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

Proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan

21-Month Filing
April 2023 – December 2024

Book 1 of 2

December 22, 2022

Docket No. 22-54-NG

Submitted to**:**
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Filing Letter & Motion

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Rhode Island Energy™
a PPL company

December 23, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket No. 22-54-NG – The Narragansett Electric Company Proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan (21-Month Plan for Period April 2023 through December 2024)

Dear Ms. Massaro:

In compliance with R.I. Gen. Laws § 39-1-27.7.1, I have enclosed 10 copies of Rhode Island Energy's[1] proposed fiscal year ("FY") 2024 Gas Infrastructure, Safety and Reliability ("ISR") Plan (the "Gas ISR Plan" or "Plan" or "21-Month Plan"). The Gas ISR Plan is designed to enhance the safety and reliability of Rhode Island Energy's natural gas distribution system.

On October 21, 2022, Rhode Island Energy submitted an earlier version of the proposed 21-Month Plan to the Division of Public Utilities and Carriers ("Division") for review as required by law. The Company consulted with the Division to try to reach an agreement on a proposed plan to be filed with the Rhode Island Public Utilities Commission ("PUC"); however, in this case, the Company and the Division were unable to reach an agreement. The Company now submits the enclosed 21-Month Plan to the PUC for review in accordance with R.I. Gen. Laws § 39-1-27.7.1(d)(4), which provides that "[i]f the company and the division cannot agree on a plan, the company shall file a proposed plan with the commission and the commission shall review and, if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service over the short and long term, approve the plan within ninety (90) days."

As detailed in the Plan, Rhode Island Energy is submitting a 21-Month Plan for approval to align with the Company's financial schedule.[2] This Plan consists of the 9-month period from April 1, 2023 through December 31, 2023 and the 12-month period from January 1, 2024 through December 31, 2024. For purposes of avoiding confusion, the Company has labeled the time periods referenced within the Plan as follows:

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[1] The Narragansett Electric Company d/b/a Rhode Island Energy (referred to herein as "Rhode Island Energy" or the "Company").

[2] On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation ("PPL), acquired 100% of the outstanding shares of common stock of the Company from National Grid USA ("National Grid"). To transition the filing of ISR plans from National Grid's fiscal year (April 1 – March 31) to PPL's fiscal year (January 1 – December 31), the Company is proposing a one-time 21-Month Plan for the period of April 1, 2023 through December 31, 2024. Subsequent ISR plans will be for 12 months from January 1 – December 31.

- FY 2023 or FY 2023-NG means April 1, 2022 through March 31, 2023
- CY 2023 means the 9-month period of April 1, 2023 through December 31, 2023
- CY 2024 means the 12-month period of January 1, 2024 through December 31, 2024
- 21-Month Plan means April 1, 2023 through December 31, 2024

The Gas ISR Plan is designed to maintain and upgrade the Company's gas delivery system through proactively replacing leak-prone pipe; upgrading the gas delivery system's custody transfer stations, pressure regulating facilities, and peak shaving plants; responding to emergency leak situations; and addressing infrastructure conflicts that arise out of state, municipal, and third-party construction projects. The Plan is intended to attain these safety and reliability goals through a cost-effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas distribution infrastructure, promote efficiency in the management and operation of the gas distribution system and directly benefit Rhode Island gas customers The Plan also helps reduce the annual methane emissions released by the gas distribution system, primarily through the replacement and abandonment of leak-prone pipe with its Proactive Main Replacement programs, consistent with the 2021 Act on Climate.

The 21-Month Plan includes a description of the categories of work Rhode Island Energy proposes to perform in CY 2023 and CY 2024, the proposed targeted spending levels for each work category and the resulting plant additions. In support of the Gas ISR Plan, the Company has included the pre-filed direct testimony of Michele V. Leone, and the joint testimony of Nathan A. Kocon and Laeyeng Hunt. As detailed in the Plan, the Company is proposing $388.53 million in capital investment (total for 21-months), which includes $18.33 million related to the Cost of Removal.

In accordance with R.I. Gen. Laws § 39-1-27.7.1(c)(2), the enclosed Plan also addresses the revenue requirement, rate design, and bill impacts. The Company's CY 2023 Gas ISR Plan revenue requirement is $46,984,604 (which is an incremental $4,547,633 over the amount in FY 2023), and the CY 2024 Gas ISR Plan revenue requirement is $75,244,391 (which is an incremental $28,259,788 over the CY 2023 revenue requirement.) The Company has included the joint pre-filed direct testimony of Stephanie A. Briggs, Jeffrey D. Oliveira, Andrew W. Elmore, and Natalie Hawk that describes the calculation of the Company's revenue requirements for CY 2023 and CY 2024. Please note that, in this case, the calculation also includes an adjustment for the tax hold harmless impact on ISR rate base.

For the average residential heating customer using 845 therms annually, the proposed FY 2024 ISR factors for the period of April 1, 2023 through December 31, 2024 will result in an annual bill increase of $113.88 or 6.6 percent, as reflected in the proposed Gas ISR Plan at Section 4, Attachment 2. The Company has included the pre-filed direct testimony of Peter R. Blazunas to describe the customer bill impacts of the proposed rate changes. The Company's filing also includes a revised tariff provision (redlined and clean) to implement the change in the ISR schedule, which the Company respectfully requests the PUC approve, together with the 21-Month Plan.

For the PUC's convenience, the Company has also included copies of its responses to Division Data Requests Set 1. In connection with the Data Requests, this filing contains a Motion for Protective Treatment of Confidential Information in accordance with 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B) and (4)(F). Rhode Island Energy seeks protection from public disclosure of certain confidential and privileged information in its response to Division 1-10, and Attachments DIV 1-8, Attachment DIV 1-35, Attachment DIV 1-38-3, Attachment DIV 1-41-1, and Attachment DIV 1-41-2. In compliance with Rule 1.3(H), National Grid has provided the PUC with one complete, unredacted copy of the confidential response and attachments in an envelope marked, **"HIGHLY CONFIDENTIAL INFORMATION - DO NOT RELEASE!"**

The Gas ISR Plan presents an opportunity to facilitate and encourage investment in Rhode Island Energy's gas utility infrastructure and enhance Rhode Island Energy's ability to provide safe, reliable and efficient gas service to customers.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 22-54-NG Service List
Leo Wold, Esq.
Al Mancini, Division (w/confidential versions)
John Bell, Division (w/confidential versions)
Rod Walker, Division (w/confidential versions)

STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

FY 2024 Gas Infrastructure, Safety and Reliability Plan	)	Docket No. 22-54-NG

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

Rhode Island Energy[1] respectfully requests that the Rhode Island Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as well as certain critical energy infrastructure information as permitted by 810-RICR-00-00-1.3(H) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B) and (4)(F). The Company also respectfully requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On December 22, 2022, the Company submitted its FY 2024 Gas Infrastructure, Safety and Reliability Plan (the "Plan" or "Gas ISR Plan") filing in the above-captioned docket. The Gas ISR Plan filing includes the Company's responses to fifty-one data requests propounded by the Division of Public Utilities and Carriers (the "Division") in connection with its pre-filing review of the Plan. The Company's response to data request Division 1-10, and Attachments DIV 1-8, Attachment DIV 1-35, Attachment DIV 1-38-3, Attachment DIV 1-41-1, and

[1] The Narragansett Electric Company d/b/a Rhode Island Energy (Rhode Island Energy or the Company).

Attachment DIV 1-41-2 (the "Confidential Attachments") contain information that is not subject to disclosure under Rhode Island's Access to Public Records Act. Specifically, the response to Division 1-10, and Attachment DIV 1-8 and Attachment DIV 1-35 contain critical energy infrastructure information ("CEII") the disclosure of which could present a threat to public safety. The CEII contained in the Company's response to Division 1-10 and the Confidential Attachments includes plans, descriptions, design standards and schematic drawings of natural gas transmission and distribution infrastructure. Additionally, Attachment 1-38-3, Attachment 1-41-1, and Attachment 1-41-2 contain certain confidential and commercially sensitive information related the Company's Exeter liquified natural gas ("LNG") Facility and the Company's contractual arrangement with the U.S. Navy for certain LNG facilities in Newport, Rhode Island, respectively, which include pricing and other commercially sensitive information. In addition to sensitive commercial information, Attachment 1-41-1 and Attachment 1-41-2 also contain personally identifiable information of military personnel that has been redacted in order to protect their privacy.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the CEII and confidential commercial information contained in the response to Division 1-10 and the Confidential Attachments.

II. LEGAL STANDARD

Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-

2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) and (4)(F) provide that the following types of records shall not be deemed public:

> (B) Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature…
>
> (F) Scientific and technological secrets and the security plans of military and law enforcement agencies, the disclosure of which would endanger the public welfare and security.

With respect to the commercial information exception to the definition of "public record," the Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be 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 Ctr. Auth.*, 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.

With respect to other exceptions to the definition of public record, the Rhode Island Supreme Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established by the Court in *Providence Journal v. Kane*, 577 A.2d 661 (R.I. 1990). Under this balancing test, the PUC may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

III. BASIS FOR CONFIDENTIALITY

The commercial information contained in Attachment DIV 1-38-3, Attachment DIV 1-41-1 and Attachment DIV 1-41-2 is confidential and privileged information and is the type of information that Rhode Island Energy would not ordinarily make public. Attachment DIV 1-38-3 is an operational assessment and study of the Exeter LNG facility (the "LNG Study") and was prepared by a third party for National Grid USA. The LNG Study is subject to confidentiality restrictions and is of the type that would not ordinarily be made public. Attachment DIV 1-41-1 and Attachment DIV 1-41-2 contain the lease and operating agreements between the Company and the U.S. Navy for the LNG transfer station in Newport, Rhode Island. This information includes commercial terms such as pricing, trucking details, and Navy identification data. Public disclosure of such information could impair Rhode Island Energy's ability to negotiate advantageous pricing or other terms with the Navy in the future and compromise the safety and security of the LNG site, thereby causing substantial harm to the detriment of the Company and its customers. Attachment DIV 1-41-1 and Attachment DIV 1-41-2 also contain the names of military personnel, their contact information and signatures of the individuals executing the Company's lease and operating agreements with the Navy. This information is not material to this regulatory proceeding and the legitimate interest in maintaining it as confidential significantly outweighs any interest the public might have in accessing it. Accordingly, Rhode Island Energy is providing the information on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

With respect to the CEII contained in the Company's response to Division 1-10 and Attachment DIV 1-8 and Attachment DIV 1-35, CEII is defined by the Federal Energy Regulatory Commission ("FERC") as:

> [S]pecific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
>
> 1. Relates details about the production, generation, transmission, or distribution of energy;
> 2. Could be useful to a person planning an attack on critical infrastructure;
> 3. Is exempt from mandatory disclosure under the [Federal] Freedom of Information Act, 5 U.S.C. § 552; and
> 4. Does not simply give the general location of the critical information.

18 CFR § 388.113(c)(2). In turn, "critical infrastructure" is defined as:

> [E]xisting and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

18 CFR § 388.113(c)(4). The design specifications and schematic drawings, maps and related information contained in the response to Division 1-10 and Attachment DIV 1-8 and Attachment DIV 1-35 fall squarely within FERC's definition of CEII. Public dissemination of this information could pose a grave threat to public health and safety as it could be used to identify vulnerabilities in, and plan attacks against, natural gas transmission and distribution infrastructure. Under the Rhode Island Supreme Court's balancing test set forth in *Providence Journal v. Kane*, the public interest in access to this information is far outweighed by the threat to the public's health and safety that could result from public dissemination of these technical details concerning natural gas infrastructure.

IV. CONCLUSION

For the foregoing reasons, Rhode Island Energy respectfully requests that the PUC grant its Motion for Protective Treatment of the response to Division 1-10 and the Confidential

Attachments. In accordance with Rule 1.3(H) the Company has submitted redacted versions of Division 1-10 and the Confidential Attachments for the public file in this matter and unredacted confidential versions subject to this motion for protective treatment.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a RHODE ISLAND ENERGY

By its attorney,

Jennifer Brooks Hutchinson

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Dated: December 23, 2022

Testimony of
Michele V. Leone

PRE-FILED DIRECT TESTIMONY

OF

MICHELE V. LEONE

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I. Introduction and Qualifications

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

A. My name is Michele V. Leone. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what capacity?

A. I am Vice President - Gas for The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), an indirect wholly owned subsidiary of PPL Corporation ("PPL").

Q. What are your principal responsibilities in that position?

A. As Vice President- Gas for Rhode Island Energy, I have responsibility for overseeing the regulated gas distribution operations of PPL in Rhode Island provided by Rhode Island Energy and provide leadership and management to ensure safe and reliable gas service to our Rhode Island customers.

Q. Please describe your educational background and professional experience.

A. In 1993 I graduated from Syracuse University with a Bachelor of Science in Environmental Engineering and in 1995, I graduated from the University of Michigan with a Master of Science in Environmental Engineering. I worked at GZA GeoEnvironmental from 1995 through 2000 as an engineer and project manager focusing on the design and implementation of remediation systems. I joined National Grid USA ("National Grid") in 2000 and held a variety of positions in different areas of National Grid during the last 22 years. I began my career on National Grid's New England Site Investigation and Remediation ("SIR") team as a project manager responsible for overseeing the investigation and remediation of historic manufactured gas plant sites in Rhode Island and Massachusetts. From 2008 to 2014, I led the Update New York and New England SIR team responsible for the effective management of approximately $750 million in environmental liabilities. In 2015, I joined the Rhode Island leadership team as the Director of Performance and Strategy. In that role, I assisted the Rhode Island Jurisdictional President in leading the regulated business. Key functions included delivery of strong operational performance in the core business during blue sky days and storm/emergency response situations, interfacing with the functions to deliver positive financial results and regulatory outcomes consistent with targets, attainment of the annual gas and electric capital investment plans, and achievement of positive regulatory outcomes. In 2018 I joined the Electric Business Unit as the Director of Process and Performance Management where I managed the newly organized business unit's performance. In 2019 I joined the Global Safety, Health and Environment teams as the Director of Sustainability and Environment. In that role, I was responsible for leading the development of consistent Group-level environmental sustainability strategies and targets that advance the Company's climate change ambitions. In 2020 I joined the New England Gas Operations team as the Director of Field Operations for Rhode Island and Cape Cod.

In that role I was responsible for the safe, reliable, and successful execution of gas customer metering, gas construction, and gas distribution maintenance for 390,000 customers. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100% of the outstanding shares of common stock of the Company from National Grid (the "Acquisition"). While in my operations role at National Grid, I held a leadership role on the transition to prepare for the Acquisition. I began working in my current position upon the closing of the Acquisition.

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

A. Yes. I testified at least once before the PUC and sponsored data requests on SIR-related issues in the Company's prior Distribution Adjustment Clause proceedings between 2008 and 2014: Docket No. 3977 (2008), Docket No. 4077 (2009), Docket No. 4196 (2010), Docket No. 4269 (2011), Docket No. 4339 (2012), Docket No. 4431 (2013), and Docket No. 4514 (2014).

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to provide an overview of the objectives of the Company's Fiscal Year ("FY") 2024 Gas Infrastructure, Safety and Reliability Plan ("FY 2024 Gas ISR Plan" or the "Plan") as well as relevant context for the Plan in supporting Rhode Island Energy's vision.

Q. How is your testimony organized?

A. My testimony is organized as follows: Section I is the Introduction. Section II discusses certain context that is relevant to the FY 2024 Gas ISR Plan. Section III is the Conclusion.

II. <u>Rhode Island Energy's FY 2024 Gas ISR Plan Context</u>

Q. Please provide context for the FY 2024 Gas ISR Plan.

A. The Rhode Island natural gas distribution system is one of the oldest in the United States and includes a large proportion of natural gas pipeline classified by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") as leak-prone. Given the Company's obligation to provide safe and reliable service to customers in compliance with applicable state and federal pipeline safety statutes and regulations, it has instituted a pipeline replacement program. Specifically, in 2012 prior to the program, almost 50 percent of the Company's distribution system was comprised of pipeline material classified as leak-prone pipeline and, as of December 31, 2021, approximately 29 percent of the Company's gas distribution system in Rhode Island is comprised of leak-prone pipe a reduction of forty percent. From FY 2012 to through FY 2022, the Company has invested a total of $673 million to replace or rehabilitate of leak-prone pipe through the Company's Proactive Main Replacement and Public Works programs.

In addition to pipeline replacement, the Company's natural gas infrastructure program includes capital investments to (i) upgrade low-pressure distribution systems to high pressure distribution systems; and (ii) enhance the operations of the Company's liquified natural gas ("LNG") and gas regulation facilities.

Q. Is the Company reviewing approaches to managing leak-prone pipeline replacement?

A. Yes. First, Rhode Island Energy's strategy is to accelerate the elimination of leak prone pipe from 15 years to approximately ten years. Second, the Company's current approach to the replacement of leak-prone pipe is typically to prioritize replacement by segment, which may result in locations or neighborhoods having some streets containing leak-prone pipe and other streets without leak-prone pipe. The Company is piloting an approach that balances the segment priority for pipeline replacement with a broader view of the surrounding area or neighborhood. Under this approach, the Company will be able to take a more holistic approach to pipeline replacement, including the integration of alternative solutions.[1]

[1] Examples of alternative gas solutions include decarbonized fuels and electric heat. Such pathways are being more fully considered and discussed as part of the PUC's Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island In Light of the Act on Climate, Docket No. 22-01-NG.

Q. Please elaborate on how replacing low pressure systems with high pressure systems enhances gas system safety and reliability.

A. By upgrading low pressure systems to high pressure systems, the Company will be better positioned to manage safety and reliability through the installation of service regulators at the customer meter. The Company's pressure regulating facilities have been designed to reliably control gas distribution system pressures and maintain continuity of supply during normal and critical gas demand periods. Also, by upgrading low pressure system to high pressure systems, the Company reduces the need to balance and manage between low- and high-pressure systems. Lastly, low-pressure systems are more susceptible to water intrusion, which creates operational issues for the gas distribution system, and in turn, lowers reliability and can increase operating costs.

Q. Please elaborate on the Company's capital investment program for LNG and gas regulation facilities.

A. The LNG program is a significant component of Rhode Island Energy's strategy to enhance the safety and reliability of the natural gas distribution system. LNG facilities and equipment provide cost-effective scalable solutions capable of adapting the gas distribution system to various demand changes, which may result from operational issues, weather fluctuations, or regulatory and policy changes. This program, together with investments in other equipment on the system, such as heaters and pressure regulating facilities, provide a balanced approach for maintaining and enhancing gas system reliability.

Q. How does the Company's FY 2024 Gas ISR Plan align with Rhode Island Energy's vision?

A. Safety and reliability are paramount to Rhode Island Energy's mission and vision. The Gas ISR Plan includes capital investment spending needed to meet state and federal regulatory requirements applicable to the Company's gas system and to maintain its distribution infrastructure in a safe and reliable condition. To address the replacement of leak-prone pipe, the Plan includes infrastructure, safety, and reliability work for cast-iron and non-cathodically protected steel mains. The Plan also contains capital spending related to safety and reliability for public works projects, mandated programs, and gas reliability, including the Southern RI Gas Expansion Project.

Q. Does the FY 2024 Gas ISR Plan address the potential impacts of the Act on Climate's requirements for reduction in carbon emissions?

A. Yes. The Company has an obligation to provide safe and reliable service to customers today and into the future. In addition, the 2021 Act on Climate established economy-wide mandatory reduction targets for greenhouse gas emissions. The Gas ISR Plan contributes to achieving both of those objectives. Through the Proactive Main Replacement Program, the Company measures methane emissions reductions on a calendar year basis. From

2012 through 2021 the Company has reduced emissions from its gas distribution system. Also, in the proposed Plan, the Company will reduce emissions from the Cumberland Portable LNG operations by installing a Boil-off Gas Recovery Manifold.

Q. Why is Rhode Island Energy filing the FY 2024 Gas ISR Plan as a 21-month plan?

A. Rhode Island Energy has a legal obligation to provide safe and reliable service to its customers.[2] To ensure this standard of service is maintained, the Company files a proposed capital spending plan each fiscal year.[3] To effectuate the transition from National Grid's fiscal year to PPL's fiscal year, Rhode Island Energy is filing a one-time 21-month plan for FY 2024. The Company will return to a 12-month plan starting with the plan for FY 2025 which also aligns with calendar year 2025.

Q. How is the Company's FY 2024 Gas ISR Plan beneficial to customers?

A. Through the FY 2024 Gas ISR Plan, the Company will maintain and upgrade its gas delivery system by proactively replacing leak-prone pipe; upgrading the gas delivery system's custody transfer stations, pressure regulating facilities, and peak shaving plants; responding to emergency leak situations; and addressing infrastructure conflicts that arise out of state, municipal, and third-party construction projects. The Company intends to

[2] R.I. Gen. Laws § 39-2-1(a) ("Every public utility is required to furnish safe, reasonable, and adequate services and facilities.").

[3] R.I. Gen. Laws § 39-1-27.7.1(d) ("… the company shall file a proposed plan with the commission and commission shall review and, if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service over the short and long term, approve the plan within ninety (90) days.)

attain these safety and reliability goals through a cost-effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas pipeline infrastructure, promote efficiency in the management and operation of the gas distribution system, which in turn, benefits Rhode Island gas customers.

III. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

Joint Testimony of
Kocon & Hunt

DIRECT JOINT TESTIMONY

OF

NATHAN KOCON

AND

LAEYENG HUNT

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I. Introduction and Qualifications

Nathan Kocon

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

A. My name is Nathan Kocon. My business address is 477 Dexter Street, Providence, RI 02907.

Q. Mr. Kocon, by whom are you employed and in what capacity?

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") as the Principal Regulatory Analyst, within the Resource and Investment Planning group, for the Rhode Island Gas Division. I support Rhode Island for all gas system issues, with a focus on those related to the capital investment strategies for Rhode Island Energy. In my role, I work closely with the Rhode Island Jurisdictional President, the Vice President - Gas, and Jurisdiction staff on all local gas issues related to the Rhode Island natural gas distribution system. In this role, I am responsible for issues related to the natural gas distribution system, developing strategies to support Company objectives regarding investment in the natural gas distribution system, and supporting Rhode Island Energy's gas capital investments i during state regulatory proceedings.

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

A. In 2005, I graduated from Northeastern University with a Bachelor of Science in Business Administration with a dual concentration in Finance and Marketing. I joined National Grid USA ("National Grid") in 2013 as a Lead Analyst in the Process and Performance group within the Customer Organization. Since that time, I completed National Grid's Performance Excellence Practitioner, Senior Practitioner, and Coach Practitioner Trainings and led several process and performance improvement initiatives. From February 2019 until May 2022, I was a Principal Regulatory Analyst, within the Resource and Investment Planning group at National Grid. Prior to joining National Grid, from 2010 to 2013, I worked for Ernst & Young in the Financial Investigations and Dispute Services – Government Contract Services group. I am also a Certified Fraud Examiner. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation, acquired 100% of the outstanding shares of common stock of the Company from National Grid (the "Acquisition"), at which time I assumed my current position with Rhode Island Energy.

Q. Mr. Kocon, have you previously testified before the Rhode Island Public Utilities Commission ("PUC")?

A. Yes, in 2021 and 2022, I testified before the PUC and filed pre-filed direct testimony in support of the Company's Fiscal Year ("FY") 2022 and FY 2023 Gas Infrastructure, Safety, and Reliability ("ISR") Plans in Docket Nos. 5099 and 5210.

Laeyeng Hunt

Q. Mrs. Hunt, please state your name and business address.

A. My name is Laeyeng Hunt. My business address is 477 Dexter St, Providence, RI 02907.

Q. Mrs. Hunt, by whom are you employed and in what capacity?

A. I am employed by Rhode Island Energy as the Director of Engineering and Asset Management. In my role, I oversee the asset management and engineering design and provide input to capital investment strategies for Rhode Island.

Q. Mrs. Hunt, please describe your educational background and professional experience.

A. In 1994, I graduated from Tufts University with a Bachelor of Science in Civil Engineering. In 1995, I graduated from Tufts University with a Master of Science in Environmental Engineering. In 2004, I joined National Grid as a Lead Engineer in the Operations Engineering group. Since that time, I have held a variety of positions in Integrity Engineering, Public Works Engineering, Resource Planning, and Resource Coordination and Scheduling. In addition, from 1995 to 2004, I worked for engineering consultant firms that provide services for the Massachusetts Water Resource Authority and Boston Water & Sewer Commission. Upon the closing of the Acquisition, I assumed my current position with Rhode Island Energy.

Q. Mrs. Hunt, have you previously testified before the PUC?

A. No.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your joint testimony?

A. The purpose of our joint testimony is to describe the Company's proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan ("Gas ISR Plan" or "Plan" or "21-Month Plan").[1] Through our testimony, we present the Company's Gas ISR Plan, which details the work the Company expects to complete under the Plan, the anticipated capital investments associated with that work, and the resulting plant additions. To gain alignment with the Company's financial schedule[2], Rhode Island Energy is submitting a 21-Month Plan for approval. The Plan consists of a 9-month period from April 1, 2023 through December 31, 2023 and a 12-month period from January 1, 2024 through

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[1] The Company is required by statute to annually file an infrastructure, safety, and reliability spending plan with the PUC for review and approval. *See* R.I. Gen. Laws § 39-1-27.7.1(d).

[2] To transition the filing of ISR plans from National Grid's fiscal year (April 1 – March 31) to PPL Corporation's ("PPL") fiscal year (January 1 – December 31), the Company is proposing a one-time 21-month plan that will run from April 1, 2023 through December 31, 2024. Subsequent ISR plans would be for 12 months from January 1 through December 31.

December 31, 2024. For purposes of avoiding confusion, the Company has labeled the time periods referenced within the Plan as follows:

- FY 2023 means April 1, 2022 through March 31, 2023;
- CY 2023 means the 9-month period of April 1, 2023 through December 31, 2023;
- CY 2024 means the 12-month period of January 1, 2024 through December 31, 2024; and
- 21-Month Plan means April 1, 2023 through December 31, 2024.

Company Witnesses Stephanie A. Briggs, Jeffrey D. Oliveira, Andrew W. Elmore, and Natalie Hawk are providing testimony on the calculation of the revenue requirements associated with the Company's 21-Month Plan, and the Company's Witness Peter R. Blazunas is providing testimony relative to (1) how the Company calculated the rate design for the ISR mechanism; (2) the calculation of the ISR factors; and (3) the customer bill impacts of the proposed ISR factors.

III. Overview

Q. What is the Gas ISR Plan designed to accomplish?

A. Overall, the Gas ISR Plan will allow the Company to meet state and federal safety and reliability requirements and to maintain and upgrade its gas distribution system to a safe and reliable condition. The Plan has been developed to improve the safety and reliability of the Company's gas system for the immediate and continuing benefit of Rhode Island's natural gas customers.

The Gas ISR Plan is designed to establish a spending plan, together with a reconcilable allowance for the anticipated capital additions being placed in service for the fiscal year and other spending needed to maintain and upgrade the Company's gas distribution system,[3] such as proactively replacing leak-prone pipe; upgrading the gas delivery system's custody transfer stations; pressure regulating facilities; and peak shaving plants; responding to emergency leak situations; and addressing infrastructure conflicts that arise out of state, municipal, and third-party construction projects. The Company intends to attain these safety and reliability goals through a cost-effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas pipeline infrastructure, promote efficiency in the management and operation of the gas distribution system and directly benefit Rhode Island gas customers. The Plan also helps reduce the annual methane emissions released by the gas distribution system, primarily through the replacement and abandonment of leak-prone pipe with its Proactive Main Replacement programs. Where possible, the Company seeks to employ cost effective scalable solutions, such as portable LNG equipment, to adapt the gas distribution system to any changes to the delivery of energy

[3] *See* R.I. Gen. Laws § 39-1-27.7.1(c)(2).In accordance with the PUC's Order in Docket No. 5099 (FY 2022 Gas ISR), effective April 1, 2021, the Company aligned the calculation of the Gas ISR revenue requirement with the Electric ISR and implemented a plant-in-service methodology to calculate the Gas ISR revenue requirement.

that might arise because of the mandates of the Act on Climate while fulfilling the duty to deliver natural gas safely and reliably to all existing customers.

Q. Explain the review of the Gas ISR Plan that has occurred to date?

A. The Company developed the Gas ISR Plan and submitted it to the Rhode Island Division of Public Utilities and Carriers ("Division") for review on October 21, 2022 in accordance with R.I. Gen. Laws § 39-1-27.7.1 (the "Revenue Decoupling Law").[4] On November 1-2, 2022 the Company met with the Division regarding the Plan and subsequently responded to fifty-one formal data requests from the Division regarding various components of the Plan. The Company also hosted the Division for a site tour of the Company's Exeter LNG Facility on November 21, 2022. The Company and the Division continued to consult regarding the proposed Plan on several occasions, including a subsequent meeting on November 29, 2022 and various other informal conversations. Despite these good faith efforts, the Company and the Division were unable to reach an agreement on the Plan. The Company now submits the Plan to the PUC for review and approval in accordance with the Revenue Decoupling Law.[5]

[4] Pursuant to R.I. Gen. Laws § 39-1-27.7.1(d), the Company must consult with the Division on a proposed plan, and the Division must cooperate in good faith with the Company to reach an agreement on the proposed plan within sixty (60) days. If the Company and the Division cannot agree on a plan, the Company shall file a proposed plan with the PUC for review, and if the PUC finds that the investments and spending are reasonably needed to maintain safe and reliable distribution service over the short and long term, the PUC must approve the plan within ninety (90) days.

