ($6,983,420) | $0 | $0 | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | ($7,291,054) | ($466,479) | ($952,275) | ($855,065) |
| 15 | Net Operating Loss | Page 17 of 38, Line 26 | $0 | $0 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | ($7,291,054) | ($466,479) | ($952,275) | ($855,065) |
| | **Allocation of FY 2022 Estimated Federal NOL** | | | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (b) = Line 5 | ($1,464,926) | ($2,221,327) | ($4,534,643) | ($4,071,736) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | ($33,254,379) | $0 | $0 | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | ($34,719,305) | ($2,221,327) | ($4,534,643) | ($4,071,736) |
| 20 | Total FY 2022 Federal NOL (Utilization) | - Page 17 of 38, Line 26 / 21% | $0 | $0 | $0 | $0 |
| 21 | Allocated FY 2022 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | $0 | $0 | $0 | $0 |
| 22 | Allocated FY 2022 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | $0 | $0 | $0 | $0 |
| 23 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | $0 | $0 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | ($307,635) | ($466,479) | ($952,275) | ($855,065) |

| Line No. | | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|
| | **Proration Calculation** | Number of Days in Month | Proration Percentage | FY22 | FY23 | FY24 | FY25 |
| 26 | April | 30 | 91.78% | ($23,529) | ($35,678) | ($72,834) | ($65,399) |
| 27 | May | 31 | 83.29% | ($21,352) | ($32,377) | ($66,094) | ($59,347) |
| 28 | June | 30 | 75.07% | ($19,245) | ($29,182) | ($59,572) | ($53,490) |
| 29 | July | 31 | 66.58% | ($17,067) | ($25,880) | ($52,832) | ($47,439) |
| 30 | August | 31 | 58.08% | ($14,890) | ($22,578) | ($46,092) | ($41,387) |
| 31 | September | 30 | 49.86% | ($12,783) | ($19,383) | ($39,569) | ($35,530) |
| 32 | October | 31 | 41.37% | ($10,606) | ($16,082) | ($32,830) | ($29,478) |
| 33 | November | 30 | 33.15% | ($8,499) | ($12,887) | ($26,307) | ($23,622) |
| 34 | December | 31 | 24.66% | ($6,321) | ($9,585) | ($19,567) | ($17,570) |
| 35 | January | 31 | 16.16% | ($4,144) | ($6,284) | ($12,827) | ($11,518) |
| 36 | February | 28 | 8.49% | ($2,177) | ($3,302) | ($6,740) | ($6,052) |
| 37 | March | 31 | 0.00% | $0 | $0 | $0 | $0 |
| 38 | Total | 365 | | ($140,613) | ($213,217) | ($435,264) | ($390,831) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($307,635) | ($466,479) | ($952,275) | ($855,065) |
| 40 | Average Deferred Tax without Proration | Line 39 × 0.5 | | ($153,817) | ($233,239) | ($476,138) | ($427,532) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $13,204 | $20,022 | $40,874 | $36,701 |

**Column Notes:**
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (h) Current Year Line 25 ÷ 12 × Current Month Col (f)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2023 Actual Incremental Capital Investment**

| Line No. | | | | NG 4/1/22 - 5/24/2022 2023 (a) | PPL 5/25/22 - 3/31/23 2023 (b) | Fiscal Year 2024 (c) | Fiscal Year 2025 (d) |
|---|---|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | | | |
| 1 | *Non-Discretionary Capital* | Docket 5209, P 33 of 33. Line 1 | 2/ | $6,130,225 | $35,305,558 | | |
| | *Discretionary Capital* | | | | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible) | Docket 5209, P 33 of 33. Line 13 | 2/ | $7,632,024 | $43,954,804 | | |
| 3 | Total Allowed Capital Included in Rate Base (non-intangible) | Sum of Lines 1 through 2 | | $13,762,249 | $79,260,362 | $0 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $13,762,249 | $79,260,362 | | |
| 5 | Retirements | Company's Record | 2/ | $2,633,153 | $15,165,012 | | |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $11,129,096 | $64,095,350 | $75,224,446 | $75,224,446 |
| | Change in Net Capital Included in Rate Base | | | | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $13,762,249 | $79,260,362 | $0 | $0 |
| 8 | Depreciation Expense | Page 33 of 38, Line 62, Col (d) | 2/ | $7,383,490 | $42,523,431 | $0 | $0 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; Then = Prior Year Line 9 | | $6,378,760 | $36,736,931 | $43,115,691 | $43,115,691 |
| 10 | Cost of Removal | Company's Record | 2/ | $1,142,377 | $6,579,244 | | |
| 11 | **Total Net Plant in Service** | **Line 9 + Line 10** | | **$7,521,136** | **$43,316,175** | **$50,837,312** | **$50,837,312** |
| | Deferred Tax Calculation: | | | | | | |
| 12 | Composite Book Depreciation Rate | Page 31 of 38, Line 3, Col ( e) | 1/ | 3.16% | 3.16% | 3.16% | 3.16% |
| 13 | Proration Percentage | | | | | | |
| 14 | Vintage Year Tax Depreciation: | | | | | | |
| 15 | Tax Depreciation and Year 1 Basis Adjustments | Col (a) = Page 21 of 38, Column (a), Line 27; Col (b) = Page 21 of 38, Col (b), Lines 18,24,25 + Col (e), Line 15, Then remaining years from Page 21 of 38, Col (e) | | $6,050,145 | $35,353,848 | $5,214,939 | $4,823,403 |
| 16 | Cumulative Tax Depreciation-NG | Col (a) = Line 15; then 0 | 3/ | $6,050,145 | | | |
| 17 | Cumulative Tax Depreciation-PPL | Col (b) = Line 15; then = Prior Year Line 17 + Current Year Line 15 | 3/ | | $35,353,848 | $40,568,787 | $45,392,190 |
| 18 | Book Depreciation | Year 1 (Columns (a) and (b)) = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12 | | $175,840 | $1,012,707 | $2,377,093 | $2,377,093 |
| 19 | Cumulative Book Depreciation | Year 1 = Line 18; then = Prior Year Line 19 + Current Year Line 18 | | $175,840 | $1,188,546 | $3,565,639 | $5,942,731 |
| 20 | Book / Tax Timer | Line 15 - Line 18 | | $5,874,306 | $34,341,141 | $2,837,846 | $2,446,311 |
| 21 | Cumulative Book / Tax Timer -NG | Col (a) = Line 20, Column (a), Then = 0 | 3/ | $5,874,306 | | | |
| 22 | Cumulative Book / Tax Timer - PPL | Col (a) = 0; Col (b) = Line 20, Column (b); then = Prior Year Line 22 + Current Year Line 20 | 3/ | | $34,341,141 | $37,178,988 | $39,625,299 |
| 23 | Cumulative Book / Tax Timer - Total | Line 21 + Line 22 | | $5,874,306 | $34,341,141 | $37,178,988 | $39,625,299 |
| 24 | Effective Tax Rate | | | 21.00% | 21.00% | 21.00% | 21.00% |
| 25 | Deferred Tax Reserve | Line 23 × Line 24 | | $1,233,604 | $7,211,640 | $7,807,587 | $8,321,313 |
| 26 | Add: FY 2023 Federal NOL (Generation) / Utilization | Page 29 of 38 , Line 13 ,Col (f) | 3/ | $23,627,830 | | | |
| 27 | Net Deferred Tax Reserve before Proration Adjustmer | Sum of Lines 25 through 26 | | $24,861,434 | $7,211,640 | $7,807,587 | $8,321,313 |
| | Rate Base Calculation: | | | | | | |
| 28 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $7,521,136 | $43,316,175 | $50,837,312 | $50,837,312 |
| 29 | Accumulated Depreciation | Year 1 (Cols (a) and (b)) = -Line 18; Then = -Line 19 | | ($175,840) | ($1,012,707) | ($3,565,639) | ($5,942,731) |
| 30 | Deferred Tax Reserve | -Line 27 | | ($24,861,434) | ($7,211,640) | ($7,807,587) | ($8,321,313) |
| 31 | Year End Rate Base before Deferred Tax Proratio | Sum of Lines 28 through 30 | | ($17,516,137) | $35,091,829 | $39,464,085 | $36,573,268 |
| | Revenue Requirement Calculation: | | | | | | |
| 32 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 (Cols (a) and (b)) = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2 | 4/ | ($8,758,069) | $17,545,914 | $28,519,888 | $38,018,676 |
| 33 | Proration Adjustment | Page 22 of 38, Line 41 | 2/ | $67,302 | $19,104 | $25,579 | $22,050 |
| 34 | Average ISR Rate Base after Deferred Tax Proration | Line 32 + Line 33 | | ($8,690,767) | $17,565,018 | $28,545,468 | $38,040,727 |
| 35 | Pre-Tax ROR | Page 37 of 38, Line 35 | | 8.23% | 8.23% | 8.23% | 8.23% |
| 36 | Proration | Line 13 | | | | | |
| 37 | Return and Taxes | Line 34 x Line 35 | | ($715,250) | $1,445,601 | $2,349,292 | $3,130,752 |
| 38 | Book Depreciation | Line 18 | | $175,840 | $1,012,707 | $2,377,093 | $2,377,093 |
| 39 | **Annual Revenue Requirement** | **Line 37 + Line 38** | | **($539,410)** | **$2,458,308** | **$4,726,385** | **$5,507,844** |

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

2/ Columns (a) and (b) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ Column (c) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 32, Columns (a) and (b) and the end of the fiscal year on Line 30, Column (c). See note 2.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2023-NG Incremental Capital Investments**

| Line No. | | | | NG Apr 1-May 24, 2022 Fiscal Year 2023 (a) | PPL May 25-Mar 31, 2023 Fiscal Year 2023 (b) |
|---|---|---|---|---|---|
| | Capital Repairs Deduction | | | | |
| 1 | Plant Additions | Page 20 of 38, Line 3, Columns (a) through (c) | | $13,762,249 | $79,260,362 |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 26.00% | 26.00% |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $3,578,185 | $20,607,694 |
| 4 | | | | | |
| 5 | Bonus Depreciation | | | | |
| 6 | Plant Additions | Line 1 | | $13,762,249 | $79,260,362 |
| 7 | Plant Additions | | | $0 | $0 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $3,578,185 | $20,607,694 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $10,184,064 | $58,652,668 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% | 0.00% |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 | $0 |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% | 0.00% |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% | 0.00% |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 | $0 |
| 15 | | | | | |
| 16 | Remaining Tax Depreciation | | | | |
| 17 | Plant Additions | Line 1 | | $13,762,249 | $79,260,362 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $3,578,185 | $20,607,694 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 | $0 |
| 20 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 17 - Line 18 - Line 19 | | $10,184,064 | $58,652,668 |
| 21 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% | 3.750% |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $381,902 | $2,199,475 |
| 23 | | | | | |
| 24 | FY23 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $947,682 | $5,457,944 |
| 25 | Cost of Removal | Page 20 of 38, Line 10 | | $1,142,377 | $6,579,244 |
| 26 | | | | | |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $6,050,145 | $34,844,358 |
| 28 | | | | | |
| 29 | Reconcilation of MACRS Tax Depreciation: | | | | |
| 30 | Apr 1 -May 24, 2022 Plant Additions | Line 1, Column (a) | | | $13,762,249 |
| 31 | Cumulative Book Depreciaiton through May 24, 2022 | Page 20 of 38, Line 18, Col (a) | | | ($175,840) |
| 32 | 2023 Plant Additions (Net Book) through Acquisition | Line 30 + Line 31 | | | $13,586,410 |
| 33 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | | 3.750% |
| 34 | Tax Depreciation | Line 32 * Line 33 | | | $509,489 |
| 35 | | | | | |
| 36 | MACRS Basis in May 25-Mar 2023 Plant Additions | Line 20, Column (b) | | | $58,652,668 |
| 37 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | | 3.750% |
| 38 | Tax Depreciation | Line 36 * Line 37 | | | $2,199,474 |
| 39 | | | | | |
| 40 | Total MACRS Tax Depreciation | Sum of Lines 34, 38, Column (b) | | | $2,708,963 |
| 41 | | | | | |

| Line No. | (c) | (d) | (e) | (f) |
|---|---|---|---|---|
| 1 | 20 Year MACRS Depreciation | | | |
| 3 | MACRS basis: | Line 20, Column (a) | $10,184,064 | |
| 4 | | | Annual | Cumulative |
| 5 | Fiscal Year | | MACRS | Tax Depr |
| 6 | FY Mar-2023 (Apr-May 2022) | 3.750% | $381,902 | $6,050,145 |
| 8 | PPL Acquisition - May 25, 2022 | | | |
| 9 | Book Cost | Line 1, Column (a) | $13,762,249 | |
| 10 | Cumulative Book Depreciation | - Page 20 of 38, Line 18, Col (a) | ($175,840) | |
| 11 | MACRS basis from Acquisition: | Line 9(e) + Line 10(e) | $13,586,410 | |
| 12 | MACRS basis (Jun-Mar 2023) | Line 20, Column (b) | $58,652,668 | |
| 13 | Total MACRS Basis in 2022 | Line 11(e) + Line 12(e) | $72,239,077 | |
| 15 | FY Mar-2023 (Jun-Mar 2023) | 3.750% | $2,708,965 | $35,353,848 |
| 16 | Mar 2024 | 7.219% | $5,214,939 | $40,568,787 |
| 17 | Mar 2025 | 6.677% | $4,823,403 | $45,392,190 |
| 18 | Mar 2026 | 6.177% | $4,462,208 | $49,854,398 |
| 19 | Mar 2027 | 5.713% | $4,127,018 | $53,981,416 |
| 20 | Mar 2028 | 5.285% | $3,817,835 | $57,799,252 |
| 21 | Mar 2029 | 4.888% | $3,531,046 | $61,330,298 |
| 22 | Mar 2030 | 4.522% | $3,266,651 | $64,596,949 |
| 23 | Mar 2031 | 4.462% | $3,223,308 | $67,820,256 |
| 24 | Mar 2032 | 4.461% | $3,222,585 | $71,042,842 |
| 25 | Mar 2033 | 4.462% | $3,223,308 | $74,266,149 |
| 26 | Mar 2034 | 4.461% | $3,222,585 | $77,488,735 |
| 27 | Mar 2035 | 4.462% | $3,223,308 | $80,712,042 |
| 28 | Mar 2036 | 4.461% | $3,222,585 | $83,934,627 |
| 29 | Mar 2037 | 4.462% | $3,223,308 | $87,157,935 |
| 30 | Mar 2038 | 4.461% | $3,222,585 | $90,380,520 |
| 31 | Mar 2039 | 4.462% | $3,223,308 | $93,603,828 |
| 32 | Mar 2040 | 4.461% | $3,222,585 | $96,826,413 |
| 33 | Mar 2041 | 4.462% | $3,223,308 | $100,049,721 |
| 34 | Mar 2042 | 4.461% | $3,222,585 | $103,272,306 |
| 35 | Mar 2043 | 2.231% | $1,611,654 | $104,883,960 |
| 36 | | 100.00% | $72,239,077 | |

1/ Capital Repairs percentage is based on the actual results of National Grid's short period FY2023 tax return and PPL's short period CY2022 tax return, which covers the period from April 2022 through December 2022.
42 When PPL files it calendar year 2023 consolidated tax return in October of 2024, the tax repairs percentage will be updated to reflect the January through March 2023 actual tax repairs.
2/ FY 2023 tax loss on retirements is based on actual tax losses from April through December 2022. When PPL files it calendar year 2023 consolidated tax return in October of 2024, a portion of the tax gain/loss on
43 retirements will be allocated to the January through March 2023 period to finalize this fiscal year.

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2023 Incremental Capital Investment**

| Line No. | Deferred Tax Subject to Proration | | NG 4/1/22 - 5/24/2022 FY23 (a) | PPL 5/25/22 - 3/31/23 FY23 (b) | FY24 (c) | FY25 (d) |
|---|---|---|---|---|---|---|
| 1 | Book Depreciation | See the corresponding Fiscal Year on Page 20 of 38, Line 18 | $175,840 | $1,012,707 | $2,377,093 | $2,377,093 |
| 2 | Bonus Depreciation | - Page 21 of 38, Line 14 | $0 | $0 | $0 | $0 |
| 3 | Remaining MACRS Tax Depreciation | - Page 21 of 38, column (e), Lines 6,18,19,20 | ($381,902) | ($2,708,965) | ($5,214,939) | ($4,823,403) |
| 4 | FY 2023 tax (gain)/loss on retirements | - Page 21 of 38, Line 24 | ($947,682) | ($5,457,944) | | |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | ($1,153,744) | ($7,154,203) | ($2,837,846) | ($2,446,311) |
| 6 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | ($242,286) | ($1,502,383) | ($595,948) | ($513,725) |
| | **Deferred Tax Not Subject to Proration** | | | | | |
| 8 | Capital Repairs Deduction | - Page 21 of 38, Line 3 | ($3,578,185) | ($20,607,694) | | |
| 9 | Cost of Removal | - Page 21 of 38, Line 25 | ($1,142,377) | ($6,579,244) | | |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2023 | | | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | ($4,720,562) | ($27,186,938) | $0 | $0 |
| 12 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | ($991,318) | ($5,709,257) | $0 | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | ($1,233,604) | ($7,211,640) | ($595,948) | ($513,725) |
| 15 | Net Operating Loss | - Page 20 of 38, Line 26 | $0 | $0 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | ($1,233,604) | ($7,211,640) | ($595,948) | ($513,725) |
| | **Allocation of FY 2023 Estimated Federal NOL** | | | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (b) = Line 5 | ($1,153,744) | ($7,154,203) | ($2,837,846) | ($2,446,311) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | ($4,720,562) | ($27,186,938) | $0 | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | ($5,874,306) | ($34,341,141) | ($2,837,846) | ($2,446,311) |
| 20 | Total FY 2023 Federal NOL (Utilization) | - Page 20 of 38, Line 26 / 21% | $0 | $0 | $0 | $0 |
| 21 | Allocated FY 2023 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | $0 | $0 | $0 | $0 |
| 22 | Allocated FY 2023 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | $0 | $0 | $0 | $0 |
| 23 | Effective Tax Rate | | 21% | 21% | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | $0 | $0 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | ($242,286) | ($1,502,383) | ($595,948) | ($513,725) |

| Line No. | Proration Calculation | (e) Number of Days in Month | (f) Proration Percentage | (g) FY23 | (h) FY23 | (i) FY24 | (j) FY25 |
|---|---|---|---|---|---|---|---|
| 26 | April | 30 | 91.78% | ($53,841) | | ($45,580) | ($39,292) |
| 27 | May | 31 | 83.29% | $0 | ($133,506) | ($41,363) | ($35,656) |
| 28 | June | 30 | 75.07% | | ($120,331) | ($37,281) | ($32,137) |
| 29 | July | 31 | 66.58% | | ($106,717) | ($33,063) | ($28,501) |
| 30 | August | 31 | 58.08% | | ($93,103) | ($28,845) | ($24,865) |
| 31 | September | 30 | 49.86% | | ($79,928) | ($24,763) | ($21,347) |
| 32 | October | 31 | 41.37% | | ($66,314) | ($20,545) | ($17,711) |
| 33 | November | 30 | 33.15% | | ($53,139) | ($16,463) | ($14,192) |
| 34 | December | 31 | 24.66% | | ($39,525) | ($12,246) | ($10,556) |
| 35 | January | 31 | 16.16% | | ($25,911) | ($8,028) | ($6,920) |
| 36 | February | 28 | 8.49% | | ($13,614) | ($4,218) | ($3,636) |
| 37 | March | 31 | 0.00% | | $0 | $0 | $0 |
| 38 | Total | 365 | | ($53,841) | ($732,088) | ($272,394) | ($234,812) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($242,286) | ($1,502,383) | ($595,948) | ($513,725) |
| 40 | Average Deferred Tax without Proration | Line 39 × 0.5 | | ($121,143) | ($751,191) | ($297,974) | ($256,863) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $67,302 | $19,104 | $25,579 | $22,050 |

**Column Notes:**
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2024 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2024 (a) | Fiscal Year 2025 (b) |
|---|---|---|---|---|---|
| | Capital Investment Allowance | | | | |
| 1 | *Non-Discretionary Capital* | Docket 22-53-EL, P 35 of 35. Line 1 | | $44,045,000 | |
| | *Discretionary Capital* | | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible) | Docket 22-53-EL, P 35 of 33. Line 13 | | $44,981,000 | $0 |
| 3 | Total Allowed Capital Included in Rate Base (non-intangible) | Sum of Lines 1 through 2 | | $89,026,000 | $0 |
| | Depreciable Net Capital Included in Rate Base | | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $89,026,000 | $0 |
| 5 | Retirements | Company's Record | | $20,913,590 | $0 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $68,112,410 | $68,112,410 |
| | Change in Net Capital Included in Rate Base | | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $89,026,000 | $0 |
| 8 | Depreciation Expense | Page 33 of 38, Line 62, Col (d) | | $49,906,920 | $0 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; Then = Prior Year Line 9 | | $39,119,080 | $39,119,080 |
| 10 | Cost of Removal | Company's Record | | $15,659,000 | |
| 11 | **Total Net Plant in Service** | **Line 9 + Line 10** | | **$54,778,080** | **$54,778,080** |
| | Deferred Tax Calculation: | | | | |
| 12 | Composite Book Depreciation Rate | Page 31 of 38, Line 3, Col ( e) | 1/ | 3.16% | 3.16% |
| 13 | Proration Percentage | | | | |
| 14 | Vintage Year Tax Depreciation: | | | | |
| 15 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 24 of 38, Line 27, Column (a), Then = Line Page 24 of 38 , Column (d) | | $26,289,484 | $5,879,867 |
| 16 | Cumulative Tax Depreciation | Prior Year Line 15 + Current Year Line 14 | | $26,289,484 | $32,169,351 |
| 17 | Book Depreciation | year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12 | | $1,076,176 | $2,152,352 |
| 18 | Cumulative Book Depreciation | Prior Year Line 17 + Current Year Line 16 | | $1,076,176 | $3,228,528 |
| 19 | Cumulative Book / Tax Timer | Line 16 - Line 18 | | $25,213,308 | $28,940,823 |
| 20 | Effective Tax Rate | | | 21.00% | 21.00% |
| 21 | Deferred Tax Reserve | Line 19 * Line 20 | | $5,294,795 | $6,077,573 |
| 22 | Add: CY 2024 Federal NOL (Generation) / Utilization | Company's Record | | $0 | $0 |
| 23 | Net Deferred Tax Reserve before Proration Adjustment | Sum of Lines 21 through 22 | | $5,294,795 | $6,077,573 |
| | Rate Base Calculation: | | | | |
| 24 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $54,778,080 | $54,778,080 |
| 25 | Accumulated Depreciation | -Line 18 | | ($1,076,176) | ($3,228,528) |
| 26 | Deferred Tax Reserve | -Line 23 | | ($5,294,795) | ($6,077,573) |
| 27 | Year End Rate Base before Deferred Tax Proration | Sum of Lines 24 through 26 | | $48,407,109 | $45,471,978 |
| | Revenue Requirement Calculation: | | | | |
| 28 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 = Current Year, Line 27 * 50%; Then = (Prior Year Line 27 + Current Year Line 27) ÷ 2 | | $24,203,554 | $46,939,544 |
| 29 | Proration Adjustment | Page 25 of 38, Line 41 | | $17,831 | $33,599 |
| 30 | Average ISR Rate Base after Deferred Tax Proration | Line 29 + Line 30 | | $24,221,385 | $46,973,142 |
| 31 | Pre-Tax ROR | Page 37 of 38, Line 33 | | 8.23% | 8.23% |
| 32 | Proration | Line 13 | | 100.00% | 100.00% |
| 33 | Return and Taxes | Year 1 = Lines 30 * 31 * 32 | | $1,993,420 | $3,865,890 |
| 34 | Book Depreciation | Line 17 | | $1,076,176 | $2,152,352 |
| 35 | **Annual Revenue Requirement** | **Line 33 + Line 34** | | **$3,069,596** | **$6,018,242** |

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

**The Narragansett Electric Company**
**d/b/a National Grid**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2024 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2024 (a) |
|---|---|---|---|---|
| | Capital Repairs Deduction | | | |
| 1 | Plant Additions | Page 23 of 38, Line 3 | | $89,026,000 |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 8.51% |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $7,576,113 |
| 4 | | | | |
| 5 | Bonus Depreciation | | | |
| 6 | Plant Additions | Line 1 | | $89,026,000 |
| 7 | Plant Additions | | | $0 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $7,576,113 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $81,449,887 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 |
| 15 | | | | |
| 16 | Remaining Tax Depreciation | | | |
| 17 | Plant Additions | Line 1 | | $89,026,000 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $7,576,113 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 |
| 20 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 17 - Line 18 - Line 19 | | $81,449,887 |
| 21 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $3,054,371 |
| 23 | | | | |
| 24 | FY24 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $0 |
| 25 | Cost of Removal | Page 23 of 38, Line 10 | | $15,659,000 |
| 26 | | | | |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $26,289,484 |

| Line No. | (b) | (c) | (d) | (e) |
|---|---|---|---|---|
| 1 | 20 Year MACRS Depreciation | | | |
| 2 | | | | |
| 3 | MACRS basis: | Line 20 | $81,449,887 | |
| 4 | | | Annual | Cumulative |
| 5 | Calendar Year | | | |
| 6 | Mar-2024 | 3.750% | $3,054,371 | $26,289,484 |
| 7 | Mar-2025 | 7.219% | $5,879,867 | $32,169,351 |
| 8 | Mar-2026 | 6.677% | $5,438,409 | $37,607,760 |
| 9 | Mar-2027 | 6.177% | $5,031,160 | $42,638,920 |
| 10 | Mar-2028 | 5.713% | $4,653,232 | $47,292,152 |
| 11 | Mar-2029 | 5.285% | $4,304,627 | $51,596,778 |
| 12 | Mar-2030 | 4.888% | $3,981,270 | $55,578,049 |
| 13 | Mar-2031 | 4.522% | $3,683,164 | $59,261,213 |
| 14 | Mar-2032 | 4.462% | $3,634,294 | $62,895,507 |
| 15 | Mar-2033 | 4.461% | $3,633,479 | $66,528,986 |
| 16 | Mar-2034 | 4.462% | $3,634,294 | $70,163,280 |
| 17 | Mar-2035 | 4.461% | $3,633,479 | $73,796,760 |
| 18 | Mar-2036 | 4.462% | $3,634,294 | $77,431,054 |
| 19 | Mar-2037 | 4.461% | $3,633,479 | $81,064,533 |
| 20 | Mar-2038 | 4.462% | $3,634,294 | $84,698,827 |
| 21 | Mar-2039 | 4.461% | $3,633,479 | $88,332,306 |
| 22 | Mar-2040 | 4.462% | $3,634,294 | $91,966,600 |
| 23 | Mar-2041 | 4.461% | $3,633,479 | $95,600,080 |
| 24 | Mar-2042 | 4.462% | $3,634,294 | $99,234,374 |
| 25 | Mar-2043 | 4.461% | $3,633,479 | $102,867,853 |
| 26 | Mar-2044 | 2.231% | $1,817,147 | $104,685,000 |
| 27 | | 100.00% | $81,449,887 | |