[5] *See* R.I. Gen. Laws § 39-1-27.7.1(d); Note 5, *supra*.

Q. Are you sponsoring any attachments to your testimony?

A. Yes. The proposed Gas ISR Plan is attached as Attachment1 to our joint testimony. The Plan is organized as follows:

Section 1 – Introduction and Summary
Section 2 – Gas Capital Investment Plan (including major categories of work)
Section 3 – Revenue Requirement Calculation
Section 4 – Rate Design and Bill Impacts
Schedule 1 – 2021 System Integrity Report

Our testimony focuses on Sections 1 and 2 of the Plan. As noted earlier, Ms. Briggs, Mr. Oliveira, Mr. Elmore, and Ms. Hawk are sponsoring the revenue requirements calculation included in Section 3 of the Plan; and Mr. Blazunas is sponsoring the rate design and bill impacts included in Section 4 of the Plan.

Q. What types of infrastructure, safety, and reliability work does the Gas ISR Plan include?

A. The Gas ISR Plan seeks not only to maintain the Company's distribution system, but also to proactively upgrade the system's condition to address problems before they arise. A safe and reliable gas delivery system in Rhode Island is essential to the health, safety, and well-being of its citizens, and for maintaining a healthy economy and continuing to attract new residents and businesses to Rhode Island. In 2008, the PUC embarked on a course of addressing Rhode Island's aging gas infrastructure with the establishment of the

Accelerated Replacement Plan. The Company filed its first Gas ISR Plan on December 20, 2010 for FY 2012. In addition to the type of infrastructure, safety, and reliability work performed under the Accelerated Replacement Plan, the Gas ISR Plan contains spending related to safety and reliability for public works, mandated programs, and reliability programs, including Southern RI Gas Expansion Project. Included in the Plan is a description of the Company's proposed budget for capital investment for the 21-Month Plan, the capital additions projected to be placed in service during the 21-Month Plan, which includes CY 2023 and CY 2024, and a five-year capital plan forecast that covers the period of April 1, 2023 through December 31, 2026 (also referred to as CY 2023 through FY 2026).

As noted in the FY 2022 Gas ISR Plan, the Southern RI Gas Expansion Project presented unique challenges for the Company with managing the Plan during the Main Installation phase of the project due to its size, cost, and complexity. Since FY 2020 and in this filing, the Company has listed the Southern RI Gas Expansion Project as a distinct category and will continue to manage the Southern RI Gas Expansion Project as a distinct portfolio of spending. Since the Main Installation phase of this project will be completed by the end of FY 2023, the Company is open to moving this program to the Discretionary – Reliability category to simplify future reporting, subject to PUC approval.

This year's Plan also includes a section describing the history and effectiveness of the Gas ISR Plan, along with a section regarding the Act on Climate and the historical and forecasted methane emissions reductions from the abandonment of leak prone pipe. The Plan also includes a copy of the most recent System Integrity Report, as ordered by the PUC in Docket No. 4781.

IV. Capital Investment Plan

Q. What levels of spending are proposed in the Gas ISR Plan?

A. For the 21-Month Plan, the Company proposes to invest a total of $388.53 million, including $99.83 million for non-discretionary capital expenditures; and $288.70 million for discretionary capital expenditures, which includes $13.15 million for the Southern RI Gas Expansion Project. The total of $388.53 million includes $18.33 million related to the Cost of Removal. The capital additions projects to be placed in-service for the 21-month period of the Plan are projected to be $346.84 million, which is included in the 21-Month Gas ISR recovery mechanism.

The Plan is broken down into categories of non-discretionary and discretionary costs, each of which contain programs designed to maintain the safety and reliability of the Company's gas delivery infrastructure. Non-discretionary programs include work required by legal, regulatory code, and/or agreement, or a result of damage or failure, with limited exceptions. Discretionary programs are not required by legal, regulatory code, and/or agreement, with limited exceptions.

Q. What levels of spending is the Company proposing for non-discretionary programs?

A. For each non-discretionary program category in the 21-Month Plan, the Company proposes the following levels of spending:

- $42.60 million net investment for Public Works programs, including $44.40 million in capital spend less $1.81 million in reimbursements;
- $57.19 million for Mandated Programs (i.e., Corrosion, Purchase Meter Replacement, Reactive Leaks (Cast Iron Joint Encapsulation/Service Replacement), Service Replacement (Reactive) – Non-Leak/Other, Main Replacement (Reactive) – Maintenance (including Water Intrusion), Low Pressure System Elimination (Proactive), Transmission Station Integrity, Pipeline Integrity – Integrity Verification Program; and
- $0.04 million for Damage/Failure programs.

Q. What levels of spending is the Company proposing for discretionary programs?

A. For the discretionary programs in the 21-Month Plan, the Company proposes the following levels of spending:

- $166.95 million for the Proactive Main Replacement and Rehabilitation program (i.e., Proactive Main Replacement, Large Diameter, and Atwells Avenue project);

- $1.08 million for the Proactive Service Replacement program;
- $107.52 million for Gas System Reliability, including work relative to System Automation, Heater Program, Tiverton Gate Station, Take Station Refurbishment, Pressure Regulating Facilities, Valve Installation/Replacement, Gas System Reliability Enhancement, Instrumentation and Regulation (I&R) – Reactive, Distribution Station Over Pressure Protection, Liquefied Natural Gas (LNG) facilities and equipment, Replace Pipe on Bridges, Access Protection Remediation, Tools and Equipment, and Weld Shop; and
- $13.15 million for the Southern RI Gas Expansion Project.

Q. What level of spending is the Company proposing for the Operation and Maintenance (“O&M”) Expenses category?

A. The Company does not propose any O&M Expenses in the 21-Month Plan.

Q. How does the Company plan to address the replacement of leak-prone pipe in Rhode Island in the 21-Month Plan?

A. To continue providing safe and reliable gas service to its Rhode Island customers, the Company’s 21-Month Plan includes the elimination or rehabilitation of a total of approximately 122.5 miles of leak-prone pipe consisting of: (1) approximately 93.2 miles of proactive main replacement including Atwells Avenue, (2) 23.0 miles of public works replacement, (3) 0.5 mile of mandated work, (4) 2.1 miles of reliability work, (5) 1.7 miles of reinforcement work, and (7) 2.1 miles of rehabilitation work. The resulting abandonment target of approximately 69.5 miles for CY 2024 is an increase of approximately 5.0 miles compared to the FY 2023 ISR Plan. The CY 2023 abandonment target of 51.0 miles was determined by using the CY 2024 target as a baseline and reviewing historical performance and current forecasts to determine how many miles would actually be abandoned between April 1, 2023 and December 31, 2023. The total number of miles abandoned and installed were typically in close alignment over a 12-month period starting on April 1 (before the COVID-19 Pandemic). The Company typically completes its final miles of abandonment between January and March and begins the installation of some new main in March. The table below shows that the target abandonment for CY 2023 is approximately 12.8 miles less than target installation miles. This is because January through March are not included as part of CY 2023. Total abandonment and installation miles are back in close alignment in CY 2024.

The table below provides a summary of the planned volume of leak-prone pipe abandonment, installation, and rehabilitation miles across the entire Gas ISR portfolio for the 21-Month Plan. Any line items highlighted in gray are rehabilitation and do not count towards the abandonment total.

	CY 2023 9-Month		CY 2024 12-Month		21-Month Plan Total	
Category	**Abandonment/ Rehabilitation Miles**	**Installation Miles**	**Abandonment/ Rehabilitation Miles**	**Installation Miles**	**Abandonment/ Rehabilitation Miles**	**Installation Miles**
NON-DISCRETIONARY						
Public Works	9.0	14.0	14.0	14.0	23.0	28.0
Mandated Programs						
Low Pressure System Elimination (Proactive)	0.0	1.0	0.5	2.6	0.5	3.6
DISCRETIONARY						
Proactive Main Replacement & Rehabilitation						
Proactive Main Replacement - LPP	39.5	46.9	53.4	51.9	92.9	98.8
CI Lining - Rehabilitation	0.0	0.0	0.4	0.0	0.4	0.0
CISBOT - Rehabilitation	0.7	0.0	1.0	0.0	1.7	0.0
Atwells Avenue	0.3	0.3	0.0	0.0	0.3	0.3
Reliability						
Gas System Reliability	1.5	1.6	0.6	1.5	2.1	3.1
Reinforcement	0.7		1.0		1.7	
Total Rehabilitation	0.7	0.0	1.4	0.0	2.1	0.0
Total Leak Prone Pipe Abandonment/ Installation	51.0	63.8	69.5	70.0	120.5	133.8
Total Rehabilitation and LPP Abandonment	**51.7**	**63.8**	**70.9**	**70.0**	**122.5**	**133.8**

The Company believes that the 21-Month Plan's leak prone pipe abandonment targets of 51.0 miles for CY 2023 and 69.5 miles for CY 2024 aligns with the resources that are forecasted to be available to perform the abandonments. Additionally, the Company is currently exploring strategies to accelerate the elimination of leak prone pipe from the gas distribution system from the current 15 year forecast to approximately 10 years. One of the likely strategies would be to increase the annual planned installation/replacement and abandonment miles of leak prone pipe.

For the 21-Month Plan, the Company is proposing spending of $209.55 million for leak-prone pipe abandonment, installation, and rehabilitation, which includes $166.95 million for the Proactive Main Replacement program (which includes $8.64 million for the Large Diameter LPCI Program and $1.14 million for the Atwells Avenue project), and $42.60 million for the Public Works program. Additional programs, such as the Low Pressure System Elimination and Gas System Reliability will also result in the abandonment of leak prone pipe. The Company has increased the Proactive Main Replacement program cast iron abandonment target percentage from seventy percent (70%) for FY 2023 to seventy-six (76%) for the CY 2023 workplan. Cast iron represents sixty seven percent (67%) of the Company's total leak-prone main inventory in Rhode Island. As illustrated on page 25 in the attached 2021 System Integrity Report, cast iron represented eighty-four (84%) of main leak repairs in 2021, which continues to support the focus on cast iron pipe for abandonment.

Q. What is the difference between installation miles and abandonment miles in relation to the replacement of leak-prone pipe?

A. Installation miles represent the units of new main that are required to be connected to the distribution system. Thus, installation miles represent the main driver for unit costs when combined with service relays and tie overs. Abandonment miles represent the total of the old leak-prone pipe that is retired or disconnected from the distribution system.

Q. How do the leak-prone pipe replacement programs in the 21-Month Plan compare to the FY 2023 programs?

A. Since the abandonment targets for CY 2024 were used as a baseline for determining the abandonment and installation targets for CY 2023, the Company will use CY 2024 to compare with FY 2023. The overall abandonment for the ISR portfolio will increase from 64.5 miles (i.e., the target for FY 2023) to 69.5 miles for CY 2024. The Company is on pace to achieve the FY 2023 target and is confident the additional 5 miles of abandonment can be achieved. The Company is actively working on efforts to increase its capacity to abandon main in the near term. These efforts include hiring additional construction, maintenance, and customer meter services personnel, along with process improvements to increase efficiencies. At a program level, for CY 2024, the Public Works program abandonment and installation miles will both remain at 14.0 miles which matches the FY 2023 targets. For CY 2024, the Main Replacement – Leak Prone Pipe program abandonment target is increasing from 49.1 miles in FY 2023 to 53.4 miles.

Q. Has the Company's efforts at replacing leak-prone pipe been effective?

A. Yes. When the ISR program was first implemented in FY 2012, approximately forty eight percent (48%) of the Company's gas distribution pipe in Rhode Island was leak-prone pipe. Through the FY 2022 Gas ISR Plan, the Company has abandoned a total of 605 miles of leak-prone pipe, which has contributed to an estimated reduction of 1,658 leaks. To monitor its system performance, the Company prepares an annual System

Integrity Report. A copy of the most recent System Integrity Report (2021) is provided in Schedule 1 at the end of the Plan. The System Integrity Report provides historical data on leak receipts, leak repairs, open leaks, and inventory of mains and services. Additional data is provided around material type for each of the listed categories. The Company considers leak receipts to be an important system performance indicator regarding the effectiveness of its leak-prone pipe abandonment program. Since 2010, the Company has seen an overall downward trend in leak receipts, which indicates that the ISR and ARP programs have contributed to this result. The System Integrity Report shows that there was a slight increase in leak receipts from 2017-2019, but the volume decreased in 2020 and 2021. Notably, variability in year-to-year annual leaks per mile will occur. Contributing factors include weather, public awareness, and overall system deterioration rates. In FY 2021, the Company noticed the increase in cast iron leak activity and increased the target abandonment percentage of cast iron main in the FY 2022 workplan to seventy percent (70%). For CY 2023, the workplan for the Proactive Main Replacement program targets abandonment of seventy-six percent (76%) cast iron main.

Q. Has the Company made any modifications in the Plan related to the replacement of leak-prone pipe?

A. Yes. As indicated above, the Company has increased the Proactive Main Replacement program cast iron abandonment percentage from seventy percent (70%) in the FY 2023 workplan to seventy-six percent (76%) for CY 2023. The Company is currently evaluating whether to expand the scope of the Public Works program criteria to include leak prone pipe in general (current criteria is only cast iron) and roads that are undergoing restoration, which could include mill/overlay paving and general beautification projects (current criteria is only full depth reconstruction paving).

V. <u>Conclusion</u>

Q. Does the 21-Month Gas ISR Plan fulfill the Company's statutory obligation to plan for the safe and reliable delivery of gas through the Company's distribution system in Rhode Island?

A. Yes. The 21-Month Gas ISR Plan will permit the capital investment in Rhode Island that is necessary to meet the needs of the Company's customers, together with a spending and work plan to maintain the overall safety and reliability of the Company's Rhode Island gas distribution system.

Q. Does this conclude your testimony?

A. Yes.

Gas ISR FY2024 Plan

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

Proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan

21-Month Filing April 2023 – December 2024

December 22, 2022

Docket No: 22-54-NG

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Section 1
Introduction & Summary

Section 1
Introduction and Summary

Proposed FY 2024 Gas Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Gas ISR Plan
April 2023 – December 2024

Introduction and Summary
FY 2024 Gas ISR Plan
21-Month Plan

Rhode Island Energy[1] submits the following proposed fiscal year ("FY") 2024 Gas Infrastructure, Safety and Reliability ("ISR") plan ("Gas ISR Plan" or "Plan" or "21-Month Plan") to the Rhode Island Public Utilities Commission ("PUC") for review and approval in compliance with R.I. Gen. Laws § 39-1-27.7.1 ("Revenue Decoupling Law"), which provides for the filing of "[a]n annual gas 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."[2] Rhode Island Energy consulted with the Rhode Island Division of Public Utilities and Carriers (the "Division") regarding the 21-Month Plan as required by the Revenue Decoupling Law; however, despite good faith efforts, the Company and the Division were unable to reach an agreement on the Plan.[3]

1 The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company").

2 R.I. Gen. Laws § 39-1-27.7.1(c)(2).

3 Pursuant to subsection (d), the Company must consult with the Division on a proposed plan, and the Division must cooperate in good faith with the Company to reach an agreement on the proposed plan within sixty (60) days. If the Company and the Division cannot agree on a plan, the Company shall file a proposed plan with the PUC for review, and if the PUC finds that the investments and spending are reasonably needed to maintain safe and reliable distribution service over the short and long term, the PUC must approve the plan within ninety (90) days.

To gain alignment with the Company's financial schedule[4], Rhode Island Energy is submitting a 21-Month Plan for approval. This Plan consists of the 9-month period from April 1, 2023 through December 31, 2023 and the 12-month from January 1, 2024 through December 31, 2024. For purposes of avoiding confusion, the Company has labeled the time periods referenced within the Plan as follows:

- FY 2023 means April 1, 2022 through March 31, 2023
- CY 2023 means the 9-month period of April 1, 2023 through December 31, 2023
- CY 2024 means the 12-month period of January 1, 2024 through December 31, 2024
- 21-Month Plan means April 1, 2023 through December 31, 2024

The proposed Gas ISR Plan addresses capital spending on gas infrastructure and other costs related to maintaining the safety and reliability of the Company's gas distribution system. Through the Plan, the Company will maintain and upgrade its gas delivery system by proactively replacing leak-prone pipe; upgrading the gas delivery system's custody transfer stations, pressure regulating facilities, and peak shaving plants; responding to emergency leak situations; and addressing infrastructure conflicts that arise out of state, municipal, and third-party construction projects. The Company intends to attain these safety and reliability goals through a cost-

4 On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation ("PPL), acquired 100% of the outstanding shares of common stock of the Company from National Grid USA ("National Grid"). To transition the filing of ISR plans from National Grid's fiscal year (April 1 – March 31) to PPL's fiscal year (January 1 – December 31), the Company is proposing a one-time 21-Month Plan for the period of April 1, 2023 through December 31, 2024. Subsequent ISR plans will be for 12 months from January 1 – December 31.

effective, coordinated work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island gas distribution infrastructure, promote efficiency in the management and operation of the gas distribution system and directly benefit Rhode Island gas customers. The Plan also helps reduce the annual methane emissions released by the gas distribution system, primarily through the replacement and abandonment of leak-prone pipe with its Proactive Main Replacement programs. Where possible, the Company seeks to employ cost effective scalable solutions, such as portable LNG equipment, to adapt the gas distribution system to any changes to the delivery of energy that might arise as a result of the mandates of the Act on Climate while fulfilling the duty to safely and reliably deliver natural gas to all existing customers.

This Introduction and Summary presents (1) a history of the Gas ISR program in Rhode Island and a statement regarding how the ISR program has contributed to safety and reliability; (2) an overview of the proposed 21-Month Plan for the statutory categories of costs and the capital additions projected to be placed in-service in CY 2023 and CY 2024; (3) the resulting 21-Month revenue requirement associated with the proposed Plan; and (4) the rate design based upon that revenue requirement and estimated typical bill impacts resulting from the rate design.

The Gas ISR Plan describes the Company's safety and reliability activities and the multi-year plan upon which the 21-Month Plan is based. The Plan also addresses capital investment in utility infrastructure for CY 2023 and CY 2024. The Plan itemizes the recommended work activities by general category and provides budgets for capital investment.

The Company will continue to file quarterly reports with the Division and the PUC concerning the progress of its Gas ISR programs. In addition, when the Company makes its reconciliation and rate adjustment filing described below, the Company will file an annual report on the prior fiscal year's activities and the resulting plant additions. In implementing an ISR plan in any fiscal year, the circumstances encountered during the year may require reasonable deviations from the original ISR plan. In such cases, the Company will include in its quarterly reports an explanation of any significant deviations.

The level of capital spending provided in the 21-Month Plan to maintain the safety and reliability of the Company's gas delivery infrastructure is $388.53 million, which would contribute to plant additions of $346.84 million. As described in more detail below, this budget amount includes $13.15 million to continue the Southern Rhode Island Gas Expansion Project, which the Company manages as a distinct spending portfolio. In addition to the $388.53 million included in the 21-Month Plan budget, the Company also plans to have capital spending that is not currently included in the ISR of $15 million for the Old Mill Lane project and $1.50 million for the LNG – Cumberland Tank Replacement project.

A description of the Company's proposed capital investment plan and capital additions projected to be placed in-service for the 21-Month Plan period, including a breakout of what will occur in CY 2023 and the CY 2024, is included in Section 2. The revenue requirement description and calculations are contained in Section 3. A description of the rate design and bill impacts are provided in Section 4.

History of the ISR Plan

The Rhode Island natural gas distribution system is one of the oldest in the United States and includes a large proportion of leak-prone and deteriorating infrastructure installed, in some instances, more than 100 years ago. The Company, which owns and operates the gas distribution system, has an obligation to provide safe and reliable service to customers in compliance with applicable state and federal pipeline safety statutes and regulations. However, the challenge of meeting this obligation is amplified on the portions of the distribution system containing leak-prone pipe, consisting of unprotected steel, cast iron, and wrought iron, and vintage Aldyl-A and Polybutylene plastic pipe.

In accordance with the Revenue Decoupling Law, the Company filed its first Gas ISR Plan on December 20, 2010 for FY 2012. The ISR program replaced the Accelerated Replacement Program ("ARP"), which began as part of the Company's 2008 rate case in Docket No. 3943. The ARP targeted the replacement of cast iron and non-cathodically protected steel mains and non-cathodically protected steel inside services. The ISR program expanded on the ARP through inclusion of other capital programs related to safety and reliability for public works, mandated programs, and reliability. Starting with the FY 2021 Reconciliation, in accordance with the PUC's Order in Docket 5099 (FY 2022 Gas ISR), effective as of April 1, 2021, the Company aligned "the calculation of its Gas ISR revenue requirement with the Electric ISR[5]" and implemented the plant-in-service methodology; the plant in-service methodology was

[5] PUC Order 24042, Docket No. 5099 Final Order, dated May 6, 2021.

used to calculate the 21-Month Plan revenue requirement. From FY 2012 to through FY 2022, the Company has invested a total of $1.144 billion through the Gas ISR program. This includes a total of $673 million that targeted the replacement or rehabilitation of leak-prone pipe through the Company's Proactive Main Replacement and Public Works programs. When the ISR program was first implemented, approximately forty eight percent (48%) of the Company's gas distribution system in Rhode Island was comprised of leak-prone pipe. As of December 31, 2021, that percentage has been reduced and approximately twenty nine percent (29%) of the Company's gas distribution system in Rhode Island is comprised of leak-prone pipe. The table below highlights a total of 605 miles of leak-prone pipe abandoned through the FY 2022 ISR Plan that has contributed to an estimated reduction of 1,658 leaks.

Description	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	Total
Total ISR Abandonment Miles	46	47	53	55	59	63	62	60	62	30	68	605
Gas Leaks Eliminated	191	186	140	121	150	103	178	160	160	79	190	1,658

To monitor its system performance, the Company prepares an annual System Integrity Report. A copy of the most recent System Integrity Report (2021) is provided as Schedule 1 at the end of the Plan. The System Integrity Report provides historical data on leak receipts, leak repairs, open leaks, and inventory of mains and services. Additional data is provided around material type for each of the listed categories. The Company considers leak receipts to be an important system performance indicator regarding the effectiveness of its leak-prone pipe abandonment program. Since 2010, the Company has seen an overall downward trend in leak receipts, which indicates that the ISR and ARP programs have contributed to this result. The System Integrity Report shows that there was a slight increase in leak receipts from 2017-2019, but the volume decreased in 2020 and 2021. Notably, variability in year-to-year annual leaks per mile will occur. Contributing factors include weather, public awareness, and overall system deterioration rates. In FY 2021, the Company noticed the increase in cast iron leak activity and increased the target abandonment percentage of cast iron main in the FY 2022 workplan to seventy percent (70%); for CY 2023, the workplan for the Proactive Main Replacement program targets abandonment of seventy-six percent (76%) cast iron main.

Act on Climate

The Company has an obligation to provide safe and reliable gas service to customers today and into the future. In addition, the 2021 Act on Climate established economy-wide mandatory reduction targets for greenhouse gas emissions. The Gas ISR Plan contributes to achieving both of those objectives. Since the inception of the ISR program, a major component of the Company's annual workplan has and will continue to include the replacement and abandonment of leak prone pipe, which contributes to the safe and reliable operation of the gas distribution system. An additional benefit of the leak prone pipe replacement is that it helps to reduce the emissions from the gas distribution system. Through the Proactive Main Replacement Program, the Company measures methane emissions reductions on a calendar year basis. From 2012 through 2021 the Company has reduced emissions from its gas distribution system by 92,918 thousand cubic feet ("MCF"). In calendar year 2023 the Company plans to reduce emissions by

17,697 MCF and another 19,369 MCF in 2024. In the 21-Month Plan, the Company will also reduce emissions from the Cumberland Portable LNG operations by installing a Boil-off Gas Recovery Manifold.

Section 2: Gas Capital Investment Plan

The Company's proposed gas capital investment plan set forth in Section 2 summarizes the Company's planned capital investments and capital additions projected to be placed in-service for the following key Discretionary[6] and Non-Discretionary[7] sub-categories.

Non-Discretionary:

A. Public Works

B. Mandated Programs

C. Damage/Failure

Discretionary:

A. Proactive Main Replacement and Rehabilitation

B. Proactive Service Replacement

C. Gas System Reliability

D. Southern RI Gas Expansion

[6] Discretionary programs are not required by law, regulatory code, or agreement, or a result of damage or failure, with limited exceptions.

[7] Non-Discretionary programs include projects that are required by law, regulatory code, and/or agreement, or which are the result of damage or failure, with limited exceptions.

The Company has included its capital budget, identified relevant projects that would be part of the Gas ISR Plan, its rationale for the need for and benefit of performing such work to provide safe and reliable service to its customers, and the resulting capital additions that would be added to the revenue requirement over the 21-Month Plan. The Company has also provided a five-year ISR capital plan to provide a preview of the longer-term approach to infrastructure, safety, and reliability and to demonstrate how the 21-Month Plan would be incorporated into that longer-term planning approach. The five-year capital plan covers the period of April 1, 2023 through December 31, 2026. Finally, the Company has provided the most recent five-year history of ISR capital spend for reference.

The Company's 21-Month Plan includes the elimination or rehabilitation of a total of approximately 122.5 miles of leak-prone pipe (approximately 93.2 miles of proactive main replacement including Atwells Avenue, 23.0 miles of public works replacement, 0.5 mile of mandated work, 2.1 miles of reliability work, 1.7 miles of reinforcement work, and 2.1 miles of rehabilitation work). This results in abandonment targets of 51.0 miles for CY 2023 and 69.5 miles for CY 2024. For CY 2023, the workplan for the Proactive Main Replacement program targets abandonment of seventy six (76%) cast iron main. This is a slight increase from the FY 2023 Plan that targeted 70% cast iron.

The 21-Month Plan also continues to include a category for Gas Expansion, namely, to reinforce the distribution mains in Southern Rhode Island (the "Southern RI Gas Expansion Project"). As noted in the FY 2022 Gas ISR Plan, the Southern RI Gas Expansion Project presented unique challenges for the Company with managing the Plan during the Main Installation phase of the project due to its size, cost, and complexity. For this filing, the Company has listed the Southern RI Gas Expansion Project as a distinct category and will continue to manage the Southern RI Gas Expansion Project as a distinct portfolio of spend. However, since the Main Installation phase of this project will be completed by the end of FY 2023, the Company is open to moving this program to the Discretionary – Reliability category to simplify future reporting, subject to PUC approval.

Section 3: Revenue Requirement

The Company has provided a calculation of the revenue requirements for the capital investment in the proposed 21-Month Plan. Section 3 of the Plan contains a description of the revenue requirement model and an illustrative calculation for the 21-Month Plan. This calculation will form the basis for the Plan rate adjustment, which would become effective on April 1, 2023 upon the PUC's approval. As provided in Section 3 of the Plan, in accordance with the Company's gas tariff, RIPUC NG-GAS No. 101, Section 3, Schedule A, Item No. 3.3, the Company will reconcile this rate adjustment as part of its annual Distribution Adjustment Charge filing. The pre-tax rate of return on rate base is the rate of return approved by the PUC in the Amended Settlement Agreement in the Company's most recent general rate case, Docket No. 4770. In the future, the pre-tax rate of return would change to reflect changes to the rate of return approved by the PUC in future rate case proceedings. Any change in the rate of return would be applicable on a prospective basis, effective at the time of the change.

Section 4: Rate Design

For purposes of rate design, the 21-Month Plan revenue requirement associated with total net capital investment is allocated to rate classes based upon the most recent rate base allocator approved in the Amended Settlement Agreement in Docket No. 4770. For each rate class, the allocated revenue requirement is divided by the applicable fiscal year (21-month period) forecasted therm deliveries to arrive at a per-therm factor unique to each rate class.

The proposed rate design and associated estimated typical bill impacts are provided in Section 4. The estimated bill impact of the Gas ISR Plan for the average Residential Heating customer, using 845 therms annually, would be an annual increase of $113.88, or 6.6%, from current bills.

Section 2
Gas Capital Investment

Section 2
Gas Capital Investment Plan

Proposed FY 2024 Gas Infrastructure, Safety, and Reliability ("ISR") Plan

21-Month Plan
April 2023 – December 2024

Gas Capital Investment Plan
FY 2024 Gas ISR Plan
21-Month Plan

Background

The Company developed its proposed capital investment plan to meet its obligation to provide safe, reliable, and efficient gas distribution service for customers at reasonable costs.[8] The Gas ISR Plan includes capital investment spending needed to meet state and federal regulatory requirements applicable to the Company's gas system and to maintain its distribution infrastructure in a safe and reliable condition. To address the replacement of leak-prone pipe, the Plan includes infrastructure, safety, and reliability work for cast-iron and non-cathodically protected steel mains. The Plan also contains capital spending related to safety and reliability for public works projects, mandated programs, and gas reliability, including the Southern RI Gas Expansion Project.

Consistent with the goals of the Revenue Decoupling Law, to continue providing provide safe and reliable gas delivery service to Rhode Island customers, it is critical that the Company remain vigilant with respect to investing in its infrastructure and have appropriate and timely cost recovery. To that end, the Company's proposed Plan identifies the capital spending investment that it expects to complete during the 21-Month Plan along with capital assets that are forecasted to be placed in service during the 21-month period of the Plan. At the end of this section,

[8] The Company delivers natural gas to approximately 273,000 Rhode Island residential and commercial and industrial customers in 32 cities and towns in Rhode Island. To provide this service, the Company owns and maintains approximately 3,200 miles of gas mains and approximately 194,000 gas services.

Table 1 contains a description of the proposed budget for the 21-Month Plan, including a breakout of what will occur in CY 2023 and CY 2024, and the resulting Plant Additions. Table 2 contains a proposed five-year spending forecast that covers the period of April 1, 2023 through December 31, 2026. Table 3 contains actual spending based on the prior five-year period, FY 2018 through FY 2022. In the 21-month period of the Plan, the Company proposes to make a total of $388.53 million of ISR investments[9], which includes $99.83 million for Non-Discretionary capital expenditures and $288.70 million for Discretionary capital expenditures, including $13.15 million for the Southern RI Gas Expansion Project. The total of $388.53 million includes $18.33 million related to Cost of Removal. The capital additions projected to be placed in-service for the 21-month period of the Plan are projected to be $346.84 million, which is included in the 21-Month Gas ISR recovery mechanism.

As set forth in Table 1 at the end of this section, the Company proposes the following levels of spending for each category of programs contained in the $388.53 million that the Company proposes for its 21-Month Plan spending:

Non-Discretionary:

- $42.60 million of net investment for Public Works programs, including $44.40 million in capital spend less $1.81 million in reimbursements;

[9] Over the course of the 21-Month Plan, the Company plans to spend $454.30 million of total capital investment, which includes $193.53 million during CY 2023 and $260.77 million during CY 2024. Of the 21-Month Plan total, $65.77 million ($26.58 million in CY 2023 and $39.19 million in CY 2024) is associated with projected growth, other non-ISR spending, and capital projects not currently included in the ISR, which are not included for recovery in the 21-Month Plan.

- $57.19 million for Mandated Programs (i.e., Corrosion, Purchase Meter Replacement, Reactive Leaks (Cast Iron Joint Encapsulation/Service Replacement), Service Replacement (Reactive) – Non-Leak/Other, Main Replacement (Reactive) – Maintenance (including Water Intrusion), Low Pressure System Elimination (Proactive), Transmission Station Integrity, Pipeline Integrity – Integrity Verification Program; and

- $0.04 million for Damage/Failure programs.

<u>Discretionary</u>:

- $166.95 million for the Proactive Main Replacement and Rehabilitation Program (i.e., Proactive Main Replacement, Large Diameter, and Atwells Avenue project);
- $1.08 million for the Proactive Service Replacement program;
- $107.52 million for Gas System Reliability, including work relative to System Automation, Heater Program, Tiverton Gate Station, Take Station Refurbishment, Pressure Regulating Facilities, Valve Installation/Replacement, Gas System Reliability Enhancement, Instrumentation and Regulation (I&R) – Reactive, Distribution Station Over Pressure Protection, Liquefied Natural Gas (LNG) facilities and equipment, Replace Pipe on Bridges, Access Protection Remediation, Tools and Equipment, and Weld Shop; and
- $13.15 million for the Southern RI Gas Expansion Project.

Description of Programs and Projects

The Non-Discretionary and Discretionary programs are described in detail below.

Non-Discretionary Work:

A. Public Works

The purpose of the Public Works program is to address existing gas infrastructure conflicts, as appropriate, and to improve the safety and reliability of the Company's natural gas distribution system in conjunction with municipal reconstruction and water and sewer projects, which provide significant incremental benefits to customers and communities. Municipal and water and sewer work affords the Company an opportunity to replace additional leak-prone pipe and reduce paving costs by coordinating the Company's gas main replacement work with planned third-party construction projects, while also benefitting customers and communities by improving service delivery and minimizing construction impacts and inconvenience. The Company has an ongoing plan to replace targeted gas mains on a risk-based approach. Coordinating the Company's Integrity programs with planned municipal and water and sewer projects has yielded increased system reliability and integrity, and optimized capital spending. Although one of the primary purposes of Public Works spending is to address direct conflicts between planned third-party projects and existing gas infrastructure, Public Works spending provides the additional opportunity to coordinate other system improvement work, such as the replacement of leak-prone pipe, system reliability upgrades, elimination of redundant main, and regulator station upgrades.

The Company will manage multiple projects to address the dynamic nature of the Public Works process through effective liaison activity. Although municipal schedules and plans change largely due to funding, other factors also contribute to the scheduling of these projects (e.g., political demand and maintenance). Changes in municipal projects can and do create additional work in developing and coordinating the Company's planning and budgeting processes. Using the Company's five-year work planning process, the Company can provide some flexibility in scheduling, coordinating, and engineering projects in concert with municipal public works initiatives. The 21-Month Plan incorporates a net of $42.60 million in spending under the Public Works category, which includes $44.40 million in capital spend and $1.81 million in forecasted reimbursements from third parties. Overall, the Public Works 21-Month Plan budget provides for the installation of 28.0 miles of gas main and the abandonment of 23.0 miles of leak-prone gas main, consisting of cast iron and unprotected steel main. Below is a summary chart of the planned installation and abandonment for CY 2023 and CY 2024 within the 21-month period of the Plan. The forecasted plant additions for this category the 21-Month Plan total $38.14 million.

Category	CY23 9-Month Leak-Prone Pipe Abandonment Miles	CY23 9-Month Main Replacement Installation Miles		CY24 12-Month Leak-Prone Pipe Abandonment Miles	CY24 12-Month Main Replacement Installation Miles
Public Works	9.0	14.0		14.0	14.0

B. <u>Mandated Programs</u>

Spending for Mandated Programs falls into the following eight categories: (1) Corrosion, (2) Purchase Meter Replacement, (3) Reactive Leaks, (4) Reactive Service Replacement - Non-leaks/Other, (5) Reactive Main Replacement-Maintenance, (6) Proactive Low Pressure System Elimination, (7) Transmission Station Integrity and (8) Pipeline Integrity.

1. **<u>Corrosion</u>** – The Rhode Island Corrosion Control Program has two components: Underground and Atmospheric Corrosion Protection. The underground corrosion controls consist of pipe coatings and cathodic protection. Cathodic protection is accomplished by establishing proper coatings on the steel pipe segments and the installation of rectifiers, anodes, insulators, and test stations for the steel pipes. In addition, the underground corrosion program includes control lines at existing regulator stations. The atmospheric corrosion controls consist of periodic inspections of exposed gas pipes and coatings (where presented) and repairs of deficiencies found. Under the corrosion control program, Rhode Island Energy installs, inspects, tests, maintains, repairs, and upgrades the underground and atmospheric corrosion control components to be compliant with Federal and State mandates. For the 21-Month Plan, the Company proposes to spend $2.94 million on this program, which includes $1.43 million for CY 2023 and $1.51 million for CY 2024. The forecasted plant additions for this category for the 21-Month Plan total approximately $2.77 million.

2. **Purchase Meter Replacement** – Capital costs for the Purchase Meter Replacement program are required for the procurement of replacement meters. For the 21-Month Plan, the Company will require approximately 34,579 meters (32,620 mandated and 1,959 miscellaneous). For CY 2023, the Company will require approximately 14,820 meters (13,980 mandated and 840 miscellaneous). The meter replacements are part of a multi-year plan and 14,820 meters represents approximately 5.35 percent of the existing meter population in Rhode Island. The Company is planning to purchase 21,770 meters in CY 2023. For CY 2024, the Company will require approximately 19,759 meters (18,640 mandated and 1,119 miscellaneous). The 19,759 meters represents approximately 7.14 percent of the existing meter population in Rhode Island. The Company is planning to purchase 32,107 meters in CY 2024. These purchasing volumes reflect the Company's efforts to compensate for ongoing meter supply chain issues by increasing our baseline inventory. It also incorporates meter orders that were initially expected in FY 2023, but are now expected to be delivered and paid for during the 21-month period of the Plan. In the 21-Month Plan, the Company forecasts that it will spend $13.47 million on the Purchase Meter Replacement program, which includes $5.91 million for CY 2023 and $7.56 million for CY 2024. The forecasted plant additions for this category for the 21-Month Plan total approximately $12.47 million.

3. **Reactive Leaks** – This category provides funding for the leak sealing of cast iron bell joints that are discovered during proactive leak surveys, public odor calls, or other activities. In addition, it provides funding for remediating leaking gas services through insertion, replacement, and/or abandonment of the services. For the 21-Month Plan, the Company proposes to spend $14.70 million for this work, which includes $6.20 million for CY 2023 and $8.50 million for CY 2024. The forecasted plant additions for this category for the 21-Month Plan total $14.03 million.

4. **Reactive Service Replacement – Non-leak/Other** – This program contains the capital costs for service relocations, service abandonments, and the installation of curb valves. For the 21-Month Plan, the Company proposes to spend $3.06 million in connection with this program, which includes $1.30 million for CY 2023 and $1.76 million for CY 2024. The budget includes funding for current final restoration paving requirements. The forecasted plant additions for this category in the 21-Month Plan total $2.99 million.

5. **Reactive Main Replacement – Maintenance** – This category of work consists of emergency main replacements or modifications because of leaks or other unplanned events where main conditions typically dictate immediate replacement and/or gas facilities are subject to water intrusion or exposure and require remedy. The

Company proposes to spend $2.04 million in this area in the 21-Month Plan, which includes $0.87 million in CY 2023 and $1.17 million in CY 2024. The reactive main and service replacement work at Oxbow Farms in Middletown, which was included in the FY 2023 plan, is currently on hold until a long-term solution is agreed to with the owner of the property. The forecasted plant additions for this category in the 21-Month Plan total $1.91 million.

6. **Proactive Low Pressure System Elimination** – The purpose of this program is to systematically replace low pressure ("LP") gas systems with high pressure ("HP") gas systems to enhance gas system safety. The Company implemented this program in response to recommendations from Federal and State government agencies following the Columbia Gas incident in Massachusetts in 2018. The Proactive LP System Elimination will systematically retire entire LP systems by transferring customers to HP systems. This program will transfer all Customers on the selected LP systems to a nearby HP system by installing new distribution mains, services, and service regulators. The new HP services will be installed to current standards with excess flow valves and service regulators at each Customer premise providing enhanced over pressure protection. In the 21-Month Plan, the Company will complete the final stages of the multi-year LP System Elimination project (begun in FY 2022) in Middletown which will allow for the eventual abandonment of the Walcott Avenue near Briarwood Avenue LP regulator station. During CY 2023 this project will install

1.0 mile of new main, and during CY 2024 this project will install 2.6 miles of new main and abandon 0.5 miles of leak prone pipe. Please note, the Company is also expected to start a Public Works main replacement job on Purgatory Road, ahead of town paving, in this area that will start in FY 2023 and finish during CY 2023, which will contribute to the overall plan to abandon this low pressure system. For the 21-Month Plan, the Company proposes to spend $3.37 million for this program, which would contribute to plant additions of $2.90 million.

7. **Transmission Station Integrity** – This program is a continuation of a rate base funded program that began several years ago and primarily consisted of in-depth compliance records and documentation reviews of pressure regulating facilities. The primary purpose of the Transmission Station Integrity program is to meet United States Department of Transportation PHSMA code requirements, pursuant to 49 CFR § 192.624, which require operators of steel gas transmission pipeline segments to reconfirm the maximum allowable operating pressure ("MAOP") of segments with pressure test documentation and material property records by 2035. Fifty percent of transmission pressure segments require MAOP reconfirmation by 2028. Where the records that substantiate the MAOP are not traceable, verifiable, and complete ("TVC"), the equipment will be re-tested, non-destructively examined, or replaced to ensure the pipelines, including those associated with transmission stations, are safe,

reliable, and fit for service. The ongoing scope of this multi-year program consists of retesting and, where necessary, replacing equipment that will not meet the PHSMA documentation requirements; the work is prioritized by a standard risk-based evaluation. Following the completion of the Allens Avenue Station Rebuild, 12 of the 24 Transmission Stations on the Company's system are now in scope for re-testing and/or replacement of equipment. The 21-Month budget proposal includes Transmission Station Integrity work for the Scott Road Take Station which includes a full replacement of the station and heating system; $3.50 million is budgeted for CY 2023 and $7.46 million for CY 2024, which will contribute to plant additions of $11.01 million in CY 2024. The 21-Month Plan budget proposal also includes Transmission Station Integrity work for the replacement and ownership transfer of the Wampanoag Trail Gate Station (this is separate from the heaters transaction); $0.66 million is budgeted for CY 2023, $1.71 million for CY 2024, and $5.40 million for FY 2025, which will contribute to plant additions of approximately $7.45 million in FY 2025. The station replacement is necessary to address both integrity verification concerns regarding the asset records as well as its age and criticality to the system. The Wampanoag Trail Gate Station is the only 200 PSIG gate station that directly feeds the Providence and East Providence distribution systems. The station is approximately 36 years old and is the initial supply point for approximately 65,000 customers based on its peak flow. The replacement will reconfirm MAOP and create new material verification records of the existing piping as required by PHMSA. Also, the replacement will ensure the 200 PSIG system is fed by a gate station that has three layers of overpressure protection owned and operated by Rhode Island Energy and isolation valves indicating a clear line of demarcation. The ownership transfer allows Rhode Island Energy to ensure maintenance of this equipment as well as the ability to provide pressure control to its major distribution systems in this region. Currently this is only 1 of 3 gate stations where the pipeline supplier provides pressure control, and will be 1 of 2 following the replacement of the Tiverton gate station. In total, for the 21-Month Plan, the Company proposes to spend $13.49 million in this overall category, which would contribute to plant additions of $11.16 million.

8. **Pipeline Integrity – Integrity Verification Program – Wampanoag Trail Pipeline Replacement** – During the 21-Month Plan the Company will continue work on the Integrity Verification Program ("IVP") – Wampanoag Trail Pipeline Replacement project, which began planning in FY 2023. This multi-year project, to replace approximately two miles of main in East Providence that runs from the Providence River Crossing to the Wampanoag Trail Take Station, is expected to be completed over five years. This scope of work does not include any pipe that runs under the Providence River or into the Wampanoag Trail Gate Station. This section of 12- to

16-inch coated steel piping is some of the oldest main operating at 200 psig (installed before 1971) on the Rhode Island gas system and is a critical piece of infrastructure for the Rhode Island gas supply. For the 21-Month Plan, the Company proposes to spend $4.13 million for this project, but would not contribute to any plant additions until after the 21-Month Plan. The 21-Month budget includes $0.38 million for CY 2023 for engineering and design work, and $3.75 million for CY 2024 to procure materials and begin the construction phase of the project. Between FY 2023 and FY 2027, the total estimated cost for this project is approximately $10.13 million.

A. <u>Damage/Failure Program</u>

The Company proposes to include funding for safety and reliability projects associated with remediation of damage or failure occurrences. Damage or failure projects are initiated in response to events outside the Company's control that require immediate action. The Company proposes a 21-Month budget of $0.044 million for such work ($0.019 million in CY 2023 and $0.025 million in CY 2024, which would contribute to plant additions of $0.042 million.

In total, the 21-Month Plan contains $99.83 million for Non-Discretionary work, which would contribute to plant additions of $86.41 million for the term of the Plan.

Discretionary Work:

A. <u>Proactive Main Replacement and Rehabilitation Program</u>

The value of and need for targeted spending on the replacement of leak-prone gas main is well-documented and has been acknowledged by the PUC and Division. For the 21-Month Plan, the Company forecasts spending $166.95 million on its Proactive Main Replacement and Rehabilitation program, which will abandon or rehabilitate approximately 95.2 miles of leak-prone gas main and associated service relays, inserts, or tie-ins. The 95.2 miles is comprised of 93.2 miles of abandonment through proactive main replacement including 0.3 mile with Atwells Avenue, 0.4 mile of rehabilitation with Cast-Iron Lining ("CI Lining"), and 1.7 miles of rehabilitation with Cast-Iron Sealing Robot ("CISBOT"). Outside of these programs, the Company also plans for 23.0 miles of abandonment through the Public Works program, 0.5 mile of abandonment through the Low Pressure System Elimination program, 2.1 mile of abandonment through the Reliability program, and an additional 1.7 miles of abandonment through Reinforcement projects. For the 21-Month Plan, this results in total abandonment of 120.5 miles and 2.1 miles of rehabilitation. Below is a summary of the planned volume of leak-prone pipe abandonment, installation, and rehabilitation miles across the entire Gas ISR portfolio for the 21-Month Plan. Any line items highlighted in gray are rehabilitation and do not count towards the abandonment total.

	CY 2023 9-Month		CY 2024 12-Month		21-Month Plan Total	
Category	**Abandonment/ Rehabilitation Miles**	**Installation Miles**	**Abandonment/ Rehabilitation Miles**	**Installation Miles**	**Abandonment/ Rehabilitation Miles**	**Installation Miles**
NON-DISCRETIONARY						
Public Works	9.0	14.0	14.0	14.0	23.0	28.0
Mandated Programs						
Low Pressure System Elimination (Proactive)	0.0	1.0	0.5	2.6	0.5	3.6
DISCRETIONARY						
Proactive Main Replacement & Rehabilitation						
Proactive Main Replacement - LPP	39.5	46.9	53.4	51.9	92.9	98.8
CI Lining - Rehabilitation	0.0	0.0	0.4	0.0	0.4	0.0
CISBOT - Rehabilitation	0.7	0.0	1.0	0.0	1.7	0.0
Atwells Avenue	0.3	0.3	0.0	0.0	0.3	0.3
Reliability						
Gas System Reliability	1.5	1.6	0.6	1.5	2.1	3.1
Reinforcement	0.7		1.0		1.7	
Total Rehabilitation	0.7	0.0	1.4	0.0	2.1	0.0
Total Leak Prone Pipe Abandonment/ Installation	51.0	63.8	69.5	70.0	120.5	133.8
Total Rehabilitation and LPP Abandonment	**51.7**	**63.8**	**70.9**	**70.0**	**122.5**	**133.8**

1. <u>Proactive Main Replacement (<16-inch)</u>

For the 21-Month Plan, the Proactive Main Replacement (<16-inch) program consists of the installation of 98.8 miles and the abandonment of approximately 92.9 miles of cast iron and unprotected steel main with a diameter of less than 16 inches, and the renewal, abandonment, or tie-over of existing services.

The total abandonment miles for CY 2023 includes FY 2023 carryover (or in progress) miles, but it also adjusts for it being a shorter fiscal year period (does not include the January 1, 2024 – March 31, 2024 period) and the net result is that planned abandonment miles are less than planned installation miles. The planned abandonment miles and planned installation miles are in close alignment for CY 2024. In prior years, the Company had assumed that 75% of the current year spend would result in a capital plant addition that same fiscal year, it also assumed the remaining 25% would result in a capital additional the next fiscal year. Based on the PUC's order to change the timing of inclusion of new main as part of the Proactive Main Replacement – Leak Prone Pipe category in ISR rate base from "main gas-in/first service connection" to when the old main associated with the specific project has been taken out of service or "abandoned"[10] AND the shift of end the fiscal year period from March 31 to December 31, the Company lowered the 75% assumption to 60%; this assumption was changed for both CY 2023 and CY 2024. The impact of this change was a $12.24 million decrease in plant additions for the 21-Month Plan from $149.76 million to $137.52 million for Proactive Main Replacement – Leak Prone Pipe.

[10] *See Narragansett Elec. Co. d/b/a National Grid's FY 2023 Gas Infrastructure, Safety And Reliability (ISR) Plan*, Docket No. 5210, Order No. 24541 at 19-20 (November 18, 2022).

2. **Proactive Large Diameter Program (>=16-inch)**

The Company operates approximately 37 miles of large diameter (greater than or equal to 16-inches) leak-prone gas mains. The Proactive Large Diameter Program consists of rehabilitating large diameter leak-prone pipe through the implementation of a sealing and lining program. Lining and sealing are cost-effective alternatives for remediating large diameter leak-prone pipe. Additional benefits of this program include minimization of impact to customers and communities, a shortened construction period and use of existing space in areas with significant underground utility congestion. For the 21-Month Plan, the Company proposes to spend a total of $8.64 million on this overall category, with $2.86 million for CY 2023 and $5.78 million for CY 2024. The Company plans to perform a Cast Iron ("CI") Lining project for Petteys Avenue in Providence, with design and service transfers planned for CY 2023 and the 0.4 mile of lining planned for CY 2024. The budget also includes six CISBOT jobs, with two planned for Newport and four planned for Providence. The CISBOT projects will address approximately 1.7 miles of cast iron main with a diameter of 16-inches or greater. For the 21-Month Plan, work in this Proactive Large Diameter Program would contribute to plant additions of $7.88 million.

3. **Proactive - Atwells Avenue Main Replacement**

The Company forecasts that the multi-year Atwells Avenue Main Replacement project in Providence will be in the final phase of construction during the 21-Month Plan. The Company has continued to work in conjunction with the City of Providence on the final restoration of Segments 1A and 1B as the City completed work on its sidewalks. DePasquale Square was the last major area that required final restoration within Segments 1A and 1B and that work was completed in FY 2023.

The start of Segment 3 of the project was deferred from FY 2023 into the 21-Month Plan as the Company continues to prioritize work in order of highest risk as well as in close conjunction with Providence Water projects and the City of Providence paving projects to ensure that leak prone pipe does not become subject to permit moratoriums and that ratepayer paving costs are minimized. The Company has prioritized higher risk work ahead of Segment 3, causing it to be delayed from the original FY 2023 schedule. Therefore, the 21-Month Plan budget includes the installation, abandonment, and final restoration of the final segment, Segment 3, which includes the installation and abandonment of approximately 0.3 mile (1,410 feet) of main. For the 21-Month Plan, the Company proposes to spend $1.14 million for this project overall, with $1.10 million during CY 2023 and $0.04 million in CY 2024. The Company forecasts plant additions of $1.09 million in the 21-Month Plan.

From the start of the Atwells Avenue project in FY 2019 through its forecasted completion in CY 2024, the total forecasted spend for Segments 1A, 1B, 2, and 3 is currently $11.57 million.

B. Proactive Service Replacement Program

For the 21-Month Plan, the Company has budgeted to replace 175 services (75 in CY 2023 and 100 in CY 2024) through the Proactive Service Replacement Program. The average cost per service was increased slightly to $6,120 in CY 2023 and $6,210 in CY 2024 to account for inflationary factors. This results in a total anticipated spend of $1.08 million for the 21-Month Plan ($0.46 million in CY 2023 and $0.62 million in CY 2024). In FY 2023 the Company is attempting to complete the final 2 copper services in Cumberland, the other 131 of 133 have been replaced between FY 2021 and FY 2023. In the 21-Month Plan, the Company will continue to pursue proactive service replacements of confirmed leak prone services on non-leak prone pipe.

C. Reliability

Reliability spending includes 14 programs to address the following: system automation, heater installations, Wampanoag Trail and Tiverton Gate Stations, take stations, pressure regulation, valve installation/replacement, gas system reliability, instrumentation and regulation, distribution station over pressure protection, LNG facilities and equipment, replace pipe on bridges, access protection remediation, capital tools and equipment, and the weld shop. The 21-Month Gas ISR Plan contains $107.52 million in spending for Gas System Reliability, which would contribute to plant additions of $98.20 million for the 21-Month period.

1. **System Automation**

The primary purpose of the System Automation program is to meet the United States Department of Transportation code requirements under 49 C.F.R. Part 192, Docket ID PHMSA 2007-27954, which were issued on December 3, 2009. These code provisions contain the following pipeline safety requirements: (a) control room management/human factors, (b) modernization of the Company's system data and telemetry recording, and (c) increasing the level of system automation and control. The overall System Automation program will increase the safety, reliability, and efficiency of the gas system and, by extension, the level of service the Company provides to its customers.

The Company's ability to provide safe and reliable service is governed to a large extent by the Company's ability to maintain adequate pressure in its gas mains. To accomplish this task, the Company has 189 gas pressure regulator stations disbursed throughout its Rhode Island gas service territory. Although a portion of these regulator stations have full system telemetry (all stations in the RI Northern Region now have telemetry) and control capability, additional stations require the installation of new telemetry equipment, and the

21-Month Plan will be a continuation of the process to equip more stations. In addition to monitoring and controlling its regulator stations, the Company must also monitor system end points to ensure that adequate system pressures are being maintained in remote areas under a variety of operating conditions. For the 21-Month Plan, the Company is proposing spending of $1.50 million, which would contribute to plant additions of $1.44 million, for its System Automation program. The Company's work in the 21-Month Plan will provide either AC or DC solar power, telemetry, and/or remote control to approximately 10-20 locations in CY 2023 and another 10-20 locations in the CY 2024.

2. **Heater Installation Program**

The Heater installation program provides for the installation and replacement of gas system heaters, which are operated to ensure proper conditioning and control of gas temperatures at key Company facilities. The 21-Month Plan proposal includes funding for the Heater Installation Program Blanket of $0.70 million for miscellaneous fuel train upgrades, heat exchanger replacement, engineering costs, burner management/safety system upgrades, etc. The 21-Month Plan proposal also includes $2.60 million for the Dey Street project for one water bath heater installation, scheduled for CY 2023, and project closeout costs, scheduled for CY 2024. The 21-Month Plan proposal also includes funding of $1.20 million for Diamond Hill to install a hydronic boiler system with materials purchasing occurring in CY

2023 and construction occurring in CY 2024. Finally, the 21-Month Plan proposal also includes funding of $1.99 million for the Smithfield Gate Station to complete the installation of a hydronic boiler system, heat exchanger piping and piping to the take station during CY 2023.

Overall for the 21-Month Plan, the Company is proposing spending of $6.48 million, which would contribute to plant additions of $7.23 million, for its Heater Installation Program. The budget for the Wampanoag Trail & Tiverton Gate Station – Heaters Replacement and Ownership Transfer is being tracked as a standalone category and is described in more detail, directly below.

3. Wampanoag Trail & Tiverton Gate Station – Heaters Replacement and Ownership Transfer

In FY 2023, Enbridge is replacing heaters at its Wampanoag Trail and Tiverton gate stations. The new heaters are designed to meet Rhode Island Energy's reliability standards, which exceed Enbridge's standards for heater design. Once the work is complete, Enbridge will transfer ownership of the heaters to Rhode Island Energy. Rhode Island Energy's current in-service forecast includes plant additions of approximately $6.12 million in FY 2023 associated with Wampanoag Trail. The work at the Tiverton Gate Station was originally forecasted to result in FY 2023 plant additions of approximately $4.95 million, and although the new assets will likely be gassed-in between February 2023 and March 2023 (pending temperature conditions), the Company's gas control is forecasting the new assets will not be fully operated as the system feed, and thus will not enable the asset transfer from Enbridge until April-June of CY 2023. Therefore, the Company has shifted the Tiverton Gate Station in-service year from FY 2023 to CY 2023; the forecasted plant additions total $5.14 million in CY 2023, which includes the CY 2023 budget of $0.19 million for project closeout costs.

4. **<u>Take Station Refurbishment</u>**

The Take Station Refurbishment program will address required modifications to the Company's custody transfer stations. The 21-Month Plan includes a blanket work order totaling $0.45 million for miscellaneous work at Take Stations across the gas system, such as odorization and generator upgrades. The primary project in this category for the 21-Month Plan is the Smithfield Gate Station, which will have spending of $3.36 million. During CY 2023, a new distribution vault will be installed outside, along with engineering for replacement of the inside gate station regulator runs. CY 2024 includes the procurement of materials and the replacement of the inside gate station regulator runs. Overall for the 21-Month Plan, the Company plans to spend $3.82 million, which would contribute to plant additions of $3.27 million, for its Take Station Refurbishment Program.