1/ Per Tax Department
2/ Per Tax Department

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2024 Incremental Capital Investment**

| Line No. | **Deferred Tax Subject to Proration** | | FY24 (a) | FY25 (b) |
|---|---|---|---|---|
| 1 | Book Depreciation | Page 23 of 38, Line 17 | $1,076,176 | $2,152,352 |
| 2 | Bonus Depreciation | - Page 24 of 38, Line 14 | $0 | |
| 3 | Remaining MACRS Tax Depreciation | - Page 24 of 38, column (d), Lines 6 and 7 | ($3,054,371) | ($5,879,867) |
| 4 | Plan Year 2024 tax (gain)/loss on retirements | - Page 24 of 38, Line 24 | $0 | |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | ($1,978,195) | ($3,727,515) |
| 6 | Effective Tax Rate | | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | ($415,421) | ($782,778) |
| | **Deferred Tax Not Subject to Proration** | | | |
| 8 | Capital Repairs Deduction | - Page 24 of 38, Line 3 | ($7,576,113) | |
| 9 | Cost of Removal | - Page 24 of 38, Line 25 | ($15,659,000) | |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2024 | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | ($23,235,113) | $0 |
| 12 | Effective Tax Rate | | 21.00% | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | ($4,879,374) | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | ($5,294,795) | ($782,778) |
| 15 | Net Operating Loss | Page 23 of 38, Line 22 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | ($5,294,795) | ($782,778) |
| | **Allocation of Plan Year 2024 Estimated Federal NOL** | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (b) = Line 5 | ($1,978,195) | ($3,727,515) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | ($23,235,113) | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | ($25,213,308) | ($3,727,515) |
| 20 | Total Plan Year 2024 Federal NOL (Utilization) | - Page 23 of 38, Line 22 / 21% | $0 | $0 |
| 21 | Allocated Plan Year 2024 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | $0 | $0 |
| 22 | Allocated Plan Year 2024 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | $0 | $0 |
| 23 | Effective Tax Rate | | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | ($415,421) | ($782,778) |

| | | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|
| | **Proration Calculation** | Number of Days in Month | Proration Percentage | FY24 | FY25 |
| 26 | April | 30 | 91.78% | ($31,773) | ($59,870) |
| 27 | May | 31 | 83.29% | ($28,833) | ($54,330) |
| 28 | June | 30 | 75.07% | ($25,988) | ($48,968) |
| 29 | July | 31 | 66.58% | ($23,047) | ($43,428) |
| 30 | August | 31 | 58.08% | ($20,107) | ($37,888) |
| 31 | September | 30 | 49.86% | ($17,262) | ($32,526) |
| 32 | October | 31 | 41.37% | ($14,322) | ($26,986) |
| 33 | November | 30 | 33.15% | ($11,476) | ($21,625) |
| 34 | December | 31 | 24.66% | ($8,536) | ($16,084) |
| 35 | January | 31 | 16.16% | ($5,596) | ($10,544) |
| 36 | February | 28 | 8.49% | ($2,940) | ($5,540) |
| 37 | March | 31 | 0.00% | $0 | $0 |
| 38 | Total | 365 | | ($189,880) | ($357,790) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($415,421) | ($782,778) |
| 40 | Average Deferred Tax without Proration | Line 39 × 0.5 | | ($207,710) | ($391,389) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $17,831 | $33,599 |

**Column Notes:**

(d) Sum of remaining days in the Apr 1-Dec 31 period (Col (c)) ÷ 275

(e) through (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

**The Narragansett Electric Company**
**d/b/a National Grid**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Fiscal Year 2025 Revenue Requirement on FY 2025 Actual Incremental Capital Investment**

| Line No. | | | | Fiscal Year 2025 (a) |
|---|---|---|---|---|
| | Capital Investment Allowance | | | |
| 1 | *Non-Discretionary Capital* | Page 38 of 38, Line 1 | | $50,134,000 |
| | *Discretionary Capital* | | | |
| 2 | Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible) | Page 38 of 38, Line 13 | | $58,047,000 |
| 3 | Total Allowed Capital Included in Rate Base (non-intangible) | Sum of Lines 1 through 2 | | $108,181,000 |
| | Depreciable Net Capital Included in Rate Base | | | |
| 4 | Total Allowed Capital Included in Rate Base in Current Year | Line 3 | | $108,181,000 |
| 5 | Retirements | Company's Record | | $27,553,093 |
| 6 | Net Depreciable Capital Included in Rate Base | Year 1 = Line 4 - Line 5; Then = Prior Year Line 6 | | $80,627,907 |
| | Change in Net Capital Included in Rate Base | | | |
| 7 | Capital Included in Rate Base | Line 3 | | $108,181,000 |
| 8 | Depreciation Expense | Page 33 of 38, Line 62, Col (d) | | $49,906,920 |
| 9 | Incremental Capital Amount | Year 1 = Line 7 - Line 8; Then = Prior Year Line 9 | | $58,274,080 |
| 10 | Cost of Removal | Company's Record | | $19,783,000 |
| 11 | **Total Net Plant in Service** | **Line 9 + Line 10** | | **$78,057,080** |
| | Deferred Tax Calculation: | | | |
| 12 | Composite Book Depreciation Rate | Page 31 of 38, Line 3, Col ( e) | 1/ | 3.16% |
| 13 | Vintage Year Tax Depreciation: | | | |
| 14 | Tax Depreciation and Year 1 Basis Adjustments | Year 1 = Page 27 of 38, Line 27, Column (a), Then = Line Page 27 of 38 , Column (d) | | $49,173,208 |
| 15 | Cumulative Tax Depreciation-PPL | Prior Year Line 15 + Current Year Line 14 | | $49,173,208 |
| 16 | Book Depreciation | year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12 | | $1,273,921 |
| 17 | Cumulative Book Depreciation | Prior Year Line 17 + Current Year Line 16 | | $1,273,921 |
| 18 | Cumulative Book / Tax Timer | Line 15 - Line 17 | | $47,899,287 |
| 19 | Effective Tax Rate | | | 21.00% |
| 20 | Deferred Tax Reserve | Line 18 * Line 19 | | $10,058,850 |
| 21 | Add: CY 2025 Federal NOL (Generation) / Utilization | Company's Record | | $0 |
| 22 | Net Deferred Tax Reserve before Proration Adjustment | Sum of Lines 20 through 21 | | $10,058,850 |
| | Rate Base Calculation: | | | |
| 23 | Cumulative Incremental Capital Included in Rate Base | Line 11 | | $78,057,080 |
| 24 | Accumulated Depreciation | -Line 17 | | ($1,273,921) |
| 25 | Deferred Tax Reserve | -Line 22 | | ($10,058,850) |
| 26 | Year End Rate Base before Deferred Tax Proration | Sum of Lines 23 through 25 | | $66,724,308 |
| | Revenue Requirement Calculation: | | | |
| 27 | Average Rate Base before Deferred Tax Proration Adjustment | Year 1 = Current Year, Line 26 * 50%; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2 | | $33,362,154 |
| 28 | Proration Adjustment | Page 28 of 38, Line 41 | | $15,284 |
| 29 | Average ISR Rate Base after Deferred Tax Proration | Line 28 + Line 29 | | $33,377,439 |
| 30 | Pre-Tax ROR | Page 37 of 38, Line 33 | | 8.23% |
| 31 | Return and Taxes | Line 29 * Line 30 | | $2,746,963 |
| 32 | Book Depreciation | Line 16 | | $1,273,921 |
| 33 | **Annual Revenue Requirement** | **Line 31 + Line 32** | | **$4,020,884** |

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Incremental Capital Investments**

| Line No. | | | | Fiscal Year 2025 (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|---|---|---|
| | Capital Repairs Deduction | | | | | | | |
| 1 | Plant Additions | Page 26 of 38, Line 3 | | $108,181,000 | 20 Year MACRS Depreciation | | | |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 24.33% | | | | |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $26,320,437 | MACRS basis: | Line 20 | $81,860,563 | |
| 4 | | | | | | | Annual | Cumulative |
| 5 | Bonus Depreciation | | | | Calendar Year | | | |
| 6 | Plant Additions | Line 1 | | $108,181,000 | Dec-2025 | 3.750% | $3,069,771 | $49,173,208 |
| 7 | Plant Additions | | | $0 | Dec-2026 | 7.219% | $5,909,514 | $55,082,722 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $26,320,437 | Dec-2027 | 6.677% | $5,465,830 | $60,548,552 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $81,860,563 | Dec-2028 | 6.177% | $5,056,527 | $65,605,079 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% | Dec-2029 | 5.713% | $4,676,694 | $70,281,773 |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 | Dec-2030 | 5.285% | $4,326,331 | $74,608,104 |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% | Dec-2031 | 4.888% | $4,001,344 | $78,609,448 |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% | Dec-2032 | 4.522% | $3,701,735 | $82,311,183 |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 | Dec-2033 | 4.462% | $3,652,618 | $85,963,801 |
| 15 | | | | | Dec-2034 | 4.461% | $3,651,800 | $89,615,601 |
| 16 | Remaining Tax Depreciation | | | | Dec-2035 | 4.462% | $3,652,618 | $93,268,219 |
| 17 | Plant Additions | Line 1 | | $108,181,000 | Dec-2036 | 4.461% | $3,651,800 | $96,920,019 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $26,320,437 | Dec-2037 | 4.462% | $3,652,618 | $100,572,637 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 | Dec-2038 | 4.461% | $3,651,800 | $104,224,437 |
| 20 | Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation | Line 17 - Line 18 - Line 19 | | $81,860,563 | Dec-2039 | 4.462% | $3,652,618 | $107,877,055 |
| 21 | 20 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 3.750% | Dec-2040 | 4.461% | $3,651,800 | $111,528,855 |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $3,069,771 | Dec-2041 | 4.462% | $3,652,618 | $115,181,473 |
| 23 | | | | | Dec-2042 | 4.461% | $3,651,800 | $118,833,273 |
| 24 | FY25 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $0 | Dec-2043 | 4.462% | $3,652,618 | $122,485,891 |
| 25 | Cost of Removal | Page 26 of 38, Line 10 | | $19,783,000 | Dec-2044 | 4.461% | $3,651,800 | $126,137,691 |
| 26 | | | | | Dec-2045 | 2.231% | $1,826,309 | $127,964,000 |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $49,173,208 | | 100.00% | $81,860,563 | |

1/ Per Tax Department
2/ Per Tax Department

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Calculation of Net Deferred Tax Reserve Proration on FY 2025 Incremental Capital Investment**

| Line No. | Deferred Tax Subject to Proration | | Plan Year 2025 (a) |
|---|---|---|---|
| 1 | Book Depreciation | Page 26 of 38, Line 16 | $1,273,921 |
| 2 | Bonus Depreciation | Page 27 of 38, Line 14 | $0 |
| 3 | Remaining MACRS Tax Depreciation | - Page 27 of 38, column (d) | ($3,069,771) |
| 4 | FY 2025 tax (gain)/loss on retirements | - Page 27 of 38, Line 24 | $0 |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | ($1,795,850) |
| 6 | Effective Tax Rate | | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | ($377,129) |
| | **Deferred Tax Not Subject to Proration** | | |
| 8 | Capital Repairs Deduction | - Page 27 of 38, Line 3 | ($26,320,437) |
| 9 | Cost of Removal | - Page 27 of 38, Line 25 | ($19,783,000) |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2025 | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | ($46,103,437) |
| 12 | Effective Tax Rate | | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | ($9,681,722) |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | ($10,058,850) |
| 15 | Net Operating Loss | - Page 26 of 38, Line 21 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | ($10,058,850) |
| | **Allocation of FY 2024 Estimated Federal NOL** | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (b) = Line 5 | ($1,795,850) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | ($46,103,437) |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | ($47,899,287) |
| 20 | Total FY 2025 Federal NOL (Utilization) | - Page 26 of 38, Line 22 / 21% | $0 |
| 21 | Allocated FY 2025 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | $0 |
| 22 | Allocated FY 2025 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | $0 |
| 23 | Effective Tax Rate | | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | ($377,129) |

| Line No. | Proration Calculation | (c) Number of Days in Month | (d) Proration Percentage | (e) (a) |
|---|---|---|---|---|
| 26 | January | 31 | 91.53% | ($28,765) |
| 27 | February | 29 | 83.61% | ($26,275) |
| 28 | March | 31 | 75.14% | ($23,613) |
| 29 | April | 30 | 66.94% | ($21,037) |
| 30 | May | 31 | 58.47% | ($18,376) |
| 31 | June | 30 | 50.27% | ($15,800) |
| 32 | July | 31 | 41.80% | ($13,138) |
| 33 | August | 31 | 33.33% | ($10,476) |
| 34 | September | 30 | 25.14% | ($7,900) |
| 35 | October | 31 | 16.67% | ($5,238) |
| 36 | November | 30 | 8.47% | ($2,662) |
| 37 | December | 31 | 0.00% | $0 |
| 38 | Total | 366 | | ($173,280) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($377,129) |
| 40 | Average Deferred Tax without Proration | Line 39 × 0.5 | | ($188,564) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $15,284 |

**Column Notes:**

(d) Sum of remaining days in the year (Col (c)) ÷ 365

(e) & (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**FY 2018 - 2023 Incremental Capital Investment Summary**

| Line No. | | | Fiscal Year 2018 (a) | Fiscal Year 2019 (b) | Fiscal Year 2020 (c) | Fiscal Year 2021 (d) | Fiscal Year 2022 (e) | Fiscal Year 2023 (f) |
|---|---|---|---|---|---|---|---|---|
| | **Capital Investment** | | | | | | | |
| 1 | ISR - Eligible Capital Investment | Col (a) = FY 2018 ISR Docket No.4682, Att MAL-1 P2, L3; Col (b)=FY 2019 ISR Docket No.4783, Att PCE-1 P3, Table 1; Col (c)= Section I of Att. PCE-1, Table 2 | $91,309,377 | $110,051,680 | $98,619,860 | $115,360,166 | $86,464,019 | $93,022,611 |
| 2 | Intangible Assest included in Total Allowed Discretionary Capital | Col (a) =0; Col (b) = FY 2019 ISR Docket No. 4783, Att. MAL-1,Page 30 of 38, Line13; Col (c) = Actual per Operation | $0 | $3,460,626 | $0 | $0 | $0 | $0 |
| 3 | ISR - Eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770 | Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P5, L1, Col (a) = Col(a)+Col(b); Col(b)=Col(c)+Col(d); Col(c)=Col(e), Col(d)=Col(j)+Col(k) | $74,843,000 | $74,843,000 | $31,184,583 | $0 | $0 | $0 |
| 4 | Incremental ISR Capital Investment (non-intangible) | Line 1 - Line 2 - Line 3 | $16,466,377 | $31,748,054 | $67,435,277 | $115,360,166 | $86,464,019 | $93,022,611 |
| | **Cost of Removal** | | | | | | | |
| 5 | ISR - Eligible Cost of Removal | Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c )= Section 1 of Att. PCE-1, Table 3 | $9,952,716 | $8,209,732 | $14,770,644 | $10,438,210 | $7,686,088 | $7,721,621 |
| 6 | ISR - Eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770 | Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L10×3÷12, [P1]L26+L45×7÷12; Col(b)=[P1]L45×5÷12+[P2]L18×7÷12; Col (c) = [P2]L18×5÷12+L39×7÷12 | $8,259,707 | $7,848,009 | $3,437,925 | $205,400 | $85,583 | $0 |
| 7 | Incremental Cost of Removal | Line 5 - Line 6 | $1,693,009 | $361,723 | $11,332,719 | $10,232,810 | $7,600,505 | $7,721,621 |
| | **Retirements** | | | | | | | |
| 8 | ISR - Eligible Retirements/Actual | Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c )=Per Company's Book | $15,206,748 | $12,015,754 | $13,944,441 | $22,589,226 | $35,100,171 | $17,798,165 |
| 9 | ISR - Eligible Retirements in Rate Base per RIPUC Docket No. 4770 | Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L5×3÷12+[P1]L25+L27+L46×7÷12; Col(b)=[P1]L46×5÷12+[P2]L19×7÷12; Col (c)=[P2]L19×5÷12+L40×7÷12 | $20,451,820 | $22,665,233 | $9,928,809 | $593,200 | $247,167 | $0 |
| 10 | Incremental Retirements | Line 8 - Line 9 | ($5,245,072) | ($10,649,479) | $4,015,632 | $21,996,026 | $34,853,004 | $17,798,165 |
| | **Net NOL Position** | | | | | | | |
| 11 | ISR - (NOL)/Utilization | Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2021 ISR Plan Docket No. 4995, Col (c )=Per Tax Departmen | ($4,571,409) | $1,506,783 | $0 | $1,695,589 | $730,905 | $35,805,866 |
| 12 | less: (NOL)/Utilization recovered in transmission rates | Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 11 | ($1,572,911) | $515,161 | $0 | $570,357 | $248,590 | $12,178,036 |
| 13 | Distribution-related (NOL)/Utilization | Maximum of (Line 11 - Line 12) or -Page 30 of 38, Line 12 | ($2,998,499) | $991,622 | $0 | $1,125,232 | $482,315 | $23,627,830 |
| 14 | (NOL)/Utilization in Rate Base per RIPUC Docket No. 4770 | Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P. 12: Col (c)= L39×7÷12 | $0 | $0 | $1,462,980 | $6,764,379 | $4,085,281 | $0 |
| 15 | Incremental (NOL)/Utilization | Line 13 - Line 14 | ($2,998,499) | $991,622 | ($1,462,980) | ($5,639,147) | ($3,602,966) | $23,627,830 |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan**
**Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")**

| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Test Year July 2016 - June 2017 | | | | | Jul & Aug 2017 | 12 Mths Aug 31 2018 | 12 Mths Aug 31 2019 | 12 Mths Aug 31 2020 | 12 Mths Aug 31 2021 | 12 Mths Aug 31 2022 |
| 1 | Total Base Rate Plant DIT Provision | | $18,265,666 | | | | | $2,580,654 | $5,847,765 | $4,355,117 | $707,056 | $3,826,291 | $0 |
| 2 | Excess DIT Amortization | | | | | | | | | ($3,074,665) | ($3,074,665) | ($3,074,665) | $0 |
| | | FY 2018 | FY 2019 | FY 2020 | FY 2021 | FY 2022 | FY 2023-NG | FY 2018 | FY 2019 | FY 2020 | FY 2021 | FY 2022 | FY 2023-NG |
| 3 | Total Base Rate Plant DIT Provision | | | | | | | $10,558,267 | $3,183,499 | ($847,583.55) | ($548,055) | $313,177 | $0 |
| 4 | Incremental FY 18 | $4,261,399 | $4,223,434 | $4,181,310 | $4,130,879 | $4,072,741 | $4,063,088 | $4,261,399 | ($37,965) | ($42,125) | ($50,431) | ($58,138) | ($9,653) |
| 5 | Incremental FY 19 | | $2,128,597 | $2,305,665 | $2,485,863 | $2,504,666 | $2,193,670 | | $2,128,597 | $177,068 | $180,198 | $18,803 | ($310,996) |
| 6 | Incremental FY 20 | | | $4,774,661 | $5,289,496 | $5,731,763 | $5,787,291 | | | $4,774,661 | $514,834 | $442,268 | $55,528 |
| 7 | Incremental FY 21 | | | | $9,206,417 | $9,930,574 | $10,022,701 | | | | $9,206,417 | $724,158 | $92,127 |
| 8 | Incremental FY 22 | | | | | $4,105,561 | $4,234,773 | | | | | $4,105,561 | $129,212 |
| 9 | Incremental FY 23 | | | | | | $981,448 | | | | | | $981,448 |
| 10 | TOTAL Plant DIT Provision | $4,261,399 | $6,352,031 | $11,261,635 | $21,112,654 | $26,345,306 | $27,282,971 | $14,819,666 | $5,274,131 | $4,062,021 | $9,302,963 | $5,545,830 | $937,665 |
| 11 | Distribution-related NOL | | | | | | | $2,998,499 | ($991,622) | $0 | ($1,125,232) | ($482,315) | 23,722,289.55 |
| 12 | Lesser of Distribution-related NOL or DIT Provision | | | | | | | $2,998,499 | ($991,622) | $0 | ($1,125,232) | ($482,315) | $937,665 |
| 13 | Total NOL | | | | | | | | | | | | 35,805,866.00 |
| 14 | NOL recovered in transmission rates | | | | | | | | | | | | 12,083,576.45 |
| 15 | Distribution-related NOL | | | | | | | | | | | | 23,722,289.55 |

Line Notes:

| | |
|---|---|
| 1(b) | RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 2 of 23, Line 29, Col (e) - (a) |
| 1(g) | RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 3 |
| 1(h) | RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 7 |
| 1(i) | RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 50 |
| 2 | RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Sch. 11-ELEC, P.11 of 20, L. 51; P. 12 of 20, L. 42 & 5 |
| 3 | Col(e) = Line 1(b)÷12×3+ Line1(d) + Line1(e)÷12×7; Col (f) = (Line1(e) + Line2( e) )÷12×5 + (Line1(f) + Line2(f) )÷12×7; Col (g) = (Line1(f) + Line2(f))÷12×5 + (Line1(g) + Line2(g) )÷12×7 |
| 4(a)~(f) | Cumulative DIT per vintage year ISR revenue requirement calculations (P.2, L.25(a)+L.27(a); P.2, L.25(b)+L.27(b); P.2, L.25(c)+L.27(c); P.2, L.25(d)+L.27(d); P.2, L.25(e)+L.27(e); P.2, L.25(f)+L.27(f)) |
| 5(b)~(f) | Cumulative DIT per vintage year ISR revenue requirement calculations (P.5, L.25(a)+P.8, L.27(c); P.5, L.25(b)+P.8, L.27(f); P.5, L.25(c)+P.8, L.27(i); P.5, L.25(d)+P.8, L.27(l); P.5, L.25(e)+P.8, L.27(o)) |
| 6(c)~(f) | Cumulative DIT per vintage year ISR revenue requirement calculations (P.10, L.25(a); P.10, L.25(b); P.10, L.25(c); P.10, L.25(d)) |
| 7(d)~(f) | Cumulative DIT per vintage year ISR revenue requirement calculations (P.13, L.25(a); P.13, L.25(b); P.13, L.25(c)) |
| 8(e)~(f) | Cumulative DIT per vintage year ISR revenue requirement calculations (P.17, L.25(a)+P.17, L.25(b)) |
| 9(f) | Cumulative DIT per vintage year ISR revenue requirement calculations (P.20, L.25(a)) |
| 4(g) -9(l) | Year over year change in cumulative DIT shown in Cols (a) through (f) |
| 10 | Sum of Lines 3 through 9 |
| 11 | Page 29 of 38, Line 13 |
| 12 | Lesser of Line 10 or Line 11 |
| 13 | Per Tax Department |
| 14 | Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 13 |
| 15 | Line 13 - Line 14 |

**THE NARRAGANSETT ELECTRIC COMPANY**
**d/b/a NATIONAL GRID**
**RIPUC Docket Nos. 4770/4780**
**Compliance Attachment 2**
**Schedule 6-ELEC**
**Page 3 of 5**

**The Narragansett Electric Company d/b/a National Grid**
**Depreciation Expense - Electric**
**For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019**

| Line | Account | | Description | Adjusted Plant Balance (a) | Approved Rate (b) | Test Year Depreciation (c) = (a) x (b) |
|---|---|---|---|---|---|---|
| | | | Intangible Plant | | | |
| 1 | 303.00 | | Intangible Cap Software | ($0) | 0.00% | $0 |
| 2 | | | | | | |
| 3 | | | Total Intangible Plant | ($0) | | $0 |
| 4 | | | | | | |
| 5 | | | Production Plant | | | |
| 6 | | | | | | |
| 7 | 330.00 | | Land Hydro | $6,989 | 0.00% | $0 |
| 8 | 331.00 | | Struct & Improvements | $1,993,757 | 0.00% | $0 |
| 9 | 332.00 | | Reservoirs Dams And Water | $1,125,689 | 0.00% | $0 |
| 10 | | | | | | |
| 11 | | | Total Production Plant | $3,126,434 | | $0 |
| 12 | | | | | | |
| 13 | | | Total Transmission Plant | $0 | | $0 |
| 14 | | | | | | |
| 15 | | | Distribution Plant | | | |
| 16 | | | | | | |
| 17 | 360 | | Land & Land Rights New | $ - | 0.00% | $ - |
| 18 | 362 | | Station Equipment | $ - | 2.32% | $ - |
| 19 | 365 | | Overhead Conductors and Devices | $ - | 3.02% | $ - |
| 20 | 367.1 | | Underground Conductors and Devices | $ - | 2.52% | $ - |
| 21 | 360.00 | | Land & Land Rights New | $ 12,874,490 | 0.00% | $ - |
| 22 | 360.10 | | Land Structures & Dist | $ 95,396 | 0.00% | $ - |
| 23 | 361.00 | | Struct & Improvements | $ 10,144,741 | 1.36% | $ 137,968 |
| 24 | 362.00 | | Station Equipment | $ 253,879,227 | 2.19% | $ 5,559,955 |
| 25 | 362.10 | | Station Equip Pollution | $ 71,597 | 2.19% | $ 1,568 |
| 26 | 362.55 | | Station Equipment - Energy Management Syste | $ 663,280 | 6.70% | $ 44,440 |
| 27 | 364.00 | | Poles, Towers And Fixtures | $ 237,914,852 | 4.27% | $ 10,158,964 |
| 28 | 365.00 | | Oh Conduct-Smart Grid | $ 308,051,305 | 2.65% | $ 8,163,360 |
| 29 | 366.10 | | Underground Manholes A | $ 23,368,987 | 1.33% | $ 310,808 |
| 30 | 366.20 | | Underground Conduit | $ 48,513,051 | 1.55% | $ 751,952 |
| 31 | 367.10 | | Underground Conductors | $ 173,808,945 | 3.42% | $ 5,944,266 |
| 32 | 368.10 | | Line Transformers - Stations | $ 10,674,398 | 2.76% | $ 294,613 |
| 33 | 368.20 | | Line Transformers - Bare Cost | $ 101,452,162 | 3.14% | $ 3,180,525 |
| 34 | 368.30 | | Line Transformers - Install Cost | $ 77,701,753 | 3.22% | $ 2,501,996 |
| 35 | 369.10 | | Overhead Services | $ 83,166,615 | 5.04% | $ 4,191,597 |
| 36 | 369.20 | | Underground Services C | $ 1,691,919 | 4.87% | $ 82,396 |
| 37 | 369.21 | | Underground Services C | $ 22,150,773 | 4.87% | $ 1,078,743 |
| 38 | 370.10 | | Meters - Bare Cost - Domestic | $ 26,366,117 | 5.61% | $ 1,479,139 |
| 39 | 370.20 | | Meters - Install Cost - Domestic | $ 10,026,102 | 5.81% | $ 582,517 |
| 40 | 370.30 | | Meters - Bare Cost - Large | $ 11,492,790 | 5.69% | $ 653,940 |
| 41 | 370.35 | | Meters - Install Cost - Large | $ 9,186,534 | 5.13% | $ 471,269 |
| 42 | 371.00 | | Installation On Custom | $ 119,825 | 3.61% | $ 4,326 |
| 43 | 373.10 | | Oh Steetlighting | $ 23,671,126 | 1.46% | $ 345,598 |
| 44 | 373.20 | | Ug Streetlighting | $ 16,012,987 | 1.52% | $ 243,397 |
| 45 | 374.00 | 1/ | Elect Equip ARO | $ - | 0.00% | $ - |
| 46 | | | | | | |
| 47 | | | Total Distribution Plant | $ 1,463,098,971 | **3.16%** | $ 46,183,339 |
| 48 | | | | | | |
| 49 | | | General Plant | | | |
| 50 | | | | | | |
| 51 | 389.00 | | Land And Land Rights | $ 842,411 | 0.00% | $ - |
| 52 | 390.00 | | Struct And Improvement Electric | $ 34,216,272 | 2.28% | $ 780,131 |
| 53 | 391.00 | | Office Furn &Fixt Electric (Fully Dep) | $ 30,645 | 0.00% | $ 29,542 |
| 54 | 391.00 | | Office Furn &Fixt Electric | $ 412,269 | 6.67% | $ 27,498 |
| 55 | 393.00 | | Stores Equipment | $ 93,412 | 5.00% | $ 4,671 |
| 56 | 394.00 | | General Plant Tools Shop | $ 1,934,730 | 5.00% | $ 96,736 |
| 57 | 395.00 | | General Plant Laboratory (Fully Dep) | $ 288,227 | 0.00% | $ - |
| 58 | 395.00 | | General Plant Laboratory (Fully Dep) | $ 1,226,832 | 6.67% | $ 81,830 |
| 59 | 397.00 | | Communication Equipment | $ 5,337,629 | 5.00% | $ 266,881 |
| 60 | 397.10 | | Communication Equipment Site Specific | $ 2,530,920 | 3.90% | $ 98,706 |
| 61 | 397.50 | | Communication Equipment Network | $ 49,498 | 5.00% | $ 2,475 |
| 62 | 398.00 | | General Plant Miscellaneous | $ 706,169 | 6.67% | $ 47,101 |
| 63 | 399.00 | | Other Tangible Property | $ 12,484 | 0.00% | $ - |
| 64 | 399.10 | 1/ | ARO | $ (0) | 0.00% | $ - |
| 65 | | | | | | |
| 66 | | | Total General Plant | $ 47,681,498 | **3.01%** | $ 1,435,572 |
| 67 | | | | | | |
| 68 | | | Grand Total - All Categories | $ 1,513,906,902 | **3.15%** | $ 47,618,911 |