5. Pressure Regulating Facilities

The Company's pressure regulating facilities have been designed to reliably control gas distribution system pressures and maintain continuity of supply during normal and critical gas demand periods. Each regulator station has specific requirements for flows and pressures based on the anticipated needs of the station. A facility includes both pressure-regulating piping and equipment and control lines, but it may also include a heater or a scrubber. The Company has instituted a program that provides for condition-based assessments of all regulator stations. Accepted engineering guidelines provide for design, planning, and operation of these gas distribution facilities. Applicable state and federal codes are followed to help ensure safe and continuous supply of natural gas to the Company's customers and the communities it serves. This program includes enhancements in response to regulator station work prioritized through condition-based assessments, which include, in part, station accessibility, pipe condition (i.e. corrosion), water intrusion, redundancy, station isolation, and common mode failure. In total, for the 21-Month Plan the Company proposes to spend $14.76 million which would contribute to plant additions of $13.63 million. This includes spending of $6.32 million in CY 2023 related to construction at 5-7 stations, engineering for 5 future stations, and the installation of a second bypass valve at 1-2 stations (to prevent a failure of a single bypass valve resulting in over pressurization). The budget also includes spending of $8.44 million in CY 2024 related to construction at 6-8 stations, engineering for 8 future stations, and the installation of a second bypass valve at 2-3 stations (for a total of 4-5 over the 21-Month Plan).

6. **Valve Installation / Replacement**

Valves are used to sectionalize portions of the gas network to support both planned and unplanned field activities. Replacement of inoperable valves is necessary to ensure the Company's continued ability to effectively isolate portions of the distribution system. New valve installations are also occasionally needed to provide the capability to reduce the size of an isolation area where existing valves would result in broader shutdown than desired. For the 21-Month Plan, the Company has budgeted $0.75 million for valve work, with approximately $0.25 million for reactionary valve work across the 21-Month period and $0.50 million for sectionalizing valve work in Newport to be completed during CY 2023. The Company forecasts plant additions of $0.76 million in the 21-Month Plan.

7. **Gas System Reliability – Gas Planning Program**

The Gas Planning program identifies projects that support system reliability through standardization and simplification of system operations (e.g., system up-ratings and de-ratings and regulator elimination), integration of systems (e.g., tie-ins), and new supply sources (e.g., take stations). The 21-Month budget includes continued funding for ongoing multi-year projects designed to eliminate single-feed systems (and low pressure segments where applicable) in Providence, North Providence, Lincoln, Woonsocket, Newport, Warwick, and Cranston. This program is forecasted to install 3.1 miles of new gas main and abandon 2.1 miles of leak prone pipe. For the 21-Month Plan, the Company proposes to spend a total of $5.94 million for this program, which would contribute to plant additions of $4.98 million.

8. <u>Instrumentation and Regulation (I&R.) Reactive Program</u>

The I&R Reactive program is established to address capital project requirements over and above the Pressure Regulation capital budget. Projects range from instrumentation replacement due to failure; replacement of obsolete/unreliable equipment, such as regulators, pilots, boilers, heat exchangers, odorant equipment, and station valves; and replacement of building roofs or doors due to deterioration. In the 21-Month Plan, the Company proposes to spend $2.48 million for this program, which would contribute to plant additions of $2.35 million.

9. <u>Distribution Station Over Pressure Protection</u>

This program is in place to address risks for over pressurization incidents at pressure regulating facilities throughout the system. Actions planned for this program include work to relocate and provide additional protections for regulator sensing and control lines to protect from third-party damage. The preferred overpressure protection is a control line header which is an extension of the main that runs along the wall of a pressure regulating vault. Control lines sense pressure off of the header that is less likely to be damaged by excavation compared to control lines connected to mains running in or near the street. Other forms of overpressure protection include the installation of additional control equipment such as override pilots in the vaults or relief valves to ensure safe and reliable regulator station operation in the event of control line damage. To ensure that potential abnormal operating conditions at regulator stations do not result in over pressurization scenarios, in the 21-Month Plan, the Company plans to:

- Purchase materials for 1-2 new relief valves during CY 2023;
- Install 1-2 new relief valves on the system during CY 2024 – locations to be finalized;
- Install 3-5 outlet control line headers during CY 2023 – Cranston, Middletown, Woonsocket, East Providence, Pawtucket; and
- Install 1-3 outlet headers during CY 2024 – locations to be finalized.

For the 21-Month Plan, the Company proposes to spend $4.29 million for this program, with $2.41 million during CY 2023 and $1.88 million during CY 2024, which would contribute to plant additions of $4.25 million across the 21-Month Plan.

10. LNG

The Liquified Natural Gas ("LNG") program is established to address specific and blanket capital project requirements to support the Company's LNG operations. There are several ongoing and upcoming site modernization and improvement projects at the Exeter LNG facility. In the 21-Month Plan, the Company will install two new boil-off compressors that will replace two compressors that were originally commissioned in the early 1970's; the 21-month spend associated with this work is approximately $7.92 million, which will result in plant additions of approximately $11.50 million during the 21-month period. During normal operation of an LNG storage site, a nominal amount of pressure/gas needs to be released from the tank, which is done through the use of the boil-off compressors at Exeter. By continuing to utilize boil-off compressors, the Company is able to capture the gas release and send it to the gas distribution system, thus avoiding gas emissions, which is in alignment with the Act on Climate goals. Additional work at the Exeter site will include spending of approximately $0.78 million to upgrade the Emergency Generator and the Uninterruptable Power Supply ("UPS"), which is being done in part to support the new boil-off compressors.

The Company will also spend approximately $3.33 million to install new Switchback Stairs to access the top of the LNG Tank. The existing setup is a single-file staircase that winds along the side of the tank. The proposed improvements will provide much safer access, will improve access for maintenance activities, and will allow for hoisting items to the top of the tank versus manually carrying them. The Company will also spend $9.17 million to move and modernize the existing Control Room, which is outdated and currently abuts the stations main electrical room, along with upgrading the HMI Hardware and Software which requires an upgrade approximately every five years.

Finally, the Exeter work includes $10.40 million to modernize the LNG Truck Station, which will add multiple layers of safety, provide process improvements to the LNG delivery process, and will tie into the sites Automated Emergency Shut-Down (AESD) system. The Truck Station results in $0 plant additions in CY 2024 and approximately $9.98 million in CY 2025.

For the Cumberland LNG facility, the Company will place the new Portable LNG Equipment in-service during CY 2023, totaling approximately $6.82 million, following the purchase that will be completed in FY 2023. Additionally, in the 21-Month Plan, the Company will spend $3.50 million to add Supplemental Portable Storage for the site, which will essentially double the site's storage capacity and increase the site's run time (at maximum output) from approximately five hours to ten hours. This enhances the reliable operation of this site, especially during inclement weather when it may not be prudent to have LNG tanker trucks traveling on the roadways.[11] The 21-Month Plan also includes approximately $0.65 million for the addition of a Boil-off Gas Recovery Manifold, which supports the Act on Climate's goals by capturing boil-off gas and sending it into the gas

[11] Please refer to Data Request Division 1-40 for additional information on portable LNG storage and transportation.

distribution system rather than releasing it into the atmosphere, and a Portable Vaporizer Tap, which will provide a backup for the plants fixed vaporizers. This portable equipment provides current and longer-term flexibility as it can be used for current operations and/or eventually moved to a different site or sold off if the equipment is no longer needed at the Cumberland LNG site. Work for the Cumberland LNG site also includes the installation of a new Water Main, which will cost approximately $0.75 million.

The 21-Month Plan also includes $11.51 million for the Company to purchase a Portable LNG Equipment setup for the Old Mill Lane site. This is very similar to the equipment purchase/transition ongoing at Cumberland, whereby the Company will purchase and operate its own equipment rather than renewing a rental agreement for the portable equipment and its operation. This will result in a shift of costs as the current leasing costs are paid through the Gas Cost Recovery factor and the cost of the equipment purchase will now flow through the Gas ISR. The Company anticipates that this investment will be recouped over 10 years of operation, when compared to the current Old Mill Lane operating model, but the payback period would end up being shorter if additional portable LNG mobilizations were required to support Enbridge pigging/ construction activities. This purchase is consistent with the Company's strategy of addressing the Aquidneck Island gas supply challenges through the use of a temporary and scalable solution rather than permanent infrastructure. The purchase of the Portable LNG Equipment for the Old Mill

Lane during the 21-month Plan results in $0 plant additions in CY 2023 or CY 2024 and approximately $9.98 million in FY 2025.

Finally, the 21-Month Plan includes $1.23 million to decommission the LNG site on the Newport Navy Yard.

In total for the 21-Month Plan the Company proposes to spend $51.43 million, with $15.78 in CY 2023 and $35.64 million in CY 2024. This spending will contribute to plant additions of $51.43 million, with $21.24 million during CY 2023 and $16.71 million in CY 2024.

11. Replace Pipe on Bridges

For the 21-Month Plan, the Company will spend $4.80 million on the Replace Pipe on Bridges program including planned activities at the following locations: Lonsdale Avenue bridge in Pawtucket, Atwells Avenue bridge in Providence, Sylvan Drive bridge in East Greenwich, Glenbridge Avenue bridge in Providence, Goat Island bridge in Newport, Admiral Street bridge in Providence (route 146 overpass), River Street bridge in Woonsocket, and Old River Road bridge in Lincoln (route 146 overpass). During CY 2023 the Company will spend approximately $1.00 million to complete work on the Lonsdale Avenue bridge and Atwells Avenue bridge, along with work on the Sylvan Drive bridge and Old River Road bridge, and project development across the other bridge locations. During

CY 2024 the Company will spend $3.80 million in total, which includes $2.00 million to replace the two gas mains located next to the Glenbridge Avenue bridge, $0.80 million for construction on the Goat Island bridge, $0.50 million for construction on the Admiral Street bridge, and $0.50 million for construction on the River Street bridge. Spending in the Replace Pipe on Bridge category will contribute to plant additions of $3.67 million for the 21-month period, with $0.75 million during CY 2023 and $2.91 million in CY 2024.

12. <u>Access Protection Remediation</u>

The Access Protection Remediation program is designed to reduce the risk of public injury by restricting and/or deterring public access to the Company's elevated gas facilities. During the lifecycle of this program, the Company has identified 18 elevated gas facilities that required remediation, and by the close of FY 2023, 16 of those facilities will have been remediated. The CY 2023 budget of $0.06 million includes the completion of the final two locations, from the original list of 18 locations, along with an additional two that were identified during FY 2023. The CY 2024 budget of $0.02 million is for general minor capital improvements that may arise with access protection remediation panels or any reactionary work that may be identified by the Gas Corrosion Team. As the Company is coming to the end of the defined locations to remediate, the Company will explore the incorporation of access protection remediation panels into the future design of bridge crossings instead of being charged to this separate program.

13. Capital Tools and Equipment

This category includes tools and equipment required to support the performance of work contained in the Gas ISR Plan and to provide for the safety and reliability of the gas distribution system. The Company will spend $1.23 million during CY 2023 on capital tools and equipment that will enhance the safety and efficiency of capital projects, which includes the purchase of four Ground Penetrating Radar Systems ("GPRS") to locate underground utilities, along with one T.D. Williamson ProStopp which is a critical tool used to isolate a segment of pipe. The Company will spend $0.91 million during CY 2024 on capital tools and equipment for a total of $2.15 million across the 21-Month Plan. This would contribute to plant additions totaling $2.05 million for the 21-Month Plan.

14. Weld Shop

The 21-Month Plan includes the purchase of welding tools and equipment to support capital projects within the ISR program and a weld shop at the Company's Allens Avenue, Providence location. The weld shop will house tools, equipment, welding stock, and provide ample space to perform welds, along with space to conduct required trainings and certifications. The build out of the new consolidated weld shop will maximize efficiency by bringing all internal welding resources to a modern and centralized location instead of maintaining two weld shop locations and the additional workplace/bays will allow more welding activities to occur simultaneously. The Company's two existing, undersized, weld shops are located on the ground floor of the Company's 477 Dexter Street, Providence location and in the back parking lot of 642 George Washington Highway, Lincoln. The Company recently hired an additional two welders, for a total of six in-house welders, to support ISR program work. This new weld shop will provide the capacity to complete larger welding fabrications in-house, which are currently outsourced due to constraints with the Company's current facilities, which can lead to delays completing stages of a project because of the extra time (coordination, transportation of materials, contractor availability, etc.) associated with involving a third-party in the process. Upon further internal review by the Company, it was determined that the Weld Shop also required the space to conduct on-site welding training and certifications for both the Company's internal welders and its contract welders. The training space did add cost to the project estimate, but having a common training space for the welders who are performing work on the gas distribution system is important to maintaining well-trained personnel that follow consistent work methods.

The cost-breakdown for the new weld shop budget is as follows:

- **Demolition/Site Prep/Site Work for building** - $2.00 million: The Company is utilizing an existing property in a central location; therefore, there will be no costs associated with purchasing commercial property within Providence. However, to facilitate and prepare the existing site for the new weld shop, the current operations at the Allens Avenue location will need to be relocated, and the meter house and scale house will need to be demolished, and capped. The Company developed the budget estimate for this category based on the scope of the work from previous job sites.

- **Foundation/Building/Design Costs - $8.00 million**: The Company developed the budget estimate for this category based on a 15,000 square foot building at $480 per square foot, which is in line with the regional average noted above. The budget estimate includes an additional $0.80 million for design costs.
- **Equipment - $1.56 million**: The budget estimate for this category is based on national averages and broken down as follows:
    - Smoke evacuation units ($0.25 million)
    - Approximate 6-Ton overhead crane ($1.00 million)
    - Forklift ($0.06 million)
    - Air compressor ($0.25 million)
- **Tools/Tooling - $0.30 million[12]**: The budget estimate for this category is based on national averages.

Total: $11.86 million

Of the $11.86 million project budget listed above, the Company is planning to advance the $2.00 million for Demolition/Site Prep/Site Work for the building into FY 2023 to help accelerate the construction timeline for the Weld Shop and ensure completion before the end of CY 2023. The Company is also planning to advance $1.00 million into FY 2023 for Equipment and Tools that will be incorporated into the initial construction phase of the weld shop. With the $3.00 million that the Company is planning to advance into FY 2023, the CY 2023 budget to complete the Weld Shop is $8.86 million. This would contribute to plant additions of approximately $11.27 million in CY 2023.

[12] Please see the response to Data Request Division 1-44, subpart (d) for a list of the tools the Company intends to purchase for the new weld shop.

E. Gas Expansion – Southern Rhode Island Project

The 21-Month Plan budget includes $0.08 million for closeout costs related to ongoing upgrades at the Cowesett Regulator Station. These close out costs will be incurred during CY 2023.

The 21-Month Plan budget also includes $9.00 million for the ongoing work at the Cranston Regulator Station. This includes $3.00 million in CY 2023 for civil site work and work to create a bypass that will enable a gas stoppage during the construction phase. This also includes $6.00 million in CY 2024 related to the construction phase of the project. The Cranston Regulator Station upgrades will contribute to plant additions of approximately $10.07 million during CY 2024.

The 21-Month Plan budget also includes $4.08 million for new regulator station near the existing Cowesett regulator station. This includes $0.58 million during CY 2023 for finalizing design and location and purchasing of project materials, and in CY 2024, the budget is $3.50 million to complete the construction phase. This new regulator station will contribute to plant additions of approximately $3.96 million during CY 2024.

In total, for 21-Month Plan, the Company estimates that it will spend a total of $13.15 million for the Southern RI Gas Expansion project, with $14.80 million projected to close to plant in-service. All of the 21-Month planned work is related to Regulator Station

Investments. The work related to the Pipeline component of the project, including final restoration activities, is forecast to be completed by the end of FY 2023. From FY 2019 through the anticipated close of the project in FY 2025, the total forecasted cost of the Southern RI Gas Expansion Project is approximately $120.33 million.

The Table below shows the total historical and forecasted spending for this project:

						21-Month Plan				
($millions)	FY 2019 Actual	FY 2020 Actual	FY 2021 Actual	FY 2022 Actual	FY 2023 Forecast	CY 2023 9-Month Proposed	CY 2024 12-Month Proposed	FY 2025 Proposed	FY 2026 Proposed	Total
Southern RI Gas Expansion	$2.39	$42.73	$41.76	$14.95	$5.26	$3.65	$9.50	$0.10	$0.00	$120.33

Excluding the Gas Expansion category, the proposed Gas ISR Plan contains $275.55 million in base spending for Discretionary work in the 21-Month Plan, with $245.63 million projected to be placed in service during the 21-Month period. Including the Gas Expansion category, the proposed Plan contains a total of $288.70 million in spending for Discretionary work with $260.43 projected to be placed in service during the 21-Month period.

Table 1
RI Energy - Gas ISR - 21-Month Plan
($000)

Categories	CY 2023 9-Month Budget	Projected Capital Additions Placed In-Service for CY 2023 9-Month	CY 2024 12-Month Budget	Projected Capital Additions Placed In-Service for CY 2024 12-Month	21-Month Budget	Projected Capital Additions Placed In-Service for 21-Month Plan
NON-DISCRETIONARY						
Public Works						
CSC/Public Works - Non-Reimbursable	$ 18,040	$ 15,753	$ 23,625	$ 21,295	$ 41,665	$ 37,048
CSC/Public Works - Reimbursable	$ 1,099	$ 1,377	$ 1,637	$ 1,440	$ 2,736	$ 2,817
CSC/Public Works - Reimbursements	$ (824)	$ (783)	$ (982)	$ (943)	$ (1,806)	$ (1,726)
Public Works Total	**$ 18,315**	**$ 16,347**	**$ 24,280**	**$ 21,792**	**$ 42,595**	**$ 38,139**
Mandated Programs						
Corrosion	$ 1,434	$ 1,340	$ 1,506	$ 1,425	$ 2,940	$ 2,765
Purchase Meters (Replacement)	$ 5,910	$ 5,383	$ 7,555	$ 7,089	$ 13,465	$ 12,472
Reactive Leaks (CI Joint Encapsulation/Service Replacement)	$ 6,200	$ 6,101	$ 8,500	$ 7,933	$ 14,700	$ 14,034
Service Replacements (Reactive) - Non-Leaks/Other	$ 1,298	$ 1,349	$ 1,757	$ 1,641	$ 3,055	$ 2,990
Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	$ 867	$ 862	$ 1,174	$ 1,051	$ 2,041	$ 1,913
Low Pressure System Elimination (Proactive)	$ 1,300	$ 1,097	$ 2,071	$ 1,800	$ 3,371	$ 2,897
Transmission Station Integrity	$ 4,201	$ 56	$ 9,289	$ 11,106	$ 13,490	$ 11,162
Pipeline Integrity - IVP - Wampanoag Trail Pipeline Replacement	$ 375	$ -	$ 3,750	$ -	$ 4,125	$ -
Mandated Total	**$ 21,585**	**$ 16,188**	**$ 35,602**	**$ 32,045**	**$ 57,187**	**$ 48,233**
Damage / Failure (Reactive)						
Damage / Failure (Reactive)	**$ 19**	**$ 18**	**$ 25**	**$ 24**	**$ 44**	**$ 42**
NON-DISCRETIONARY TOTAL	**$ 39,919**	**$ 32,553**	**$ 59,907**	**$ 53,861**	**$ 99,826**	**$ 86,414**
DISCRETIONARY						
Proactive Main Replacement & Rehabilitation						
Main Replacement (Proactive) - Leak Prone Pipe	$ 72,160	$ 61,139	$ 85,006	$ 76,384	$ 157,166	$ 137,523
Main Replacement (Proactive) - Large Diameter LPCI Program	$ 2,859	$ 3,041	$ 5,782	$ 4,842	$ 8,641	$ 7,883
Atwells Avenue	$ 1,100	$ 1,045	$ 43	$ 42	$ 1,143	$ 1,087
Proactive Main Replacement Total	**$ 76,119**	**$ 65,225**	**$ 90,831**	**$ 81,268**	**$ 166,950**	**$ 146,493**
Proactive Service Replacement						
Proactive Service Replacement Total	**$ 459**	**$ 383**	**$ 621**	**$ 556**	**$ 1,080**	**$ 939**
Reliability						
System Automation	$ 692	$ 688	$ 810	$ 748	$ 1,502	$ 1,436
Heater Installation Program	$ 5,006	$ 5,501	$ 1,477	$ 1,731	$ 6,483	$ 7,232
Wampanoag Trail & Tiverton GS - Heaters Replacement and Ownership Transfer	$ 190	$ 5,141	$ -	$ -	$ 190	$ 5,141
Take Station Refurbishment	$ 1,064	$ 1,040	$ 2,751	$ 2,233	$ 3,815	$ 3,273
Pressure Regulating Facilities	$ 6,323	$ 6,049	$ 8,441	$ 7,579	$ 14,764	$ 13,628
Valve Installation/Replacement - Primary Valve Program & Aquidneck Island Low Pressure Valves	$ 606	$ 517	$ 144	$ 247	$ 750	$ 764
Gas System Reliability	$ 2,520	$ 1,917	$ 3,423	$ 3,063	$ 5,943	$ 4,980
I&R - Reactive	$ 1,052	$ 1,170	$ 1,423	$ 1,183	$ 2,475	$ 2,353
Distribution Station Over Pressure Protection	$ 2,410	$ 2,327	$ 1,877	$ 1,924	$ 4,287	$ 4,251
LNG	$ 15,781	$ 21,240	$ 35,644	$ 16,710	$ 51,425	$ 37,950
Replace Pipe on Bridges	$ 1,000	$ 761	$ 3,800	$ 2,974	$ 4,800	$ 3,735
Access Protection Remediation	$ 60	$ 109	$ 20	$ 29	$ 80	$ 138
Tools & Equipment	$ 1,233	$ 1,171	$ 913	$ 877	$ 2,146	$ 2,048
Weld Shop	$ 8,860	$ 11,267	$ -	$ -	$ 8,860	$ 11,267
Reliability Total	**$ 46,797**	**$ 58,898**	**$ 60,723**	**$ 39,298**	**$ 107,520**	**$ 98,196**
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$ 123,375**	**$ 124,506**	**$ 152,175**	**$ 121,122**	**$ 275,550**	**$ 245,628**
Southern RI Gas Expansion Project						
Pipeline	$ -	$ -	$ -	$ -	$ -	$ -
Other Upgrades/Investments	$ -	$ -	$ -	$ -	$ -	$ -
Regulator Station Investment	$ 3,650	$ 71	$ 9,500	$ 14,731	$ 13,150	$ 14,802
Southern RI Gas Expansion Project Total	**$ 3,650**	**$ 71**	**$ 9,500**	**$ 14,731**	**$ 13,150**	**$ 14,802**
DISCRETIONARY TOTAL (With Gas Expansion)	**$ 127,025**	**$ 124,577**	**$ 161,675**	**$ 135,853**	**$ 288,700**	**$ 260,430**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$ 163,294**	**$ 157,059**	**$ 212,082**	**$ 174,983**	**$ 375,376**	**$ 332,042**
CAPITAL ISR TOTAL (With Gas Expansion)	**$ 166,944**	**$ 157,130**	**$ 221,582**	**$ 189,714**	**$ 388,526**	**$ 346,844**
Notable Capital Projects Not Currently Included in the ISR						
Old Mill Lane	$ 5,000	$ -	$ 10,000	$ -	$ 15,000	$ -
LNG - Cumberland Tank Replacement	$ 500	$ -	$ 1,000	$ -	$ 1,500	$ -
Total	**$ 5,500**	**$ -**	**$ 11,000**	**$ -**	**$ 16,500**	**$**

Table 2
RI Energy - Gas ISR Spending Forecast
($000)

Categories	CY 2023 9-month	CY 2024 12-month	FY 2025	FY 2026	FY 2026
NON-DISCRETIONARY					
Public Works	$ 18,315	$ 24,280	$ 32,840	$ 36,609	$ 40,209
Mandated Programs	$ 21,585	$ 35,602	$ 38,952	$ 37,584	$ 41,524
Damage / Failure (Reactive)	$ 19	$ 25	$ 25	$ 25	$ 25
NON-DISCRETIONARY TOTAL	**$ 39,919**	**$ 59,907**	**$ 71,817**	**$ 74,218**	**$ 81,758**
DISCRETIONARY					
Proactive Main Replacement	$ 73,260	$ 85,049	$ 113,676	$ 121,439	$ 127,511
Proactive Main Rehabilitation - Large Diameter LPCI	$ 2,859	$ 5,782	$ 6,438	$ 6,567	$ 6,698
Proactive Service Replacement	$ 459	$ 621	$ 624	$ 637	$ 649
Reliability	$ 46,797	$ 60,723	$ 46,382	$ 55,429	$ 56,646
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$ 123,375**	**$ 152,175**	**$ 167,120**	**$ 184,071**	**$ 191,504**
Southern RI Gas Expansion Project	$ 3,650	$ 9,500	$ 200	$ -	$ -
DISCRETIONARY TOTAL (With Gas Expansion)	**$ 127,025**	**$ 161,675**	**$ 167,320**	**$ 184,071**	**$ 191,504**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$ 163,294**	**$ 212,082**	**$ 238,937**	**$ 258,289**	**$ 273,262**
CAPITAL ISR TOTAL (With Gas Expansion)	**$ 166,944**	**$ 221,582**	**$ 239,137**	**$ 258,289**	**$ 273,262**
Notable Capital Projects Not Currently Included in the ISR					
Old Mill Lane	$ 5,000	$ 10,000	$ -	$ -	$ -
LNG - Cumberland Tank Replacement	$ 500	$ 1,000	$ 38,501	$ 44,000	$ 43,000
Smart Gas Meter - IS Integration	$ -	$ -	$ 2,250	$ 750	$ -
Total	**$ 5,500**	**$ 11,000**	**$ 40,751**	**$ 44,750**	**$ 43,000**

Table 3
RI Energy - Gas ISR - Historical Spend
($000)

Categories	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
	Actual	Actual	Actual	Actual	Actual	Actual
NON-DISCRETIONARY						
Public Works	$ 8,597	$ 14,590	$ 13,575	$ 16,523	$ 12,997	$ 22,257
Mandated Programs	$ 16,370	$ 22,110	$ 18,868	$ 19,043	$ 17,518	$ 18,160
Damage / Failure (Reactive)	$ -	$ 1,610	$ -	$ -	$ -	$ -
Special Projects	$ 5,020	$ 1,780	$ 8,486	$ -	$ -	$ -
NON-DISCRETIONARY TOTAL	**$ 29,987**	**$ 40,080**	**$ 40,928**	**$ 35,566**	**$ 30,516**	**$ 40,417**
DISCRETIONARY						
Proactive Main Replacement	$ 48,872	$ 51,210	$ 52,548	$ 58,032	$ 60,896	$ 72,261
Proactice Main Replacement - Large Diameter LPCI	$ -	$ 1,180	$ -	$ 1,115	$ 1,419	$ 3,265
Atwells Avenue	$ -	$ -	$ 81	$ 906	$ 5,612	$ 1,240
Service Replacement - Proactive	$ -	$ -	$ -	$ -	$ 240	$ 396
Reliability	$ 8,403	$ 13,950	$ 10,290	$ 15,933	$ 24,836	$ 28,886
SUBTOTAL DISCRETIONARY (Without Gas Expansion)	**$ 57,275**	**$ 66,330**	**$ 62,918**	**$ 75,986**	**$ 93,003**	**$ 106,048**
Southern RI Gas Expansion Project	$ -	$ -	$ 2,390	$ 42,729	$ 41,755	$ 14,952
DISCRETIONARY TOTAL (With Gas Expansion)	**$ 57,275**	**$ 66,330**	**$ 65,308**	**$ 118,715**	**$ 134,758**	**$ 121,000**
CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)	**$ 87,262**	**$ 106,410**	**$ 103,846**	**$ 111,552**	**$ 123,519**	**$ 146,464**
CAPITAL ISR TOTAL (With Gas Expansion)	**$ 87,262**	**$ 106,410**	**$ 106,236**	**$ 154,281**	**$ 165,274**	**$ 161,416**
O&M Total	$ 488	$ 560	$ 179	$ -	$ -	$ -
GAS ISR GRAND TOTAL	**$ 87,750**	**$ 106,970**	**$ 106,415**	**$ 154,281**	**$ 165,274**	**$ 161,416**

Schedule 1

2021 System Integrity Report

2021 System Integrity Report - RI

Enterprise Gas Distribution System Trend-Based Integrity Analysis

09-30-2022

Gas Distribution Engineering

Gas Asset Management – Gas Process & Engineering

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Region	Name	Title	Phone
MA	Michael Tupper	Director	1 (508) 654-3134
	Leomary Bader	Manager	1 (781) 907-2785
	Peter Sullivan	Senior Engineer	1 (617) 655-4018
RI	Laeyeng Hunt	Director	1 (508) 962-0043
	Barry Foster	Manager	1 (401) 465-8841
	Yan Wang-Jiang	Senior Engineer	1 (617) 455-7537

01

Overall Assessment Summary

Distribution Integrity

Assessment Summary

- Distribution Engineering has reviewed all of the findings in the annual Trend-Based Distribution System Integrity Analysis (System Integrity Report) in accordance with our Distribution Integrity Management Plan (DIMP), Any anomalies found were either explained as non-systemic or set up for continued research and/or monitoring. These will be explained in notes to this report.
- Below is a summary of the individual key integrity measure results for the federal (PHMSA) filing entities that constitute RI Energy (formerly National Grid – RI)

Percent Change 2020 To 2021	RI
Leak Receipts	-13.2%
Workable Leak Backlog	21.3%
LPP Main Inventory	-4.7%
LPP Service Inventory	-3.7%
Overall Main Leak Rate	6.6%
Cast Iron Main Break Rate	76.1%
Steel Main Corrosion Leak Rate	39.2%
Service Leak Rate	72.3%

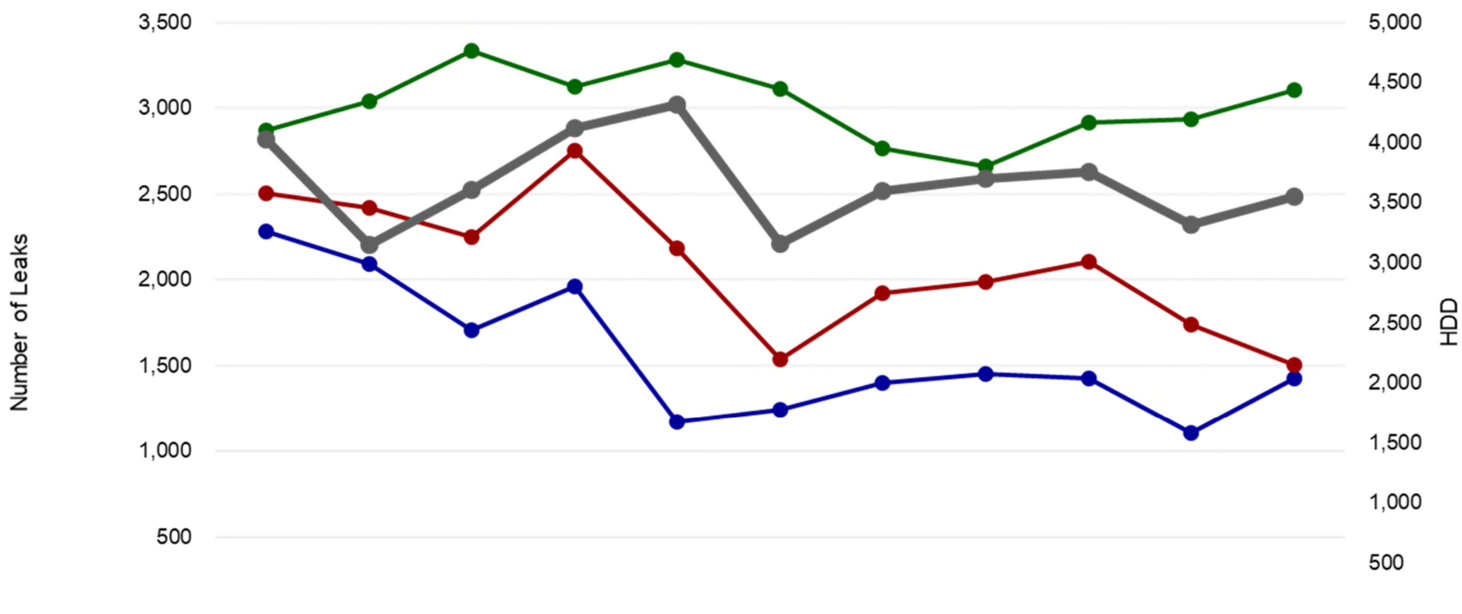
Color Code Ranges	-100.0%	0.0%	0.1%	3.0%	3.1%	10.0%	10.1%	100.0%

02

Leak Receipts, Repairs, and Backlog By HDD Trend (Mains & Services)

Total Leak Receipts, Repairs, and Backlog

(Excluding Damages)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Leak Repairs	2,286	2,096	1,709	1,961	1,173	1,245	1,398	1,456	1,424	1,104	1,426
Leak Receipts	2,502	2,417	2,252	2,753	2,183	1,541	1,924	1,989	2,107	1,738	1,508
Leak Backlogs	2,874	3,042	3,332	3,125	3,281	3,116	2,766	2,664	2,915	2,936	3,105
HDD	4,026	3,151	3,608	4,123	4,318	3,156	3,593	3,699	3,757	3,319	3,549

Years

Overall Regional Distribution Integrity Assessment Summary

Rhode Island (RI)	
	• Leak receipts decreased. • Workable leak backlog increased. • Leak prone main and service inventories continue to decline steadily. • Overall main leak rate slightly increased. Steel main corrosion rate increased and Cast Iron main break rate increased. • Service leak rate increased.

03

PHMSA Reported Incidents

PHMSA Reported Incidents

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RI

Total
0

04

Leaks Management Analysis (Mains & Services)

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Leak Receipts As A Function Of Total System Pipe Mileage

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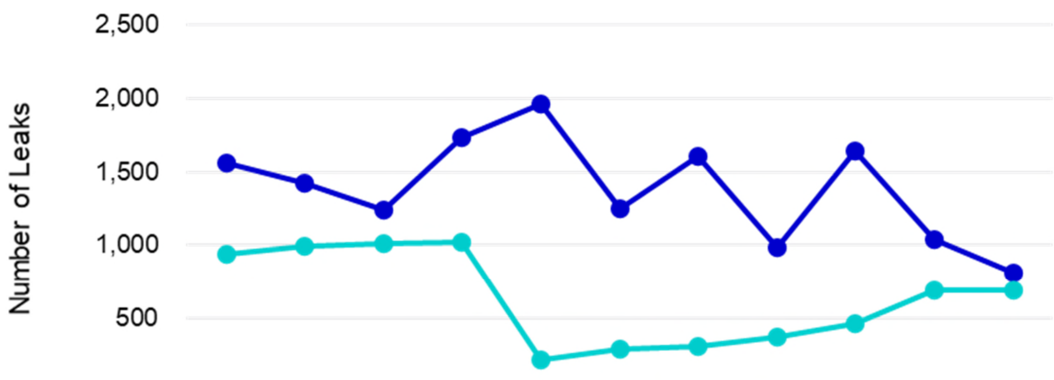
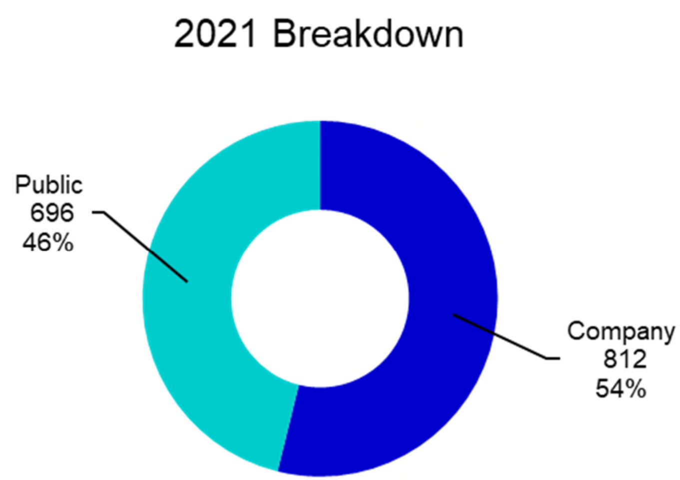
RI

- 1,597 Leak Receipts (Including Damages)
- 3,227 Miles of Main; 194,450 #'s of Services (2,305 miles)
- 5,532 total miles of pipe
- 0.29 Leak Receipts per Mile of Pipe

Leak Receipts By Discovery Source
(Excluding Damages)

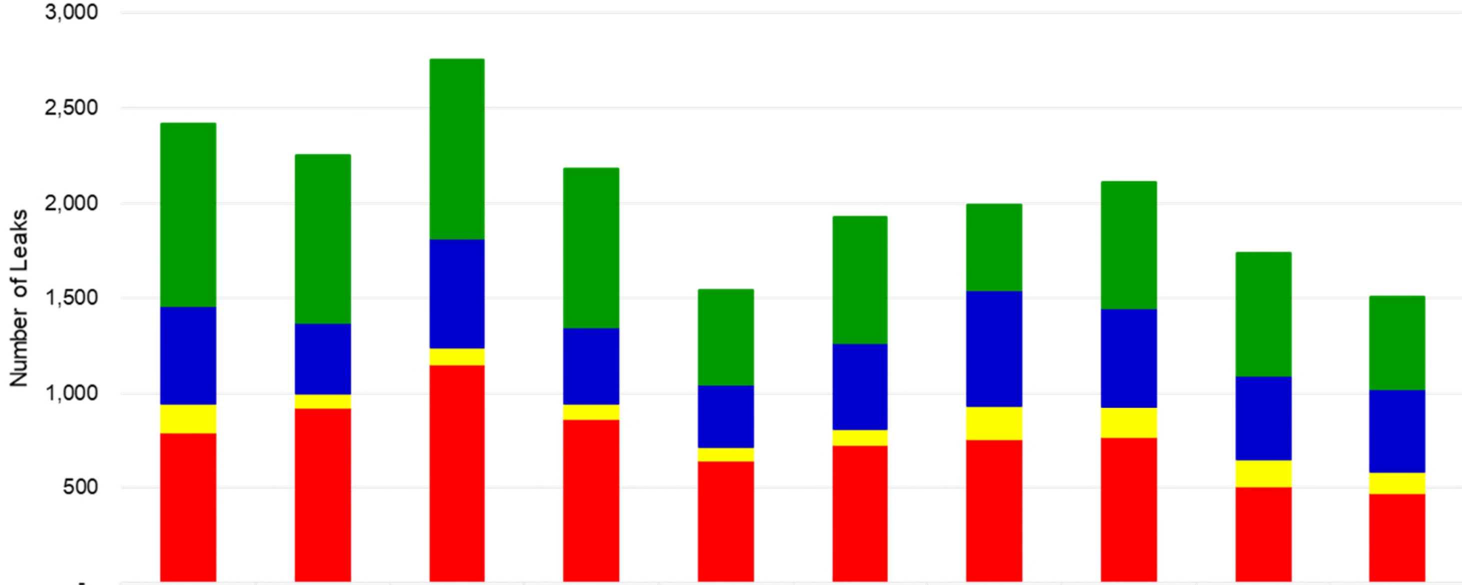


	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Company	1,559	1,422	1,238	1,730	1,966	1,247	1,609	987	1,638	1,040	812
Public	943	995	1,014	1,023	217	294	315	374	469	698	696



Leak Receipts By Type

(Excluding Damages)

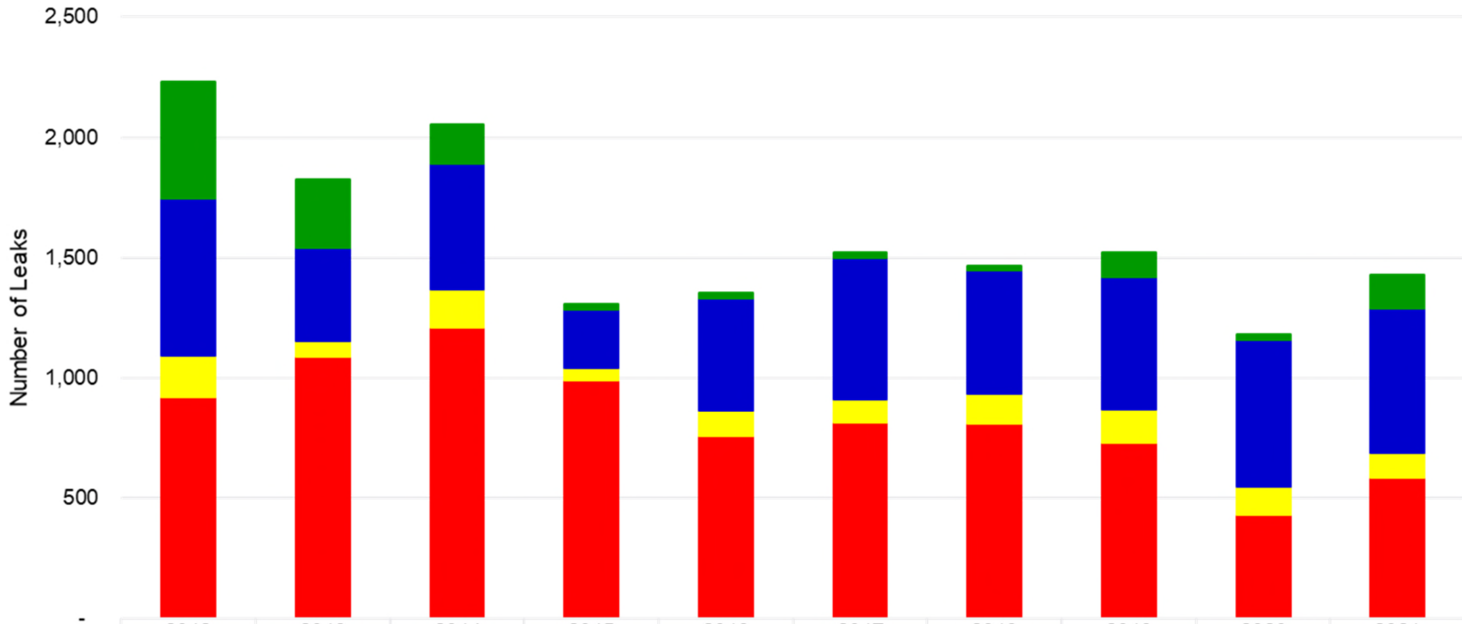


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Type 3	959	881	937	838	494	658	444	659	642	486
Type 2	512	370	577	401	331	459	609	522	446	438
Type 2A	154	79	89	80	72	83	178	159	143	112
Type 1	792	922	1,150	864	644	724	758	767	507	472
Total	2,417	2,252	2,753	2,183	1,541	1,924	1,989	2,107	1,738	1,508

05

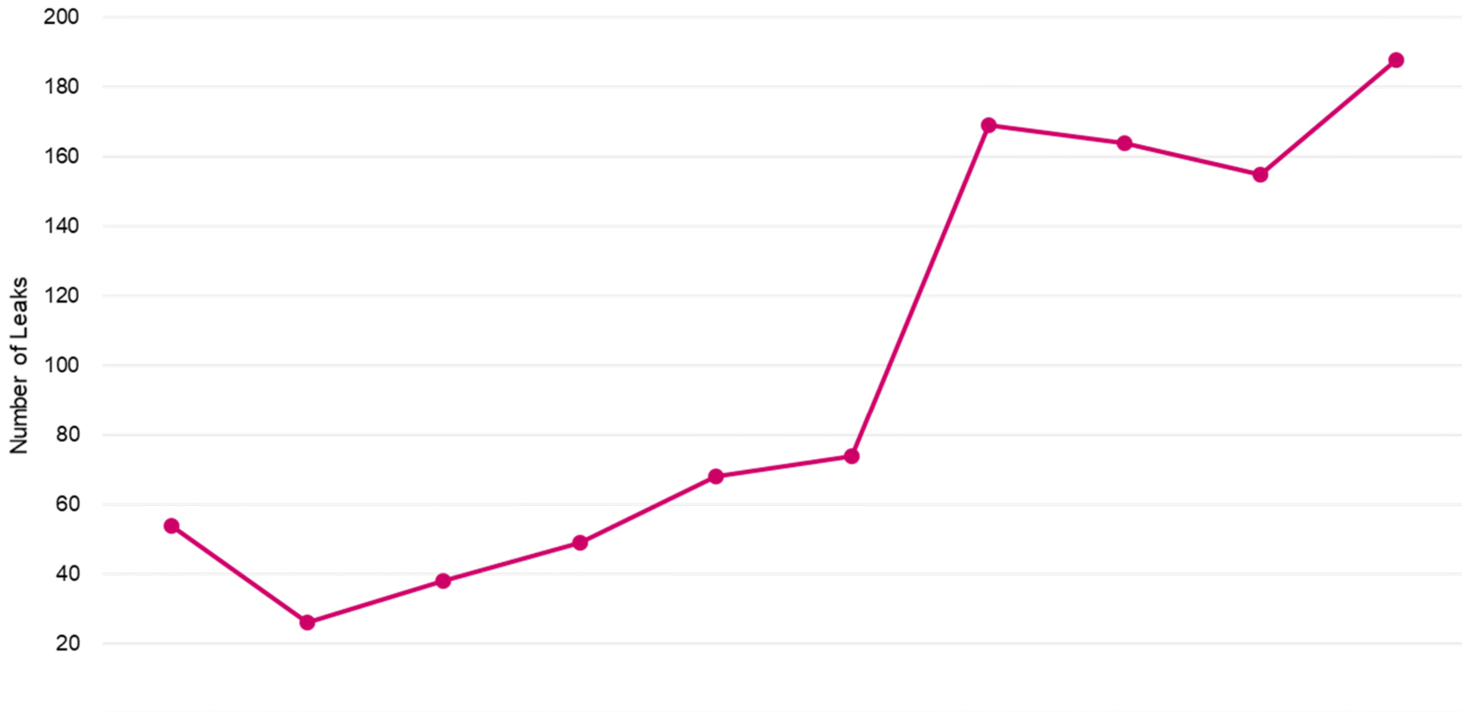
Leaks Repaired Analysis (Mains & Services)

Leak Repaired By Type
(Including Damages)



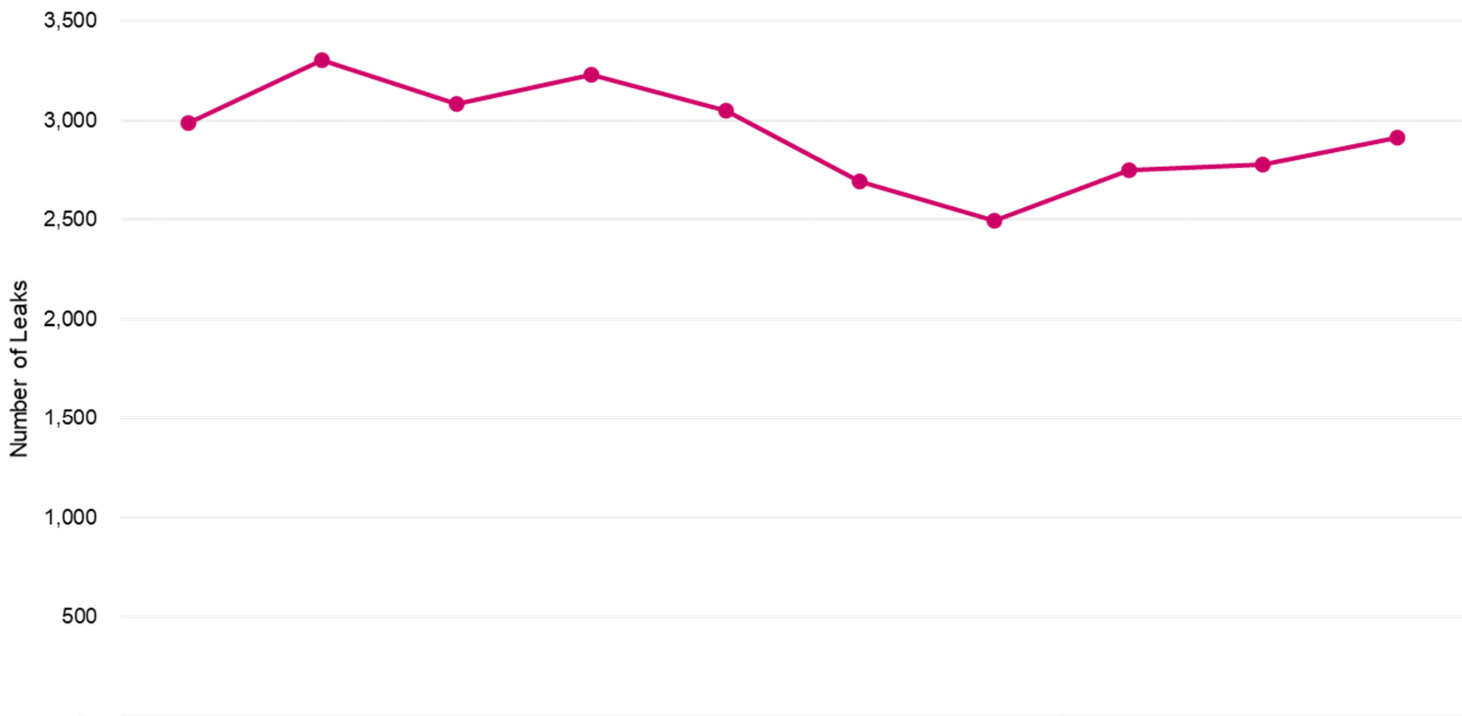
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Type 3	486	286	162	24	21	24	21	103	24	137
Type 2	651	383	522	244	469	588	513	551	612	604
Type 2A	172	68	160	49	106	99	123	140	116	104
Type 1	921	1,087	1,209	991	756	812	809	728	429	581

Workable Leak Backlog
(Year-End)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	54	26	38	49	68	74	169	164	155	188

Open Type 3 Leak Backlog
(Year-End)

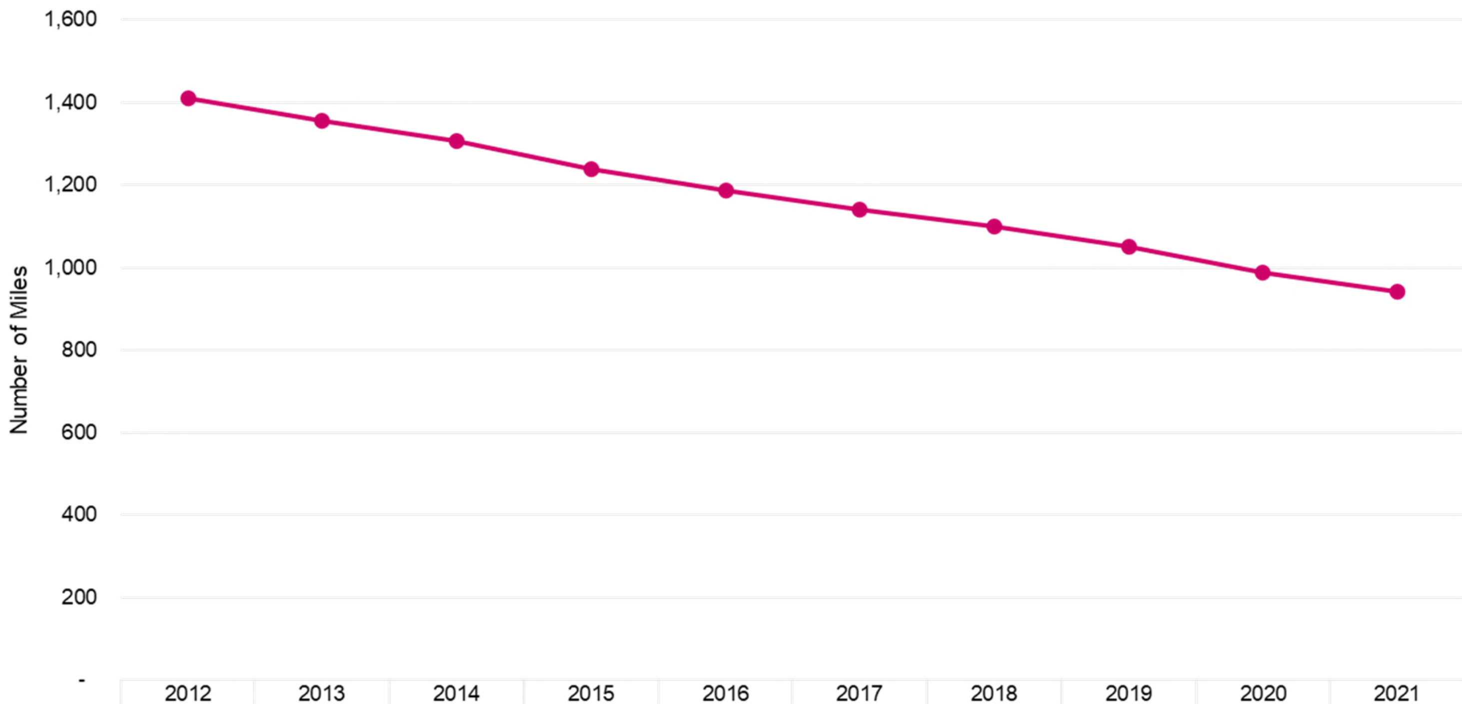


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	2,988	3,306	3,087	3,232	3,048	2,692	2,495	2,751	2,781	2,917

06

Main Inventory Analysis

Main Inventory LPP Trend
(Miles)



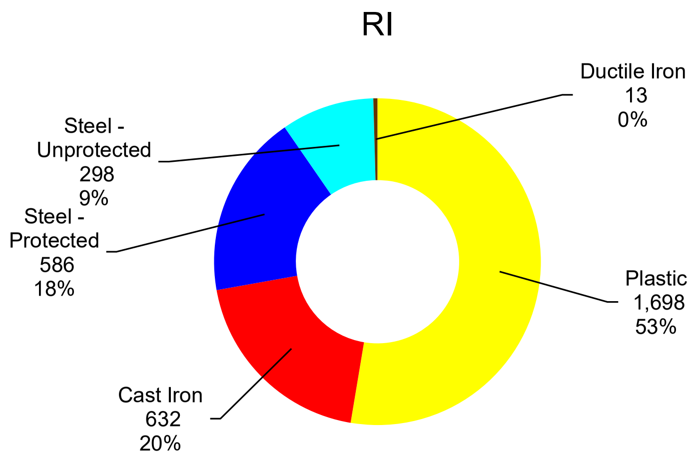
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	1,409	1,355	1,305	1,237	1,186	1,140	1,100	1,052	989	942

Years

Main Inventory

2021 RI ENERGY

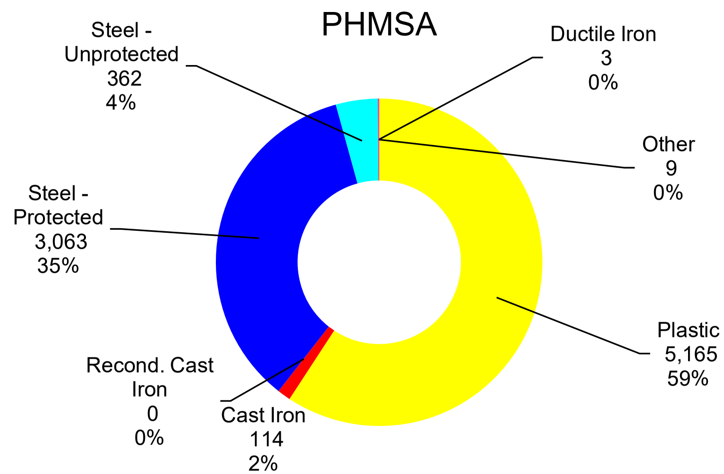
3,227 Miles



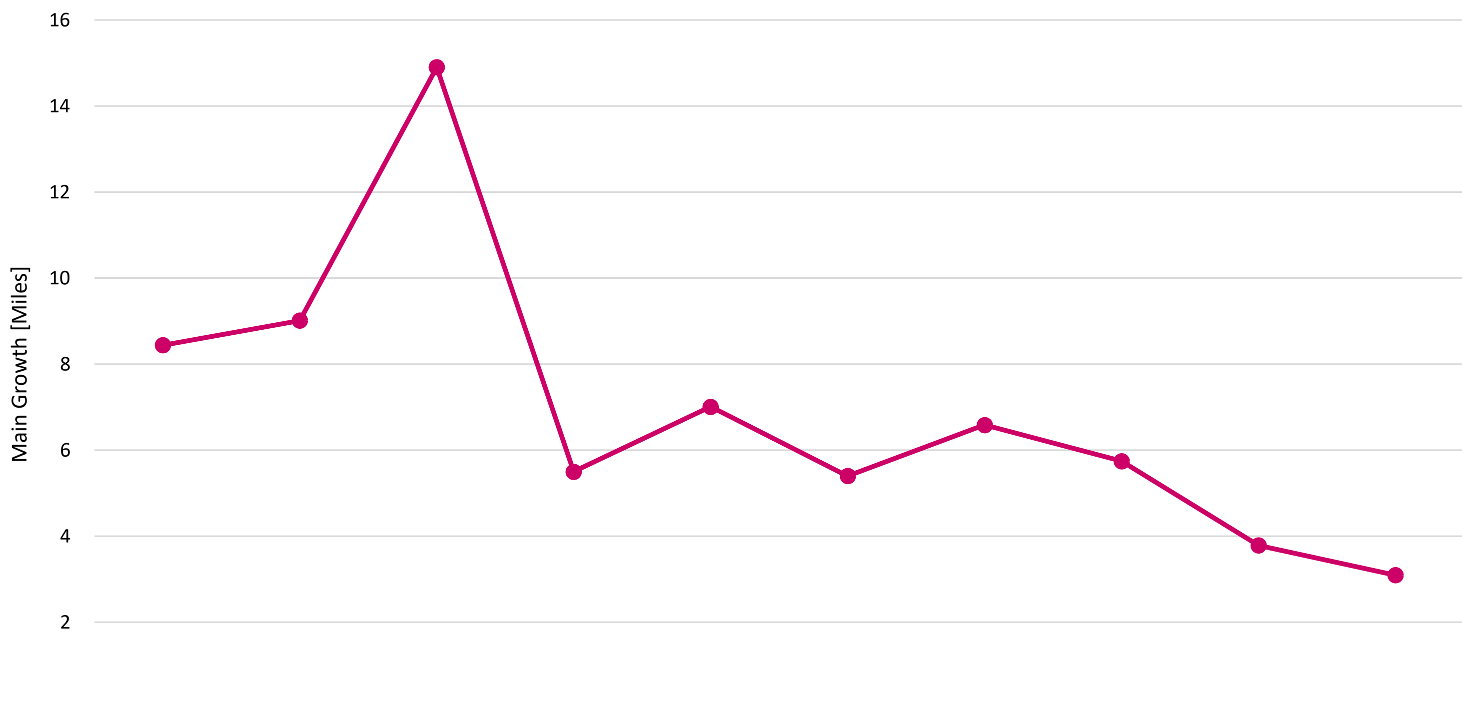
2021 PHMSA Average

(Excluding National Grid & RI Energy)

- 127 Companies (2,000+ Miles of Main)
- 8,713 Miles of Main Per Company



Main Growth
(Miles)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	8	9	15	6	7	5	7	6	4	3

Main Replacement

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NGRID & RI Energy

Rate Case Supported "Leak-Prone" Main Replacement Levels

Region	2021 Total Main (Miles)	2021 Leak Prone Main (Miles)	Leaks/Miles of Total Main (Repair Rate)	Leaks/Miles of Leak Prone Main (Repair Rate)	(5) 2021 Annual "Planned" Replacement (Miles)	Planned Replacement % of Leak Prone System	(5) 2021 Annual "Actual" Replacement (Miles)	Actual Replacement % of Leak Prone System	(5) 2022 Annual "Planned" Replacement (Miles)	Years to LPP Main Elimination based on "Current" Annual Plan
NYC	4,190	1,437	0.43	1.20	22.0	1.5%	55.0	3.8%	45.0	23
LI	8,399	3,155	0.06	0.15	123.0	3.9%	127.0	4.0%	116.0	23
Upstate NY	8,902	414	0.02	0.38	44.0	10.6%	47.0	11.4%	45.0	9
RI	3,227	942	0.24	0.84	65.0	6.9%	47.0	5.0%	65.0	14
BGC & EGC	7,241	2,901	0.62	1.40	115.0	4.0%	47.4	1.6%	110.0	19
CCC & CLW	3,890	186	0.09	1.50	40.0	21.5%	26.3	14.1%	34.0	6

Notes:
1. Leaks per mile of total main excludes Excavation leaks.
2. Leaks per mile of Leak-Prone main (LPP) excludes Excavation leaks and Plastic leaks.
3. Leak-Prone Pipe = Unprotected steel (Bare & Coated) + CI/WI + Aldyl-A (MD, 1985 and prior) + Other.
4. Miles of Leak-Prone main replaced includes all Proactive programs (Main Replacement program & System Reinforcement) and all Reactive programs (Public Works, Water Intrusion & Leak/reactive).
5. Annual planned and actual replacement miles are CY.
6. Data sources are 2016, 2017, 2018 US Gas Leak Prone Pipe Replacement Programs monthly reports from Gas Resource Management CMS.