**The Narragansett Electric Company**
**d/b/a National Grid**
**ISR Depreciation Rate per RIPUC Docket No. 4995**

| Line | Description | Adjusted Plant Balance (d) | Average Rate (e)=(f)/(d) | Approved Depreciation (f) |
|---|---|---|---|---|
| 1 | Total Distribution Plant | $ 1,463,098,971 | 3.16% | $ 46,183,339 |
| 2 | Communication Equipment | $ 7,918,047 | 4.65% | $ 368,062 |
| 3 | Total ISR eligible Plant | $ 1,471,017,018 | **3.16%** | $ 46,551,401 |
| 4 | | | | |
| 5 | Non-ISR or Communication Plant | $ 42,889,885 | | |
| 6 | Grand Total - All Plant | $ 1,513,906,902 | | |

Line Notes:
1 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on left Line 47
2 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on Left Lines 59 through 61
3 Line 1+Line 2
5 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on Left Lines 59 through 61
6 Line 3+Line 6
Column Notes:

(a) - (c) - Per Docket 4770/4780 Compliance Attachment 2, Schedule 6 ELEC, Pages 3 & 4

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-ELEC
Page 1 of 5

**The Narragansett Electric Company d/b/a National Grid**
**Depreciation Expense - Electric**
**For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019**

**The Narragansett Electric Company**
**d/b/a National Grid**
**ISR Depreciation Expense in Base Rates**

| Line No. | Description | | Reference | Amount | | less non-ISR eligible plant | ISR Eligible Amount |
|---|---|---|---|---|---|---|---|
| | | | (a) | (b) | | (c) | (d) |
| 1 | Total Company Rate Year Distribution Depreciation Expense | | Sum of Page 2, Line 16 and Line 17 | $50,128,332 | 1 | | |
| 2 | Test Year Depreciation Expense | | Per Company Books | $69,031,187 | 2 | | |
| 3 | Less : Test Year IFA related Depreciation Expense | | Page 4, Line 30, Column (c) | ($19,814,202) | 3 | | |
| 4 | Less: ARO and other adjustments | | Page 4, Line 30, Column (b) + Column (d) | ($55,610) | 4 | | |
| 5 | Adjusted Total Company Test Year Distribution Depreciation Expense | | Sum of Line 2 through Line 4 | $49,161,375 | 5 | | |
| 6 | Depreciation Expense Adjustment | | Line 1 - Line 5 | $966,957 | 6 | | |
| 7 | | | | | 7 | | |
| 8 | | | | Per Book | 8 | | |
| 9 | Test Year Depreciation Expense 12 Months Ended 06/30/17: | | | Amount | 9 | | |
| 10 | Total Distribution Utility Plant 06/30/17 | | Page 4, Line 28, Column (e) | $2,141,474,644 | 10 | ($39,763,450) | $2,101,711,193 |
| 11 | Less Non Depreciable Plant | | Page 4, Line 26, Column (e) | ($627,567,742) | 11 | | ($627,567,742) |
| 12 | Depreciable Utility Plant 6/30/17 | | Line 10 + Line 11 | $1,513,906,902 | 12 | ($39,763,450) | $1,474,143,451 |
| 13 | | | | | 13 | | |
| 14 | Plus: Added Plant 2 Mos Ended 08/31/17 | | Schedule 11-ELEC, Page 6, Line 7 | $12,473,833 | 14 | $0 | $12,473,833 |
| 15 | Less: Streetlights retired in the 2 Mos Ended 08/31/17 | | Per Company Books | ($1,057,011) | 15 | $0 | ($1,057,011) |
| 16 | Less: Retired Plant 2 Months Ended 08/31/17 | 1/ | Line 14 x Retirement Rate | ($3,699,739) | 16 | $0 | ($3,699,739) |
| 17 | Depreciable Utility Plant 08/31/17 | | Line 12 + Line 14 + Line 16 | $1,521,623,985 | 17 | ($39,763,450) | $1,481,860,535 |
| 18 | | | | | 18 | | |
| 19 | Average Depreciable Plant from 06/30/17 to 08/31/17 | | (Line 12 + Line 17)/2 | $1,517,765,443 | 19 | | $1,478,001,993 |
| 20 | | | | | 20 | | |
| 21 | Composite Book Rate % | | As Approved in RIPUC Docket No. 4323 | 3.40% | 21 | | 3.40% |
| 22 | | | | | 22 | | |
| 23 | Book Depreciation Reserve 06/30/17 | | Page 5, Line 69, Column (e) | $652,405,159 | 23 | | |
| 24 | Plus: Book Depreciation Expense excluding Streetlight Retirement | | 1/6 of (Line 19 excl. Line 15 x Line 21) | $8,603,666 | 24 | | $8,381,334 |
| 25 | Less: Streetlights retired in the 2 Mos Ended 08/31/17 and Dep. for 2 Mos | | 1/12 of (Line 15 x SL Dep Rate) | ($1,307) | 25 | | ($1,307) |
| 26 | Less: Net Cost of Removal/(Salvage) | 2/ | Line 14 x Cost of Removal Rate | ($1,281,063) | 26 | | |
| 27 | Less: Retired Plant | | Line 16 | ($3,699,739) | 27 | | |
| 28 | Book Depreciation Reserve 08/31/17 | | Sum of Line 23 through Line 27 | $656,026,715 | 28 | | |
| 29 | | | | | 29 | | |
| 30 | Depreciation Expense 12 Months Ended 08/31/18 | | | | 30 | | |
| 31 | Total Utility Plant 08/31/17 | | Line 10 + Line 14 + Line 15 + Line 16 | $2,149,191,727 | 31 | ($39,763,450) | $2,109,428,277 |
| 32 | Less Non Depreciable Plant | | Line 11 | ($627,567,742) | 32 | $0 | ($627,567,742) |
| 33 | Depreciable Utility Plant 08/31/17 | | Line 31 + Line 32 | $1,521,623,985 | 33 | ($39,763,450) | $1,481,860,535 |
| 34 | | | | | 34 | | |
| 35 | Plus: Plant Added in 12 Months Ended 08/31/18 | | Schedule 11-ELEC, Page 6, Line 14 | $74,843,000 | 35 | $0 | $74,843,000 |
| 36 | Less: Plant Retired in 12 Months Ended 08/31/18 | 1/ | Line 35 x Retirement rate | ($22,198,434) | 36 | $0 | ($22,198,434) |
| 37 | Depreciable Utility Plant 08/31/18 | | Sum of Line 33 through Line 36 | $1,574,268,551 | 37 | ($39,763,450) | $1,534,505,101 |
| 38 | | | | | 38 | | |
| 39 | Average Depreciable Plant for 12 Months Ended 08/31/18 | | (Line 33 + Line 37)/2 | $1,547,946,268 | 39 | ($39,763,450) | $1,508,182,818 |
| 40 | | | | | 40 | | |
| 41 | Composite Book Rate % | | As Approved in RIPUC Docket No. 4323 | 3.40% | 41 | | 3.40% |
| 42 | | | | | 42 | | |
| 43 | Book Depreciation Reserve 08/31/17 | | Line 28 | $656,026,715 | 43 | | |
| 44 | Plus: Book Depreciation 08/31/18 | | Line 39 x Line 41 | $52,630,173 | 44 | | $51,278,216 |
| 45 | Less: Net Cost of Removal/(Salvage) | 2/ | Line 35 x Cost of Removal Rate | ($7,686,376) | 45 | | |
| 46 | Less: Retired Plant | | Line 36 | ($22,198,434) | 46 | | |
| 47 | Book Depreciation Reserve 08/31/18 | | Sum of Line 43 through Line 46 | $678,772,079 | 47 | | |

1/ 3 year average retirement over plant addition in service FY 15 ~ FY17 29.66%
2/ 3 year average Cost of Removal over plant addition in service FY 15 ~ FY17 10.27%

Compliance Attachment 2
Schedule 6-ELEC
Page 2 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric

For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

**The Narragansett Electric Company**
**d/b/a National Grid**
**ISR Depreciation Expense in Base Rates**
**(Continued)**

| Line No. | | Description | | Reference<br>(a) | Amount<br>(b) | | less non-ISR eligible plant<br>(c) | ISR Eligible Amount<br>(d) |
|---|---|---|---|---|---|---|---|---|
| 1 | | **Rate Year Depreciation Expense 12 Months Ended 08/31/19:** | | | | 1 | | |
| 2 | | Total Utility Plant 08/31/18 | | Page 1, Line 31 + Line 35 + Line 36 | $2,201,836,293 | 2 | ($39,763,450) | $2,162,072,843 |
| 3 | | Less Non-Depreciable Plant | | Page 1, Line 11 | ($627,567,742) | 3 | $0 | ($627,567,742) |
| 4 | | Depreciable Utility Plant 08/31/18 | | Line 2 + Line 3 | $1,574,268,551 | 4 | ($39,763,450) | $1,534,505,101 |
| 5 | | | | | | 5 | | |
| 6 | | Plus: Added Plant 12 Months Ended 08/31/19 | | Schedule 11-ELEC, Page 6, Line 38 | $77,541,000 | 6 | ($2,698,000) | $74,843,000 |
| 7 | | Less: Depreciable Retired Plant | 1/ | Line 6 x Retirement rate | ($22,998,661) | 7 | $800,227 | ($22,198,434) |
| 8 | | | | | | 8 | | |
| 9 | | Depreciable Utility Plant 08/31/19 | | Sum of Line 4 through Line 7 | $1,628,810,891 | 9 | ($41,661,224) | $1,587,149,667 |
| 10 | | | | | | 10 | | |
| 11 | | Average Depreciable Plant for Rate Year Ended 08/31/19 | | (Line 4 + Line 9)/2 | $1,601,539,721 | 11 | ($40,712,337) | $1,560,827,384 |
| 12 | | | | | | 12 | | |
| 13 | | Proposed Composite Rate % | | Page 4, Line 18, Columnumn (f) | 3.15% | 13 | | 3.16% |
| 14 | | | | | | 14 | | |
| 15 | | Book Depreciation Reserve 08/31/18 | | Page 1, Line 47 | $678,772,079 | 15 | | |
| 16 | | Plus: Book Depreciation Expense | | Line 11 x Line 13 | $50,375,341 | 16 | | $49,322,145 |
| 17 | | Plus: Unrecovered Reserve Adjustment | | Schedule NWA-1-ELECTRIC, Part VI, Page 6 | ($247,009) | 17 | | ($247,009) |
| 18 | | Less: Net Cost of Removal/(Salvage) | 2/ | Line 6 x Cost of Removal Rate | ($7,963,461) | 18 | | |
| 19 | | Less: Retired Plant | | Line 7 | ($22,998,661) | 19 | | |
| 20 | | Book Depreciation Reserve 08/31/19 | | Sum of Line 15 through Line 19 | $697,938,290 | 20 | | $49,075,136 |
| 21 | | | | | | 21 | | |
| 22 | | **Rate Year Depreciation Expense 12 Months Ended 08/31/20:** | | | | 22 | | |
| 23 | | Total Utility Plant 08/31/19 | | Line 2 + Line 6 + Line 7 | $2,256,378,633 | 23 | ($41,661,224) | $2,214,717,409 |
| 24 | | Less Non-Depreciable Plant | | Page 1, Line 11 | ($627,567,742) | 24 | $0 | ($627,567,742) |
| 25 | | Depreciable Utility Plant 08/31/19 | | Line 23 + Line 24 | $1,628,810,891 | 25 | ($41,661,224) | $1,587,149,667 |
| 26 | | | | | | 26 | | |
| 27 | | Plus: Added Plant 12 Months Ended 08/31/20 | | Schedule 11-ELEC, Page 5, Line 15(i) | $2,000,000 | 27 | ($2,000,000) | $0 |
| 28 | | Less: Depreciable Retired Plant | 1/ | Line 27 x Retirement rate | ($593,200) | 28 | $593,200 | $0 |
| 29 | | | | | | 29 | | |
| 30 | | Depreciable Utility Plant 08/31/20 | | Sum of Line 25 through Line 28 | $1,630,217,691 | 30 | ($43,068,024) | $1,587,149,667 |
| 31 | | | | | | 31 | | |
| 32 | | Average Depreciable Plant for Rate Year Ended 08/31/20 | | (Line 25 + Line 30)/2 | $1,629,514,291 | 32 | ($42,364,624) | $1,587,149,667 |
| 33 | | | | | | 33 | | |
| 34 | | Proposed Composite Rate % | | Page 4, Line 18, Column (f) | 3.15% | 34 | | 3.16% |
| 35 | | | | | | 35 | | |
| 36 | | Book Depreciation Reserve 08/31/20 | | Line 20 | $697,938,290 | 36 | | |
| 37 | | Plus: Book Depreciation Expense | | Line 32 x Line 34 | $51,255,262 | 37 | | $50,153,929 |
| 38 | | Plus: Unrecovered Reserve Adjustment | | Schedule NWA-1-ELECTRIC, Part VI, Page 6 | ($247,009) | 38 | | ($247,009) |
| 39 | | Less: Net Cost of Removal/(Salvage) | 2/ | Line 27 x Cost of Removal Rate | ($205,400) | 39 | | |
| 40 | | Less: Retired Plant | | Line 28 | ($593,200) | 40 | 7 mos FY20 | 12 mos |
| 41 | | Book Depreciation Reserve 08/31/20 | | Sum of Line 36 through Line 40 | $748,147,943 | 41 | $ 436,419,633 | $49,906,920 |
| 42 | | | | | | 42 | | |
| 43 | | **Rate Year Depreciation Expense 12 Months Ended 08/31/21:** | | | | 43 | | |
| 44 | | Total Utility Plant 08/31/20 | | Line 23 + Line 27 + Line 28 | $2,257,785,433 | 44 | ($43,068,024) | $2,214,717,409 |
| 45 | | Less Non-Depreciable Plant | | Page 1, Line 11 | ($627,567,742) | 45 | $0 | ($627,567,742) |
| 46 | | Depreciable Utility Plant 08/31/20 | | Line 44 + Line 45 | $1,630,217,691 | 46 | ($43,068,024) | $1,587,149,667 |
| 47 | | | | | | 47 | | |
| 48 | | Plus: Added Plant 12 Months Ended 08/31/21 | | Schedule 11-ELEC, Page 5, Line 15(l) | $2,000,000 | 48 | ($2,000,000) | $0 |
| 49 | | Less: Depreciable Retired Plant | 1/ | Line 48 x Retirement rate | ($593,200) | 49 | $593,200 | $0 |
| 50 | | | | | | 50 | | |
| 51 | | Depreciable Utility Plant 08/31/21 | | Sum of Line 46 through Line 49 | $1,631,624,491 | 51 | ($44,474,824) | $1,587,149,667 |
| 52 | | | | | | 52 | | |
| 53 | | Average Depreciable Plant for Rate Year Ended 08/31/21 | | (Line 46 + Line 51)/2 | $1,630,921,091 | 53 | ($43,771,424) | $1,587,149,667 |
| 54 | | | | | | 54 | | |
| 55 | | Proposed Composite Rate % | | Page 4, Line 18, Columnumn (f) | 3.15% | 55 | | 3.16% |
| 56 | | | | | | 56 | | |
| 57 | | Book Depreciation Reserve 08/31/20 | | Line 41 | $748,147,943 | 57 | | |
| 58 | | Plus: Book Depreciation Expense | | Line 53 x Line 55 | $51,299,512 | 58 | | $50,153,929 |
| 59 | | Plus: Unrecovered Reserve Adjustment | | Schedule NWA-1-ELECTRIC, Part VI, Page 6 | ($247,009) | 59 | | ($247,009) |
| 60 | | Less: Net Cost of Removal/(Salvage) | 2/ | Line 48 x Cost of Removal Rate | ($205,400) | 60 | | |
| 61 | | Less: Retired Plant | | Line 49 | ($593,200) | 61 | | |
| 62 | | Book Depreciation Reserve 08/31/21 | | Sum of Line 57 through Line 61 | $798,401,846 | 62 | | $49,906,920 |
| 63 | | | | | | | | |
| 64 | 1/ | 3 year average retirement over plant addition in service FY 15 ~ FY17 | | 29.66% | Retirements | | | |
| 65 | 2/ | 3 year average Cost of Removal over plant addition in service FY 15 ~ FY17 | | 10.27% | COR | | | |
| 66 | | | | | | | | |
| 67 | | Book Depreciation RY2 | | Line 37 (a) + Line 38 (b) | | | | $51,008,253 |
| 68 | | Less: General Plant Depreciation (assuming add=retirement) | | - Page 31 of 38, Line 66 (c) | | | | ($1,435,572) |
| 69 | | Plus: Comm Equipment Depreciation | | Page 31 of 38, sum of Lines 59 (c) through 61 (c) | | | | $368,062 |
| 70 | | Total | | | | | | $49,940,743 |
| 71 | | 7 Months | | | | | | x7/12 |
| 72 | | FY 2020 Depreciation Expense | | Line 66 (d) ×7 ÷12 | | | | $29,132,100 |
| 73 | | | | | | | | |
| 74 | | Book Depreciation RY3 | | Line 58 (a) + Line 59 (b) | | | | $51,052,503 |
| 75 | | Less: General Plant Depreciation | | - Page 31 of 38, Line 66 (c) | | | | ($1,435,572) |
| 76 | | Plus: Comm Equipment Depreciation | | Page 31 of 38, sum of Lines 59 (c) through 61 (c) | | | | $368,062 |
| 77 | | Total | | | | | | $49,984,993 |
| 78 | | FY 2021 Depreciation Expense | | Line 66 (d) ×5 ÷12 + Line 73 (d) ×7 ÷12 | | | | $49,966,556 |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Fiscal Year Year 2023 ISR Property Tax Recovery Adjustment 1**
**(000s)**

| Line | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| | **Effective tax Rate Calculation** | **End of FY 2018** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2019** |
| 1 | Plant In Service | $1,595,499 | $111,243 | $3,137 | $114,380 | | ($12,016) | | $1,697,863 |
| 2 | Accumulated Depr | $672,116 | | | | $52,896 | ($12,016) | ($7,949) | $705,047 |
| 3 | Net Plant | $923,383 | | | | | | | $992,816 |
| 4 | Property Tax Expense | $30,354 | | | | | | | $32,077 |
| 5 | Effective Prop Tax Rate | 3.29% | | | | | | | 3.23% |
| | **Effective tax Rate Calculation** | **End of FY 2019** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2020** |
| 6 | Plant In Service | $1,697,863 | $98,620 | $8,892 | $107,511 | | ($14,649) | | $1,790,725 |
| 7 | Accumulated Depr | $705,047 | | | | $54,164 | ($14,649) | ($14,771) | $729,791 |
| 8 | Net Plant | $992,816 | | | | | | | $1,060,934 |
| 9 | Property Tax Expense | $32,077 | | | | | | | $32,568 |
| 10 | Effective Prop Tax Rate | 3.23% | | | | | | | 3.07% |
| | **Effective Tax Rate Calculation** | **End of FY 2020** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2021** |
| 11 | Plant In Service | $1,790,725 | $115,360 | $3,150 | $118,510 | | ($22,589) | | $1,886,646 |
| 12 | Accumulated Depr | $729,791 | | | | $57,246 | ($22,589) | ($11,374) | $753,074 |
| 13 | Net Plant | $1,060,934 | | | | | | | $1,133,572 |
| 14 | Property Tax Expense | $32,568 | | | | | | | $33,333 |
| 15 | Effective Prop Tax Rate | 3.07% | | | | | | | 2.94% |
| | **Effective Tax Rate Calculation** | **End of FY 2021** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2022** |
| 16 | Plant In Service | $1,886,646 | $86,464 | $13,092 | $99,557 | | ($35,100) | | $1,951,103 |
| 17 | Accumulated Depr | $753,074 | | | | $59,937 | ($35,100) | ($7,686) | $770,224 |
| 18 | Net Plant | $1,133,572 | | | | | | | $1,180,878 |
| 19 | Property Tax Expense | $33,333 | | | | | | | $33,955 |
| 20 | Effective Prop Tax Rate | 2.94% | | | | | | | 2.88% |
| | **Effective Tax Rate Calculation** | **End of FY 2022** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2023** |
| 21 | Plant In Service | $1,951,103 | $93,023 | $11,660 | $104,682 | | ($17,798) | | $2,037,987 |
| 22 | Accumulated Depr | $770,224 | | | | $63,562 | ($17,798) | ($8,431) | $807,556 |
| 23 | Net Plant | $1,180,878 | | | | | | | $1,230,431 |
| 24 | Property Tax Expense | $33,955 | | | | | | | $34,532 |
| 25 | Effective Prop Tax Rate | 2.88% | | | | | | | 2.81% |
| | **Effective Tax Rate Calculation** | **End of FY 2023** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2024** |
| 26 | Plant In Service | $2,037,987 | $89,026 | $13,092 | $102,118 | | ($20,914) | | $2,119,191 |
| 27 | Accumulated Depr | $807,556 | | | | $63,646 | ($20,914) | ($15,659) | $834,630 |
| 28 | Net Plant | $1,230,431 | | | | | | | $1,284,562 |
| 29 | Property Tax Expense | $34,532 | | | | | | | $36,931 |
| 30 | Effective Prop Tax Rate | 2.81% | | | | | | | 2.88% |
| | **Effective Tax Rate Calculation** | **End of FY 2024** | **ISR Additions** | **Non-ISR Add's** | **Total Add's** | **Bk Depr (1)** | **Retirements** | **COR** | **End of FY 2025** |
| 31 | Plant In Service | $2,119,191 | $108,181 | $11,660 | $119,841 | | ($27,553) | | $2,211,479 |
| 32 | Accumulated Depr | $834,630 | | | | $65,096 | ($27,553) | ($19,783) | $852,389 |
| 33 | Net Plant | $1,284,562 | | | | | | | $1,359,090 |
| 34 | Property Tax Expense | $36,931 | | | | | | | $38,150 |
| 35 | Effective Prop Tax Rate | 2.88% | | | | | | | 2.81% |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Fiscal Year Year 2023 ISR Property Tax Recovery Adjustment 2 (continued)**
**(000s)**

| | **Property Tax Recovery Calculation** | (a) | (b) | (c) | (d | (e) | (f) | (g) | (h) | (i) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cumulative Increm. ISR Prop. Tax for FY2018 | | | Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 months | | | Cumulative Increm. ISR Prop. Tax for FY2019 7 months | | |
| 36 | Incremental ISR Additions | | $92,660 | | | $111,243 | | | $35,209 | |
| 37 | Book Depreciation: base allowance on ISR eligible plant | | ($43,032) | | | ($43,032) | | | $0 | |
| 38 | Book Depreciation: current year ISR additions | | ($1,317) | | | ($1,628) | | | ($979) | |
| 39 | COR | | $9,980 | | | $7,949 | | | $362 | |
| 40 | Net Plant Additions | | $58,291 | | | $74,532 | | | $34,591 | |
| 41 | RY Effective Tax Rate | | 3.98% | | | 3.98% | | | 3.28%<br>1.91% | |
| 42 | ISR Year Effective Tax Rate | 3.29% | | | 3.23% | | | | | |
| 43 | RY Effective Tax Rate | 3.98% | -0.69% | | 3.98% | -0.75% | | 3.23% | | |
| 44 | RY Effective Tax Rate 5 mos for FY 2019 | | -0.69% | | 5 month | -0.31% | | 3.28% | -0.05% | |
| 45 | RY Net Plant times 5 mo rate | $746,900 | -0.69% | ($5,191) | $746,900 | -0.31% | ($2,338) | | -0.03% 7 mos | |
| 46 | FY 2014 Net Adds times ISR Year Effective Tax rate | $1,566 | 3.29% | $51 | $1,232 | 1.35% | $17 | $930,873 | -0.03% | ($279) |
| 47 | FY 2015 Net Adds times ISR Year Effective Tax rate | $34,308 | 3.29% | $1,128 | $32,324 | 1.35% | $435 | | | |
| 48 | FY 2016 Net Adds times ISR Year Effective Tax rate | $33,535 | 3.29% | $1,102 | $32,090 | 1.35% | $432 | $17,082 | 1.88% | $322 |
| 49 | FY 2017 Net Adds times ISR Year Effective Tax rate | $38,200 | 3.29% | $1,256 | $37,040 | 1.35% | $499 | $34,591 | 1.88% | $651 |
| 50 | FY 2018 Net Adds times ISR Year Effective Tax rate | $58,291 | 3.29% | $1,916 | $55,850 | 1.35% | $752 | | | |
| 51 | FY 2019 Net Adds times ISR Year Effective Tax rate | | | | $74,532 | 1.35% | $1,003 | | | |
| 52 | Total ISR Property Tax Recovery | | | $263 | | | $800 | | | $694 |

| | | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cumulative Increm. ISR Prop. Tax for FY2020 | | | Cumulative Increm. ISR Prop. Tax for FY2021 | | | Cumulative Increm. ISR Prop. Tax for FY2022 | | |
| 53 | Incremental ISR Additions | | $67,435 | | | $115,360 | | | $86,464 | |
| 54 | Book Depreciation: base allowance on ISR eligible plant | | $0 | | | $0 | | | ($29,112) | |
| 55 | Book Depreciation: current year ISR additions | | ($1,002) | | | ($1,475) | | | ($815) | |
| 56 | COR | | $11,333 | | | $10,233 | | | $7,601 | |
| 57 | Net Plant Additions | | $77,766 | | | $124,118 | | | $64,137 | |
| 58 | RY Effective Tax Rate | | 3.38% | | | 3.58% | | | 3.66% | |
| 59 | ISR Property Tax Recovery on non-ISR | | | | | | | | | |
| 60 | ISR Year Effective Tax Rate | 3.07% | | | 2.94% | | | 2.88% | | |
| 61 | RY Effective Tax Rate | 3.38% | -0.31% | | 3.58% | -0.64% | | 3.66% | -0.79% | |
| 62 | RY Effective Tax Rate 7 mos for FY 2019 | | | | | | | | | |
| 63 | RY Net Plant times Rate Difference | $902,404 | -0.31% | ($2,825) | $853,576 | * -0.64% | ($5,427) | $833,223 | * -0.79% | ($6,574) |
| 64 | Non-ISR plant times rate difference | ($2,269) | -0.31% | $7 | ($4,269) | * -0.64% | $27 | ($6,269) | * -0.79% | $49 |
| 65 | FY 2018 Net Incremental times rate difference | $16,396 | 3.07% | $503 | $15,710 | * 2.94% | $462 | $15,024 | * 2.88% | $432 |
| 66 | FY 2019 Net Incremental times rate difference | $32,757 | 3.07% | $1,006 | $30,923 | * 2.94% | $909 | $29,089 | * 2.88% | $836 |
| 67 | FY 2020 Net Incremental times rate difference | $77,766 | 3.07% | $2,388 | $75,762 | * 2.94% | $2,228 | $73,758 | * 2.88% | $2,121 |
| 68 | FY 2021 Net Incremental times rate difference | | | | $124,118 | * 2.94% | $3,650 | $121,168 | * 2.88% | $3,484 |
| 69 | FY 2022 Net Adds times rate differenc | | | | | | | $64,137 | * 2.88% | $1,844 |
| 70 | Total ISR Property Tax Recovery | | | $1,079 | | | $1,850 | | | $2,192 |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Fiscal Year Year 2023 ISR Property Tax Recovery Adjustment 3 (continued)**
**(000s)**

| | | (s) | (t) | (u) | (v) | (w) | (x) | (y) | (z) | (aa) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cumulative Increm. ISR Prop. Tax for FY2023 | | | Cumulative Increm. ISR Prop. Tax for FY2024 | | | Cumulative Increm. ISR Prop. Tax for FY2025 | | |
| 71 | Incremental ISR Additions | | $93,023 | | | $89,026 | | | $108,181 | |
| 72 | Book Depreciation: base allowance on ISR eligible plant | | ($49,907) | | | ($49,907) | | | ($49,907) | |
| 73 | Book Depreciation: current year ISR additions | | ($1,189) | | | ($1,076) | | | ($47,899) | |
| 74 | COR | | $7,722 | | | $15,659 | | | $19,783 | |
| 75 | Net Plant Additions | | $49,649 | | | $53,702 | | | $30,158 | |
| 76 | RY Effective Tax Rate | | 3.66% | | | 3.66% | | | 3.66% | |
| 77 | ISR Property Tax Recovery on non-ISR | | | | | | | | | |
| 78 | ISR Year Effective Tax Rate | 2.81% | | | 2.88% | | | 2.81% | | |
| 79 | RY Effective Tax Rate | 3.66% | -0.86% | | 3.66% | -0.79% | | 3.66% | -0.86% | |
| 80 | RY Effective Tax Rate 7 mos for FY 2019 | | | | | | | | | |
| 81 | RY Net Plant times Rate Difference | $833,223 | * -0.86% | ($7,141) | $833,223 | * -0.79% | ($6,574) | $833,223 | * -0.86% | ($7,141) |
| 82 | Non-ISR plant times rate difference | ($8,269) | * -0.86% | $71 | ($10,269) | * -0.79% | $81 | ($12,269) | * -0.86% | $105 |
| 83 | FY 2018 Net Incremental times rate difference | $14,338 | * 2.81% | $402 | $13,652 | * 2.88% | $392 | $12,966 | * 2.81% | $364 |
| 84 | FY 2019 Net Incremental times rate difference | $27,254 | * 2.81% | $765 | $25,420 | * 2.88% | $731 | $23,586 | * 2.81% | $662 |
| 85 | FY 2020 Net Incremental times rate difference | $71,754 | * 2.81% | $2,014 | $69,750 | * 2.88% | $2,005 | $67,746 | * 2.81% | $1,902 |
| 86 | FY 2021 Net Incremental times rate difference | $118,217 | * 2.81% | $3,318 | $115,267 | * 2.88% | $3,314 | $112,317 | * 2.81% | $3,153 |
| 87 | FY 2022 Net Incremental times rate difference | $62,506 | * 2.81% | $1,755 | $60,875 | * 2.88% | $1,750 | $59,244 | * 2.81% | $1,663 |
| 88 | FY 2023 Net Incremental times rate difference | $49,649 | * 2.81% | $1,394 | $47,272 | * 2.88% | $1,359 | $44,895 | * 2.81% | $1,260 |
| 89 | FY 2024 Net Incremental times rate difference | | | | $53,702 | * 2.88% | $1,544 | $51,550 | * 2.81% | $1,447 |
| 90 | FY 2025 Net Incremental times rate difference | | | | | | | $30,158 | * 2.81% | $847 |
| 91 | Total ISR Property Tax Recovery | | | $2,578 | | | $4,603 | | | $4,261 |

**Line Notes**

| | |
|---|---|
| 1(a) - 15(h) | Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 20, |
| 16(a) - 20(a) | =11(h) - 15(h) |
| 16(b) - 16(d) | Docket No. 5098 Attachment 1C, Page 26 of 29, 16(b) to 16(d) |
| 16(e) | Docket 5098, C. Att. 2, Sch 6-ELEC, P2: (L37(b) + L38(b)) +( (Page 2 of 38, L 6(a) + Page 5 of 38, L 6(a)+Page 10 of 38, L(a)+, L6(a)) × 0.0316+Page 8 of 3833(d)+, L(b))/1000 + (L1(c)+L6(c)+L11(c))×0.0301+, L6(a) × 0.0316× 0.5)/1000+L16(c)×0.5×0.0301 |
| 16(f) - 17(g) | Docket No. 5098 Attachment 1C, Page 26 of 29, 16(f) to 17(g) |
| 16(h) | Sum of Lines 16(a) through 16(g) |
| 17(h) | Sum of Lines 17(a) through 17(g) |
| 18(h) | =16(h)-17(h) |
| 19(h) | Per Company's Book |
| 20(h) | Line 19(h) ÷ 18(h) |
| 21(a) - 25(a) | =16(h) - 20(h) |
| 21(b) | Page 20 of 38, Line 3(a) through 3(c) / 1000 |
| 21(c) | Per Company's Book |
| 21(d) | Line 21(b) + Line 21(c) |
| 21(f), 22(f) | Per Company's Book |
| 21(h) | Line21(a) + 21(d) + 21(f) |
| 22(e) | Per Company's Book |
| 22(h) | Line22(a) + 22(e) + 22(f) + 22(g) |
| 23(h) | 21(h)-22(h) |

**Line Notes**

| | |
|---|---|
| 24(h) | Per Company's Book |
| 25(h) | Line 24(h) ÷ 23(h) |
| 36(a) - 52(i) | Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g) |
| 53(j) - 70(o) | Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g) |
| 53(q) - 67(r) | Docket No. 5098 Attachment 1C, Page 26 of 29, 38(j) to 50(k) |
| 68(p) | =68(m) - (Page 13 of 38, Line 19(b) ÷ 1000 |
| 69(p) | =57(q) |
| 68(q) - 69(q) | =60(p) |
| 68(r) - 69(r) | =68(p) to 69(p) x 68(q) to 69(q) |
| 70(r) | Sum of Lines 63(r) through 69(r) |
| 71(t) | Page 20 of 38, Line 3(a) through 3(c) / 100( |
| 72(t) | Page 20 of 38, Line 8(a) through 8(c) / 1000 |
| 73(t) | Page 20 of 38, Line 19(a) through 19(c) /1000 |
| 74(t) | Page 20 of 38, Line 10(a) through 10(c) / 1000 |
| 75(t) | Sum of Lines 71(t) through 74(t) |
| 76(t) | =58(q) |
| 78(s) | =25(h) |

**Line Notes**

| | |
|---|---|
| 79(s) | =76(t) |
| 79(t) | 78(s) -79(s) |
| 81(s) | Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, (L51-L62)/1000] |
| 82(s) | =64(p) - 2000 |
| 83(s) | =65(p) - (Page 2 of 38, Line 19(i) / 1000 |
| 84(s) | =66(p) - (Page 5 of 38, Line 19(e) + Page 8 of 38, Line 33(o))/1000 |
| 85(s) | =67(p) - (Page 10 of 38, Line 19(d) through 19(f) / 1000 |
| 86(s) | =68(p) - (Page 13 of 38, Line 19(c) through 19(e) / 1000 |
| 87(s) | =69(p) - (Page 17 of 38, Line 19(b) through 19(d) / 1000 |
| 88(s) | =75(t) |
| 81(t)-82(t) | =79(t) |
| 83(t)-88(t) | =78(s) |
| 81(u) - 88(u) | =81(s) to 88(s) x 81(t) to 88(t) |
| 91(u) | Sum of Lines 81(u) through 88(u) |

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Weighted Average Cost of Capital

| Line No. | | (a) | (b) | (c ) | (d) | (e) |
|---|---|---|---|---|---|---|
| 1 | Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013 | | | | | |
| 2 | | Ratio | Rate | Weighted Rate | Taxes | Return |
| 3 | Long Term Debt | 49.95% | 4.96% | 2.48% | | 2.48% |
| 4 | Short Term Debt | 0.76% | 0.79% | 0.01% | | 0.01% |
| 5 | Preferred Stock | 0.15% | 4.50% | 0.01% | | 0.01% |
| 6 | Common Equity | 49.14% | 9.50% | 4.67% | 2.51% | 7.18% |
| 7 | | 100.00% | | 7.17% | 2.51% | 9.68% |
| 8 | | | | | | |
| 9 | (d) - Column (c) x 35% divided by (1 - 35%) | | | | | |
| 10 | | | | | | |
| 11 | Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018 | | | | | |
| 12 | | Ratio | Rate | Weighted Rate | Taxes | Return |
| 13 | Long Term Debt | 49.95% | 4.96% | 2.48% | | 2.48% |
| 14 | Short Term Debt | 0.76% | 0.79% | 0.01% | | 0.01% |
| 15 | Preferred Stock | 0.15% | 4.50% | 0.01% | | 0.01% |
| 16 | Common Equity | 49.14% | 9.50% | 4.67% | 1.24% | 5.91% |
| 17 | | 100.00% | | 7.17% | 1.24% | 8.41% |
| 18 | | | | | | |
| 19 | (d) - Column (c) x 21% divided by (1 - 21%) | | | | | |
| 20 | | | | | | |
| 21 | Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018 | | | | | |
| 22 | | Ratio | Rate | Weighted Rate | Taxes | Return |
| 23 | Long Term Debt | 48.35% | 4.62% | 2.23% | | 2.23% |
| 24 | Short Term Debt | 0.60% | 1.76% | 0.01% | | 0.01% |
| 25 | Preferred Stock | 0.10% | 4.50% | 0.00% | | 0.00% |
| 26 | Common Equity | 50.95% | 9.28% | 4.73% | 1.26% | 5.99% |
| 27 | | 100.00% | | 6.97% | 1.26% | 8.23% |
| 28 | | | | | | |
| 29 | (d) - Column (c) x 21% divided by (1 - 21%) | | | | | |
| 30 | | | | | | |
| 31 | FY18 Blended Rate | | Line 7(e) x 75% + Line 17(e) x 25% | | | 9.36% |
| 32 | | | | | | |
| 33 | FY19 Blended Rate | | Line 17 x 5 ÷ 12 + Line 27 x 7 ÷ 12 | | | 8.31% |
| 34 | | | | | | |
| 35 | FY20 and after Rate | | | Line 27(e) | | 8.23% |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Incremental Capital Investment**

| Line No. | | | Fiscal Year 2025 (a) | In Base Rates Included In Docket No. 4770 (b) | Amount to be Included in FY 2025 ISR (c) = (a) - (b) |
|---|---|---|---|---|---|
| | **Non Discretionary Capital** | | | | |
| 1 | Fiscal Year 2025 Proposed Non-Discretionary Capital Additions | Column (a) Section 2, Chart 18, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k). | **$50,134,000** | **$0** | $50,134,000 |
| | **Discretionary Capital** | | | | |
| 2 | Cumulative CY 2024 Discretionary Capital ADDITIONS | Page do not print of 38, Line 4 | $609,689,179 | | |
| 3 | FY 2025 Discretionary Capital ADDITIONS | Section 2, Chart 18, Col 2 | $58,047,000 | | |
| 4 | Cumulative Actual Discretionary Capital Additions | Line 2 + Line 3 | $667,736,179 | | |
| 5 | Cumulative FY 2024 Discretionary Capital SPENDING | Page do not print of 38, Line 7 | $683,915,033 | | |
| 6 | FY 2025 Discretionary Capital SPENDING | Section 2, Chart 18, Col 1 | $90,240,000 | | |
| 7 | Cumulative Actual Discretionary Capital Spending | Line 5 + Line 6 | $774,155,033 | | |
| 8 | Cumulative FY 2024 Approved Discretionary Capital SPENDING | Page do not print of 38, Line 10 | $685,430,536 | | |
| 9 | FY 2025 Approved Discretionary Capital SPENDING | Section 2, Chart 18, Col 1 | $90,240,000 | | |
| 10 | Cumulative Actual Approved Discretionary Capital Spending | Line 8 + Line 9 | $775,670,536 | | |
| 11 | Cumulative Allowed Discretionary Capital Included in Rate Base | Lesser of Line 4, Line 7, or Line 10 | $667,736,179 | | |
| 12 | Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base | Page do not print of 38, Line 11 | $609,689,179 | | |
| 13 | Total Allowed Discretionary Capital Included in Rate Base Current Year | Line 11 - Line 12 | **$58,047,000** | **$0** | **$58,047,000** |
| 14 | **Total Allowed Capital Included in Rate Base Current Year** | Line 1 + Line 13 | **$108,181,000** | **$0** | **$108,181,000** |
| 15 | Intangible Assets included in Total Allowed Discretionary Capital | Section 2, Chart 10, Column 2 note | | | $0 |
| 16 | **Total Allowed Discretionary Capital Included in non-Intangible Rate Base Current Year** | Line 14 - Line 15 | | | **$108,181,000** |

The Narragansett Electric Company
d/b/a Rhode Island Energy
Impact of Elimination of ADIT and Hold Harmless Commitment for the FY 2025 Plan
Fiscal Year 2025 - April 2024-March 2025

**Inputs**

| | | | | |
|---|---|---|---|---|
| 1 | Tax Rate | | **21.00%** | |
| | **Gas and Distribution** | | | |
| 2 | Long Term Debt | | **48.350%** | |
| 3 | Short Term Debt | | **0.600%** | |
| 4 | Preferred Stock | | **0.100%** | |
| 5 | Debt Weighting | Lines 2+3+4 | **49.050%** | |
| 6 | Equity Weighting | 1 - Line 5 | **50.950%** | |
| 7 | Long Term Debt Rate | | **4.620%** | |
| 8 | Short Term Debt Rate | | **1.760%** | |
| 9 | Cost of Debt | Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8 | **4.585%** | |
| 10 | Cost of Equity | | **9.275%** | |
| 11 | Revenue WACC (pre-tax) | Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6 | **8.2300%** | |
| 12 | WACC (after-tax) | (Line 9 * Line 5) + (Line 10 * Line 6) | **6.975%** | |
| 13 | Rate Base - PPL (after purchase) | Page 2. Line 9, Column (c) | $ 212,985,124 | Fiscal Year 2025 |
| 14 | Rate Base - NG (before sale) | Page 2. Line 9, Column (f) | $ 173,446,023 | Fiscal Year 2025 |
| 15 | **Deferred Taxes / Hold Harmless** | **Lines 8 - 9** | **$ 39,539,101** | Elimination of Deferred Taxes |

**Distribution ROE Mechanics**

Notes:
1. The sale of the business is treated as a sale of assets for income tax purposes causing the reversal of cumulative timing differences and a payment to the government of the amounts that had been recorded as deferred tax liabilities by National Grid ("NG").
2. PPL does not assume the interest-free liability of ADIT from NG because NG paid this tax liability to the government as a result of the sales transaction. As such, PPL has to replace the no-cost capital with other capital. This calculation assumes that the substitute for the eliminated DTL is debt and equity in the same proportion as stated in Lines 5 and 6.
3. The revenue credit for hold harmless is reflected on Line 23.
4. Line 28 reflects the goodwill tax deduction needed to hold customers harmless from the increased revenue requirement due to the rate base increase from the elimination of deferred taxes. Any tax deduction lower than the amount reflected on this line will not provide enough of a tax benefit to share with customers.
5. Line 29 relects the cash tax benefit of the goodwill tax deduction and is recorded for GAAP reporting (not reflected for FERC reporting). There is not an income statement tax benefit since the goodwill tax deduction is a flip between current and deferred taxes. This amount grossed up for tax is the revenue credit reflected on Line 23.

| | | | Post-Acquisition Results for ISR Capital Adjustments through the Date of Acquisition | Results for ISR Capital Adjustments through the Date of Acquisition as if the Acqusition did not occur | Difference | |
|---|---|---|---|---|---|---|
| | | | (a) | (b) | (c) = (a) - (b) | |
| 16 | Rate Base after Acqusition | Line 13 | 212,985,124 | 212,985,124 | - | |
| 17 | ADIT Adjustment | - Line 15 | - | (39,539,101) | 39,539,101 | |
| 18 | **Adjusted Rate Base** | **Lines 16 + 17** | **212,985,124** | **173,446,023** | **39,539,101** | |
| 19 | Debt Return (4.576%) | Lines 18 * 5 * 9 | 4,789,854 | 3,900,654 | 889,201 | |
| 20 | Equity Return (9.275%) | Lines 18 * 6 * 10 | 10,064,852 | 8,196,387 | 1,868,465 | |
| 21 | Taxes on Equity (21%) | (Line 20 / (1 - Line 1)) * Line 1 | 2,675,467 | 2,178,786 | 496,680 | |
| 22 | **Total Unadjusted Revenue** | **Sum of Lines 19 , 20, 21** | **17,530,173** | **14,275,827** | **3,254,346** | |
| 23 | Revenue Adjustment for Fiscal Year 2025 | - Line 15 * Line 11 | (3,254,068) | - | (3,254,068) | Note 1 |
| 24 | **Total Revenue** | **Lines 23 + 24** | **14,276,105** | **14,275,827** | **278** | |
| 25 | Interest Expense | Lines 18, Col (b) * 5 * 9 | 3,900,654 | 3,900,654 | - | |
| 26 | Tax Expense | (Lines 24 - 25) * Line 1 | 2,178,845 | 2,178,786 | 58 | |
| 27 | **Net Income** | **Lines 24 - 25 - 26** | **8,196,607** | **8,196,387** | **220** | |
| | **Impact of Transaction** | | | | | |
| 28 | Transaction-related Tax Deduction | - Line 23 * (1-Line 1) / Line 1 | 12,241,494 | | | |
| 29 | Cash Tax Benefit at 21% | Line 28 * Line 1 | 2,570,714 | | | |
| 30 | Cash Tax Benefit Grossed Up | Line 29 / (1-Line 1) | 3,254,068 | | | |

Note 1: There is a slight variation in the calculated hold harmless amount in the ISR filing due to the roundings that are used to calculate the WACC in the ISR files.

The Narragansett Electric Company-Elec
d/b/a Rhode Island Energy
Average ISR Rate Base after Deferred Tax Proration

| | | Post-Acquisition | Prorated | Post-Acquisition After Proration | | No Acquisition | Prorated | No Acquisition After Proration | |
|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | | (d) | (e) | (f) | |
| 1 | **Plan Year 2025** | | | | | | | | |
| 2 | FY 2018 | 11,912,412 | 100% | 11,912,412 | | 12,642,481 | 100% | 12,642,481 | |
| 3 | FY 2019 | 23,907,021 | 100% | 23,907,021 | | 20,939,212 | 100% | 20,939,212 | |
| 4 | FY 2019 Intangible | 744,152 | 100% | 744,152 | | 292,917 | 100% | 292,917 | |
| 5 | FY 2020 | 38,777,816 | 100% | 38,777,816 | | 34,716,287 | 100% | 34,716,287 | |
| 6 | FY 2021 | 62,061,985 | 100% | 62,061,985 | | 58,494,054 | 100% | 58,494,054 | |
| 7 | FY 2022 | 37,541,011 | 100% | 37,541,011 | | 33,001,402 | 100% | 33,001,402 | |
| 8 | FY 2023 | 38,040,727 | 100% | 38,040,727 | | 13,359,670 | 100% | 13,359,670 | |
| 9 | | 212,985,124 | | 212,985,124 | Page 2, Line 13 | 173,446,023 | | 173,446,023 | Page 2, Line 14 |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Annual Revenue Requirement Summary - AMF Capital Investment**

| Line No. | | Fiscal Year 4/1/24 - 3/31/25 2025 (a) |
|---|---|---|
| | **AMF Incremental Capital Investment:** | |
| 1 | Meters - Forecasted Revenue Requirement on FY 2025 Incremental Capital included in ISR | $1,859,751 |
| 2 | Software - Forecasted Revenue Requirement on FY 2025 Incremental Capital included in ISR | $2,154,005 |
| 3 | Network - Forecasted Revenue Requirement on FY 2025 Incremental Capital included in ISR | $589,757 |
| 4 | Subtotal | $4,603,512 |
| 5 | MDMS Software - Depreciation - No Return | $118,564 |
| 6 | **Total AMF Capital Investment Component of Revenue Requirement** | **$4,722,076** |
| 7 | Deferrals to Offset AMF Capital Investment Revenue Requirement | (4,722,076) |
| 8 | **Net AMF Capital Investment Component of Revenue Requirement** | **$0** |

Column/Line Notes:

| | |
|---|---|
| 1 | Page 2, Line 23 |
| 2 | Page 3, Line 23 |
| 3 | Page 4, Line 23 |
| 4 | Total Lines 1 through 3 |
| 5 | Page 5, Line 23 |
| 6 | Line 4 + Line 5 |
| 7 | Page 10, Column AC, Line 5 |
| 8 | Line 6 + Line 7 |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Annual Revenue Requirement - AMF Capital Investment - Meters**

| | | Source | | Fiscal Year 2025 |
|---|---|---|---|---|
| | | | (a) | (b) |
| 1 | 370 - Meters | In-Service Plant | | $ 29,971,477 |
| 2 | Plant Capital Overheads | Input | 0% | $0 |
| 3 | Capital Spend - Annual | Line 1 + Line 2 | | $29,971,477 |
| 4 | Capital Spend - Cumulative | PY Line 4 + CY Line 3 | | $29,971,477 |
| 5 | 370 - COR - Annual | Input | | $0 |
| 6 | Cumulative COR | Line 5 | | $0 |
| 7 | Annual Federal Tax Depreciation | Page 6, Line 27 | | $2,997,148 |
| 8 | Cumulative Federal Tax Depreciation | PY Line 8 + CY Line 7 | | $2,997,148 |
| 9 | Annual Book Depreciation | Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a | 4.49% | $672,560 |
| 10 | Cumulative Book Depreciation | Line 9 | | $672,560 |
| 11 | Accumulated Deferred Income Tax | (Line 10 - Line 8) x 21% | 21% | $488,163 |
| | **Rate Base Calculation** | | | |
| 12 | Plant In Service | Line 4 | | $29,971,477 |
| 13 | Accumulated Reserve for Depreciation | - Line 10 | | ($672,560) |
| 14 | Deferred Tax Reserve (ADIT) | - Line 11 | | ($488,163) |
| 15 | Year End Rate Base | Sum of Lines 12 through 14 | | $28,810,754 |
| | **Revenue Requirement Calculation** | | | |
| 16 | Average Rate Base | Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2 | | $14,405,377 |
| 17 | Deferred Tax Proration Adjustment | Page 9, Column F, Line 41 | | $19,784 |
| 18 | Average Rate Base adjusted | Line 16 + Line 17 | | $14,425,161 |
| 19 | Pre-Tax WACC | RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4 | | 8.23% |
| 20 | Return and Taxes | Line 18 x Line 19 | | $1,187,191 |
| 21 | Book Depreciation | Line 9 | | $672,560 |
| 22 | Property Taxes | RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing | 2.81% | $0 |
| **23** | **Annual Revenue Requirement** | **Line 20 + 21 + 22** | | **$1,859,751** |

CY = Current Year
PY = Prior Year
Property Taxes - Zero for Year 1
Book Depreciation Rate - RIPUC Docket No. 4770

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Annual Revenue Requirement - AMF Capital Investment - Software (Excluding MDMS)**

| | | Source | | Fiscal Year 2025 |
|---|---|---|---|---|
| | | | (a) | (b) |
| 1 | 303 - Software | In-Service Plant | | $ 19,782,755 |
| 2 | Plant Capital Overheads | Input | 0% | $0 |
| 3 | Capital Spend - Annual | Line 1 + Line 2 | | $19,782,755 |
| 4 | Capital Spend - Cumulative | PY Line 4 + CY Line 3 | | $19,782,755 |
| 5 | 303- COR - Annual | Input | | $0 |
| 6 | Cumulative COR | Line 5 | | $0 |
| 7 | Annual Federal Tax Depreciation | Page 7, Line 27 | | $3,297,192 |
| 8 | Cumulative Federal Tax Depreciation | PY Line 8 + CY Line 7 | | $3,297,192 |
| 9 | Annual Book Depreciation | Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a | 14.29% | $1,413,053 |
| 10 | Cumulative Book Depreciation | Line 9 | | $1,413,053 |
| 11 | Accumulated Deferred Income Tax | (Line 10 - Line 8) x 21% | 21% | $395,669 |
| | **Rate Base Calculation** | | | |
| 12 | Plant In Service | Line 4 | | $19,782,755 |
| 13 | Accumulated Reserve for Depreciation | - Line 10 | | ($1,413,053) |
| 14 | Deferred Tax Reserve (ADIT) | - Line 11 | | ($395,669) |
| 15 | Year End Rate Base | Sum of Lines 12 through 14 | | $17,974,032 |
| | **Revenue Requirement Calculation** | | | |
| 16 | Average Rate Base | Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2 | | $8,987,016 |
| 17 | Deferred Tax Proration Adjustment | Page 9, Column G, Line 41 | | $16,036 |
| 18 | Average Rate Base adjusted | Line 16 + Line 17 | | $9,003,052 |
| 19 | Pre-Tax WACC | RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4 | | 8.23% |
| 20 | Return and Taxes | Line 18 x Line 19 | | $740,951 |
| 21 | Book Depreciation | Line 9 | | $1,413,053 |
| 22 | Property Taxes | RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing | 2.81% | $0 |
| **23** | **Annual Revenue Requirement** | **Line 20 + 21 + 22** | | **$2,154,005** |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Annual Revenue Requirement - AMF Capital Investment - Network**

| | | Source | | Fiscal Year 2025 |
|---|---|---|---|---|
| | | | (a) | (b) |
| 1 | 397 - Network | In-Service Plant | | $ 5,407,058 |
| 2 | Plant Capital Overheads | Input | 0% | $0 |
| 3 | Capital Spend - Annual | Line 1 + Line 2 | | $5,407,058 |
| 4 | Capital Spend - Cumulative | PY Line 4 + CY Line 3 | | $5,407,058 |
| 5 | 397 - COR - Annual | Input | | $0 |
| 6 | Cumulative COR | Line 5 | | $0 |
| 7 | Annual Federal Tax Depreciation | Page 8, Line 27 | | $772,669 |
| 8 | Cumulative Federal Tax Depreciation | PY Line 8 + CY Line 7 | | $772,669 |
| 9 | Annual Book Depreciation | Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a | 14.29% | $386,218 |
| 10 | Cumulative Book Depreciation | Line 9 | | $386,218 |
| 11 | Accumulated Deferred Income Tax | (Line 10 - Line 8) x 21% | 21% | $81,155 |
| | **Rate Base Calculation** | | | |
| 12 | Plant In Service | Line 4 | | $5,407,058 |
| 13 | Accumulated Reserve for Depreciation | - Line 10 | | ($386,218) |
| 14 | Deferred Tax Reserve (ADIT) | - Line 11 | | ($81,155) |
| 15 | Year End Rate Base | Sum of Lines 12 through 14 | | $4,939,685 |
| | **Revenue Requirement Calculation** | | | |
| 16 | Average Rate Base | Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2 | | $2,469,843 |
| 17 | Deferred Tax Proration Adjustment | Page 9, Column H, Line 41 | | $3,289 |
| 18 | Average Rate Base adjusted | Line 16 + Line 17 | | $2,473,132 |
| 19 | Pre-Tax WACC | RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4 | | 8.23% |
| 20 | Return and Taxes | Line 18 x Line 19 | | $203,539 |
| 21 | Book Depreciation | Line 9 | | $386,218 |
| 22 | Property Taxes | RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing | 2.81% | $0 |
| **23** | **Annual Revenue Requirement** | **Line 20 + 21 + 22** | | **$589,757** |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Annual Revenue Requirement - AMF Capital Investment - MDMS**

| | | Source | | Fiscal Year 2025 |
|---|---|---|---|---|
| | | | (a) | (b) |
| 1 | 303 - Software | In-Service Plant | | $ 1,659,895 |
| 2 | Plant Capital Overheads | Input | 0% | $0 |
| 3 | Capital Spend - Annual | Line 1 + Line 2 | | $1,659,895 |
| 4 | Capital Spend - Cumulative | PY Line 4 + CY Line 3 | | $1,659,895 |
| 5 | 303- COR - Annual | Input | | $0 |
| 6 | Cumulative COR | Line 5 | | $0 |
| 7 | Annual Federal Tax Depreciation | N/A | | $0 |
| 8 | Cumulative Federal Tax Depreciation | PY Line 8 + CY Line 7 | | $0 |
| 9 | Annual Book Depreciation | Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a | 14.29% | $118,564 |
| 10 | Cumulative Book Depreciation | Line 9 | | $118,564 |
| 11 | Accumulated Deferred Income Tax | (Line 10 - Line 8) x 21% | 21% | $0 |
| | **Rate Base Calculation** | | | |
| 12 | Plant In Service | Line 4 | | $0 |
| 13 | Accumulated Reserve for Depreciation | - Line 10 | | $0 |
| 14 | Deferred Tax Reserve (ADIT) | - Line 11 | | $0 |
| 15 | Year End Rate Base | Sum of Lines 12 through 14 | | $0 |
| | **Revenue Requirement Calculation** | | | |
| 16 | Average Rate Base | Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2 | | $0 |
| 17 | Deferred Tax Proration Adjustment | | | $0 |
| 18 | Average Rate Base adjusted | Line 16 + Line 17 | | $0 |
| 19 | Pre-Tax WACC | RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4 | | 0.00% |
| 20 | Return and Taxes | Line 18 x Line 19 | | $0 |
| 21 | Book Depreciation | Line 9 | | $118,564 |
| 22 | Property Taxes | RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing | 2.81% | $0 |
| **23** | **Annual Revenue Requirement** | **Line 20 + 21 + 22** | | **$118,564** |