07

Main Leaks Repaired Analysis

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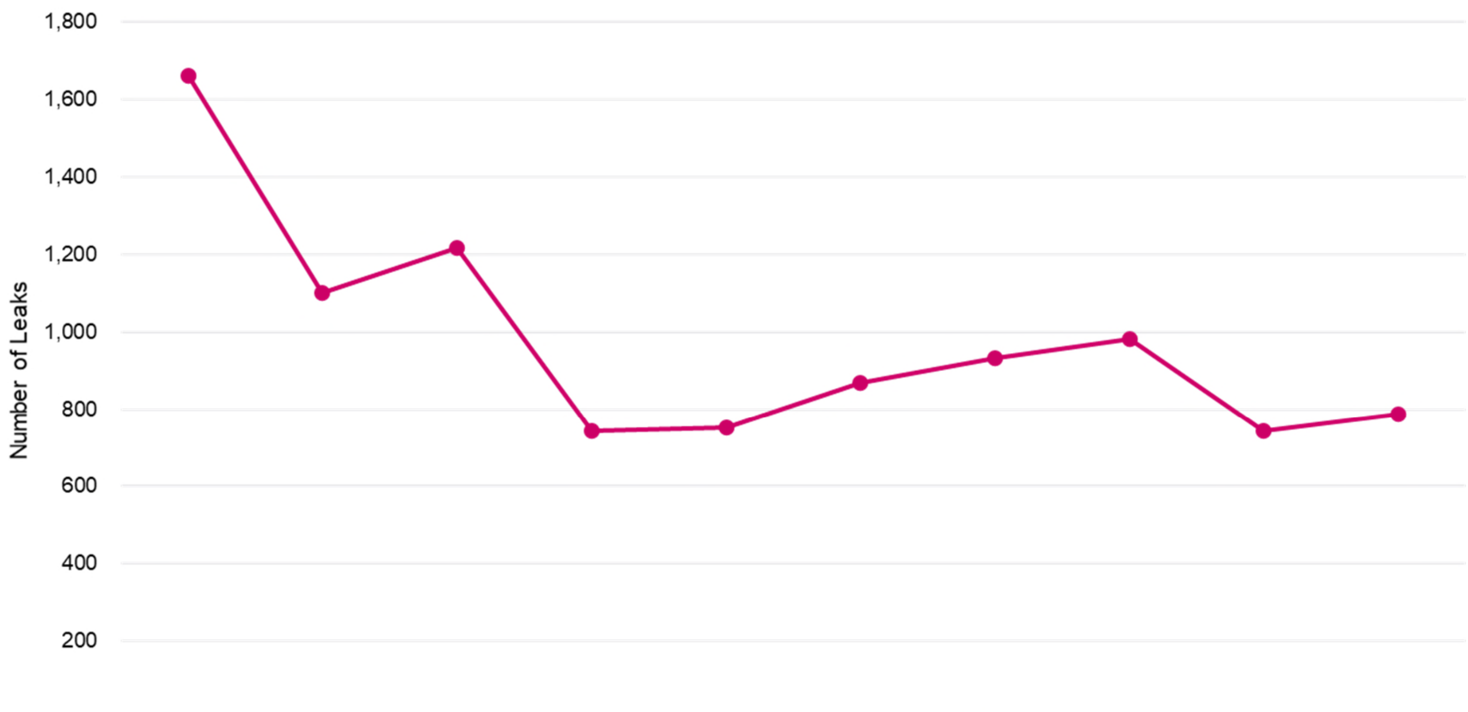
Main Leaks Repaired

(Including Damages)

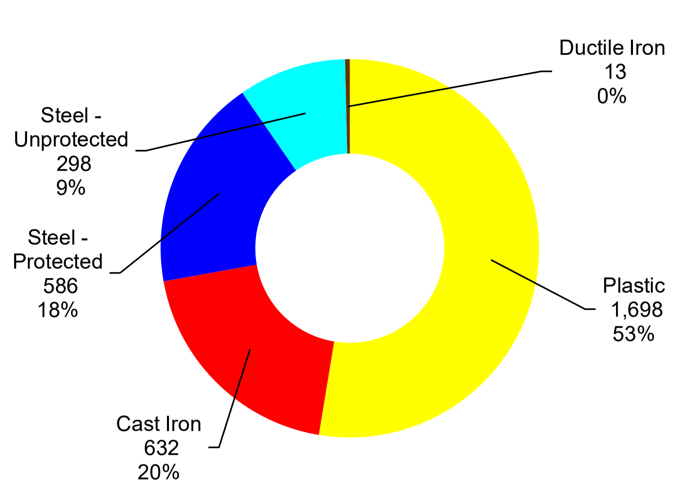


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	1,663	1,102	1,216	744	751	869	932	982	743	787

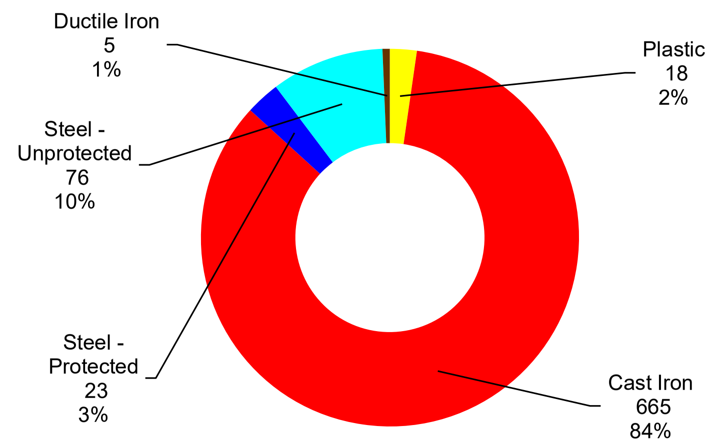
Years

Main Inventory Compared to Main Leak Repairs by Material

Main Inventory

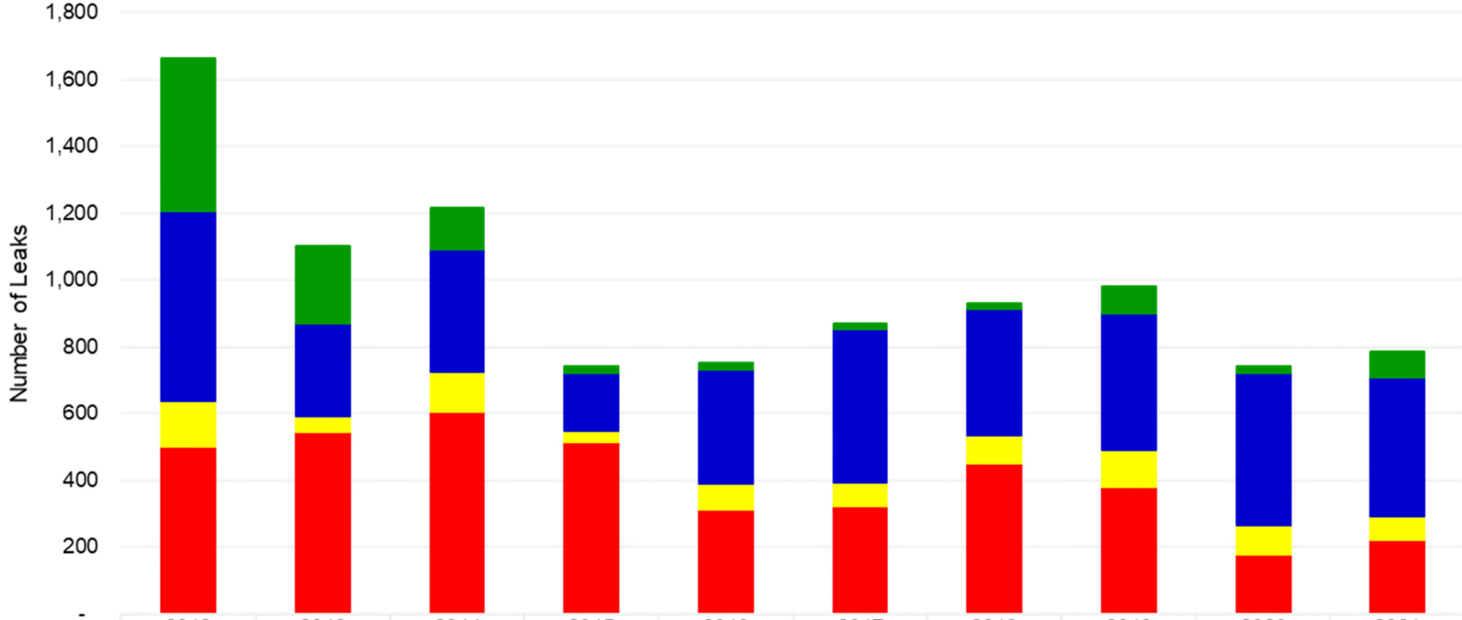


Main Leak Repairs



Main Leaks Repaired by Type

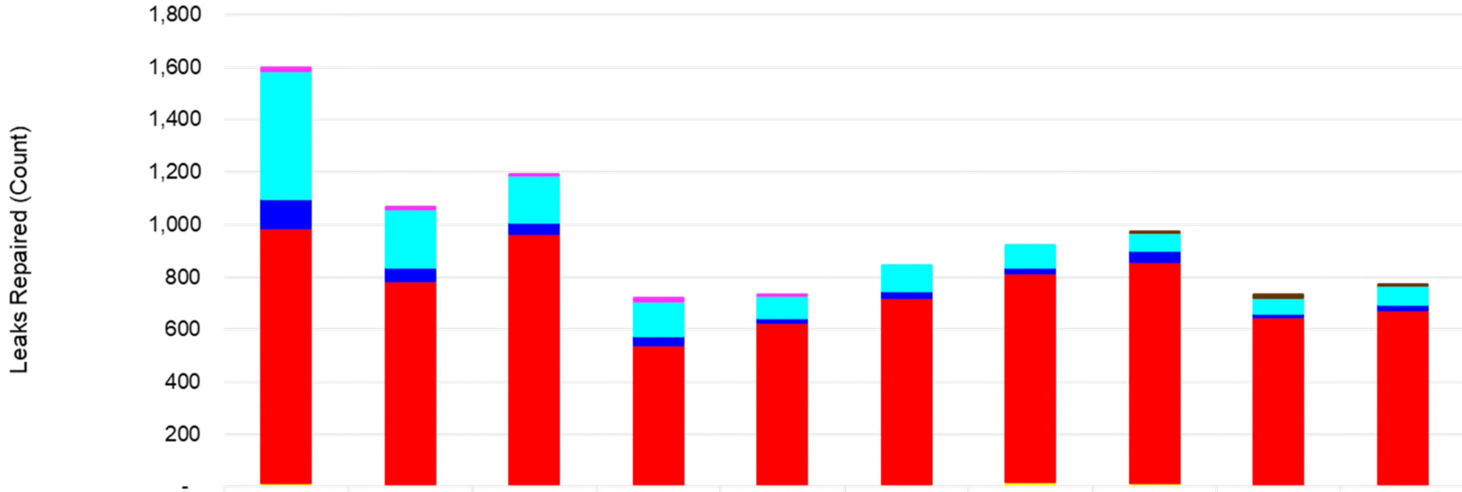
(Including Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Type 3	455	233	123	22	19	15	17	80	19	79
Type 2	568	278	367	176	343	461	381	413	459	415
Type 2A	141	47	121	32	76	69	83	111	86	71
Type 1	499	544	605	514	313	324	451	378	179	222

Main Leaks Repaired by Material

(Excluding Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Ductile Iron	-	-	-	-	-	-	-	2	14	5
Other	10	6	6	12	4	-	-	-	-	-
Steel - Unprotected	490	225	180	135	87	100	86	68	58	74
Steel - Protected	109	52	42	33	19	23	20	44	15	22
Recond. Cast Iron	-	-	-	-	-	-	-	-	-	-
Cast Iron	974	777	960	534	619	712	797	842	646	661
Plastic	14	7	5	7	6	10	19	14	1	11

Years

Main Leaks Repaired by Leak Cause

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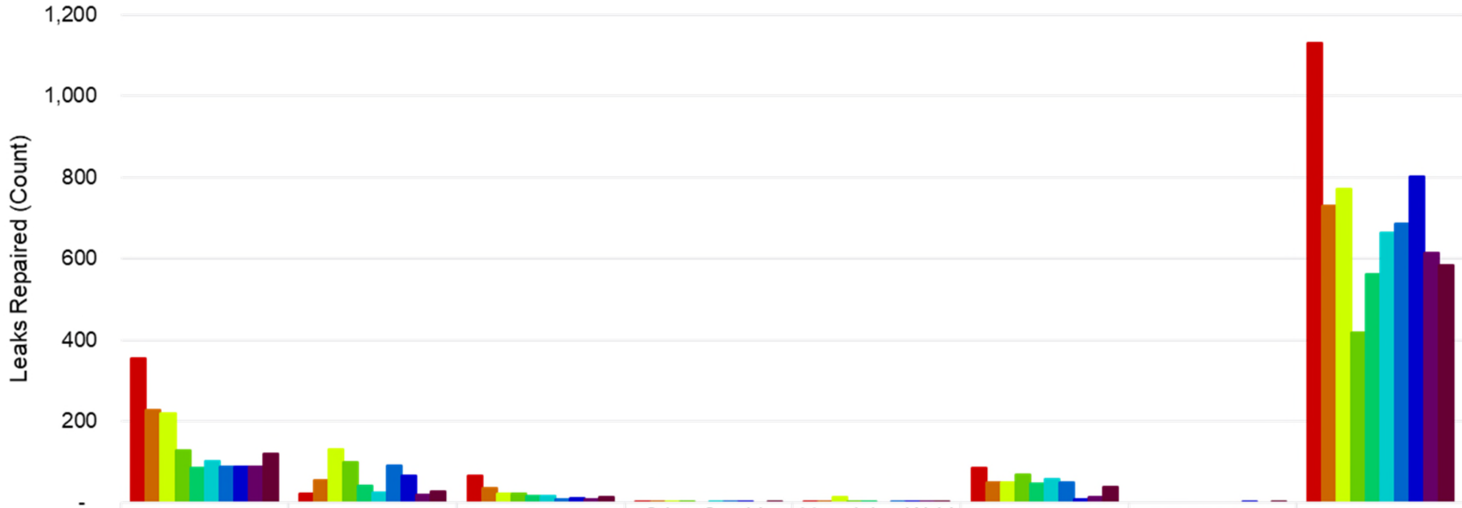
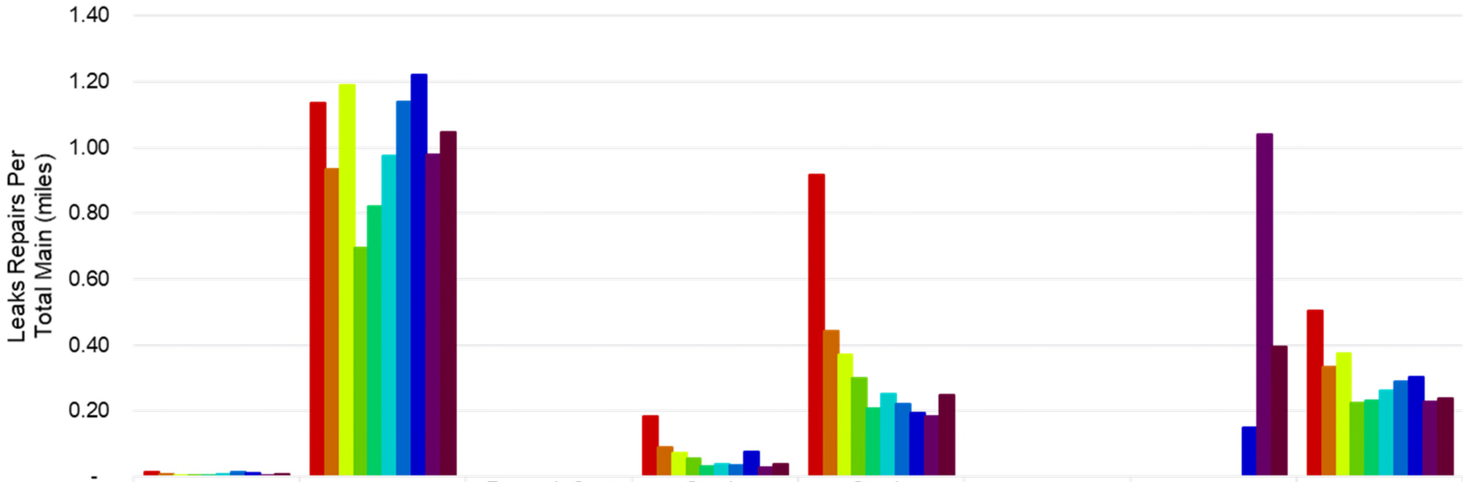


	Corrosion	Natural Force	Excavation	Other Outside Force	Material or Weld Failure	Equipment	Operations	CI Joint Leaks
2012	357	22	66	1	1	86	-	1,130
2013	228	54	35	1	3	49	-	732
2014	222	131	23	4	15	49	-	772
2015	129	99	23	1	2	70	-	420
2016	85	40	16	-	2	46	-	562
2017	102	26	16	1	-	58	-	666
2018	88	90	8	1	4	50	-	688
2019	87	66	12	3	4	7	1	802
2020	87	18	9	-	2	13	-	614
2021	120	27	14	1	1	38	2	584

Leak Cause

Main Leaks Rates by Material
(Excluding Damages)



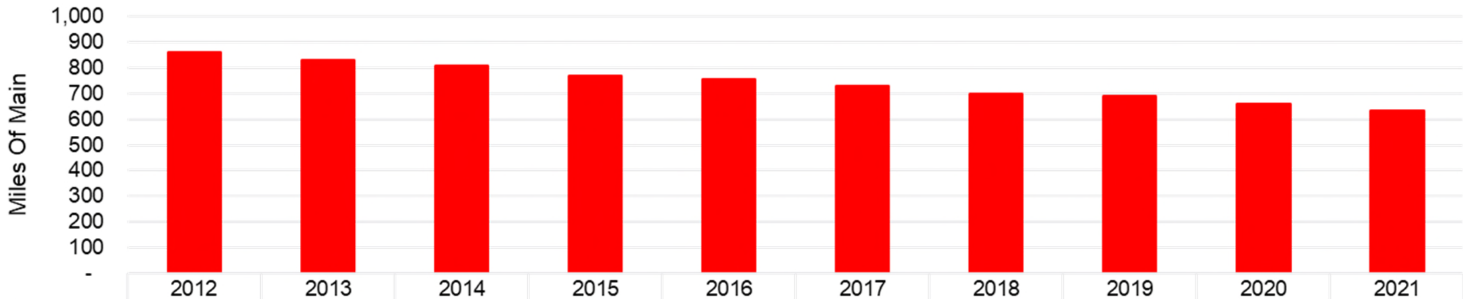
	Plastic	Cast Iron	Recond. Cast Iron	Steel - Protected	Steel - Unprotected	Other	Ductile Iron	Total
2012	0.01	1.13	-	0.18	0.92	-	-	0.50
2013	0.01	0.93	-	0.09	0.44	-	-	0.34
2014	0.00	1.19	-	0.07	0.37	-	-	0.37
2015	0.01	0.69	-	0.06	0.30	-	-	0.22
2016	0.00	0.82	-	0.03	0.21	-	-	0.23
2017	0.01	0.98	-	0.04	0.25	-	-	0.26
2018	0.01	1.14	-	0.04	0.22	-	-	0.29
2019	0.01	1.22	-	0.08	0.20	-	0.15	0.30
2020	0.00	0.98	-	0.03	0.18	-	1.04	0.23
2021	0.01	1.05	-	0.04	0.25	-	0.40	0.24

Material

A Closer Look At Cast Iron Mains

CI Main Inventory Compared to CI Attrition Rate

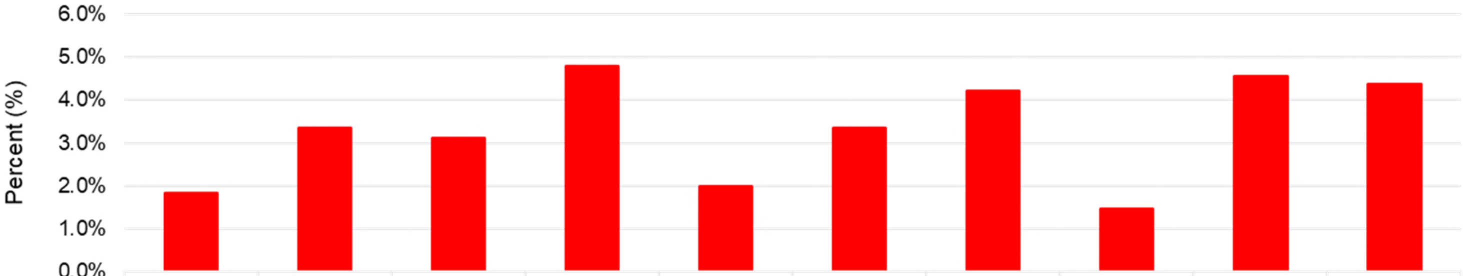
Cast Iron Main Inventory



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cast Iron	859	831	806	769	754	730	700	690	660	632

Years

Cast Iron Reduction Percentage

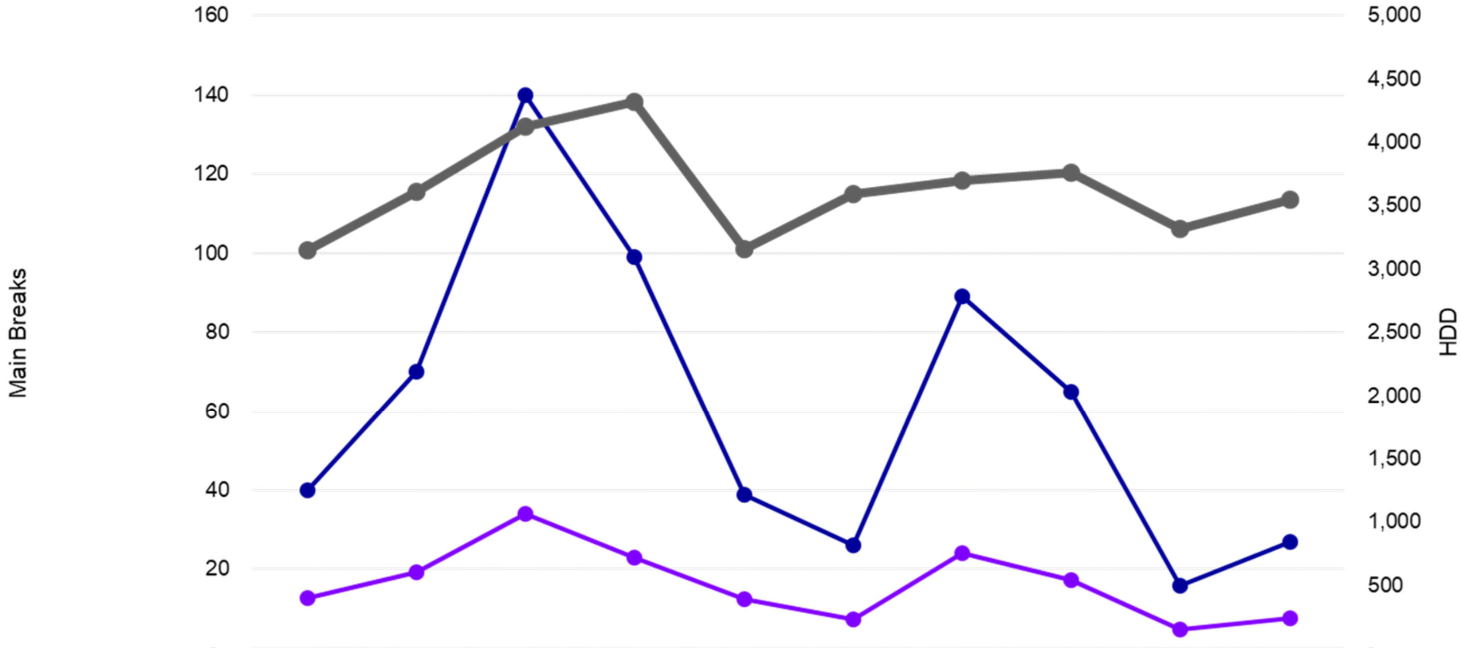


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cast Iron	1.8%	3.3%	3.1%	4.8%	2.0%	3.3%	4.2%	1.5%	4.6%	4.4%

Years

Note: 2019 Providence stopped issuing permits due to paving patch issues

CI Main Breaks Compared to HDD



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Leak Repairs	40	70	140	99	39	26	89	65	16	27
Leak Repairs/HDD	12.69	19.40	33.96	22.93	12.36	7.24	24.06	17.30	4.82	7.61
HDD	3,151	3,608	4,123	4,318	3,156	3,593	3,699	3,757	3,319	3549

- Note: Repairs/HDD is Multiplied By 1,000

Cast Iron Main Break Rates

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	0.05	0.08	0.17	0.13	0.05	0.04	0.13	0.09	0.02	0.04

Cast Iron Main Break Rates
(Comparison by Diameter)

	Unknown	2" or Less	Over 2" Thru 4"	Over 4" Thru 8"	Over 8" Thru 12"	Over 12"
RI			0.05	0.05		0.03

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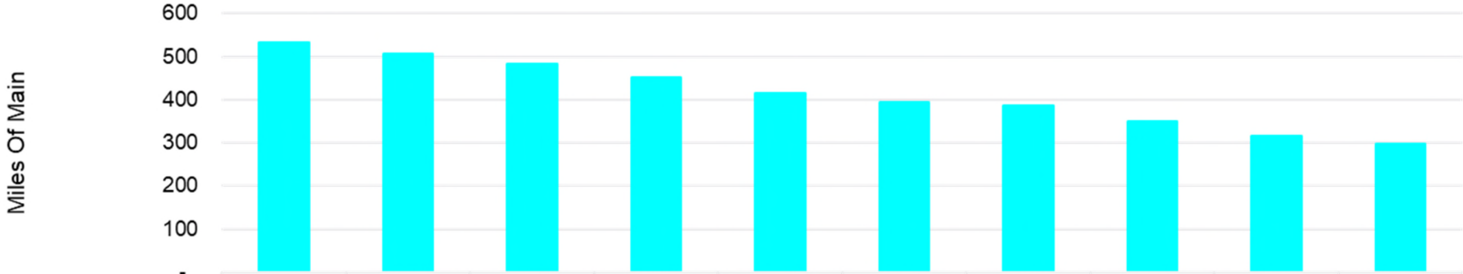
A Closer Look At Steel Mains