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Meters**

| Line No. | | | | Fiscal Year 2025 (a) |
|---|---|---|---|---|
| | Capital Repairs Deduction | | | |
| 1 | Plant Additions | Page 2, Line 4 | | $29,971,477 |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 0.00% |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $0 |
| 4 | | | | |
| 5 | Bonus Depreciation | | | |
| 6 | Plant Additions | Line 1 | | $29,971,477 |
| 7 | Plant Additions | | | $0 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $0 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $29,971,477 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 |
| 15 | | | | |
| 16 | Remaining Tax Depreciation | | | |
| 17 | Plant Additions | Line 1 | | $29,971,477 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $0 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 |
| 20 | Remaining Plant Additions Subject to 10 YR MACRS Tax Depreciation | Line 17 - Line 18 - Line 19 | | $29,971,477 |
| 21 | 10 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 10.000% |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $2,997,148 |
| 23 | | | | |
| 24 | FY25 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $0 |
| 25 | Cost of Removal | | | $0 |
| 26 | | | | |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $2,997,148 |

| (b) | (c) | (d) | (e) |
|---|---|---|---|
| 10 Year MACRS Depreciation | | | |
| MACRS basis: | Line 20 | $29,971,477 | |
| | | Annual | Cumulative |
| Fiscal Year | | | |
| March 2025 | 10.000% | $2,997,148 | $2,997,148 |
| March 2026 | 18.000% | $5,394,866 | $8,392,014 |
| March 2027 | 14.400% | $4,315,893 | $12,707,907 |
| March 2028 | 11.520% | $3,452,714 | $16,160,621 |
| March 2029 | 9.220% | $2,763,370 | $18,923,991 |
| March 2030 | 7.370% | $2,208,898 | $21,132,889 |
| March 2031 | 6.550% | $1,963,132 | $23,096,021 |
| March 2032 | 6.550% | $1,963,132 | $25,059,152 |
| March 2033 | 6.560% | $1,966,129 | $27,025,281 |
| March 2034 | 6.550% | $1,963,132 | $28,988,413 |
| March 2035 | 3.280% | $983,064 | $29,971,478 |
| | 100.00% | $29,971,477 | |

1/ Per Tax Department
2/ Per Tax Department

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Software**

| Line No. | | | | Fiscal Year 2025 (a) |
|---|---|---|---|---|
| | Capital Repairs Deduction | | | |
| 1 | Plant Additions | Page 4, Line 4 | | $19,782,755 |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 0.00% |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $0 |
| 4 | | | | |
| 5 | Bonus Depreciation | | | |
| 6 | Plant Additions | Line 1 | | $19,782,755 |
| 7 | Plant Additions | | | $0 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $0 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $19,782,755 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 |
| 15 | | | | |
| 16 | Remaining Tax Depreciation | | | |
| 17 | Plant Additions | Line 1 | | $19,782,755 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $0 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 |
| 20 | Remaining Plant Additions Subject to 3 YR MACRS Tax Depreciation Straight Line | Line 17 - Line 18 - Line 19 | | $19,782,755 |
| 21 | 3 YR MACRS Tax Depreciation Rates Straight Line | Per IRS Publication 946 | | 16.667% |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $3,297,192 |
| 23 | | | | |
| 24 | FY25 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $0 |
| 25 | Cost of Removal | | | $0 |
| 26 | | | | |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $3,297,192 |

3 Year MACRS Depreciation Straight Line

| (b) | (c) | (d) | (e) |
|---|---|---|---|
| MACRS basis: | Line 20 | $19,782,755 | |
| | | Annual | Cumulative |
| Fiscal Year | | | |
| March 2025 | 16.667% | $3,297,192 | $3,297,192 |
| March 2026 | 33.333% | $6,594,186 | $9,891,378 |
| March 2027 | 33.333% | $6,594,186 | $16,485,563 |
| March 2028 | 16.667% | $3,297,192 | $19,782,755 |
| | 100.00% | $19,782,755 | |

1/ Per Tax Department
2/ Per Tax Department

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Network**

| Line No. | | | | Fiscal Year 2025 (a) |
|---|---|---|---|---|
| | Capital Repairs Deduction | | | |
| 1 | Plant Additions | Page 4, Line 4 | | $5,407,058 |
| 2 | Capital Repairs Deduction Rate | Per Tax Department | 1/ | 0.00% |
| 3 | Capital Repairs Deduction | Line 1 * Line 2 | | $0 |
| 4 | | | | |
| 5 | Bonus Depreciation | | | |
| 6 | Plant Additions | Line 1 | | $5,407,058 |
| 7 | Plant Additions | | | $0 |
| 8 | Less Capital Repairs Deduction | Line 3 | | $0 |
| 9 | Plant Additions Net of Capital Repairs Deduction | Line 6 + Line 7 - Line 8 | | $5,407,058 |
| 10 | Percent of Plant Eligible for Bonus Depreciation | Per Tax Department | | 0.00% |
| 11 | Plant Eligible for Bonus Depreciation | Line 9 * Line 10 | | $0 |
| 12 | Bonus Depreciation Rate | at 0% | | 0.00% |
| 13 | Total Bonus Depreciation Rate | Line 12 | | 0.00% |
| 14 | Bonus Depreciation | Line 11 * Line 13 | | $0 |
| 15 | | | | |
| 16 | Remaining Tax Depreciation | | | |
| 17 | Plant Additions | Line 1 | | $5,407,058 |
| 18 | Less Capital Repairs Deduction | Line 3 | | $0 |
| 19 | Less Bonus Depreciation | Line 14 | | $0 |
| 20 | Remaining Plant Additions Subject to 7 YR MACRS Tax Depreciation | Line 17 - Line 18 - Line 19 | | $5,407,058 |
| 21 | 7 YR MACRS Tax Depreciation Rates | Per IRS Publication 946 | | 14.290% |
| 22 | Remaining Tax Depreciation | Line 20 * Line 21 | | $772,669 |
| 23 | | | | |
| 24 | FY25 (Gain)/Loss incurred due to retirements | Per Tax Department | 2/ | $0 |
| 25 | Cost of Removal | | | $0 |
| 26 | | | | |
| 27 | Total Tax Depreciation and Repairs Deduction | Sum of Lines 3, 14, 22, 24, and 25 | | $772,669 |

| (b) | (c) | (d) | (e) |
|---|---|---|---|
| 7 Year MACRS Depreciation | | | |
| MACRS basis: | Line 20 | $5,407,058 | |
| | | Annual | Cumulative |
| Fiscal Year | | | |
| March 2025 | 14.290% | $772,669 | $772,669 |
| March 2026 | 24.490% | $1,324,189 | $2,096,858 |
| March 2027 | 17.490% | $945,695 | $3,042,552 |
| March 2028 | 12.490% | $675,342 | $3,717,894 |
| March 2029 | 8.930% | $482,850 | $4,200,744 |
| March 2030 | 8.920% | $482,310 | $4,683,054 |
| March 2031 | 8.930% | $482,850 | $5,165,904 |
| March 2032 | 4.460% | $241,155 | $5,407,059 |
| | 100.00% | $5,407,058 | |

1/ Per Tax Department
2/ Per Tax Department

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Calculation of Net Deferred Tax Reserve Proration on FY 2025 Incremental Capital Investment**

| Line No. | Deferred Tax Subject to Proration | | Meters FY 2025 (a) | Software FY 2025 (b) | Network FY 2025 (c) |
|---|---|---|---|---|---|
| 1 | Book Depreciation | Page 2, 3, 4; Line 9 | $672,560 | $1,413,053 | $386,218 |
| 2 | Bonus Depreciation | Page 5,6, 7; Line 14 | $0 | $0 | $0 |
| 3 | Remaining MACRS Tax Depreciation | Page 5,6, 7; Line 22 | ($2,997,148) | ($3,297,192) | ($772,669) |
| 4 | FY 2025 tax (gain)/loss on retirements | Page 5,6, 7; Line 24 | $0 | $0 | $0 |
| 5 | Cumulative Book / Tax Timer | Sum of Lines 1 through 4 | ($2,324,588) | ($1,884,139) | ($386,451) |
| 6 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% |
| 7 | Deferred Tax Reserve | Line 5 * Line 6 | ($488,163) | ($395,669) | ($81,155) |
| | **Deferred Tax Not Subject to Proration** | | | | |
| 8 | Capital Repairs Deduction | Page 5,6, 7; Line 3 | $0 | $0 | $0 |
| 9 | Cost of Removal | Page 5,6, 7; Line 25 | $0 | $0 | $0 |
| 10 | Book/Tax Depreciation Timing Difference at 3/31/2025 | | | | |
| 11 | Cumulative Book / Tax Timer | Line 8 + Line 9 + Line 10 | $0 | $0 | $0 |
| 12 | Effective Tax Rate | | 21.00% | 21.00% | 21.00% |
| 13 | Deferred Tax Reserve | Line 11 * Line 12 | $0 | $0 | $0 |
| 14 | Total Deferred Tax Reserve | Line 7 + Line 13 | ($488,163) | ($395,669) | ($81,155) |
| 15 | Net Operating Loss | | $0 | $0 | $0 |
| 16 | Net Deferred Tax Reserve | Line 14 + Line 15 | ($488,163) | ($395,669) | ($81,155) |
| | **Allocation of FY 2024 Estimated Federal NOL** | | | | |
| 17 | Cumulative Book/Tax Timer Subject to Proration | Col (b) = Line 5 | ($2,324,588) | ($1,884,139) | ($386,451) |
| 18 | Cumulative Book/Tax Timer Not Subject to Proration | Line 11 | $0 | $0 | $0 |
| 19 | Total Cumulative Book/Tax Timer | Line 17 + Line 18 | ($2,324,588) | ($1,884,139) | ($386,451) |
| 20 | Total FY 2025 Federal NOL (Utilization) | | $0 | $0 | $0 |
| 21 | Allocated FY 2025 Federal NOL Not Subject to Proration | (Line 18 / Line 19 ) * Line 20 | $0 | $0 | $0 |
| 22 | Allocated FY 2025 Federal NOL Subject to Proration | (Line 17 / Line 19 ) * Line 20 | $0 | $0 | $0 |
| 23 | Effective Tax Rate | | 21% | 21% | 21% |
| 24 | Deferred Tax Benefit subject to proration | Line 22 * Line 23 | $0 | $0 | $0 |
| 25 | Net Deferred Tax Reserve subject to proration | Line 7 + Line 24 | ($488,163) | ($395,669) | ($81,155) |

| Line No. | Proration Calculation | Number of Days in Month (d) | Proration Percentage (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|
| 26 | January | 31 | 91.53% | ($37,235) | ($30,180) | ($6,190) |
| 27 | February | 29 | 83.61% | ($34,011) | ($27,567) | ($5,654) |
| 28 | March | 31 | 75.14% | ($30,566) | ($24,774) | ($5,081) |
| 29 | April | 30 | 66.94% | ($27,231) | ($22,072) | ($4,527) |
| 30 | May | 31 | 58.47% | ($23,786) | ($19,279) | ($3,954) |
| 31 | June | 30 | 50.27% | ($20,451) | ($16,576) | ($3,400) |
| 32 | July | 31 | 41.80% | ($17,006) | ($13,784) | ($2,827) |
| 33 | August | 31 | 33.33% | ($13,560) | ($10,991) | ($2,254) |
| 34 | September | 30 | 25.14% | ($10,226) | ($8,288) | ($1,700) |
| 35 | October | 31 | 16.67% | ($6,780) | ($5,495) | ($1,127) |
| 36 | November | 30 | 8.47% | ($3,446) | ($2,793) | ($573) |
| 37 | December | 31 | 0.00% | $0 | $0 | $0 |
| 38 | Total | 366 | | ($224,297) | ($181,799) | ($37,288) |
| 39 | Deferred Tax Without Proration | Line 25 | | ($488,163) | ($395,669) | ($81,155) |
| 40 | Average Deferred Tax without Proration | Line 39 × 0.5 | | ($244,082) | ($197,835) | ($40,577) |
| 41 | Proration Adjustment | Line 38 - Line 40 | | $19,784 | $16,036 | $3,289 |

**Column Notes:**
(e) Sum of remaining days in the year (Col (d)) ÷ 365
(f), (g), (h) Current Year Line 25 ÷ 12 × Current Month Col (e)

**The Narragansett Electric Company**
**d/b/a Rhode Island Energy**
**Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF**
**Deferral Balances**

| Line No. | | Rate Year Ending August 31, 2019 | | | Rate Year Ending August 31, 2020 | | | Rate Year Ending August 31, 2021 | | | Rate Year Ending August 31, 2022 | | | Rate Year Ending August 31, 2023 | | | August 31, 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Actual Spend | Rate Allowance | Deferral | Actual Spend | Rate Allowance | Deferral | Actual Spend | Rate Allowance | Deferral | Actual Spend | Rate Allowance | Deferral | Actual Spend | Rate Allowance | Deferral | Actual Cumulative Deferral |
| | | (a) | (b) | (c)=(a)-(b) | (d) | (e) | (f)=(d)-(e) | (g) | (h) | (i)=(g)-(h) | (j) | (k) | (l)=(j)-(k) | (m) | (n) | (o)=(m)-(n) | (p) = (c)+(f)+(i)+(l)+=(o) |
| 1 | AMI Business Case Study | $2,000,000 | $666,667 | $1,333,333 | $0 | $666,667 | ($666,667) | $0 | $666,667 | ($666,667) | $0 | $666,667 | ($666,667) | $0 | $666,667 | ($666,667) | ($1,333,333) |
| 2 | GIS Enhancements (IS | $11,119 | $142,333 | ($131,214) | $20,451 | $142,333 | ($121,883) | $8,739 | $142,333 | ($133,595) | $115,356 | $142,333 | ($26,978) | $0 | $142,333 | ($142,333) | ($556,002) |
| 3 | Special Sector: Storage | $0 | $112,586 | ($112,586) | $5,464 | $259,668 | ($254,204) | $5,564 | $411,986 | ($406,422) | $0 | $411,986 | ($411,986) | $0 | $411,986 | ($411,986) | ($1,597,184) |
| 4 | Special Sector: Electric Transportation | $312,370 | $681,300 | ($368,930) | $1,106,790 | $1,151,751 | ($44,961) | $1,023,537 | $2,151,776 | ($1,128,239) | $1,419,934 | $2,151,776 | ($731,842) | $1,252,963 | $2,151,776 | ($898,813) | ($3,172,785) |
| | | | | $0 | | | $0 | | | $0 | | | $0 | | | $0 | |
| 5 | **Total** | **$2,323,489** | **$1,602,886** | **$720,603** | **$1,132,705** | **$2,220,419** | **($1,087,714)** | **$1,037,839** | **$3,372,762** | **($2,334,923)** | **$1,535,290** | **$3,372,762** | **($1,837,472)** | **$1,252,963** | **$3,372,762** | **($2,119,799)** | **($6,659,305)** |
| 6 | AMF Related Grid Mod in Base Rates | | $325,733 | ($325,733) | | $946,878 | ($946,878) | | $1,234,459 | ($1,234,459) | | $1,234,459 | ($1,234,459) | | $1,234,459 | ($1,234,459) | ($4,975,988) |

| Line No. | | Forecasted Rate Year Ending August 31, 2024 | | | Forecasted Rate Year Ending August 31, 2025 | | | Forecasted Rate Year Ending August 31, 2026 | | | Forecasted Cumulative Defereral August 31, 2026 | | | Deferral Balance Used for AMF Capital Revenue Requirement FY 2025 | Forecasted Remaining Deferral As of 8/31/26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Forecasted Spend | Rate Allowance | Deferral | Forecasted Spend | Rate Allowance | Deferral | Forecasted Spend | Rate Allowance | Deferral | Actual Spend | Rate Allowance | Deferral | | |
| | | (q) | (r) | (s)=(q)-(r) | (t) | (u) | (v)=(t)-(u) | (w) | (x) | (y)=(w)-(x) | (z) | (aa) | (ab)=(p)+(s)+(v)+(y) | (ac) | (ad) |
| 1 | AMI Business Case Study | $0 | $666,667 | ($666,667) | $0 | $666,667 | ($666,667) | $0 | $666,667 | ($666,667) | $0 | $666,667 | ($3,333,333) | $0 | ($3,333,333) |
| 2 | GIS Enhancements (IS | $0 | $142,333 | ($142,333) | $0 | $142,333 | ($142,333) | $0 | $142,333 | ($142,333) | $115,356 | $142,333 | ($983,002) | $0 | ($983,002) |
| 3 | Special Sector: Storage | $0 | $411,986 | ($411,986) | $0 | $411,986 | ($411,986) | $0 | $411,986 | ($411,986) | $0 | $411,986 | ($2,833,142) | $2,833,142 | $0 |
| 4 | Special Sector: Electric Transportation | $936,940 | $2,151,776 | ($1,214,836) | $776,940 | $2,151,776 | ($1,374,836) | $755,940 | $2,151,776 | ($1,395,836) | $1,419,934 | $2,151,776 | ($7,158,293) | $1,888,934 | ($5,269,359) |
| | | | | $0 | | | $0 | | | $0 | | | $0 | $0 | $0 |
| 5 | **Total** | **$936,940** | **$3,372,762** | **($2,435,822)** | **$776,940** | **$3,372,762** | **($2,595,822)** | **$755,940** | **$3,372,762** | **($2,616,822)** | **$1,535,290** | **$3,372,762** | **($14,307,771)** | **$4,722,076** | ($9,585,695) |
| 6 | AMF Related Grid Mod in Base Rates | $0 | $1,234,459 | ($1,234,459) | $0 | $1,234,459 | ($1,234,459) | $0 | $1,234,459 | ($1,234,459) | $0 | $1,234,459 | ($8,679,365) | $0 | ($8,679,365) |

Line Notes:
1b, 1e, 1h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 26
2b, 2e, 2h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 27
3b, 3e, 3h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 36
4b, 4e, 4h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 33
4p Docket No. 4770, Electric Transportation Rate Year 5 Annual Report, Table 4, Column E
Columns k, n, r, u, x - Rate Allowance from Rate Year August 2021 continued until next base distribution rate case

Columns a, d, g, j, m - actual revenue requirement on actual spend
Columns q, t, w - forecated revenue requirement on forecasted spend

# Section 6
# Rate Design

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors
(for the 12 months beginning April 1, 2024)

| | | Residential A-16 / A-60 (a) | Small C&I C-06 (b) | General C&I G-02 (c) | Large Demand B-32 (d) | Large Demand G-32 (e) | Lighting S-05 / S-06 S-10 / S-14 (f) | Propulsion X-01 (g) |
|---|---|---|---|---|---|---|---|---|
| (1) | O&M Factor per kWh | $0.00227 | $0.00223 | $0.00201 | $0.00101 | $0.00101 | $0.01765 | $0.00040 |
| (2) | O&M Factor per kW | n/a | n/a | n/a | $0.06 | n/a | n/a | n/a |
| (3) | CapEx kWh Charge | $0.00697 | $0.00585 | n/a | n/a | n/a | $0.01234 | $0.00065 |
| (4) | CapEx kW Charge | n/a | n/a | $1.90 | $1.88 | $1.88 | n/a | n/a |
| (5) | Back-Up Service CapEx kW Charge | n/a | n/a | n/a | $0.18 | n/a | n/a | n/a |

(1) Page 2, Line (6); Column (d) applicable to supplemental kWh deliveries only
(2) Page 4, Line (4), applicable to backup service only
(3) Page 3, Line (6)
(4) Page 3, Line (8); Column (d) applicable to supplemental service only
(5) Page 4, Line (6), applicable to backup service only

The Narragansett Electric Company
Plan Year 2024 Proposed Operations & Maintenance Factors
(for the 12 months beginning April 1, 2024)

| | | Total (a) | Residential A-16 / A60 (b) | Small C&I C-06 (c) | General C&I G-02 (d) | Large Demand B-32 / G-32 (e) | Lighting S-05 / S-06 S-10 / S-14 (f) | Propulsion X-01 (g) |
|---|---|---|---|---|---|---|---|---|
| (1) | Plan Year 2025 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense | $ 14,140,000 | | | | | | |
| (2) | Operating & Maintenance Expense - Rate Year Allowance ($000s) | $44,205 | $22,620 | $4,919 | $7,563 | $ 7,045 | $2,036 | $22 |
| (3) | Percentage of Total | 100.00% | 51.17% | 11.13% | 17.11% | 15.94% | 4.61% | 0.05% |
| (4) | Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense | $14,140,000 | $7,235,534 | $1,573,457 | $2,419,202 | $2,253,508 | $651,262 | $7,037 |
| (5) | Forecasted kWh - April 2024 through March 2025 | 7,355,461,607 | 3,187,341,542 | 703,673,646 | 1,199,342,991 | 2,210,918,152 | 36,896,441 | 17,288,835 |
| (6) | Proposed Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh | | $0.00227 | $0.00223 | $0.00201 | $0.00101 | $0.01765 | $0.00040 |

(1) per Section 5: Attachment 1, Page 1, Line (4), Column (b):
Total O&M Expense Component of Revenue Requirement: $ 14,140,000
(2) per R.I.P.U.C. 4770, Compliance Attachment 6 (August 16, 2018), (Schedule 1B), Page 3, Line 88
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places

The Narragansett Electric Company
Plan Year 2025 Proposed CapEx Factors
(for the 12 months beginning April 1, 2024)

| | | Total (a) | Residential A-16 / A60 (b) | Small C&I C-06 (c) | General C&I G-02 (d) | Large Demand B-32 / G-32 (e) | Lighting S-05 / S-06 S-10 / S-14 (f) | Propulsion X-01 (g) |
|---|---|---|---|---|---|---|---|---|
| (1) | Plan Year 2025 Capital Investment Component of Revenue Requirement Including Tax Hold Harmless Adjustment | $ 40,057,806 | | | | | | |
| (2) | Total Rate Base ($000s) | $729,511 | $404,995 | $75,009 | $117,155 | $123,849 | $8,296 | $208 |
| (3) | Percentage of Total | 100.00% | 55.52% | 10.28% | 16.06% | 16.98% | 1.14% | 0.03% |
| (4) | Allocated Revenue Requirement | $40,057,806 | $22,238,457 | $4,118,766 | $6,433,049 | $6,800,613 | $455,516 | $11,405 |
| (5) | Forecasted kWh - April 2024 through March 2025 | 7,355,461,607 | 3,187,341,542 | 703,673,646 | 1,199,342,991 | 2,210,918,152 | 36,896,441 | 17,288,835 |
| (6) | Proposed CapEx Factor - kWh charge | | $0.00697 | $0.00585 | n/a | n/a | $0.01234 | $0.00065 |
| (7) | Forecasted kW - April 2024 through March 2025 | | | | 3,380,743 | 3,610,684 | | |
| (8) | Proposed CapEx Factor - kW Charge | | n/a | n/a | $1.90 | $1.88 | n/a | n/a |

(1) per Section 5: Attachment 1, Page 1, Line (15), Column (b) plus Line (17), Column (b):

| | | |
|---|---|---|
| Total Capital Investment Component of Revenue Requirement | $ | 43,311,874 |
| Tax Hold Harmless Adjustment | $ | (3,254,068) |
| Total Capital Investment Component of Revenue Requirement Including Tax Hold Harmless Adjustment | $ | 40,057,806 |

(2) R.I.P.U.C. 4770, Compliance Attachment 6 (August 16, 2018), (Schedule 1A), Page 1, Line 9
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per Company forecasts
(6) For non demand-based rate classes, Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) For demand-based rate classes, Line (4) ÷ Line (7), truncated to 2 decimal places
Note: charges apply to kW>10 for rate class G-02 and kW>200 for rate class B-32/G-32

The Narragansett Electric Company
Calculation of Operations & Maintenance and CapEx Factors
and Base Distribution Charge for Back-up Service Rates

| | | Large Demand B-32 |
|---|---|---|
| | Operations & Maintenance Factors | |
| (1) | Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense | $2,253,508 |
| (2) | Forecasted kW - April 2024 through March 2025 | 3,610,684 |
| (3) | Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW | $0.62 |
| (4) | Proposed Discounted O&M kW Factor Charge | $0.06 |
| | CapEx Factors | |
| (5) | Proposed CapEx kW Factor Charge | $1.88 |
| (6) | Proposed Discounted CapEx kW Factor Charge | $0.18 |

(1) Page 2, Line (4), Column (e)
(2) per Company forecasts
(3) Line (1) ÷ Line (2), truncated to 2 decimal places
(4) Line (3) x 0.10, truncated to 2 decimal places
(5) Page 3, Line (8), Column (e)
(6) Line (5) x 0.10, truncated to 2 decimal places

# Section 7
# Bill Impacts

Proposed FY 2025 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

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

| Monthly kWh | Rates Effective October 1, 2023 | | | | Proposed Rates Effective April 1, 2024 | | | | $ Increase (Decrease) | | | | Increase (Decrease) % of Total Bill | | | | Percentage of Customers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | |
| (a) | (b) | (c) | (d) | (e) = (a) + (b) + (c) | (f) | (g) | (h) | (i) = (f) + (g) + (h) | (j) = (f) - (b) | (k) = (g) - (c) | (l) = (h) - (d) | (m) = (j) + (k) + (l) | (n) = (j) / (e) | (o) = (k) / (e) | (p) = (l) / (e) | (q) = (m) / (e) | (r) |
| 150 | $29.05 | $26.61 | $2.32 | $57.98 | $29.01 | $26.61 | $2.32 | $57.94 | ($0.04) | $0.00 | $0.00 | ($0.04) | -0.1% | 0.0% | 0.0% | -0.1% | 30.1% |
| 300 | $47.30 | $53.22 | $4.19 | $104.71 | $47.20 | $53.22 | $4.18 | $104.60 | ($0.10) | $0.00 | ($0.01) | ($0.11) | -0.1% | 0.0% | 0.0% | -0.1% | 12.9% |
| 400 | $59.46 | $70.96 | $5.43 | $135.85 | $59.33 | $70.96 | $5.43 | $135.72 | ($0.13) | $0.00 | $0.00 | ($0.13) | -0.1% | 0.0% | 0.0% | -0.1% | 11.6% |
| 500 | $71.62 | $88.71 | $6.68 | $167.01 | $71.47 | $88.71 | $6.67 | $166.85 | ($0.15) | $0.00 | ($0.01) | ($0.16) | -0.1% | 0.0% | 0.0% | -0.1% | 9.6% |
| 600 | $83.78 | $106.45 | $7.93 | $198.16 | $83.60 | $106.45 | $7.92 | $197.97 | ($0.18) | $0.00 | ($0.01) | ($0.19) | -0.1% | 0.0% | 0.0% | -0.1% | 7.7% |
| 700 | $95.94 | $124.19 | $9.17 | $229.30 | $95.73 | $124.19 | $9.16 | $229.08 | ($0.21) | $0.00 | ($0.01) | ($0.22) | -0.1% | 0.0% | 0.0% | -0.1% | 19.0% |
| 1,200 | $156.75 | $212.89 | $15.40 | $385.04 | $156.38 | $212.89 | $15.39 | $384.66 | ($0.37) | $0.00 | ($0.01) | ($0.38) | -0.1% | 0.0% | 0.0% | -0.1% | 6.8% |
| 2,000 | $254.05 | $354.82 | $25.37 | $634.24 | $253.43 | $354.82 | $25.34 | $633.59 | ($0.62) | $0.00 | ($0.03) | ($0.65) | -0.1% | 0.0% | 0.0% | -0.1% | 2.3% |

| | | | Rates Effective October 1, 2023 | Proposed Rates Effective April 1, 2024 | Line Item on Bill |
|---|---|---|---|---|---|
| | | | (s) | (t) | |
| (1) | Distribution Customer Charge | | $6.00 | $6.00 | Customer Charge |
| (2) | LIHEAP Enhancement Charge | | $0.79 | $0.79 | LIHEAP Enhancement Charge |
| (3) | Renewable Energy Growth Program Charge | | $4.02 | $4.02 | RE Growth Program |
| (4) | Distribution Charge (per kWh) | | $0.04580 | $0.04580 | |
| (5) | Operating & Maintenance Expense Charge | | $0.00245 | $0.00227 | |
| (6) | Operating & Maintenance Expense Reconciliation Factor | | $0.00016 | $0.00016 | |
| (7) | CapEx Factor Charge | | $0.00710 | $0.00697 | |
| (8) | CapEx Reconciliation Factor | | ($0.00151) | ($0.00151) | |
| (9) | Revenue Decoupling Adjustment Factor | | $0.00076 | $0.00076 | Distribution Energy Charge |
| (10) | Pension Adjustment Factor | | ($0.00394) | ($0.00394) | |
| (11) | Storm Fund Replenishment Factor | | $0.00788 | $0.00788 | |
| (12) | Arrearage Management Adjustment Factor | | $0.00005 | $0.00005 | |
| (13) | Performance Incentive Factor | | $0.00000 | $0.00000 | |
| (14) | Low Income Discount Recovery Factor | | $0.00262 | $0.00262 | |
| (15) | LRS Adjustment Factor | | $0.00388 | $0.00388 | |
| (16) | Long-term Contracting for Renewable Energy Charge | | $0.00660 | $0.00660 | Renewable Energy Distribution Charge |
| (17) | Net Metering Charge | | $0.00628 | $0.00628 | |
| (18) | Base Transmission Charge | | $0.03115 | $0.03115 | |
| (19) | Transmission Adjustment Factor | | $0.00183 | $0.00183 | Transmission Charge |
| (20) | Transmission Uncollectible Factor | | $0.00044 | $0.00044 | |
| (21) | Base Transition Charge | | $0.00000 | $0.00000 | Transition Charge |
| (22) | Transition Adjustment | | $0.00021 | $0.00021 | |
| (23) | Energy Efficiency Program Charge | | $0.00986 | $0.00986 | Energy Efficiency Programs |
| (24) | Last Resort Service Base Charge | | $0.16525 | $0.16525 | |
| (25) | LRS Adminstrative Cost Adjustment Factor | | $0.00383 | $0.00383 | Supply Services Energy Charge |
| (26) | Renewable Energy Standard Charge | | $0.00833 | $0.00833 | |
| | Line Item on Bill | | | | |
| (27) | Customer Charge | | $6.00 | $6.00 | |
| (28) | LIHEAP Enhancement Charge | | $0.79 | $0.79 | |
| (29) | RE Growth Program | | $4.02 | $4.02 | |
| (30) | Transmission Charge | kWh x | $0.03342 | $0.03342 | |
| (31) | Distribution Energy Charge | kWh x | $0.06525 | $0.06494 | |
| (32) | Transition Charge | kWh x | $0.00021 | $0.00021 | |
| (33) | Energy Efficiency Programs | kWh x | $0.00986 | $0.00986 | |
| (34) | Renewable Energy Distribution Charge | kWh x | $0.01288 | $0.01288 | |
| (35) | Supply Services Energy Charge | kWh x | $0.17741 | $0.17741 | |

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023
Column (t): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023

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

| Monthly kWh | Rates Effective October 1, 2023 | | | | | | Proposed Rates Effective April 1, 2024 | | | | | | $ Increase (Decrease) | | | | Increase (Decrease) % of Total Bill | | | | Percentage of Customers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Delivery Services | Supply Services | Low Income Discount | Discounted Total | GET | Total | Delivery Services | Supply Services | Low Income Discount | Discounted Total | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | |
| (a) | (b) | (c) | (d) = [(b)+(c)] x-.25 | (e) = (b) + (c) + (d) | (f) | (g) = (e) + (f) | (h) | (i) | (j) = [(h)+(i)] x-.25 | (k) = (h) + (i) + (j) | (l) | (m) = (k) + (l) | (n) = [(h)+(j)] - [(b)+(d)] | (o) = (i) - (c) | (p) = (l) - (f) | (q) = (n) + (o) + (p) | (r) = (n) / (g) | (s) = (o) / (g) | (t) = (p) / (g) | (u) = (q) / (g) | (v) |
| 150 | $28.66 | $26.61 | ($13.82) | $41.45 | $1.73 | $43.18 | $28.61 | $26.61 | ($13.81) | $41.41 | $1.73 | $43.14 | ($0.04) | $0.00 | $0.00 | ($0.04) | -0.1% | 0.0% | 0.0% | -0.1% | 32.1% |
| 300 | $46.51 | $53.22 | ($24.93) | $74.80 | $3.12 | $77.92 | $46.42 | $53.22 | ($24.91) | $74.73 | $3.11 | $77.84 | ($0.07) | $0.00 | ($0.01) | ($0.08) | -0.1% | 0.0% | 0.0% | -0.1% | 15.4% |
| 400 | $58.41 | $70.96 | ($32.34) | $97.03 | $4.04 | $101.07 | $58.29 | $70.96 | ($32.31) | $96.94 | $4.04 | $100.98 | ($0.09) | $0.00 | $0.00 | ($0.09) | -0.1% | 0.0% | 0.0% | -0.1% | 12.5% |
| 500 | $70.31 | $88.71 | ($39.76) | $119.26 | $4.97 | $124.23 | $70.16 | $88.71 | ($39.72) | $119.15 | $4.96 | $124.11 | ($0.11) | $0.00 | ($0.01) | ($0.12) | -0.1% | 0.0% | 0.0% | -0.1% | 9.6% |
| 600 | $82.21 | $106.45 | ($47.17) | $141.49 | $5.90 | $147.39 | $82.02 | $106.45 | ($47.12) | $141.35 | $5.89 | $147.24 | ($0.14) | $0.00 | ($0.01) | ($0.15) | -0.1% | 0.0% | 0.0% | -0.1% | 7.2% |
| 700 | $94.11 | $124.19 | ($54.58) | $163.72 | $6.82 | $170.54 | $93.89 | $124.19 | ($54.52) | $163.56 | $6.82 | $170.38 | ($0.16) | $0.00 | $0.00 | ($0.16) | -0.1% | 0.0% | 0.0% | -0.1% | 16.4% |
| 1,200 | $153.61 | $212.89 | ($91.63) | $274.87 | $11.45 | $286.32 | $153.24 | $212.89 | ($91.53) | $274.60 | $11.44 | $286.04 | ($0.27) | $0.00 | ($0.01) | ($0.28) | -0.1% | 0.0% | 0.0% | -0.1% | 5.2% |
| 2,000 | $248.81 | $354.82 | ($150.91) | $452.72 | $18.86 | $471.58 | $248.19 | $354.82 | ($150.75) | $452.26 | $18.84 | $471.10 | ($0.46) | $0.00 | ($0.02) | ($0.48) | -0.1% | 0.0% | 0.0% | -0.1% | 1.6% |

| | | Rates Effective October 1, 2023 | Proposed Rates Effective April 1, 2024 | Line Item on Bill |
|---|---|---|---|---|
| | | (w) | (x) | |
| (1) | Distribution Customer Charge | $6.00 | $6.00 | Customer Charge |
| (2) | LIHEAP Enhancement Charge | $0.79 | $0.79 | LIHEAP Enhancement Charge |
| (3) | Renewable Energy Growth Program Charge | $4.02 | $4.02 | RE Growth Program |
| (4) | Distribution Charge (per kWh) | $0.04580 | $0.04580 | Distribution Energy Charge |
| (5) | Operating & Maintenance Expense Charge | $0.00245 | $0.00227 | |
| (6) | Operating & Maintenance Expense Reconciliation Factor | $0.00016 | $0.00016 | |
| (7) | CapEx Factor Charge | $0.00710 | $0.00697 | |
| (8) | CapEx Reconciliation Factor | ($0.00151) | ($0.00151) | |
| (9) | Revenue Decoupling Adjustment Factor | $0.00076 | $0.00076 | |
| (10) | Pension Adjustment Factor | ($0.00394) | ($0.00394) | |
| (11) | Storm Fund Replenishment Factor | $0.00788 | $0.00788 | |
| (12) | Arrearage Management Adjustment Factor | $0.00005 | $0.00005 | |
| (13) | Performance Incentive Factor | $0.00000 | $0.00000 | |
| (14) | Low Income Discount Recovery Factor | $0.00000 | $0.00000 | |
| (15) | LRS Adjustment Factor | $0.00388 | $0.00388 | |
| (16) | Long-term Contracting for Renewable Energy Charge | $0.00660 | $0.00660 | Renewable Energy Distribution Charge |
| (17) | Net Metering Charge | $0.00628 | $0.00628 | |
| (18) | Base Transmission Charge | $0.03115 | $0.03115 | Transmission Charge |
| (19) | Transmission Adjustment Factor | $0.00183 | $0.00183 | |
| (20) | Transmission Uncollectible Factor | $0.00044 | $0.00044 | |
| (21) | Base Transition Charge | $0.00000 | $0.00000 | Transition Charge |
| (22) | Transition Adjustment | $0.00021 | $0.00021 | |
| (23) | Energy Efficiency Program Charge | $0.00986 | $0.00986 | Energy Efficiency Programs |
| (24) | Last Resort Service Base Charge | $0.16525 | $0.16525 | Supply Services Energy Charge |
| (25) | LRS Adminstrative Cost Adjustment Factor | $0.00383 | $0.00383 | |
| (26) | Renewable Energy Standard Charge | $0.00833 | $0.00833 | |
| | Line Item on Bill | | | |
| (27) | Customer Charge | $6.00 | $6.00 | |
| (28) | LIHEAP Enhancement Charge | $0.79 | $0.79 | |
| (29) | RE Growth Program | $4.02 | $4.02 | |
| (30) | Transmission Charge | $0.03342 | $0.03342 | |
| (31) | Distribution Energy Charge | $0.06263 | $0.06232 | |
| (32) | Transition Charge | $0.00021 | $0.00021 | |
| (33) | Energy Efficiency Programs | $0.00986 | $0.00986 | |
| (34) | Renewable Energy Distribution Charge | $0.01288 | $0.01288 | |
| (35) | Supply Services Energy Charge | $0.17741 | $0.17741 | |
| (36) | Discount percentage | 25% | 25% | |

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023

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

| Monthly kWh | Rates Effective October 1, 2023 | | | | | | Proposed Rates Effective April 1, 2024 | | | | | | $ Increase (Decrease) | | | | Increase (Decrease) % of Total Bill | | | | Percentage of Customers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Delivery Services | Supply Services | Low Income Discount | Discounted Total | GET | Total | Delivery Services | Supply Services | Low Income Discount | Discounted Total | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | |
| (a) | (b) | (c) | (d) = [(b)+(c)] x-.30 | (e) = (b) + (c) + (d) | (f) | (g) = (e) + (f) | (h) | (i) | (j) = [(h)+(i)] x-.30 | (k) = (h) + (i) + (j) | (l) | (m) = (k) + (l) | (n) = [(h)+(j)] - [(b)+(d)] | (o) = (i) - (c) | (p) = (l) - (f) | (q) = (n) + (o) + (p) | (r) = (n) / (g) | (s) = (o) / (g) | (t) = (p) / (g) | (u) = (q) / (g) | (v) |
| 150 | $28.66 | $26.61 | ($16.58) | $38.69 | $1.61 | $40.30 | $28.61 | $26.61 | ($16.57) | $38.65 | $1.61 | $40.26 | ($0.04) | $0.00 | $0.00 | ($0.04) | -0.1% | 0.0% | 0.0% | -0.1% | 32.1% |
| 300 | $46.51 | $53.22 | ($29.92) | $69.81 | $2.91 | $72.72 | $46.42 | $53.22 | ($29.89) | $69.75 | $2.91 | $72.66 | ($0.06) | $0.00 | $0.00 | ($0.06) | -0.1% | 0.0% | 0.0% | -0.1% | 15.4% |
| 400 | $58.41 | $70.96 | ($38.81) | $90.56 | $3.77 | $94.33 | $58.29 | $70.96 | ($38.78) | $90.47 | $3.77 | $94.24 | ($0.09) | $0.00 | $0.00 | ($0.09) | -0.1% | 0.0% | 0.0% | -0.1% | 12.5% |
| 500 | $70.31 | $88.71 | ($47.71) | $111.31 | $4.64 | $115.95 | $70.16 | $88.71 | ($47.66) | $111.21 | $4.63 | $115.84 | ($0.10) | $0.00 | ($0.01) | ($0.11) | -0.1% | 0.0% | 0.0% | -0.1% | 9.6% |
| 600 | $82.21 | $106.45 | ($56.60) | $132.06 | $5.50 | $137.56 | $82.02 | $106.45 | ($56.54) | $131.93 | $5.50 | $137.43 | ($0.13) | $0.00 | $0.00 | ($0.13) | -0.1% | 0.0% | 0.0% | -0.1% | 7.2% |
| 700 | $94.11 | $124.19 | ($65.49) | $152.81 | $6.37 | $159.18 | $93.89 | $124.19 | ($65.42) | $152.66 | $6.36 | $159.02 | ($0.15) | $0.00 | ($0.01) | ($0.16) | -0.1% | 0.0% | 0.0% | -0.1% | 16.4% |
| 1,200 | $153.61 | $212.89 | ($109.95) | $256.55 | $10.69 | $267.24 | $153.24 | $212.89 | ($109.84) | $256.29 | $10.68 | $266.97 | ($0.26) | $0.00 | ($0.01) | ($0.27) | -0.1% | 0.0% | 0.0% | -0.1% | 5.2% |
| 2,000 | $248.81 | $354.82 | ($181.09) | $422.54 | $17.61 | $440.15 | $248.19 | $354.82 | ($180.90) | $422.11 | $17.59 | $439.70 | ($0.43) | $0.00 | ($0.02) | ($0.45) | -0.1% | 0.0% | 0.0% | -0.1% | 1.6% |

| | Rates Effective October 1, 2023 | Proposed Rates Effective April 1, 2024 | Line Item on Bill |
|---|---|---|---|
| | (w) | (x) | |
| (1) Distribution Customer Charge | $6.00 | $6.00 | Customer Charge |
| (2) LIHEAP Enhancement Charge | $0.79 | $0.79 | LIHEAP Enhancement Charge |
| (3) Renewable Energy Growth Program Charge | $4.02 | $4.02 | RE Growth Program |
| (4) Distribution Charge (per kWh) | $0.04580 | $0.04580 | |
| (5) Operating & Maintenance Expense Charge | $0.00245 | $\boxed{\$0.00227}$ | |
| (6) Operating & Maintenance Expense Reconciliation Factor | $0.00016 | $0.00016 | |
| (7) CapEx Factor Charge | $0.00710 | $\boxed{\$0.00697}$ | |
| (8) CapEx Reconciliation Factor | ($0.00151) | ($0.00151) | |
| (9) Revenue Decoupling Adjustment Factor | $0.00076 | $0.00076 | Distribution Energy Charge |
| (10) Pension Adjustment Factor | ($0.00394) | ($0.00394) | |
| (11) Storm Fund Replenishment Factor | $0.00788 | $0.00788 | |
| (12) Arrearage Management Adjustment Factor | $0.00005 | $0.00005 | |
| (13) Performance Incentive Factor | $0.00000 | $0.00000 | |
| (14) Low Income Discount Recovery Factor | $0.00000 | $0.00000 | |
| (15) LRS Adjustment Factor | $0.00388 | $0.00388 | |
| (16) Long-term Contracting for Renewable Energy Charge | $0.00660 | $0.00660 | Renewable Energy Distribution Charge |
| (17) Net Metering Charge | $0.00628 | $0.00628 | |
| (18) Base Transmission Charge | $0.03115 | $0.03115 | |
| (19) Transmission Adjustment Factor | $0.00183 | $0.00183 | Transmission Charge |
| (20) Transmission Uncollectible Factor | $0.00044 | $0.00044 | |
| (21) Base Transition Charge | $0.00000 | $0.00000 | Transition Charge |
| (22) Transition Adjustment | $0.00021 | $0.00021 | |
| (23) Energy Efficiency Program Charge | $0.00986 | $0.00986 | Energy Efficiency Programs |
| (24) Last Resort Service Base Charge | $0.16525 | $0.16525 | |
| (25) LRS Adminstrative Cost Adjustment Factor | $0.00383 | $0.00383 | Supply Services Energy Charge |
| (26) Renewable Energy Standard Charge | $0.00833 | $0.00833 | |
| Line Item on Bill | | | |
| (27) Customer Charge | $6.00 | $6.00 | |
| (28) LIHEAP Enhancement Charge | $0.79 | $0.79 | |
| (29) RE Growth Program | $4.02 | $4.02 | |
| (30) Transmission Charge | $0.03342 | $0.03342 | |
| (31) Distribution Energy Charge | $0.06263 | $\boxed{\$0.06232}$ | |
| (32) Transition Charge | $0.00021 | $0.00021 | |
| (33) Energy Efficiency Programs | $0.00986 | $0.00986 | |
| (34) Renewable Energy Distribution Charge | $0.01288 | $0.01288 | |
| (35) Supply Services Energy Charge | $0.17741 | $0.17741 | |
| (36) Discount percentage | 30% | 30% | |

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023

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

| | Rates Effective October 1, 2023 | | | | Proposed Rates Effective April 1, 2024 | | | | $ Increase (Decrease) | | | | Increase (Decrease) % of Total Bill | | | | Percentage |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly kWh | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | of Customers |
| (a) | (b) | (c) | (d) | (e) = (a) + (b) + (c) | (f) | (g) | (h) | (i) = (f) + (g) + (h) | (j) = (f) - (b) | (k) = (g) - (c) | (l) = (h) - (d) | (m) = (j) + (k) + (l) | (n) = (j) / (e) | (o) = (k) / (e) | (p) = (l) / (e) | (q) = (m) / (e) | (r) |
| 250 | $45.30 | $42.81 | $3.67 | $91.78 | $45.25 | $42.81 | $3.67 | $91.73 | ($0.05) | $0.00 | $0.00 | ($0.05) | -0.1% | 0.0% | 0.0% | -0.1% | 56.3% |
| 500 | $73.63 | $85.62 | $6.64 | $165.89 | $73.53 | $85.62 | $6.63 | $165.78 | ($0.10) | $0.00 | ($0.01) | ($0.11) | -0.1% | 0.0% | 0.0% | -0.1% | 16.9% |
| 1,000 | $130.27 | $171.23 | $12.56 | $314.06 | $130.07 | $171.23 | $12.55 | $313.85 | ($0.20) | $0.00 | ($0.01) | ($0.21) | -0.1% | 0.0% | 0.0% | -0.1% | 8.1% |
| 1,500 | $186.92 | $256.85 | $18.49 | $462.26 | $186.62 | $256.85 | $18.48 | $461.95 | ($0.30) | $0.00 | ($0.01) | ($0.31) | -0.1% | 0.0% | 0.0% | -0.1% | 5.0% |
| 2,000 | $243.56 | $342.46 | $24.42 | $610.44 | $243.16 | $342.46 | $24.40 | $610.02 | ($0.40) | $0.00 | ($0.02) | ($0.42) | -0.1% | 0.0% | 0.0% | -0.1% | 13.6% |

| | | Rates Effective October 1, 2023 | Proposed Rates Effective April 1, 2024 | Line Item on Bill |
|---|---|---|---|---|
| | | (s) | (t) | |
| (1) | Distribution Customer Charge | $10.00 | $10.00 | Customer Charge |
| (2) | LIHEAP Enhancement Charge | $0.79 | $0.79 | LIHEAP Enhancement Charge |
| (3) | Renewable Energy Growth Program Charge | $6.19 | $6.19 | RE Growth Program |
| (4) | Distribution Charge (per kWh) | $0.04482 | $0.04482 | Distribution Energy Charge |
| (5) | Operating & Maintenance Expense Charge | $0.00239 | $\boxed{\$0.00223}$ | |
| (6) | Operating & Maintenance Expense Reconciliation Factor | $0.00016 | $0.00016 | |
| (7) | CapEx Factor Charge | $0.00589 | $\boxed{\$0.00585}$ | |
| (8) | CapEx Reconciliation Factor | ($0.00064) | ($0.00064) | |
| (9) | Revenue Decoupling Adjustment Factor | $0.00076 | $0.00076 | |
| (10) | Pension Adjustment Factor | ($0.00394) | ($0.00394) | |
| (11) | Storm Fund Replenishment Factor | $0.00788 | $0.00788 | |
| (12) | Arrearage Management Adjustment Factor | $0.00005 | $0.00005 | |
| (13) | Performance Incentive Factor | $0.00000 | $0.00000 | |
| (14) | Low Income Discount Recovery Factor | $0.00262 | $0.00262 | |
| (15) | LRS Adjustment Factor | $0.00265 | $0.00265 | |
| (16) | Long-term Contracting for Renewable Energy Charge | $0.00660 | $0.00660 | Renewable Energy Distribution Charge |
| (17) | Net Metering Charge | $0.00628 | $0.00628 | |
| (18) | Base Transmission Charge | $0.03129 | $0.03129 | Transmission Charge |
| (19) | Transmission Adjustment Factor | ($0.00388) | ($0.00388) | |
| (20) | Transmission Uncollectible Factor | $0.00029 | $0.00029 | |
| (21) | Base Transition Charge | $0.00000 | $0.00000 | Transition Charge |
| (22) | Transition Adjustment | $0.00021 | $0.00021 | |
| (23) | Energy Efficiency Program Charge | $0.00986 | $0.00986 | Energy Efficiency Programs |
| (24) | Last Resort Service Base Charge | $0.15915 | $0.15915 | Supply Services Energy Charge |
| (25) | LRS Adminstrative Cost Adjustment Factor | $0.00375 | $0.00375 | |
| (26) | Renewable Energy Standard Charge | $0.00833 | $0.00833 | |
| | Line Item on Bill | | | |
| (27) | Customer Charge | $10.00 | $10.00 | |
| (28) | LIHEAP Enhancement Charge | $0.79 | $0.79 | |
| (29) | RE Growth Program | $6.19 | $6.19 | |
| (30) | Transmission Charge | $0.02770 | $0.02770 | |
| (31) | Distribution Energy Charge | $0.06264 | $\boxed{\$0.06244}$ | |
| (32) | Transition Charge | $0.00021 | $0.00021 | |
| (33) | Energy Efficiency Programs | $0.00986 | $0.00986 | |
| (34) | Renewable Energy Distribution Charge | $0.01288 | $0.01288 | |
| (35) | Supply Services Energy Charge | $0.17123 | $0.17123 | |

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023
Column (t): Line (5) per Section 6, Page 1, Line (1), Column (b). Line (7) per Section 6, Page 1, Line (3), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023

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

| | | | Rates Effective October 1, 2023 | | | | Proposed Rates Effective April 1, 2024 | | | | $ Increase (Decrease) | | | | Increase (Decrease) % of Total Bill | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| kW | Monthly Power Hours Use | kWh | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total | Delivery Services | Supply Services | GET | Total |
| | (a) | | (b) | (c) | (d) | (e) = (a) + (b) + (c) | (f) | (g) | (h) | (i) = (f) + (g) + (h) | (j) = (f) - (b) | (k) = (g) - (c) | (l) = (h) - (d) | (m) = (j) + (k) + (l) | (n) = (j) / (e) | (o) = (k) / (e) | (p) = (l) / (e) | (q) = (m) / (e) |
| 20 | 200 | 4,000 | $566.94 | $684.92 | $52.16 | $1,304.02 | $568.58 | $684.92 | $52.23 | $1,305.73 | $1.64 | $0.00 | $0.07 | $1.71 | 0.1% | 0.0% | 0.0% | 0.1% |
| 50 | 200 | 10,000 | $1,232.04 | $1,712.30 | $122.68 | $3,067.02 | $1,239.44 | $1,712.30 | $122.99 | $3,074.73 | $7.40 | $0.00 | $0.31 | $7.71 | 0.2% | 0.0% | 0.0% | 0.3% |
| 100 | 200 | 20,000 | $2,340.54 | $3,424.60 | $240.21 | $6,005.35 | $2,357.54 | $3,424.60 | $240.92 | $6,023.06 | $17.00 | $0.00 | $0.71 | $17.71 | 0.3% | 0.0% | 0.0% | 0.3% |
| 150 | 200 | 30,000 | $3,449.04 | $5,136.90 | $357.75 | $8,943.69 | $3,475.64 | $5,136.90 | $358.86 | $8,971.40 | $26.60 | $0.00 | $1.11 | $27.71 | 0.3% | 0.0% | 0.0% | 0.3% |
| 20 | 300 | 6,000 | $653.14 | $1,027.38 | $70.02 | $1,750.54 | $654.50 | $1,027.38 | $70.08 | $1,751.96 | $1.36 | $0.00 | $0.06 | $1.42 | 0.1% | 0.0% | 0.0% | 0.1% |
| 50 | 300 | 15,000 | $1,447.54 | $2,568.45 | $167.33 | $4,183.32 | $1,454.24 | $2,568.45 | $167.61 | $4,190.30 | $6.70 | $0.00 | $0.28 | $6.98 | 0.2% | 0.0% | 0.0% | 0.2% |
| 100 | 300 | 30,000 | $2,771.54 | $5,136.90 | $329.52 | $8,237.96 | $2,787.14 | $5,136.90 | $330.17 | $8,254.21 | $15.60 | $0.00 | $0.65 | $16.25 | 0.2% | 0.0% | 0.0% | 0.2% |
| 150 | 300 | 45,000 | $4,095.54 | $7,705.35 | $491.70 | $12,292.59 | $4,120.04 | $7,705.35 | $492.72 | $12,318.11 | $24.50 | $0.00 | $1.02 | $25.52 | 0.2% | 0.0% | 0.0% | 0.2% |
| 20 | 400 | 8,000 | $739.34 | $1,369.84 | $87.88 | $2,197.06 | $740.42 | $1,369.84 | $87.93 | $2,198.19 | $1.08 | $0.00 | $0.05 | $1.13 | 0.0% | 0.0% | 0.0% | 0.1% |
| 50 | 400 | 20,000 | $1,663.04 | $3,424.60 | $211.99 | $5,299.63 | $1,669.04 | $3,424.60 | $212.24 | $5,305.88 | $6.00 | $0.00 | $0.25 | $6.25 | 0.1% | 0.0% | 0.0% | 0.1% |
| 100 | 400 | 40,000 | $3,202.54 | $6,849.20 | $418.82 | $10,470.56 | $3,216.74 | $6,849.20 | $419.41 | $10,485.35 | $14.20 | $0.00 | $0.59 | $14.79 | 0.1% | 0.0% | 0.0% | 0.1% |
| 150 | 400 | 60,000 | $4,742.04 | $10,273.80 | $625.66 | $15,641.50 | $4,764.44 | $10,273.80 | $626.59 | $15,664.83 | $22.40 | $0.00 | $0.93 | $23.33 | 0.1% | 0.0% | 0.0% | 0.1% |
| 20 | 500 | 10,000 | $825.54 | $1,712.30 | $105.74 | $2,643.58 | $826.34 | $1,712.30 | $105.78 | $2,644.42 | $0.80 | $0.00 | $0.04 | $0.84 | 0.0% | 0.0% | 0.0% | 0.0% |
| 50 | 500 | 25,000 | $1,878.54 | $4,280.75 | $256.64 | $6,415.93 | $1,883.84 | $4,280.75 | $256.86 | $6,421.45 | $5.30 | $0.00 | $0.22 | $5.52 | 0.1% | 0.0% | 0.0% | 0.1% |
| 100 | 500 | 50,000 | $3,633.54 | $8,561.50 | $508.13 | $12,703.17 | $3,646.34 | $8,561.50 | $508.66 | $12,716.50 | $12.80 | $0.00 | $0.53 | $13.33 | 0.1% | 0.0% | 0.0% | 0.1% |
| 150 | 500 | 75,000 | $5,388.54 | $12,842.25 | $759.62 | $18,990.41 | $5,408.84 | $12,842.25 | $760.46 | $19,011.55 | $20.30 | $0.00 | $0.84 | $21.14 | 0.1% | 0.0% | 0.0% | 0.1% |
| 20 | 600 | 12,000 | $911.74 | $2,054.76 | $123.60 | $3,090.10 | $912.26 | $2,054.76 | $123.63 | $3,090.65 | $0.52 | $0.00 | $0.03 | $0.55 | 0.0% | 0.0% | 0.0% | 0.0% |
| 50 | 600 | 30,000 | $2,094.04 | $5,136.90 | $301.29 | $7,532.23 | $2,098.64 | $5,136.90 | $301.48 | $7,537.02 | $4.60 | $0.00 | $0.19 | $4.79 | 0.1% | 0.0% | 0.0% | 0.1% |
| 100 | 600 | 60,000 | $4,064.54 | $10,273.80 | $597.43 | $14,935.77 | $4,075.94 | $10,273.80 | $597.91 | $14,947.65 | $11.40 | $0.00 | $0.48 | $11.88 | 0.1% | 0.0% | 0.0% | 0.1% |
| 150 | 600 | 90,000 | $6,035.04 | $15,410.70 | $893.57 | $22,339.31 | $6,053.24 | $15,410.70 | $894.33 | $22,358.27 | $18.20 | $0.00 | $0.76 | $18.96 | 0.1% | 0.0% | 0.0% | 0.1% |