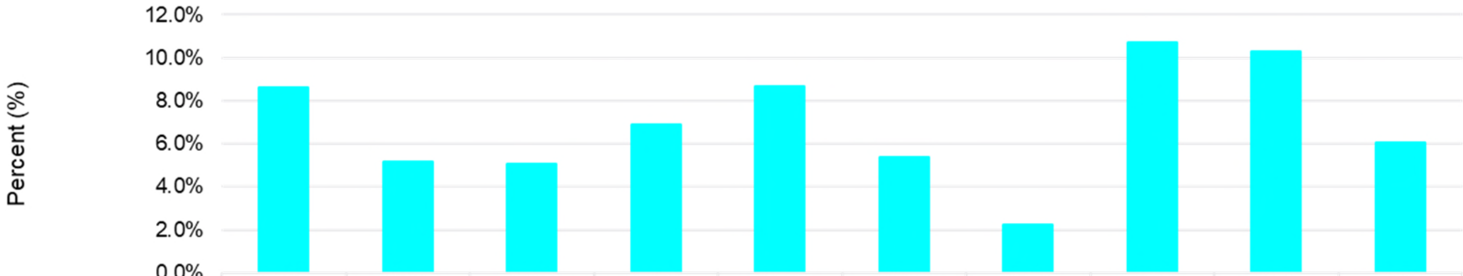
Unprotected Steel Main Inventory Compared to Steel Attrition Rate

Unprotected Steel Main Inventory



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Steel - Unprotected	534	508	483	452	416	395	386	349	316	298

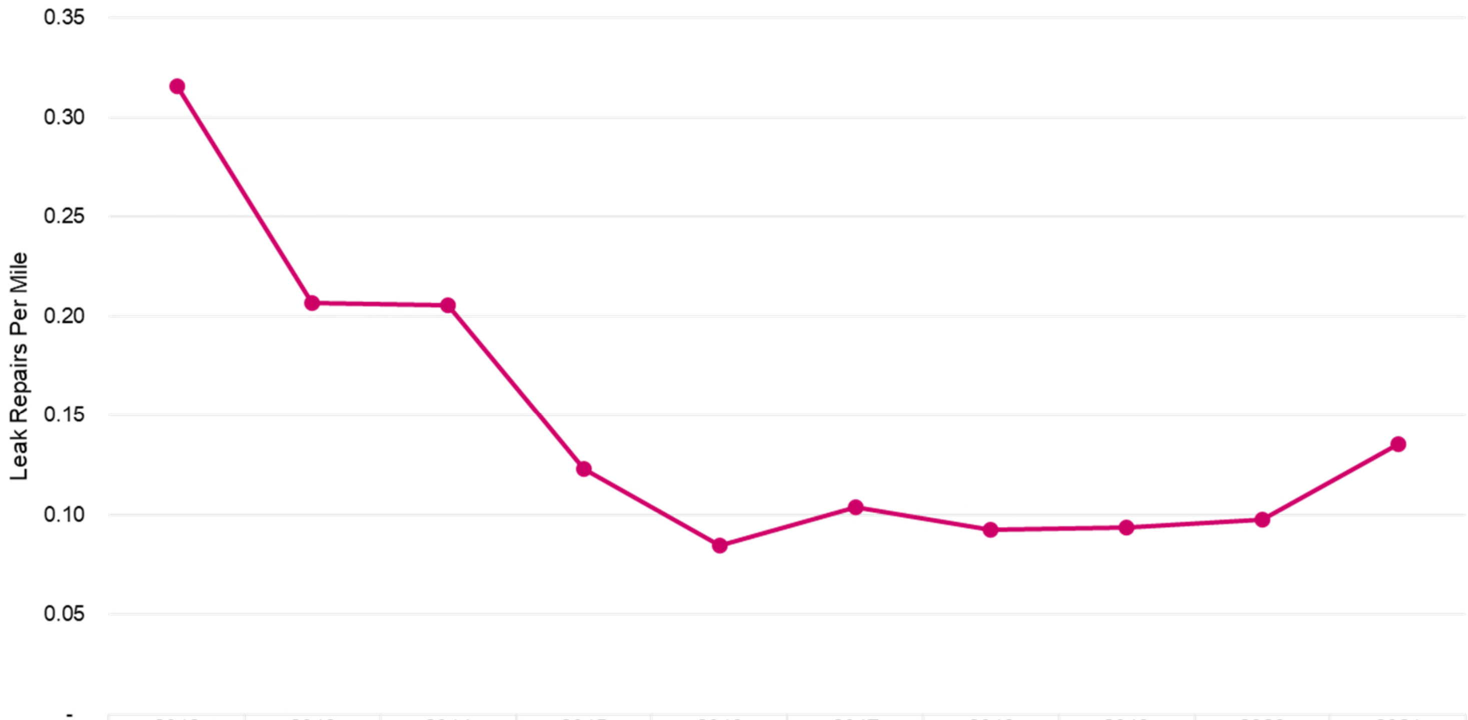
Unprotected Steel Reduction Percentage



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Steel - Unprotected	8.6%	5.2%	5.1%	6.9%	8.7%	5.4%	2.3%	10.7%	10.3%	6.1%

Main Corrosion Leak Rates

(Corrosion Leak Repairs Per Mile of Total Steel)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	0.32	0.21	0.21	0.12	0.08	0.10	0.09	0.09	0.10	0.14

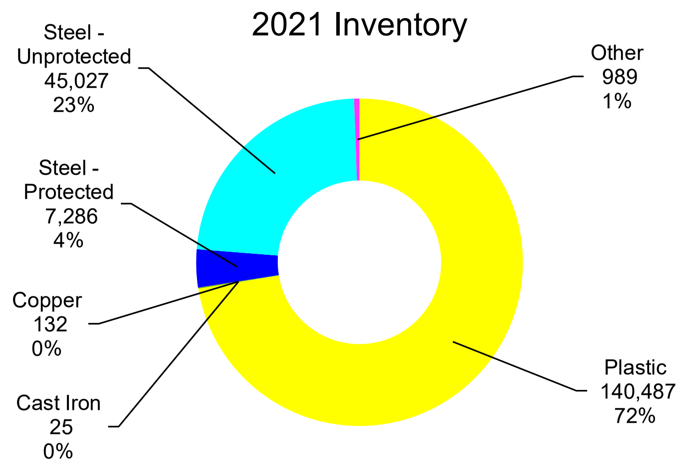
Note: Includes **ALL** corrosion leaks, regardless of main material

08

Service Inventory Analysis

Service Inventory Analysis by Material

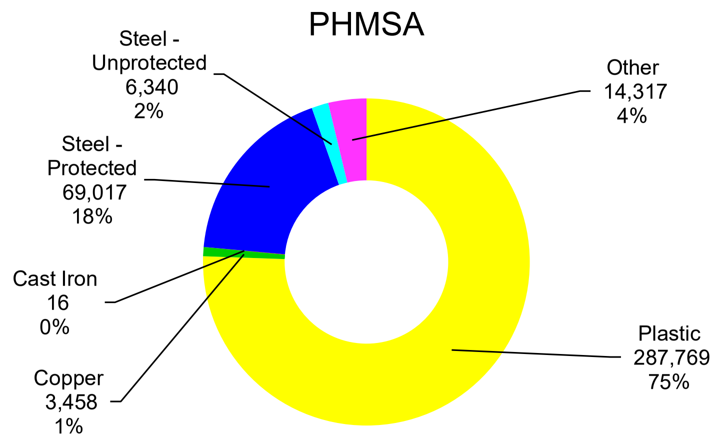
2021 RI ENERGY



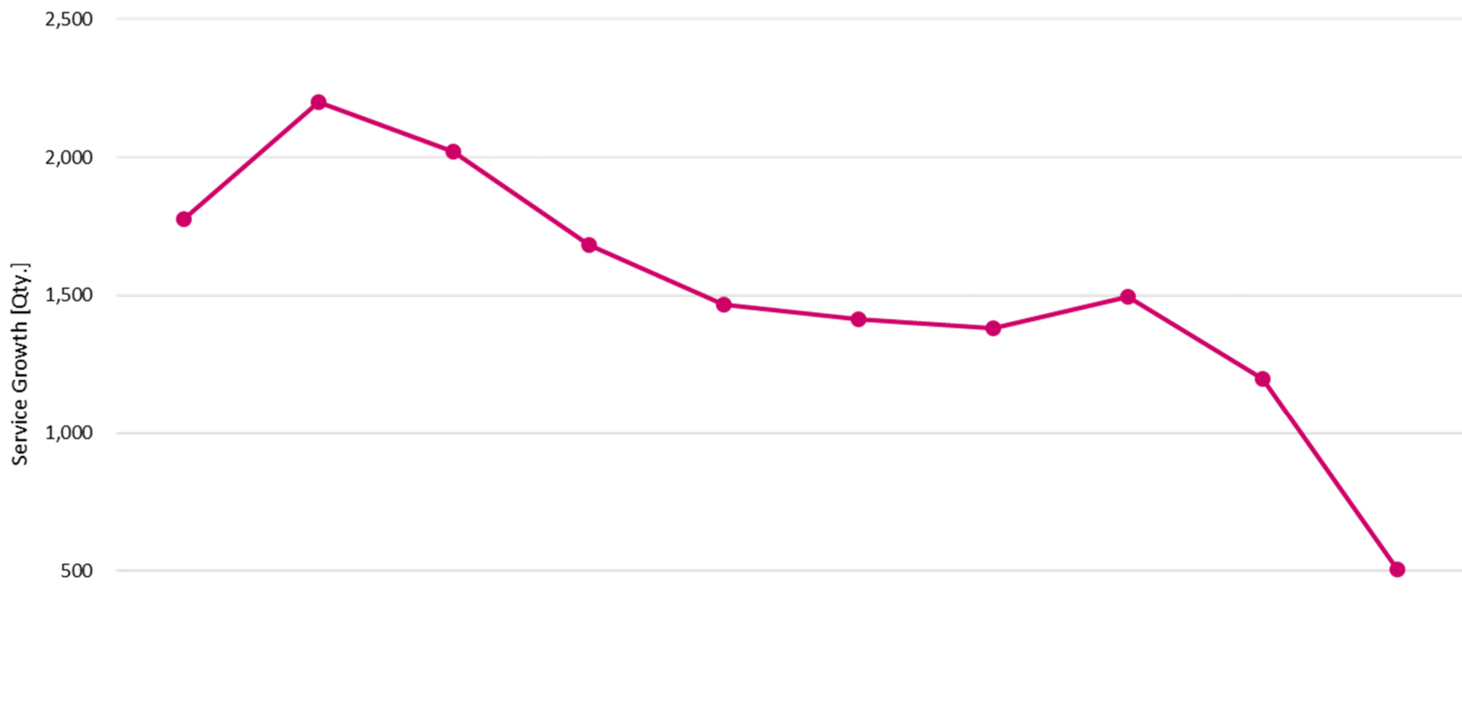
2021 PHMSA Average

(Excluding National Grid & RI Energy)

- 40 Companies
- 400,000 Services Per Company



Service Growth



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	1,778	2,200	2,023	1,684	1,468	1,414	1,382	1,497	1,200	504

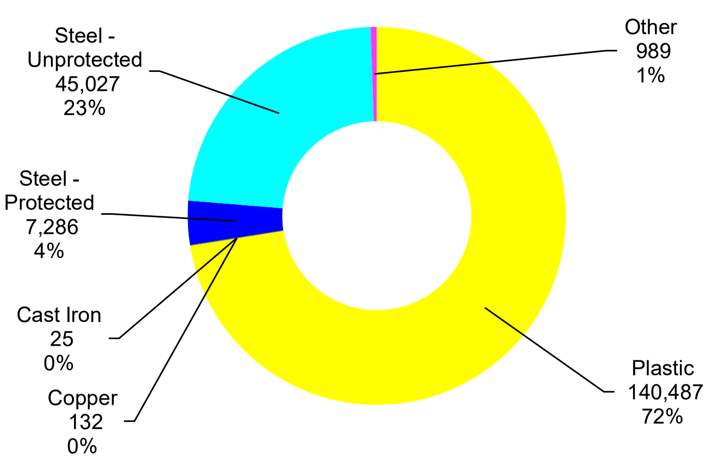
09

Service Leaks Repaired Analysis

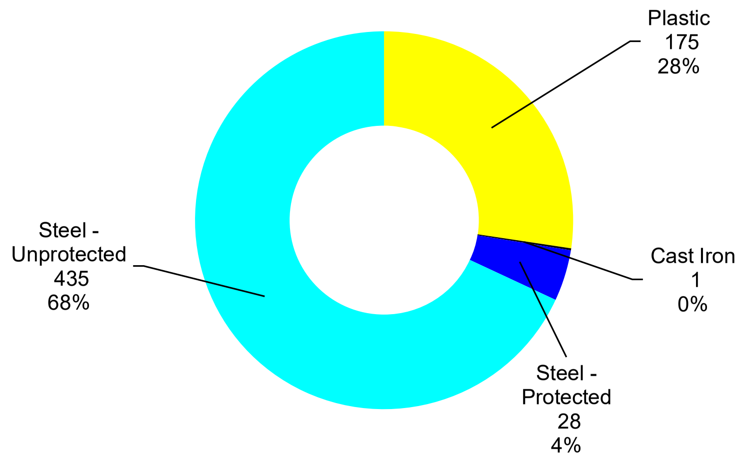
Service Inventory Compared to Service Leak Repairs by Material

(Including Damages)

Service Inventory



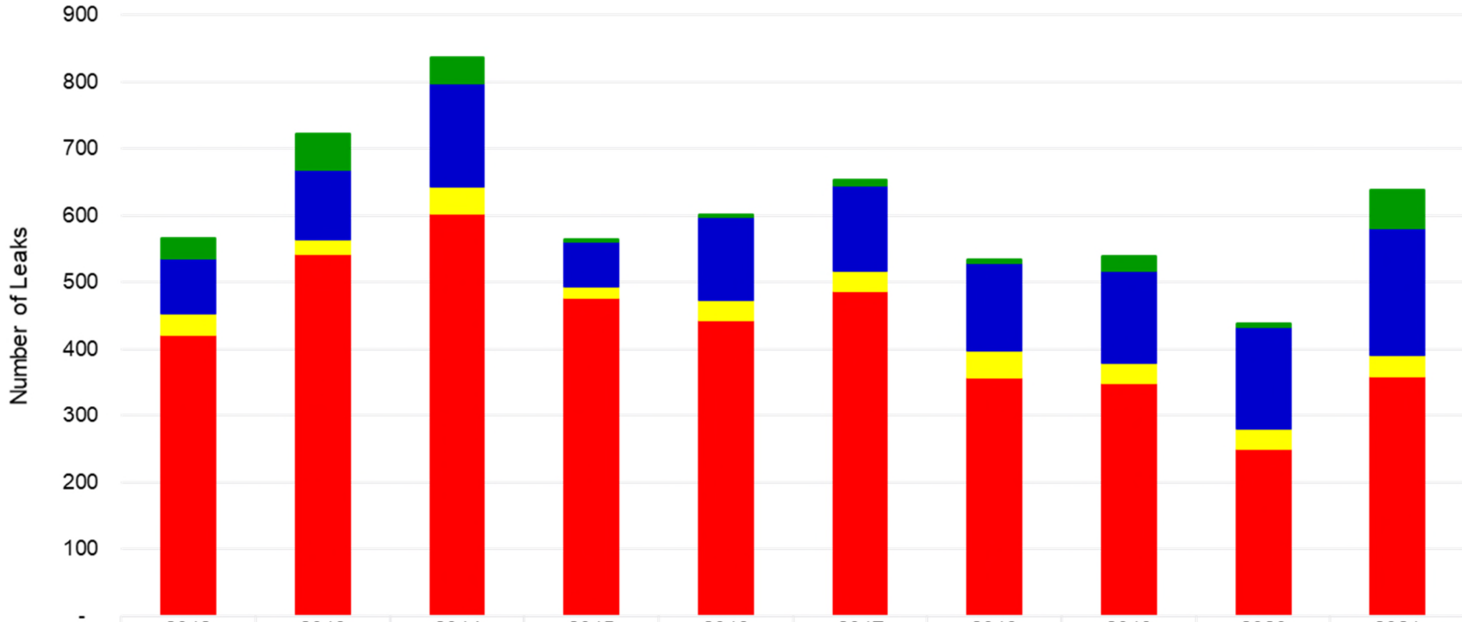
Service Leak Repairs



Plastic Leaks By Leak Cause

Region	Corrosion	Equipment	Excavation	Material or Weld Failure	Natural Force	Operations	Other	Other Outside Force	Total
RI	44	35	82	4		2	2	6	175

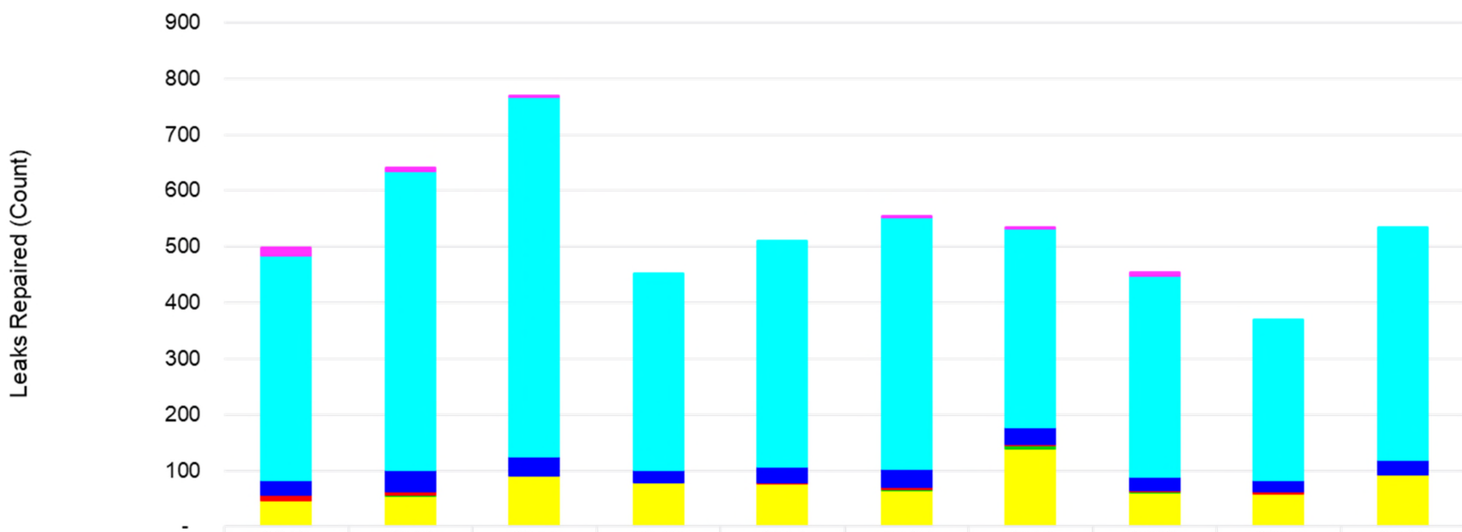
Service Leaks Repaired by Type
(Including Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Type 3	31	53	39	2	2	9	4	23	5	58
Type 2	83	105	155	68	126	127	132	138	153	189
Type 2A	31	21	39	17	30	30	40	29	30	33
Type 1	422	543	604	477	443	488	358	350	250	359

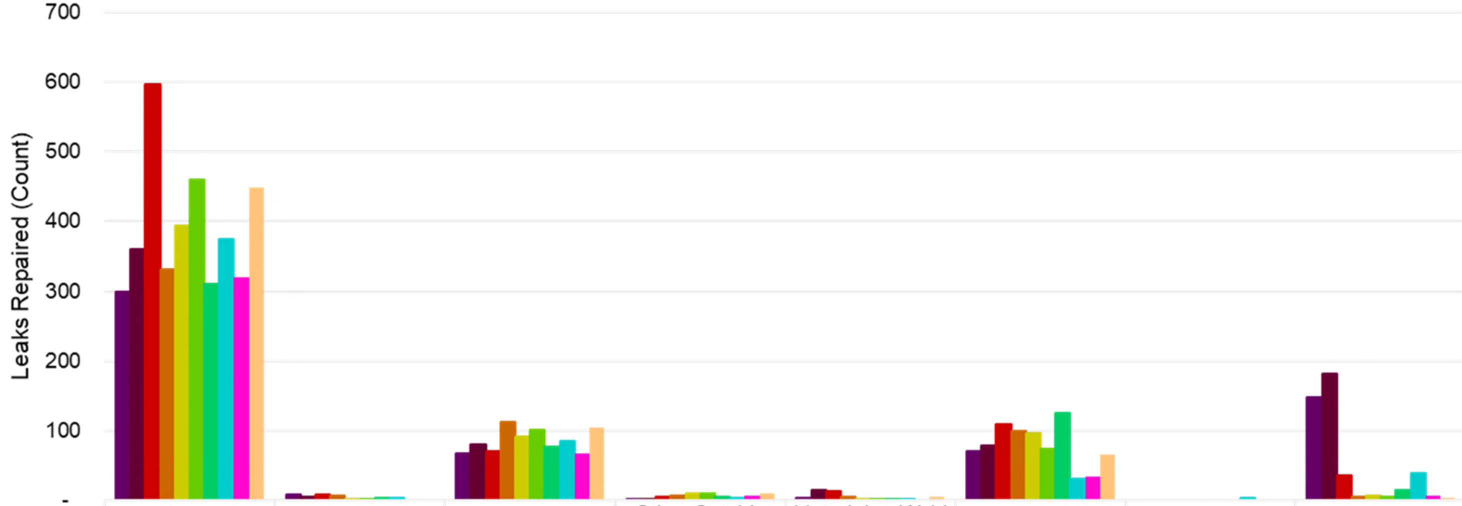
Service Leaks Repaired by Material

(Excluding Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Other	14	6	1	-	-	1	1	5	-	-
Steel - Unprotected	402	534	642	350	403	448	356	360	287	414
Steel - Protected	26	40	33	24	29	33	29	25	21	26
Cast Iron	11	6	-	-	2	4	3	2	3	1
Copper	-	1	-	-	-	3	5	1	-	-
Plastic	46	55	92	78	76	64	140	61	59	93

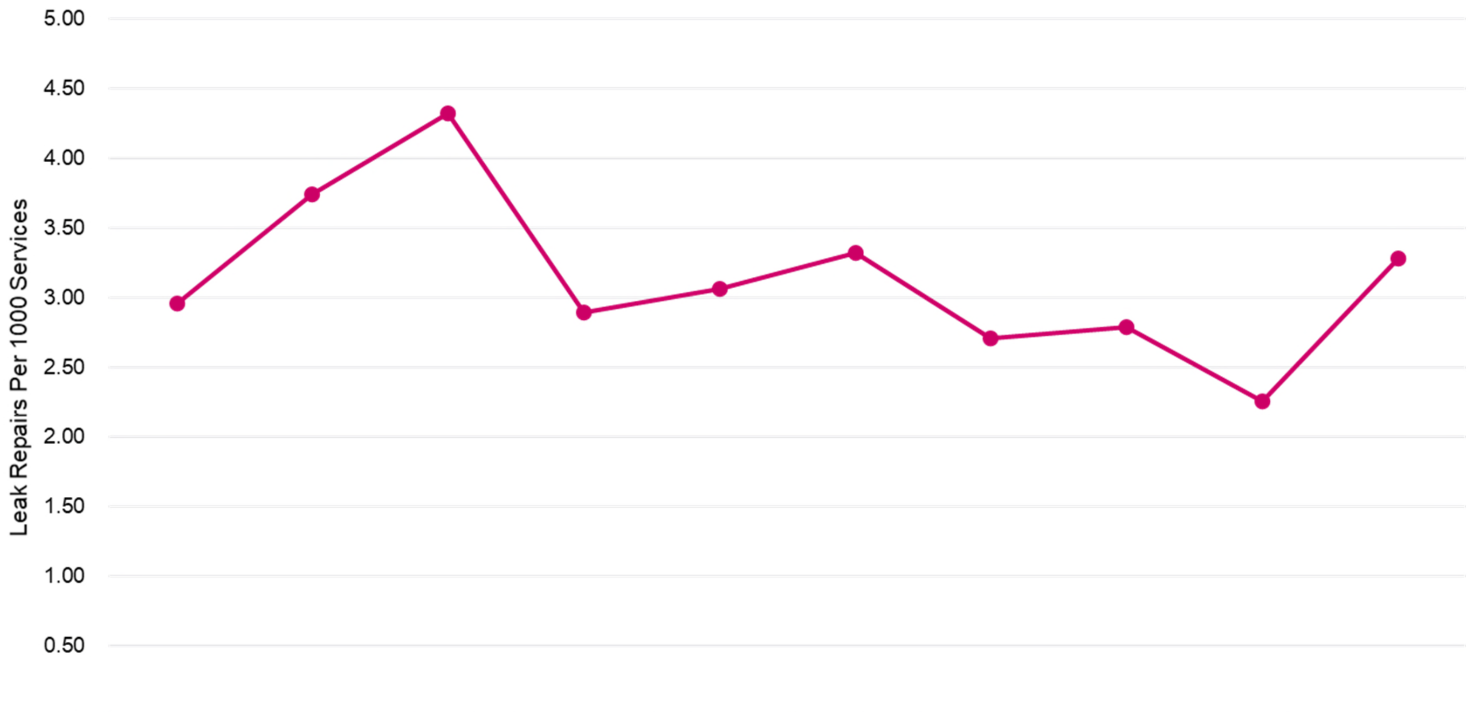
Service Leaks Repaired by Leak Cause



	Corrosion	Natural Force	Excavation	Other Outside Force	Material or Weld Failure	Equipment	Operations	Other
2012	300	8	67	1	3	70	-	148
2013	360	5	80	1	15	79	-	182
2014	597	8	70	5	13	110	-	35
2015	332	7	112	6	4	99	-	4
2016	395	1	91	10	2	96	-	6
2017	460	2	101	10	2	74	-	5
2018	310	3	78	4	1	125	-	15
2019	375	3	85	3	2	31	3	38
2020	320	-	68	6	2	34	2	6
2021	449	-	105	10	4	66	2	3

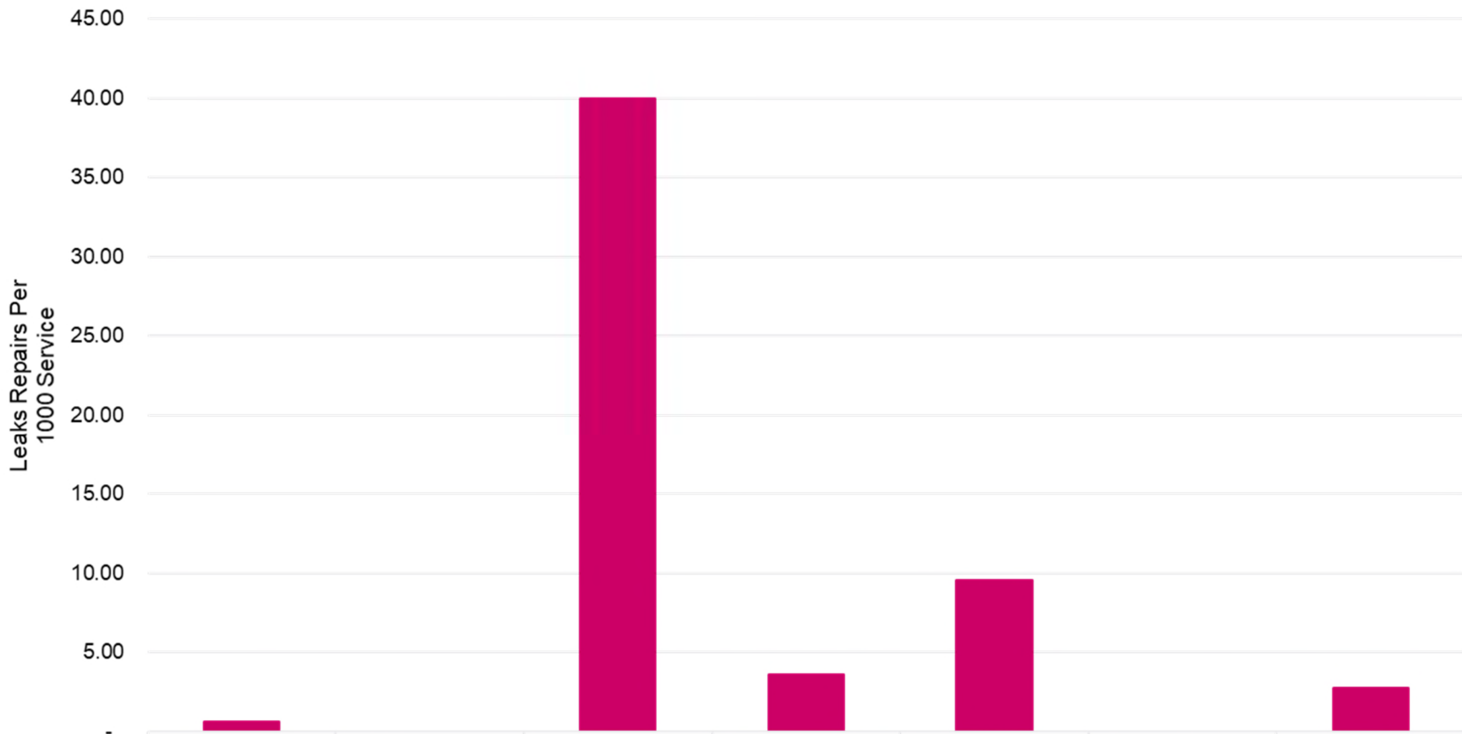
Leak Cause

Service Leak Rate
(Including Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	2.96	3.74	4.32	2.89	3.07	3.33	2.71	2.79	2.26	3.29

Service Leak Rate
(Excluding Damages)



	Plastic	Copper	Cast Iron	Steel - Protected	Steel - Unprotected	Other	Total
RI	0.65	-	40.00	3.63	9.54	-	2.75

Note: RI cast iron leak rate high due to small number of cast iron services.