| | | Rates Effective October 1, 2023 | Proposed Rates Effective April 1, 2024 | Line Item on Bill |
|---|---|---|---|---|
| | | (r) | (s) | |
| (1) | Distribution Customer Charge | $145.00 | $145.00 | Customer Charge |
| (2) | LIHEAP Enhancement Charge | $0.79 | $0.79 | LIHEAP Enhancement Charge |
| (3) | Renewable Energy Growth Program Charge | $63.55 | $63.55 | RE Growth Program |
| (4) | Base Distribution Demand Charge (per kW > 10kW) | $6.90 | $6.90 | Distribution Demand Charge |
| (5) | CapEx Factor Demand Charge (per kW > 10kW) | $1.68 | $\boxed{\$1.90}$ | |
| (6) | Distribution Charge (per kWh) | $0.00476 | $0.00476 | Distribution Energy Charge |
| (7) | Operating & Maintenance Expense Charge | $0.00215 | $\boxed{\$0.00201}$ | |
| (8) | Operating & Maintenance Expense Reconciliation Factor | $0.00016 | $0.00016 | |
| (9) | CapEx Reconciliation Factor | ($0.00140) | ($0.00140) | |
| (10) | Revenue Decoupling Adjustment Factor | $0.00076 | $0.00076 | |
| (11) | Pension Adjustment Factor | ($0.00394) | ($0.00394) | |
| (12) | Storm Fund Replenishment Factor | $0.00788 | $0.00788 | |
| (13) | Arrearage Management Adjustment Factor | $0.00005 | $0.00005 | |
| (14) | Performance Incentive Factor | $0.00000 | $0.00000 | |
| (15) | Low Income Discount Recovery Factor | $0.00262 | $0.00262 | |
| (16) | LRS Adjustment Factor | $0.00265 | $0.00265 | |
| (17) | Long-term Contracting for Renewable Energy Charge | $0.00660 | $0.00660 | Renewable Energy Distribution Charge |
| (18) | Net Metering Charge | $0.00628 | $0.00628 | |
| (19) | Transmission Demand Charge | $4.97 | $4.97 | Transmission Demand Charge |
| (20) | Base Transmission Charge | $0.01011 | $0.01011 | Transmission Adjustment |
| (21) | Transmission Adjustment Factor | ($0.00594) | ($0.00594) | |
| (22) | Transmission Uncollectible Factor | $0.00029 | $0.00029 | |
| (23) | Base Transition Charge | $0.00000 | $0.00000 | Transition Charge |
| (24) | Transition Adjustment | $0.00021 | $0.00021 | |
| (25) | Energy Efficiency Program Charge | $0.00986 | $0.00986 | Energy Efficiency Programs |
| (26) | Last Resort Service Base Charge | $0.15915 | $0.15915 | Supply Services Energy Charge |
| (27) | LRS Adminstrative Cost Adjustment Factor | $0.00375 | $0.00375 | |
| (28) | Renewable Energy Standard Charge | $0.00833 | $0.00833 | |
| | Line Item on Bill | | | |
| (29) | Customer Charge | $145.00 | $145.00 | |
| (31) | LIHEAP Enhancement Charge | $0.79 | $0.79 | |
| (30) | RE Growth Program | $63.55 | $63.55 | |
| (32) | Transmission Adjustment | $0.00446 | $0.00446 | |
| (33) | Distribution Energy Charge | $0.01569 | $\boxed{\$0.01555}$ | |
| (34) | Distribution Demand Charge | $8.58 | $\boxed{\$8.80}$ | |
| (35) | Transmission Demand Charge | $4.97 | $4.97 | |
| (34) | Transition Charge | $0.00021 | $0.00021 | |
| (35) | Energy Efficiency Programs | $0.00986 | $0.00986 | |
| (36) | Renewable Energy Distribution Charge | $0.01288 | $0.01288 | |
| (37) | Supply Services Energy Charge | $0.17123 | $0.17123 | |

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023
Column (s): Line (5) per Section 6, Page 1, Line (4), Column (c). Line (7) per Section 6, Page 1, Line (1), Column (c). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023

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

| | | | Rates Effective October 1, 2023 | | | | Proposed Rates Effective April 1, 2024 | | | | $ Increase (Decrease) | | | | Increase (Decrease) % of Total Bill | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| kW | Monthly Power Hours Use (a) | kWh | Delivery Services (b) | Supply Services (c) | GET (d) | Total (e) = (a) + (b) + (c) | Delivery Services (f) | Supply Services (g) | GET (h) | Total (i) = (f) + (g) + (h) | Delivery Services (j) = (f) - (b) | Supply Services (k) = (g) - (c) | GET (l) = (h) - (d) | Total (m) = (j) + (k) + (l) | Delivery Services (n) = (j) / (e) | Supply Services (o) = (k) / (e) | GET (p) = (l) / (e) | Total (q) = (m) / (e) |
| 200 | 200 | 40,000 | $4,473.66 | $4,943.47 | $392.38 | $9,809.51 | $4,470.86 | $4,943.47 | $392.26 | $9,806.59 | ($2.80) | $0.00 | ($0.12) | ($2.92) | 0.0% | 0.0% | 0.0% | 0.0% |
| 750 | 200 | 150,000 | $16,260.16 | $18,538.00 | $1,449.92 | $36,248.08 | $16,249.66 | $18,538.00 | $1,449.49 | $36,237.15 | ($10.50) | $0.00 | ($0.43) | ($10.93) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,000 | 200 | 200,000 | $21,617.66 | $24,717.33 | $1,930.62 | $48,265.61 | $21,603.66 | $24,717.33 | $1,930.04 | $48,251.03 | ($14.00) | $0.00 | ($0.58) | ($14.58) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,500 | 200 | 300,000 | $32,332.66 | $37,076.00 | $2,892.03 | $72,300.69 | $32,311.66 | $37,076.00 | $2,891.15 | $72,278.81 | ($21.00) | $0.00 | ($0.88) | ($21.88) | 0.0% | 0.0% | 0.0% | 0.0% |
| 2,500 | 200 | 500,000 | $53,762.66 | $61,793.33 | $4,814.83 | $120,370.82 | $53,727.66 | $61,793.33 | $4,813.37 | $120,334.36 | ($35.00) | $0.00 | ($1.46) | ($36.46) | 0.0% | 0.0% | 0.0% | 0.0% |
| 5,000 | 200 | 1,000,000 | $107,337.66 | $123,586.67 | $9,621.85 | $240,546.18 | $107,267.66 | $123,586.67 | $9,618.93 | $240,473.26 | ($70.00) | $0.00 | ($2.92) | ($72.92) | 0.0% | 0.0% | 0.0% | 0.0% |
| 7,500 | 200 | 1,500,000 | $160,912.66 | $185,380.00 | $14,428.86 | $360,721.52 | $160,807.66 | $185,380.00 | $14,424.49 | $360,612.15 | ($105.00) | $0.00 | ($4.37) | ($109.37) | 0.0% | 0.0% | 0.0% | 0.0% |
| 10,000 | 200 | 2,000,000 | $214,487.66 | $247,173.33 | $19,235.88 | $480,896.87 | $214,347.66 | $247,173.33 | $19,230.04 | $480,751.03 | ($140.00) | $0.00 | ($5.84) | ($145.84) | 0.0% | 0.0% | 0.0% | 0.0% |
| 20,000 | 200 | 4,000,000 | $428,787.66 | $494,346.67 | $38,463.93 | $961,598.26 | $428,507.66 | $494,346.67 | $38,452.27 | $961,306.60 | ($280.00) | $0.00 | ($11.66) | ($291.66) | 0.0% | 0.0% | 0.0% | 0.0% |
| 200 | 300 | 60,000 | $5,391.66 | $7,415.20 | $533.62 | $13,340.48 | $5,387.46 | $7,415.20 | $533.44 | $13,336.10 | ($4.20) | $0.00 | ($0.18) | ($4.38) | 0.0% | 0.0% | 0.0% | 0.0% |
| 750 | 300 | 225,000 | $19,702.66 | $27,807.00 | $1,979.57 | $49,489.23 | $19,686.91 | $27,807.00 | $1,978.91 | $49,472.82 | ($15.75) | $0.00 | ($0.66) | ($16.41) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,000 | 300 | 300,000 | $26,207.66 | $37,076.00 | $2,636.82 | $65,920.48 | $26,186.66 | $37,076.00 | $2,635.94 | $65,898.60 | ($21.00) | $0.00 | ($0.88) | ($21.88) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,500 | 300 | 450,000 | $39,217.66 | $55,614.00 | $3,951.32 | $98,782.98 | $39,186.16 | $55,614.00 | $3,950.01 | $98,750.17 | ($31.50) | $0.00 | ($1.31) | ($32.81) | 0.0% | 0.0% | 0.0% | 0.0% |
| 2,500 | 300 | 750,000 | $65,237.66 | $92,690.00 | $6,580.32 | $164,507.98 | $65,185.16 | $92,690.00 | $6,578.13 | $164,453.29 | ($52.50) | $0.00 | ($2.19) | ($54.69) | 0.0% | 0.0% | 0.0% | 0.0% |
| 5,000 | 300 | 1,500,000 | $130,287.66 | $185,380.00 | $13,152.82 | $328,820.48 | $130,182.66 | $185,380.00 | $13,148.45 | $328,711.11 | ($105.00) | $0.00 | ($4.37) | ($109.37) | 0.0% | 0.0% | 0.0% | 0.0% |
| 7,500 | 300 | 2,250,000 | $195,337.66 | $278,070.00 | $19,725.32 | $493,132.98 | $195,180.16 | $278,070.00 | $19,718.76 | $492,968.92 | ($157.50) | $0.00 | ($6.56) | ($164.06) | 0.0% | 0.0% | 0.0% | 0.0% |
| 10,000 | 300 | 3,000,000 | $260,387.66 | $370,760.00 | $26,297.82 | $657,445.48 | $260,177.66 | $370,760.00 | $26,289.07 | $657,226.73 | ($210.00) | $0.00 | ($8.75) | ($218.75) | 0.0% | 0.0% | 0.0% | 0.0% |
| 20,000 | 300 | 6,000,000 | $520,587.66 | $741,520.00 | $52,587.82 | $1,314,695.48 | $520,167.66 | $741,520.00 | $52,570.32 | $1,314,257.98 | ($420.00) | $0.00 | ($17.50) | ($437.50) | 0.0% | 0.0% | 0.0% | 0.0% |
| 200 | 400 | 80,000 | $6,309.66 | $9,886.93 | $674.86 | $16,871.45 | $6,304.06 | $9,886.93 | $674.62 | $16,865.61 | ($5.60) | $0.00 | ($0.24) | ($5.84) | 0.0% | 0.0% | 0.0% | 0.0% |
| 750 | 400 | 300,000 | $23,145.16 | $37,076.00 | $2,509.22 | $62,730.38 | $23,124.16 | $37,076.00 | $2,508.34 | $62,708.50 | ($21.00) | $0.00 | ($0.88) | ($21.88) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,000 | 400 | 400,000 | $30,797.66 | $49,434.67 | $3,343.01 | $83,575.34 | $30,769.66 | $49,434.67 | $3,341.85 | $83,546.18 | ($28.00) | $0.00 | ($1.16) | ($29.16) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,500 | 400 | 600,000 | $46,102.66 | $74,152.00 | $5,010.61 | $125,265.27 | $46,060.66 | $74,152.00 | $5,008.86 | $125,221.52 | ($42.00) | $0.00 | ($1.75) | ($43.75) | 0.0% | 0.0% | 0.0% | 0.0% |
| 2,500 | 400 | 1,000,000 | $76,712.66 | $123,586.67 | $8,345.81 | $208,645.14 | $76,642.66 | $123,586.67 | $8,342.89 | $208,572.22 | ($70.00) | $0.00 | ($2.92) | ($72.92) | 0.0% | 0.0% | 0.0% | 0.0% |
| 5,000 | 400 | 2,000,000 | $153,237.66 | $247,173.33 | $16,683.79 | $417,094.78 | $153,097.66 | $247,173.33 | $16,677.96 | $416,948.95 | ($140.00) | $0.00 | ($5.83) | ($145.83) | 0.0% | 0.0% | 0.0% | 0.0% |
| 7,500 | 400 | 3,000,000 | $229,762.66 | $370,760.00 | $25,021.78 | $625,544.44 | $229,552.66 | $370,760.00 | $25,013.03 | $625,325.69 | ($210.00) | $0.00 | ($8.75) | ($218.75) | 0.0% | 0.0% | 0.0% | 0.0% |
| 10,000 | 400 | 4,000,000 | $306,287.66 | $494,346.67 | $33,359.77 | $833,994.10 | $306,007.66 | $494,346.67 | $33,348.10 | $833,702.43 | ($280.00) | $0.00 | ($11.67) | ($291.67) | 0.0% | 0.0% | 0.0% | 0.0% |
| 20,000 | 400 | 8,000,000 | $612,387.66 | $988,693.33 | $66,711.71 | $1,667,792.70 | $611,827.66 | $988,693.33 | $66,688.38 | $1,667,209.37 | ($560.00) | $0.00 | ($23.33) | ($583.33) | 0.0% | 0.0% | 0.0% | 0.0% |
| 200 | 500 | 100,000 | $7,227.66 | $12,358.67 | $816.10 | $20,402.43 | $7,220.66 | $12,358.67 | $815.81 | $20,395.14 | ($7.00) | $0.00 | ($0.29) | ($7.29) | 0.0% | 0.0% | 0.0% | 0.0% |
| 750 | 500 | 375,000 | $26,587.66 | $46,345.00 | $3,038.86 | $75,971.52 | $26,561.41 | $46,345.00 | $3,037.77 | $75,944.18 | ($26.25) | $0.00 | ($1.09) | ($27.34) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,000 | 500 | 500,000 | $35,387.66 | $61,793.33 | $4,049.21 | $101,230.20 | $35,352.66 | $61,793.33 | $4,047.75 | $101,193.74 | ($35.00) | $0.00 | ($1.46) | ($36.46) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,500 | 500 | 750,000 | $52,987.66 | $92,690.00 | $6,069.90 | $151,747.56 | $52,935.16 | $92,690.00 | $6,067.72 | $151,692.88 | ($52.50) | $0.00 | ($2.18) | ($54.68) | 0.0% | 0.0% | 0.0% | 0.0% |
| 2,500 | 500 | 1,250,000 | $88,187.66 | $154,483.33 | $10,111.29 | $252,782.28 | $88,100.16 | $154,483.33 | $10,107.65 | $252,691.14 | ($87.50) | $0.00 | ($3.64) | ($91.14) | 0.0% | 0.0% | 0.0% | 0.0% |
| 5,000 | 500 | 2,500,000 | $176,187.66 | $308,966.67 | $20,214.77 | $505,369.10 | $176,012.66 | $308,966.67 | $20,207.47 | $505,186.80 | ($175.00) | $0.00 | ($7.30) | ($182.30) | 0.0% | 0.0% | 0.0% | 0.0% |
| 7,500 | 500 | 3,750,000 | $264,187.66 | $463,450.00 | $30,318.24 | $757,955.90 | $263,925.16 | $463,450.00 | $30,307.30 | $757,682.46 | ($262.50) | $0.00 | ($10.94) | ($273.44) | 0.0% | 0.0% | 0.0% | 0.0% |
| 10,000 | 500 | 5,000,000 | $352,187.66 | $617,933.33 | $40,421.71 | $1,010,542.70 | $351,837.66 | $617,933.33 | $40,407.13 | $1,010,178.12 | ($350.00) | $0.00 | ($14.58) | ($364.58) | 0.0% | 0.0% | 0.0% | 0.0% |
| 20,000 | 500 | 10,000,000 | $704,187.66 | $1,235,866.67 | $80,835.60 | $2,020,889.93 | $703,487.66 | $1,235,866.67 | $80,806.44 | $2,020,160.77 | ($700.00) | $0.00 | ($29.16) | ($729.16) | 0.0% | 0.0% | 0.0% | 0.0% |
| 200 | 600 | 120,000 | $8,145.66 | $14,830.40 | $957.34 | $23,933.40 | $8,137.26 | $14,830.40 | $956.99 | $23,924.65 | ($8.40) | $0.00 | ($0.35) | ($8.75) | 0.0% | 0.0% | 0.0% | 0.0% |
| 750 | 600 | 450,000 | $30,030.16 | $55,614.00 | $3,568.51 | $89,212.67 | $29,998.66 | $55,614.00 | $3,567.19 | $89,179.85 | ($31.50) | $0.00 | ($1.32) | ($32.82) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,000 | 600 | 600,000 | $39,977.66 | $74,152.00 | $4,755.40 | $118,885.06 | $39,935.66 | $74,152.00 | $4,753.65 | $118,841.31 | ($42.00) | $0.00 | ($1.75) | ($43.75) | 0.0% | 0.0% | 0.0% | 0.0% |
| 1,500 | 600 | 900,000 | $59,872.66 | $111,228.00 | $7,129.19 | $178,229.85 | $59,809.66 | $111,228.00 | $7,126.57 | $178,164.23 | ($63.00) | $0.00 | ($2.62) | ($65.62) | 0.0% | 0.0% | 0.0% | 0.0% |
| 2,500 | 600 | 1,500,000 | $99,662.66 | $185,380.00 | $11,876.78 | $296,919.44 | $99,557.66 | $185,380.00 | $11,872.40 | $296,810.06 | ($105.00) | $0.00 | ($4.38) | ($109.38) | 0.0% | 0.0% | 0.0% | 0.0% |
| 5,000 | 600 | 3,000,000 | $199,137.66 | $370,760.00 | $23,745.74 | $593,643.40 | $198,927.66 | $370,760.00 | $23,736.99 | $593,424.65 | ($210.00) | $0.00 | ($8.75) | ($218.75) | 0.0% | 0.0% | 0.0% | 0.0% |
| 7,500 | 600 | 4,500,000 | $298,612.66 | $556,140.00 | $35,614.70 | $890,367.36 | $298,297.66 | $556,140.00 | $35,601.57 | $890,039.23 | ($315.00) | $0.00 | ($13.13) | ($328.13) | 0.0% | 0.0% | 0.0% | 0.0% |
| 10,000 | 600 | 6,000,000 | $398,087.66 | $741,520.00 | $47,483.66 | $1,187,091.32 | $397,667.66 | $741,520.00 | $47,466.16 | $1,186,653.82 | ($420.00) | $0.00 | ($17.50) | ($437.50) | 0.0% | 0.0% | 0.0% | 0.0% |
| 20,000 | 600 | 12,000,000 | $795,987.66 | $1,483,040.00 | $94,959.49 | $2,373,987.15 | $795,147.66 | $1,483,040.00 | $94,924.49 | $2,373,112.15 | ($840.00) | $0.00 | ($35.00) | ($875.00) | 0.0% | 0.0% | 0.0% | 0.0% |

| | | Rates Effective October 1, 2023 (r) | Proposed Rates Effective April 1, 2024 (s) | Line Item on Bill |
|---|---|---|---|---|
| (1) | Distribution Customer Charge | $1,100.00 | $1,100.00 | Customer Charge |
| (2) | LIHEAP Enhancement Charge | $0.79 | $0.79 | LIHEAP Enhancement Charge |
| (3) | Renewable Energy Growth Program Charge | $522.87 | $522.87 | RE Growth Program |
| (4) | Base Distribution Demand Charge (per kW > 200kW) | $5.30 | $5.30 | Distribution Demand Charge |
| (5) | CapEx Factor Demand Charge (per kW > 200kW) | $1.88 | $1.88 | |
| (6) | Distribution Charge (per kWh) | $0.00430 | $0.00430 | Distribution Energy Charge |
| (7) | Operating & Maintenance Expense Charge | $0.00108 | $0.00101 | |
| (8) | Operating & Maintenance Expense Reconciliation Factor | $0.00016 | $0.00016 | |
| (9) | CapEx Reconciliation Factor | ($0.00086) | ($0.00086) | |
| (10) | Revenue Decoupling Adjustment Factor | $0.00076 | $0.00076 | |
| (11) | Pension Adjustment Factor | ($0.00394) | ($0.00394) | |
| (12) | Storm Fund Replenishment Factor | $0.00788 | $0.00788 | |
| (13) | Arrearage Management Adjustment Factor | $0.00005 | $0.00005 | |
| (14) | Performance Incentive Factor | $0.00000 | $0.00000 | |
| (15) | Low Income Discount Recovery Factor | $0.00262 | $0.00262 | |
| (16) | LRS Adjustment Factor | $0.00057 | $0.00057 | |
| (17) | Long-term Contracting for Renewable Energy Charge | $0.00660 | $0.00660 | Renewable Energy Distribution Charge |
| (18) | Net Metering Charge | $0.00628 | $0.00628 | |
| (19) | Transmission Demand Charge | $5.07 | $5.07 | Transmission Demand Charge |
| (20) | Base Transmission Charge | $0.01124 | $0.01124 | Transmission Adjustment |
| (21) | Transmission Adjustment Factor | ($0.00123) | ($0.00123) | |
| (22) | Transmission Uncollectible Factor | $0.00032 | $0.00032 | |
| (23) | Base Transition Charge | $0.00000 | $0.00000 | Transition Charge |
| (24) | Transition Adjustment | $0.00021 | $0.00021 | |
| (25) | Energy Efficiency Program Charge | $0.00986 | $0.00986 | Energy Efficiency Programs |
| (26) | Last Resort Service Base Charge | $0.10746 | $0.10746 | Supply Services Energy Charge |
| (27) | LRS Adminstrative Cost Adjustment Factor | $0.00780 | $0.00780 | |
| (28) | Renewable Energy Standard Charge | $0.00833 | $0.00833 | |
| | Line Item on Bill | | | |
| (29) | Customer Charge | $1,100.00 | $1,100.00 | |
| (30) | LIHEAP Enhancement Charge | $0.79 | $0.79 | |
| (31) | RE Growth Program | $522.87 | $522.87 | |
| (32) | Transmission Adjustment | $0.01033 | $0.01033 | |
| (33) | Distribution Energy Charge | $0.01262 | $0.01255 | |
| (34) | Distribution Demand Charge | $7.18 | $7.18 | |
| (35) | Transmission Demand Charge | $5.07 | $5.07 | |
| (34) | Transition Charge | $0.00021 | $0.00021 | |
| (35) | Energy Efficiency Programs | $0.00986 | $0.00986 | |
| (36) | Renewable Energy Distribution Charge | $0.01288 | $0.01288 | |
| (37) | Supply Services Energy Charge | $0.12359 | $0.12359 | |

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023
Column (s): Line (5) per Section 6, Page 1, Line (4), Column (e). Line (7) per Section 6, Page 1, Line (1), Column (e). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2023

| | Non-Discretionary | | |
|---|---|---|---|
| 1 | "Non-Discretionary Capital Investment" shall mean capital investment related to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) 'non-discretionary' electric plant in service or b) actual 'non-discretionary' capital spending for 'Non-Discretionary' Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure. | | |
| | Spending Rationale | Definition | Budget Discipline Model |
| 2 | Customer Requests/Customer Requirements | Customer Requests/Public Requirements projects include capital expenditures required for the Company to meet customer requests for service and public requirements. Such items include new business requests (residential and commercial), new metering installations, outdoor lighting, third-party attachments, land rights, municipal relocations, generator interconnections, and other requirements including municipal and customer interconnections. | Self-Standing Budget for entire category; uncapped -- subject only to prudency review, as long as the definition for this category is strictly met. |
| 3 | Damage Failure | Damage Failure projects are required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or other unplanned events. The Damage/Failure spending rationale is typically non-discretionary in terms of scope and timing. The Damage/Failure budget may also include the cost of purchasing strategic spares to respond to equipment failures. | |
| | Discretionary | | |
| 4 | "Discretionary Capital Investment" shall mean capital investment, other than 'Non-Discretionary' Capital Investment defined below, approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) actual 'discretionary' electric plant in service or b) approved 'discretionary' capital spending for Discretionary Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure. | | |

| | Spending Rationale | Definition | Budget Discipline Model |
|---|---|---|---|
| 5 | Asset Condition | Asset Condition projects are required to reduce the likelihood and consequences of failures of T&D assets. Examples of such projects include replacing system elements such as overhead lines, underground cable or substation equipment. Asset Condition investments reflect targeted replacement of assets based on condition rather than wholesale replacement based on "end of useful life" criteria. | Asset Condition and System Capacity & Performance to be considered one budget with a 2.5% overspend tolerance. However, if spending exceeds the tolerance, any revenue requirement adjustments should be applied to all overspend, including that within the tolerance margin. These costs could be included in the next ISR factor. If the Company identifies a specific need that will cause the budgets to exceed the 2.5% threshold, the Company will discuss with the Division the potential to include it in the current ISR reconciliation. |
| 6 | System Capacity & Performance | System Capacity & Performance projects are required to upgrade the capability of the distribution system to provide adequate stability, thermal loading, and voltage performance under anticipated system conditions. This category also includes reliability projects required to improve power quality, reliability and resiliency performance. | |
| 7 | Non-Infrastructure | Non-Infrastructure projects are ones that do not fit into one of the foregoing categories, but which are required to run the electric system. Examples in this rationale include substation physical security, radio system upgrades and the purchase of test equipment. | Corporate overheads have no formal cap, but subject to accounting review.<br><br>General Equipment and Telecommunications are one budget with a 2.5% overspend tolerance. However, if spending exceeds the tolerance, any revenue requirement adjustments should be applied to all overspend, including that within the tolerance margin. These costs could be included in the next ISR factor. If the Company identifies a specific need that will cause the budgets to exceed the 2.5% threshold, the Company will discuss with the Division the potential to include it in the current ISR reconciliation. |
| 8 | Separately Tracked Major Projects | **Screening Criteria (to be considered for a separately tracked major project):**<br>1.Project spans greater than two ISR fiscal years.<br>2.Excludes programs (e.g. breaker replacements, URD, UG)<br>3.Substation project with a total project cost >$10 million<br><br>*The Company would be open to discussing with the Division including additional substation projects >$5 million.<br><br>**Discussion Phase with Division to Determine if this is a Separately Tracked Major Project:**<br>1.Risk Potential (based on subject matter experts and similar projects)<br>2.Execution Complexity<br>3.Scope Complexity | The Company would discuss with the Division what will be a separately tracked large project when a project is first initiated. The Company would be held to budgetary constraints after the Construction Resource Procurement phase when estimate accuracy is refined to +/-10%. If costs for a project exceed its estimate accuracy of 10%, 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. |

| | O&M | | |
|---|---|---|---|
| | Spending Rationale | Definition | Budget Discipline Model |
| 9 | Vegetation Management, I&M & Other O&M | Operation and maintenance expenses on vegetation management; operation and maintenance expenses on system inspection, including expenses from expected resulting repairs; and any other costs relating to maintaining safety and reliability that are mutually agreed upon by the division and the company. | Company obtains approval of budgets for Fiscal Year. O&M is one budget with a 2.5% overspend tolerance. However, if spending exceeds the tolerance, any revenue requirement adjustments should be applied to all overspend, including that within the tolerance margin. These costs could be included in the next ISR factor. |

**Major Project Lifecycle**

| | **Stage** | **Milestones During This Stage:** |
|---|---|---|
| 10 | Study Phase | • Consistent estimate methods across all alternatives.<br>• Subject matter expert consultation with field visits to develop scopes.<br>• Desktop environmental, subsurface, and permitting review.<br>• Project Management consultation to develop construction execution assumptions.<br>• Depending on the status of the project, there may be additional revisions to study estimate depending on available information. |
| 11 | Preliminary Engineering | • Engineering consultant onboarded.<br>• Sound Study<br>• Ground Borings<br>• Scope refined<br>• Preliminary outage planning<br>• Detailed design begins<br>• Estimates are refined as additional information becomes available. |
| 12 | Detailed Engineering | • Scope/Drawings Ready for Bid<br>• Material Procurement<br>• Final Design Complete<br>• Permits Received (in parallel with Construction Resource Procurement)<br>• Estimates are refined as additional information becomes available. |
| 13 | Construction Resource Procurement | • RFP Issued<br>• Negotiations/Clarifications with Bidders<br>• Construction Contractor Awarded<br>• Estimate (+/- 10%) refined – budget discipline applied |
| 14 | Construction | • Construction Commences<br>• Construction Complete<br>• Change Orders Reviewed/Approved |
| 15 | Closeout | • Lessons Learned Documented<br>• Project Financially Closed |

# JOINT PRE-FILED DIRECT TESTIMONY

# OF

**STEPHANIE A. BRIGGS**

**JEFFREY D. OLIVEIRA**

**AND**

**NATALIE HAWK**

# Table of Contents

## I. Introduction

### Stephanie A. Briggs

**Q. Please state your full name and business address.**

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

**Q. Please state your position and responsibilities in that position.**

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

**Q. Please describe your education and professional experience.**

A. In 2000, I received a Bachelor of Arts degree in Accounting from Bryant College. In 2004, I joined National Grid USA Service Company, Inc. ("National Grid Service Company") as a Senior Analyst in the Accounting Department. In this position, I was responsible for supporting the books and records of one of National Grid USA's ("National Grid") New York affiliates. In 2009, I joined National Grid Service Company's Regulatory Accounting Group. In 2011, I was promoted to Lead Specialist for Revenue Requirements supporting New York. In 2017, I was promoted to Director of Revenue Requirements for New York. In July 2020, I became Director of Revenue Requirements for New England. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of the Company from National Grid USA (the "Acquisition") at which time I began working in my current position.

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

A. Yes. I provided pre-filed direct testimony in numerous dockets including the Company's 2022 Annual Retail Rate Filing, Docket No. 5234, the Company's 2021 Performance Incentive Mechanism Factor Filing, as part of Docket No. 4770, the Fiscal Year 2022 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing, Docket No. 5098, the Company's 2022 Distribution Adjustment Charge Filing, Docket No. 22-13-NG, the Company's Advanced Metering Functionality Business Case, Docket No. 22-49-EL, the Company's Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability Plan, Docket No. 22-53-EL, Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan, Docket No. 22-54-NG, the Company's 2023 Electric Revenue Decoupling Mechanism Reconciliation Filing, Docket No. 23-16-EL, the Company's 2023 Residential Assistance Recovery filing, Docket No. 23-17-EL, the Company's 2023 Distribution Adjustment Charge Filing, Docket No. 23-23-NG, and most recently in the

Company's Petition for Acceleration Due to Distribution Generation Project in Docket Nos. 23-37-EL and 23-38-EL. I also have testified before the Massachusetts Department of Public Utilities and New York Public Service Commission on behalf of the Company's former affiliates as a revenue requirement witness in various proceedings.

<u>**Jeffrey D. Oliveira**</u>

**Q. Please state your full name and business address.**

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

**Q. Please state your position and responsibilities in that position.**

A. I am employed by the 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. Please describe your education and professional experience.**

A. In 2000, I earned an associate degree in Business Administration from Bristol Community College in Fall River, Massachusetts. I was employed by National Grid Service Company and its predecessor companies from 1999-2022. From 1999 through 2000, I was employed by Fall River Gas Company as a Staff Accountant. In 2001, after Fall River Gas Company merged with Southern Union Company, I continued as a Staff

Accountant with increased responsibilities. In August of 2006, the Company acquired the Rhode Island gas distribution assets of Southern Union Company at which time I joined the National Grid Service Company as a Senior Accounting Analyst. In January 2009, I became a Senior Revenue Requirement Analyst in National Grid Service Company's Strategy and Regulation Department. In July 2011, I was promoted to Lead Revenue Requirement Analyst in the New England Revenue Requirements group of the New England Regulatory Department of the National Grid Service Company. Upon closing of the Acquisition, I began working in my current position.

**Q. Have you previously filed testimony or testified before the PUC?**

A. Yes. I have testified before the Commission on numerous occasions, including the Fiscal Year 2024 Electrical Infrastructure, Safety, and Reliability Plan, Docket No. 22-53-EL and the Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan, Docket No. 22-54-NG.

**Natalie Hawk**

**Q. Please state your full name and business address.**

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

**Q. Please state your position and your responsibilities within that position.**

A. I am employed by the Services Corporation as the Director of tax accounting and reporting. My current responsibilities are to oversee the accounting and reporting of income and non-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. Please describe your education and professional experience.**

A. In 1992, I received a Bachelor of Science in Business Administration degree with a major in Accounting from Kutztown University. In 1998, I received a Master's in Business Administration degree from Lehigh University. In 1993, I started my career as a first-year Accountant in the Accounting Department at Metropolitan Edison Company, a wholly owned subsidiary of GPU, Inc. GPU is a public utility holding company based in New Jersey that was acquired by First Energy in 2001. I held various accounting roles in Accounting Operations, the Tax Department and Plant Accounting. In 2001, I accepted a position at Services Corporation as an Accounting Analyst in the Tax Department. My responsibilities included accounting for income and non-income taxes, and I later became involved in financial tax reporting for SEC and regulatory purposes, preparing tax information and providing guidance on tax matters for rate cases, formula rates and other rate mechanisms. I was promoted to Team Leader in 2004, 1st-level Manager in 2011, 2nd-level Manager in 2015 and to my current position as Tax Director in 2021.

**Q. Have you previously filed testimony or testified before the PUC or any other jurisdiction?**

A. Yes, I have testified before the PUC in support of the Company's filings in several proceedings as follows: FY 2024 Gas Infrastructure, Safety and Reliability Plan Filing, Docket No. 22-54-NG, FY 2024 Electric Infrastructure, Safety and Reliability Plan Filing, Docket No. 22-53-EL, FY 2023 Gas Infrastructure, Safety and Reliability Plan Reconciliation Filing in Docket No. 5210 and FY 2023 Electric Infrastructure, Safety and Reliability Plan Reconciliation Filing in Docket No. 5209.

## II. Purpose of Joint Testimony

**Q. What is the purpose of your joint testimony?**

A. The purpose of this joint testimony is to sponsor Section 5 of the proposed fiscal year ("FY") 2025 Electric ISR Plan ("Electric ISR Plan" or "Plan"), which covers the period April 1, 2024 through March 31, 2025. Section 5 describes the calculation of the Company's revenue requirement for FY 2025 in Attachment 1 of that section. The revenue requirement is based on the Electric ISR Plan operation and maintenance (O&M) expenses and capital investment, which are described in the joint pre-filed direct testimony of Witnesses Nicole Gooding, Christopher Rooney, Kathy Castro, Ryan Constable, Eric Wiesner, and Daniel Glenning. We also describe the impact of the sale of the Company to PPL Rhode Island Holdings, LLC ("PPL Rhode Island")[1] on the FY 2025 revenue requirement. The Company's FY 2023 Electric ISR Plan for the period April 1, 2022 through March 31, 2023 approved in Docket No. 5209 is referenced in this section as "FY 2023-NG." Section 5, Attachment 3 represents the revenue requirement for the Advanced Metering Functionality ("AMF") capital investments.

## III. <u>Electric ISR Plan Revenue Requirement</u>

**Q. Please summarize the revenue requirement for the Company's FY 2025 Electric ISR Plan on Attachment 1.**

A. As shown on Section 5, Attachment 1, Page 1, Column (b), the Company's FY 2025 Electric ISR Plan cumulative revenue requirement totals $54,197,806, or an decrease of $1,220,252 below the amount currently being billed for the Electric ISR Plan. The FY 2025 Plan revenue requirement consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, the Company's Inspection and Maintenance ("I&M") program, and Other Programs, (2) the Company's capital investment in electric utility infrastructure, (3) the FY 2025 Property Tax Recovery Adjustment, and (4) an adjustment for the tax hold harmless impact on ISR rate base as will be described below. Lines 1, 2 and 3 of Column (b) reflect the forecasted FY2025 revenue requirement related to O&M expenses

[1] PPL Rhode Island Holdings, LLC is a wholly owned indirect subsidiary of PPL Corporation.

for VM, I&M, and Other Programs of $13,075,000, $700,000, and $365,000 respectively. The Electric ISR Plan includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program ("Contact Voltage Program"), mandated by R.I. Gen. Laws § 39-2-25 and approved by the Commission in Docket No. 4237. Contact Voltage Program costs are included in the $700,000 of I&M expenses referred to above. Prior ISR proposals included a reduction to I&M expenses related to Contact Voltage Program costs that were being recovered in base distribution rates in RIPUC Docket No. 4323; however, this reduction is no longer required because in the Company's most recent general rate case in RIPUC Docket No. 4770, Contact Voltage Program costs were excluded from the cost of service to be recovered in base distribution rates, effective September 1, 2018.

**Q. Did the Company calculate the Electric ISR Plan revenue requirement on Attachment 1 in the same fashion as calculated in the previous Electric ISR Factor submissions?**

A. Yes.

**Q. Please explain the increase of FY 2025 Electric ISR Plan revenue requirement over the amount currently being billed for Electric ISR Plan on Attachment 1.**

A. As mentioned above, the Company's FY 2025 Electric ISR Plan revenue requirement is $1,220,252 lower than the FY 2024 Electric ISR Plan revenue requirement. Of the total

$54,197,806 revenue requirement in FY 2025, $35,029,505 in capital investment revenue requirement and $4,261,485 in property tax recovery adjustment are associated with incremental ISR Plan capital investment for FY 2018 through FY 2024, which the PUC has approved in previous Electric ISR Plan or reconciliation filings. The decrease in the FY 2025 revenue requirement associated with previous fiscal years' capital investments compared to the approved FY 2024 Plan revenue requirement on that same investment totals $1,451,559 and is due 1) a decrease in actual FY 2023 incremental capital investment compared to the amounts included in the FY 2024 plan revenue requirement for FY 2023, 2) an increase to vintage rate base affected by the sale as described below, 3) an increase due to the half-year convention applied in the year of installation. The FY 2025 revenue requirement on vintage year FY 2024 incremental ISR Plan capital investment increased by $2,948,646 from the FY 2024 revenue requirement on the same investment. The movement in the property tax recovery adjustment related to prior years' investment as well as rate base embedded in current distribution rates is a decrease of $1,187,639. The FY 2025 proposed incremental ISR Plan capital investment and the resulting increase in property tax expense due to that incremental investment accounts for $4,867,413 of the FY 2025 revenue requirement increase over the FY 2024 revenue requirement. There was a decrease of $973,000 related to the total FY VM, I&M and Other Program O&M expense over the prior year. Lastly, the total FY 2025 revenue requirement was reduced for the tax hold harmless adjustment of $3,254,068.

**Q. What are the impacts of the sale of the Company to PPL Rhode Island on the Electric ISR Plan revenue requirement calculations?**

A. On May 25, 2022, PPL Rhode Island, a wholly owned indirect subsidiary of PPL, acquired 100% of the outstanding shares of common stock of Company from National Grid (the "Acquisition"). The Acquisition was treated as an asset acquisition for tax purposes under Internal Revenue Code (IRC) §338(h)(10) ("the §338 election"), which resulted in the recognition of all book and tax timing differences and the reversal of the related deferred tax assets and liabilities in FY 2023. In addition, the Company utilized all its available Net Operating Losses ("NOL") to offset taxable income generated from the sale, which resulted in the reversal of all NOL related deferred tax assets in FY 2023. The reversal of all deferred tax assets and liabilities, including NOL deferred tax assets, reduced net deferred tax liabilities which increased the ISR rate base in the vintage revenue requirement calculations by $39,539,101 for FY 2025 per Attachment 2, Page 1, Line 15. Consequently, the increase in rate base ultimately increases the return on rate base recoverable through the ISR mechanism. The impact to the Electric ISR Plan revenue requirement is an increase of approximately $3,254,068 in FY 2025 as shown on Section 5, Attachment 1, Page 1, Line 18 and shown in detail on Section 5, Attachment 2.

**Q. How does the Company propose to address the above increases to the revenue requirements on the FY 2025 Electric ISR Plan revenue requirement as a result of the Acquisition?**

A. As part of the transaction approval proceeding before the Division of Public Utilities and Carriers in Docket No. D-21-09, PPL committed to hold harmless Rhode Island customers from any changes to Accumulated Deferred Income Taxes ("ADIT") as a result of the Acquisition.[2] The Company is proposing to reduce the FY 2025 revenue requirements by the calculated hold harmless amounts as shown on Section 5, Attachment 1, Page 1, Line 18. Because of the §338 election, PPL generated tax-deductible goodwill, which creates cash tax benefits to the Company. These cash tax benefits will be shared with the customer in the form of revenue credits to offset the increase in revenue requirements from the increase in rate base because of the elimination of deferred taxes from the Acquisition. Under National Grid ownership, the Company generally filed its federal income tax return in December for its most recently completed fiscal year, and that timing has required the Company in past ISR Plan dockets to file revised Electric ISR Plan revenue requirements reflecting the actual tax deductions or NOL generated or utilized as submitted in its tax return. The Company revised the revenue requirement in this filing to reflect the actual tax repairs deductibility percentages, tax loss on retirements and NOL utilization on vintage FY 2023 ISR Plan capital investment. These updates were per the Company's April through May 2022 results in National Grid's short period FY 2023 federal income tax return and the Company's June through December results in PPL's short period calendar year 2022 federal income tax return. The actual tax repairs deductibility percentages and tax losses

[2] *See* Report and Order, Docket No. D-21-09 at 257, commitment #16 (February 23, 2023).

on retirements for the Company's January through March 2023 period within vintage FY2023 ISR Plan capital investment will not be updated until PPL files its calendar year 2023 tax return in October of 2024.

**Q. Please describe any changes to the presentation of the revenue requirements calculations because of the Acquisition.**

A. Because of the §338 election, the sale resulted in the reversal of book and tax timing differences and the related deferred taxes. In addition, tax depreciation starts over on a new tax basis equal to net book value on the date of Acquisition. To reflect these impacts of the Acquisition, the calculations of the FY 2023 rate base and revenue requirement for the vintage plan years FY 2018 through FY 2023 were separated into two columns in Section 5, Attachment 1, Pages 2, 5, 10, 13, 17, and 20. The first FY 2023 column labeled as "NG, 4/1/22-5/24/22", reflects the 55 days of National Grid ownership. The second FY 2023 column labeled as "PPL, 5/25/22-3/31/23" reflects the period from acquisition date through March 31, 2023, which represents the first year (i.e., 10-month period) under PPL's ownership where the deferred taxes under National Grid's ownership are reversed and the tax basis becomes equal to net book basis, causing the book and tax timing difference and tax depreciation to start over. Because PPL files a tax return on a calendar year basis, the period January 1 through March 31, 2023, represents a portion of PPL's 2023 tax return. Consequently, the second FY 2023 column in the FY2023 year representing PPL's ownership period will not be final until PPL files its calendar year 2023 tax return in October of 2024, at which time the 2023 calendar year results will be allocated to the January 1 through March 31, 2023 period to finalize the tax deductions for the FY2023 year.

**Q. Please summarize the revenue requirement for the AMF related capital investment in the Company's FY 2025 Electric ISR Plan on Attachment 3.**

A. In Docket No. 22-49-EL, the PUC approved the Company to seek recovery of AMF capital investments through the Electric ISR Plan. Section 5, Attachment 3, is the FY 2025 revenue requirement on the AMF capital investment placed in service during FY 2025. As shown on Attachment 3, Page 1, Line 6 the total FY 2025 revenue requirement is $4,722,076. As approved by the PUC, the annual revenue requirement associated with AMF capital investments that are eligible for ISR cost recovery each year, should be offset by the Special Sector deferral balances listed on Attachment PUC 7-13 in Docket No. 22-49-EL, Lines 3 and 4. The amount of deferral balance in FY 2025 used to offset the AMF related capital revenue requirement is shown on Attachment 3, Page 1, Line 7 and detailed on Attachment 3, Page 10. For FY 2025, this results in a net revenue requirement of $0 to be recovered from customers through the Electric ISR Plan. Similar to the Electric ISR capital investments on Attachment 1, the actual FY 2025 AMF capital investments will be reconciled in the annual FY 2025 Electric ISR Plan Reconciliation filing.

**Q. Is the MDMS capital investment associated with AMF to be placed in service during FY 2025 included in the capital revenue requirement on Attachment 3?**

A. Yes, the portion of the MDMS capital investment associated with AMF that is forecasted to be placed into service during FY 2025 is included in the total AMF capital revenue requirement on Attachment 3, Page 1, Line 6. However, per the PUC's approval in Docket No. 22-49-EL, the MDMS capital associated with AMF is not eligible to be included in AMF rate base and earn a return in the capital revenue requirement. The MDMS capital investment is allowed to be amortized over the depreciable life of the asset, as calculated on Attachment 3, Page 5 and included on Attachment 3, Page 1, Line 5.

## IV. <u>Conclusion</u>

**Q. Does this conclude your testimony?**

A. Yes.

# PRE-FILED DIRECT TESTIMONY

# OF

# TYLER G. SHIELDS

# Table of Contents

**I. Introduction and Qualifications**

**Q. Please state your full name and business address.**

A. My name is Tyler G. Shields, and my business address is 280 Melrose Street, Providence, Rhode Island 02907.

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

A. I am employed by the PPL Services Corporation ("Services Corporation") as a Rates and Regulatory Specialist. The Services Corporation provides administrative, management, and support services to PPL Corporation ("PPL") and its subsidiary companies, including The Narragansett Electric Company (the "Company"). My current duties include revenue requirement and rates analyses and regulatory filings, regulatory strategies, and reconciliations for the Company.

**Q. Please describe your educational background and training.**

A. I earned a Bachelor of Arts in Economics from the University of Connecticut in 2013.

**Q. Please describe your professional experience.**

A In March 2015, I began my career as a pricing analyst at Granite Telecommunications in Quincy, Massachusetts. In February 2017, I was promoted to product pricing team lead. My responsibilities included auditing customer accounts and maintaining the pricing and billing databases to ensure accuracy. In January 2021, I was hired by Charles Stark

Draper Laboratory as a Program Analyst, creating pricing proposals for prospective clients, and validating financial data for key stakeholders on a weekly basis. In November 2022, I was hired by the Services Corporation and have been performing my current role since that time.

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

A. Yes. I provided pre-filed direct testimony in the Company's Fiscal Year 2023 Electric Revenue Decoupling Mechanism ("RDM") Reconciliation Filing in Docket No. 23-16-EL, the Company's Gas RDM Reconciliation filing in Docket No. 23-23-NG, the Company's Distribution Adjustment Charge ("DAC") filing in Docket No. 23-23-NG, and the Company's FY 2023 Electric Infrastructure, Safety and Reliability ("ISR") Plan Annual Reconciliation Filing in Docket No. 5209.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to describe the calculation of the proposed factors designed to recover the fiscal year ("FY") 2025 revenue requirement on cumulative actual and forecasted incremental capital investment through March 31, 2025 and FY 2025 operation and maintenance ("O&M") expense resulting from the Company's FY 2025 Electric ISR Plan proposed in this filing and to provide the customer bill impacts of the proposed rate changes.

## II. Infrastructure, Safety, and Reliability Provision

**Q. Please describe the Company's ISR Plan tariff provision.**

A. The Company's ISR Provision, R.I.P.U.C. No. 2199, describes the process for establishing and implementing annual rate adjustments designed to recover the costs associated with the electric ISR plan. The tariff consists of two separate mechanisms: (1) an Infrastructure Investment Mechanism ("IIM") designed to recover the costs associated with incremental capital investment; and (2) an Operation and Maintenance Mechanism ("O&MM") designed to recover certain annual O&M expense pertaining to Inspection and Maintenance ("I&M"), Vegetation Management ("VM") activities, and any other O&M expense as approved by the PUC.

### A. Infrastructure Investment Mechanism

**Q. Please describe the operation of the IIM.**

A. The IIM provides for the recovery of incremental capital investment through CapEx Factors. In conjunction with the filing of the annual electric ISR plan by January 1 of each year, the Company proposes CapEx Factors for each rate class designed to recover the revenue requirement associated with forecasted and actual cumulative capital investment through the end of the upcoming ISR plan year. The proposed CapEx Factors become effective on and after April 1 of each ISR plan year upon PUC approval.

**Q. How are the CapEx Factors designed?**

A. First, the revenue requirement approved by the PUC, which will reflect both an estimate of incremental capital investment for the upcoming ISR plan year plus the cumulative actual and forecasted incremental capital investment for prior ISR plan years including the current ISR plan year, is allocated to each of the Company's rate classes based upon the rate base allocator. The rate base allocator is the percentage of total rate base allocated to each rate class taken from the Company's most recent general rate case before the PUC that contained an allocated cost of service study.

Next, unit rates for each rate class are developed from the allocated revenue requirement. For non-demand rate classes, a per-kWh rate is calculated by dividing each rate class's share of the revenue requirement by its forecasted kWh deliveries for the period during which the rates will be in effect. For demand-based rate classes, Rate G-02 and Rates G-32/B-32, the CapEx Factors are per-kW rates and are calculated by dividing the allocated revenue requirement for each rate class by an estimate of the kW billing demand for the period the rates will be in effect.

**Q. Please explain why the revenue requirement is allocated using a rate base allocator.**

A. A rate base allocator is used to allocate the revenue requirement associated with cumulative incremental capital investment to the Company's rate classes as it is similar to the manner by which the revenue requirement on capital investment would be allocated in an allocated cost of service study. Since capital investment is primarily related to plant in service, which forms the largest part of rate base, allocating the incremental capital investment using the rate base allocator contained in the allocated cost of service study in the Company's most recent general rate case is an appropriate way to spread the revenue requirement to each of the rate classes.

**Q. Is the revenue requirement, which contains, in part, an estimate of incremental capital investment, and revenue generated from the CapEx Factors subject to reconciliation?**

A. Yes. The Company submits its annual ISR Reconciliation Filing by August 1 of each year in which the Company compares the revenue requirement on actual cumulative incremental capital investment to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over- or under-recovery of the revenue requirement is credited to or recovered from customers through CapEx Reconciling Factors effective on the October 1 following the filing. The amount approved for recovery or crediting through CapEx Reconciling Factors is also subject to reconciliation with actual amounts billed through the CapEx Reconciling Factors, and any difference reflected in future CapEx Reconciling Factors.

**B. <u>Operation and Maintenance Mechanism</u>**

**Q. Please describe the operation of the O&MM.**

A. The O&MM provides for the recovery of the proposed O&M expense presented in the ISR plan. The O&M Factor for each rate class is designed to recover the sum of the annual forecasted O&M expense for the upcoming ISR plan year, as approved by the PUC in the Company's annual electric ISR plan filing.

**Q. How are the O&M Factors designed?**

A. To determine each rate class's O&M Factor, the forecasted O&M expense is allocated to each of the Company's rate classes based upon the O&M allocator derived from allocated distribution O&M expense (i.e., FERC accounts 580-598). This distribution O&M allocator is the percentage of total distribution O&M expense allocated to each rate class taken from the most recent proceeding before the PUC that contained an allocated cost of service study.

Once the rate class O&M revenue requirement has been determined, per-unit rates are developed for each rate class. For Large Demand Back Up Service Rate B-32, the O&M Factor for Backup Service is in the form of a demand, or per-kW, rate and is calculated by dividing the allocated O&M expense for the combined Rate B-32/G-32 rate class by an estimate of the kW billing demand for the 12 month period the factor is to be in effect, truncating the result to 2 decimal places, then applying a 90% discount by multiplying the resulting charge by 0.1. For all other rate classes, a per-kWh rate is developed by dividing the allocated O&M expense by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect.

**Q. Why is the O&M expense allocated using a distribution O&M allocator?**

A. As with the allocation of the revenue requirement on capital investment, the O&M expense is allocated in a manner that is similar to the way these costs would be allocated in an allocated cost of service study. Therefore, the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last general rate case is used to spread these costs to each of the Company's rate classes.

**Q. Regarding Rates G-02 and B-32/G-32, why are the CapEx Factors designed as demand (per-kW) charges and the O&M Factors as per-kWh charges?**

A. The current distribution rate structure for Rates G-02 and B-32/G-32 include both demand and kWh rates. The designs of the CapEx Factors and O&M Factors for these rate classes are intended to not significantly change the relationship between the existing rates and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts.

**Q. Are the O&M Factors subject to reconciliation?**

A. Yes. In the Company's annual ISR Reconciliation Filing, the Company compares the actual O&M expense to actual billed revenue generated from the O&M Factors for the applicable reconciliation period, and any over- or under-recovery of actual expense is credited to or recovered from customers through the O&M Reconciling Factor effective on the October 1 following the filing. The O&M Reconciling Factor is a uniform per-kWh rate applicable to all rate classes. The amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation with actual amounts billed through the O&M Reconciling Factor and any difference reflected in future O&M Reconciling Factors.

## III. Proposed Factors

### A. CapEx Factors

**Q. Please describe the calculation of the proposed CapEx Factors.**

A. The CapEx Factors are designed on a FY 2025 ISR capital-related revenue requirement net of tax hold harmless adjustments of $40,057,806[1] as developed in the testimony of

[1] See Section 5: Attachment 1, Page 1, Line 16, Columns (b) plus Line 18, Columns (b).

Company Witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, and Natalie Hawk. The revenue requirement is allocated to the rate classes based on the rate base allocator approved in Docket No. 4770, and the factors are designed as described above using forecasted billing units for the period April 1, 2024, through March 31, 2025. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, page 3.

## B. O&M FACTORS

**Q. Please describe the calculation of the proposed O&M Factors.**

A. The proposed O&M Factors are designed to recover forecasted O&M expense for FY 2025 of $14,140,000[2] as developed in the testimony of Company Witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, and Natalie Hawk. The Company has allocated this O&M expense using the distribution O&M allocator approved in Docket No. 4770. O&M Factors are designed as I describe above. The calculation of the proposed O&M Factors is set forth in the ISR Plan, Section 6, page 2.

**Q. Is the Company providing a summary of all proposed factors?**

A. Yes. The Summary of Proposed Factors is presented in Section 6, page 1.

[2] See Section 5: Attachment 1, Page 1, Line 4, Column (b).

**IV. Bill Impacts**

**Q. Has the Company prepared monthly bill impacts illustrating the effect of the proposed ISR factors?**

A. Yes. The monthly bill impacts for each rate class are shown in Section 7 of the ISR Plan. For a residential customer receiving Last Resort Service and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill decrease of $0.16, or 0.1%.

**V. Summary of Retail Delivery Rates**

**Q. Is the Company including a revised Summary of Retail Delivery Rates tariff, R.I.P.U.C. No. 2095, in this filing?**

A. No, the Company is not revising this tariff at this time. The Company will submit its Annual Retail Rate Filing in February 2024 and will propose additional rate changes for effect April 1, 2024. Therefore, the Company will submit a compliance filing following the PUC's decision in both the Annual Retail Rate Filing docket and this docket that will include the Summary of Retail Delivery rates tariff reflecting all of the approved rate changes for effect April 1, 2024.

**VI. Docket 4600**

**Q. Did the Company apply the Docket 4600 principles of rate design to the FY 2025 Electric ISR Plan?**

A. The Company did not perform a specific analysis of the rate design principles in the context of the proposed FY 2025 Electric ISR Plan. Rhode Island Gen. Laws § 39-1-27.7.1 provides for a spending plan for each fiscal year and an annual rate-reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget. The PUC has previously approved the rate design for the ISR recovery factors as part of the ISR Provision, R.I.P.U.C. No. 2199, effective September 1, 2018. The Company is not proposing any changes to the current rate design as part of the FY 2025 Electric ISR Plan.

## VII. AMF Recovery Mechanism

**Q. Is there an AMF CapEx Factor and bill impact for FY 2025?**

A. No, as shown on Section 5, Attachment 3, Line 8 and discussed in the testimony of Witnesses Briggs, Oliveira, and Hawk, the proposed net AMF capital revenue requirement for FY 2025 is zero. Therefore, there is no AMF CapEx Factor to be recovered from ratepayers for FY 2025. The proposed FY 2025 AMF capital revenue requirement will be reconciled with actual FY 2025 AMF capital revenue requirement and if needed, an AMF CapEx Reconciliation Factor will be determined.

## VIII. Conclusion

**Q. Does this conclude your testimony?**

A. Yes, it does.