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Distribution DOT Report Data Comparison

Distribution DOT Data Comparison

2021

		RI - LPP INVENTORY					
		2021		2020		Delta(21-20)	%
		943	Main	989	Main	-47	-4.8%
		43,507	Service	45,184	Service	-1677	-3.7%
2020 - 2021 DOT Comparisons		**RI**					
		2021		2020		Delta(21-20)	%
Main Inventory	Cast Iron	632	miles	660	miles	-28	-4.2%
	Reconditioned Cast Iron	0	miles	0	miles	+0	0.0%
	Plastic	1698	miles	1,643	miles	+55	3.3%
	UP Bare Steel	158	miles	172	miles	-13	-7.6%
	UP Coated Steel	139	miles	144	miles	-5	-3.5%
	Total UP Steel	298	miles	316	miles	-18	-5.7%
	CP Bare Steel	0	miles	0	miles	+0	N/A
	CP Coated Steel	586	miles	592	miles	-6	-1.0%
	Total CP Steel	586	miles	592	miles	-6	-1.0%
	Other	0	miles	0	miles	-0	0.0%
	Ductile Iron	13	miles	13	miles	-1	-7.4%
	TOTAL MAIN	**3,227**	**miles**	**3,225**	**miles**	**+2**	**0.1%**
Main Leaks	Corrosion	120	repairs	87	repairs	+33	37.9%
	Natural Forces	27	repairs	18	repairs	+9	50.0%
	Excavation	14	repairs	9	repairs	+5	55.6%
	Other Outside Force	1	repairs	0	repairs	+1	N/A
	Material or Welds	1	repairs	2	repairs	-1	-50.0%
	Equipment	38	repairs	13	repairs	+25	192.3%
	Operations	2	repairs	0	repairs	+2	N/A
	Other	584	repairs	614	repairs	-30	-4.9%
	TOTAL MAIN LEAKS	**787**	**repairs**	**743**	**repairs**	**+44**	**5.9%**
Service Inventory	Copper	71	svcs	132	svcs	-61	-46.2%
	Plastic	142,839	svcs	140,487	svcs	+2352	1.7%
	UP Bare Steel	37915	svcs	39,373	svcs	-1458	-3.7%
	UP Coated Steel	5,496	svcs	5,654	svcs	-158	-2.8%
	Total UP Steel	43,411	svcs	45,027	svcs	-1616	-3.6%
	CP Bare Steel	0	svcs	0	svcs	+0	N/A
	CP Coated Steel	7,153	svcs	7,286	svcs	-133	-1.8%
	Total CP Steel	7,153	svcs	7,286	svcs	-133	-1.8%
	Other	951	svcs	989	svcs	-38	-3.8%
	Cast Iron / Wrought Iron	25	svcs	25	svcs	+0	0.0%
	TOTAL SERVICES	**194,450**	**svcs**	**193,946**	**svcs**	**+504**	**0.3%**
Service Leaks Excluding Above Ground Leaks	Corrosion	449	repairs	320	repairs	+129	40.3%
	Natural Forces	0	repairs	0	repairs	+0	N/A
	Excavation	105	repairs	68	repairs	+37	54.4%
	Other Outside Force	10	repairs	6	repairs	+4	66.7%
	Material or Welds	4	repairs	2	repairs	+2	100.0%
	Equipment	66	repairs	34	repairs	+32	94.1%
	Operations	2	repairs	2	repairs	+0	0.0%
	Other	3	repairs	6	repairs	-3	-50.0%
	TOTAL SVC LEAKS	**639**	**repairs**	**438**	**repairs**	**+201**	**45.9%**
Service Leaks Including Above Ground Leaks	Corrosion	450	repairs	320	repairs	+130	40.6%
	Natural Forces	0	repairs	0	repairs	+0	N/A
	Excavation	105	repairs	68	repairs	+37	54.4%
	Other Outside Force	17	repairs	6	repairs	+11	183.3%
	Material or Welds	4	repairs	2	repairs	+2	100.0%
	Equipment	67	repairs	35	repairs	+32	91.4%
	Operations	2	repairs	2	repairs	+0	0.0%
	Other	3	repairs	6	repairs	-3	-50.0%
	TOTAL SVC LEAKS	**648**	**repairs**	**439**	**repairs**	**+209**	**47.6%**
Total Leak Repairs (Main & Service) Excluding Above Ground Leak		1,426	repairs	1,181	repairs	+245	20.7%
Total Leak Repairs (Main & Service) Including Above Ground Leak		1,237	repairs	1,182	repairs	+55	4.7%
Workable Backlog As of 12/31		188	leaks	155	leaks	+33	21.3%
UFG (Net)		2.7%		2.9%		-0.20%	-6.9%
Average Service Length (Ft)		62.0	ft	61.6	ft	+0	0.0%

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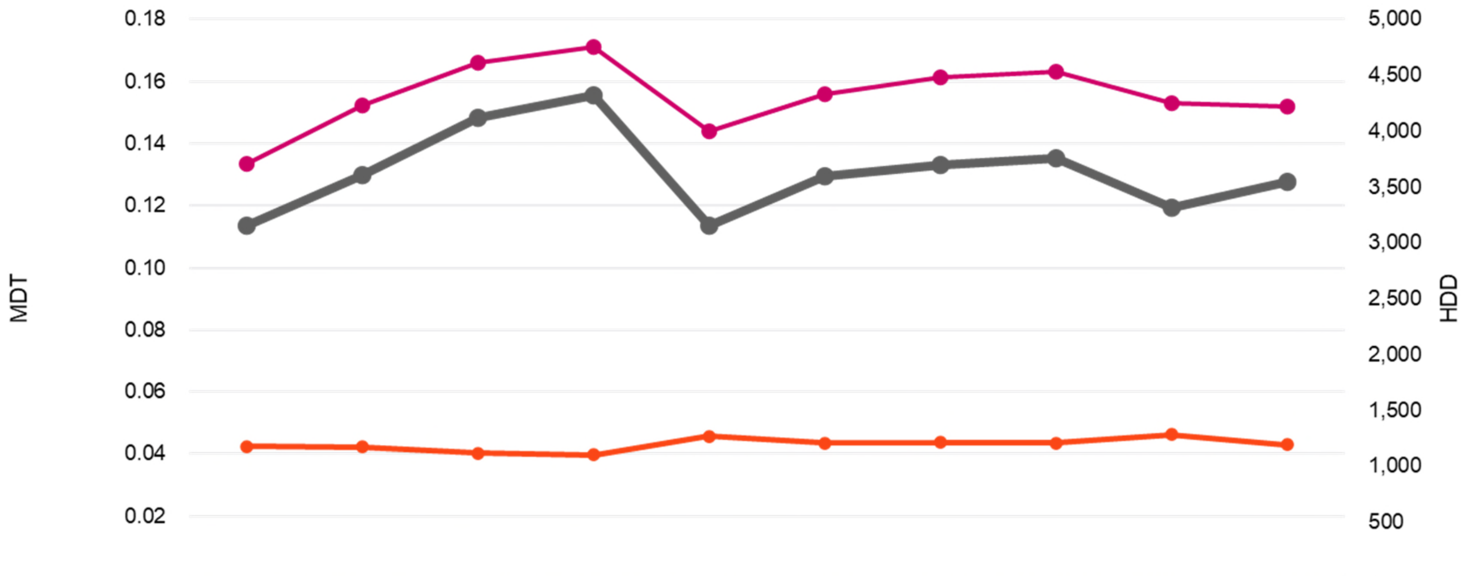
Gas Distribution System Statistics

Average Customer Used Rate

(Compared to HDD)

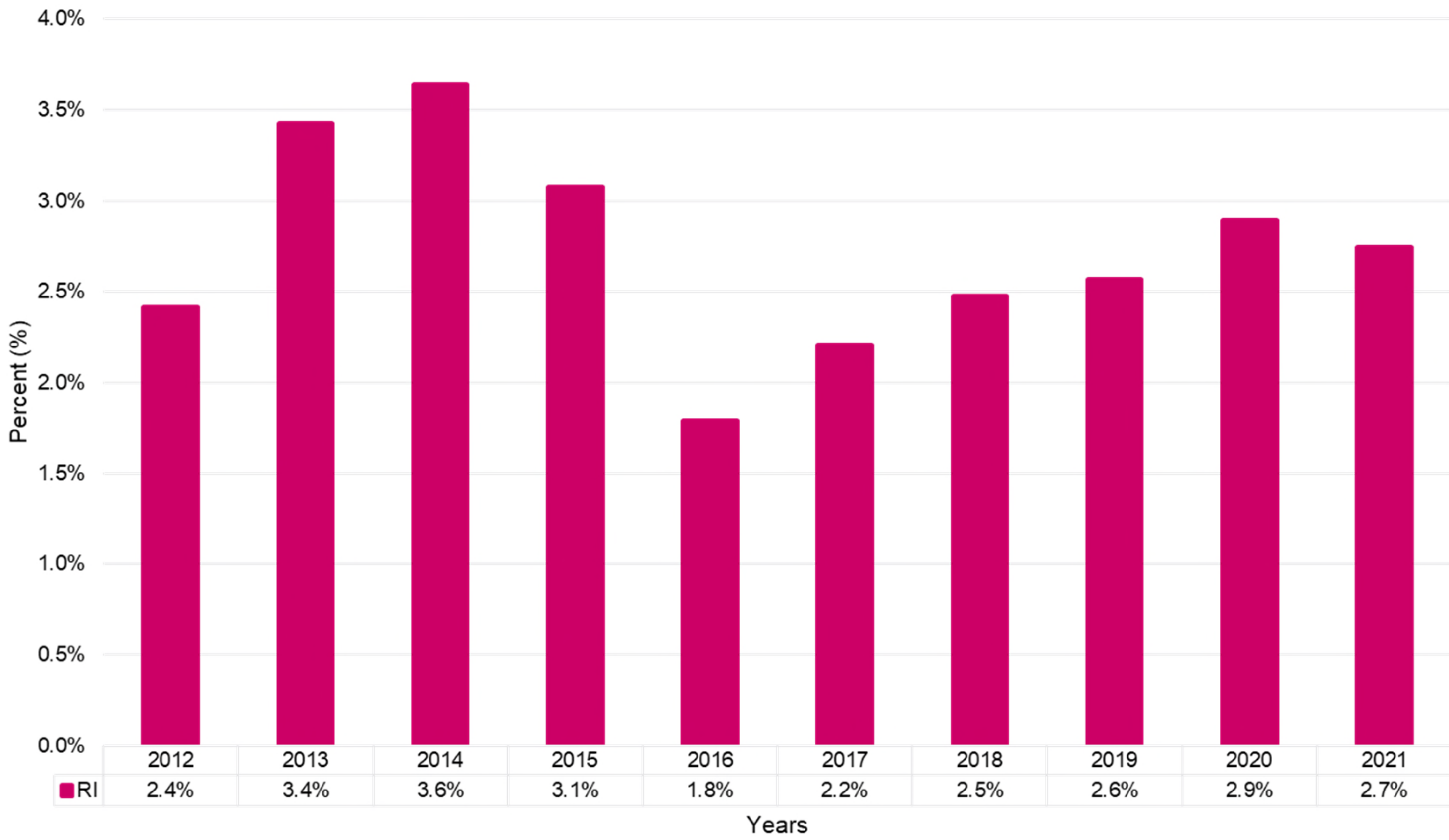


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	0.13	0.15	0.17	0.17	0.14	0.16	0.16	0.16	0.15	0.15
ACUR/HDD	0.04	0.04	0.04	0.04	0.05	0.04	0.04	0.04	0.05	0.04
HDD	3,151	3,608	4,123	4,318	3,156	3,593	3,699	3,757	3,319	3,549

Notes:

- Average Customer Used Rate (ACUR) = Sendout (MDT) / Total Customer
- Total Customer includes Residential and Commercial
- ACUR/HDD = (Average Customer Used Rate / HDD) * 1000
- HDD: Heating Degree Days
- MDT: Million Dekatherm

Gross Unaccounted For Gas



Gas Distribution System Statistics

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2021	Pipeline / Customer / Sendout Statistics									
Region	Miles of Main	Number of Services	Average Service Length (ft/svc)	Miles of Services	Total Distribution Pipeline	Residential Customers	Commercial and Industrial Customers	Total Customers	Sendout (MDT)	Sendout (MDT) / HDD
NYC	4,190	572,715	45.0	4,881	9,071	1,204,270	74,128	1,278,398	198,683	60
LI	8,400	559,566	65.0	6,889	15,289	559,329	63,942	623,271	104,341	32
UNY	8,902	573,272	72.4	7,861	16,763	589,128	48,552	637,680	156,466	39
NYS	**21,492**	**1,705,553**	**60.8**	**19,630**	**41,122**	**2,352,727**	**186,622**	**2,539,349**	**459,490**	**44**
BGC/EGC	7,264	566,981	49.5	5,314	12,578	689,338	52,903	742,241	117,198	32
CGC	3,895	200,913	75.4	2,869	6,765	201,422	17,636	219,058	25,786	7
RI	3,227	194,450	62.6	2,305	5,532	248,240	25,132	273,372	41,559	12
NE	**14,386**	**962,344**	**57.5**	**10,489**	**24,875**	**1,139,000**	**95,671**	**1,234,671**	**184,543**	**17**
NGRID	**35,878**	**2,667,897**	**59.6**	**30,119**	**65,997**	**3,491,727**	**282,293**	**3,774,020**	**644,033**	**30**

Caution:
- This chart is for comparative-illustrative purposes only. The data is not audited & many assumption have been made.
- Inventory data is from the Annual DOT/PHMSA Distribution Reports.
- Customer data is from the Gas Customer Data base- Active Gas Accounts
- Sendout data is from the sendouts for the 12-month period used to calculate UFG for the DOT Reports.

Gas Distribution System Statistics

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2021	Percentages of NGRID/RI Energy System					Asset Ratios			Gas Consumption Ratios			
Region	Percent of Main (%)	Percent of Service (%)	Percent of Distribution Pipeline (%)	Percent of Customers (%)	Percent of Sendout (%)	Service Density (svc / mile of main)	Meter Density (Customers / service)	Customer Density (Customers / Mile of Total Pipline)	Main Capacities Used (Sendout MDT / Mile of Main)	Service Capacities Used (Sendout MDT / Service)	Pipeline Capacities Used (Sendout MDT / Mile Of Pipe)	Customer Usage (Sendout MDT / Customer)
NYC	11.7%	21.5%	13.7%	33.9%	30.8%	136.70	2.23	140.94	47.42	0.35	21.90	0.16
LI	23.4%	21.0%	23.2%	16.5%	16.2%	66.62	1.11	40.77	12.42	0.19	6.82	0.17
UNY	24.8%	21.5%	25.4%	16.9%	24.3%	64.40	1.11	38.04	17.58	0.27	9.33	0.25
NYS	**59.9%**	**63.9%**	**62.3%**	**67.3%**	**71.3%**	**79.36**	**1.49**	**61.75**	**21.38**	**0.27**	**11.17**	**0.18**
BGC/EGC	20.2%	21.3%	19.1%	19.7%	18.2%	78.05	1.31	59.01	16.13	0.21	9.32	0.16
CGC	10.9%	7.5%	10.3%	5.8%	4.0%	51.58	1.09	32.38	6.62	0.13	3.81	0.12
RI	9.0%	7.3%	8.4%	7.2%	6.5%	60.26	1.41	49.42	12.88	0.21	7.51	0.15
NE	**40.1%**	**36.1%**	**37.7%**	**32.7%**	**28.7%**	**66.89**	**1.28**	**49.64**	**12.83**	**0.19**	**7.42**	**0.15**
NGRID	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**74.36**	**1.41**	**57.18**	**17.95**	**0.24**	**9.76**	**0.17**

Gas Distribution System Statistics

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2021	Leak Prone Pipe Inventory						Leak Prone Pipe Percentages		
Region	Leak Prone Main (miles)	Percent of Total Main (%)	Leak Prone Services	Percent of Total Services	Miles of Leak prone Services	Total Leak Prone Pipe (miles)	Percent of Total Leak Prone Main	Percent of Total Leak Prone Services	Percent of Total Leak Prone Pipe
NYC	1,437	34.3%	111,259	19.4%	948	2,385	17.4%	23.1%	17.4%
LI	3,155	37.6%	78,484	14.0%	966	4,121	38.1%	16.3%	30.0%
UNY	414	4.7%	140,908	24.6%	1,932	2,346	5.0%	29.2%	17.1%
NYS	**4,624**	**21.5%**	**330,651**	**19.4%**	**3,806**	**8,430**	**55.9%**	**68.5%**	**61.4%**
BGC/EGC	2,582	35.5%	101,361	17.9%	950	3,532	31.2%	21.0%	25.7%
CGC	126	3.2%	6,939	3.5%	99	225	1.5%	1.4%	1.6%
RI	942	29.2%	43,507	22.4%	516	1,458	11.4%	9.0%	10.6%
NE	**3,650**	**25.4%**	**151,807**	**15.8%**	**1,655**	**5,305**	**44.1%**	**31.5%**	**38.7%**
NGRID	**8,274**	**23.1%**	**482,458**	**18.1%**	**5,447**	**13,721**	**100.0%**	**100.0%**	**100.0%**

Notes:
- Leak-Prone Main includes Cast Iron/Wrought Iron, Unprotected Steel , Aldyl-A and Other Material.
- Leak-Prone Service includes Cast Iron/Wrought Iron, Copper and Unprotected Steel.

Gas Distribution System Statistics

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2021	Leak Data				Leak Rate Ratios					
Region	Total Leak Receipts (Main & Service)	Total Leak Repairs (Main & Service)	Year End Workable Leak Backlog	Total Repairs and Workable Leaks	Total Leak Receipts per Mile Total Pipe	Total Leak Receipts per Mile Leak Prone Pipe	Total Leak Repairs Per Mile Total Pipe	Total Leak Repairs Per Mile Leak Prone Pipe	Repairs and Workables per Mile Total Pipe	Repairs and Workable per Mile Leak Prone Pipe
NYC	2,729	2,734	20	2,754	0.30	1.14	0.30	1.15	0.30	1.15
LI	1,712	1,659	-	1,659	0.11	0.42	0.11	0.40	0.11	0.40
UNY	793	897	6	903	0.05	0.34	0.05	0.38	0.05	0.38
NYS	**5,234**	**5,290**	**26**	**5,316**	**0.13**	**0.62**	**0.13**	**0.63**	**0.13**	**0.63**
BGC/EGC	5,679	8,111	486	8,597	0.45	1.61	0.64	2.30	0.68	2.43
CGC	729	799	16	815	0.11	3.24	0.12	3.55	0.12	3.62
RI	1,508	1,426	188	1,614	0.27	1.03	0.26	0.98	0.29	1.11
NE	**1,508**	**10,336**	**690**	**11,026**	**0.06**	**0.28**	**0.42**	**1.95**	**0.44**	**2.08**
NGRID	**13,150**	**15,626**	**716**	**16,342**	**0.20**	**0.96**	**0.24**	**1.14**	**0.25**	**1.19**

- Notes:
- Total Leak Receipts (Main & Service) data excludes Excavation Leaks.
- Total Leak Repairs (Main & Service) data includes Excavation Leaks.
- Total Leak Repairs (Main & Service) data excludes Above Ground Leaks.

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System Integrity Report Analysis

(Findings and Explanations)

Analysis of Findings and Explanations

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Rhode Island (RI)	
	• Total leak receipts have decreased by 13.2% (230) in 2021 compared to 2020. • MAIN – Leak repairs have increased by 5.9% (44) in 2021 compared to 2020. Total Cast Iron Joint leaks comprise 74% of all main leaks. • SERVICE – Leak repairs have increased by 45.9% (201) compared to 2020. Corrosion leaks comprise 70% of all service leaks. • TOTAL – Gas leak repairs increased by 29.2% (322) in 2021.

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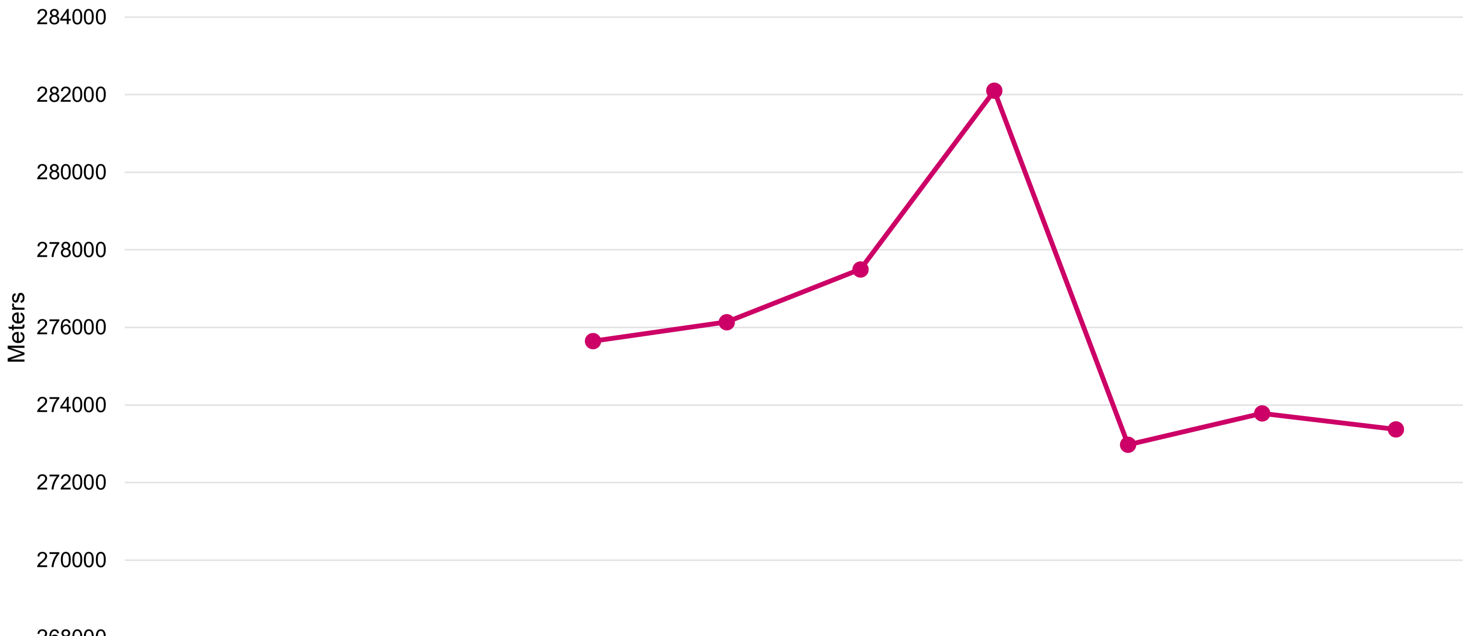
Meter Statistics

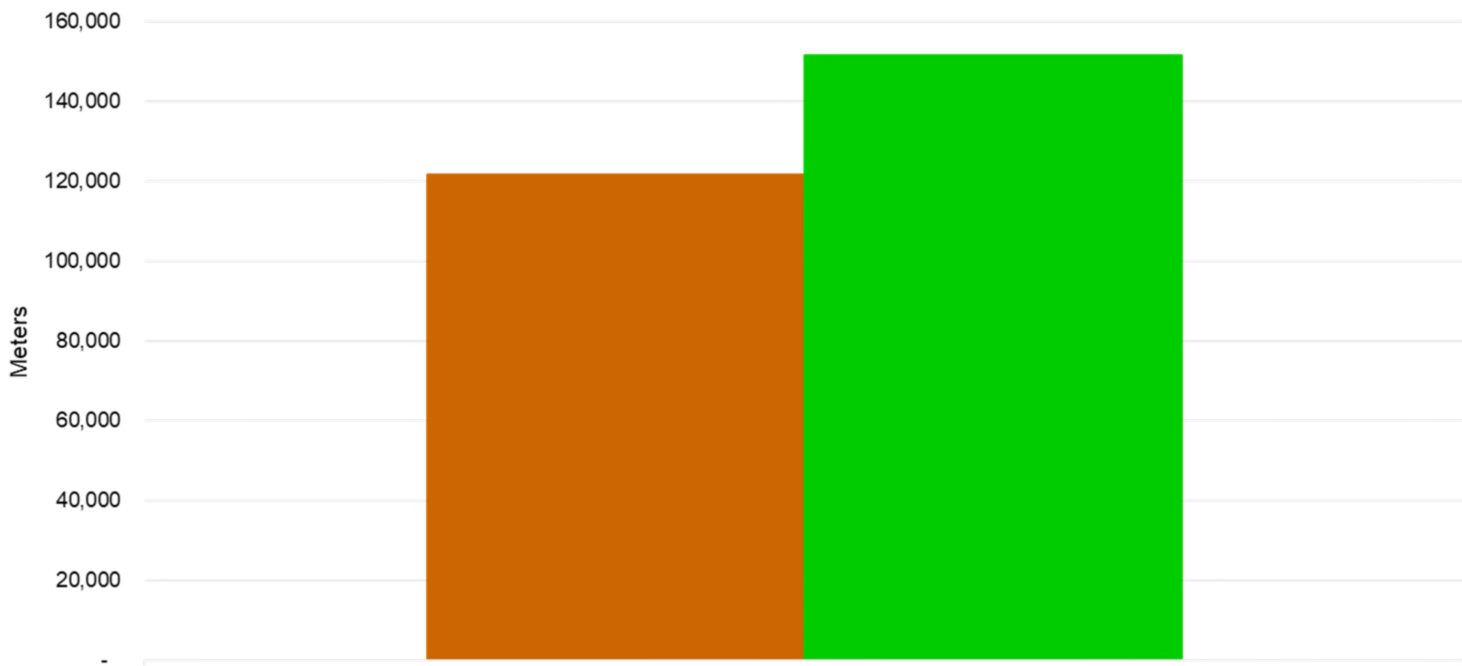
Meter Population



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI				275,646	276,137	277,497	282,106	272,974	273,783	273,372

Meter Population by Region

Inside vs Outside



	RI
Inside	121,743
Outside	151,629

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Appendices

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2021 Material Cause Matrix

(Main Leak Repairs)

2021 Material Cause Matrix

(Main Leaks)

RI Main Leaks	Corrosion	Natural Force	Excavation	Other Outside Force	Material or Weld Failure	Equipment	Operations	Other	Total
Plastic	1	-	7	1	1	7	1	-	**18**
Cast Iron	40	26	4	-	-	14	1	580	**665**
Recond. Cast Iron	-	-	-	-	-	-	-	-	**-**
Steel - Protected	10	1	1	-	-	11	-	-	**23**
Steel - Unprotected	68	-	2	-	-	6	-	-	**76**
Other	-	-	-	-	-	-	-	-	**-**
Ductile Iron	1	-	-	-	-	-	-	4	**5**
Total	120	27	14	1	1	38	2	584	787

2021 Material Cause Matrix

(Service Leak Repairs)

2021 Material Cause Matrix

(Service Leaks)

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RI Service Leaks	Corrosion	Natural Force	Excavation	Other Outside Force	Material or Weld Failure	Equipment	Operations	Other	Total
Plastic	44	-	82	6	4	35	2	2	**175**
Copper	-	-	-	-	-	-	-	-	**-**
Cast Iron	1	-	-	-	-	-	-	-	**1**
Steel - Unprotected	388	-	21	3	-	22	-	1	**435**
Steel - Protected	16	-	2	1	-	9	-	-	**28**
Other	-	-	-	-	-	-	-	-	**-**
Total	449	-	105	10	4	66	2	3	639

Main Inventory Trend by Material

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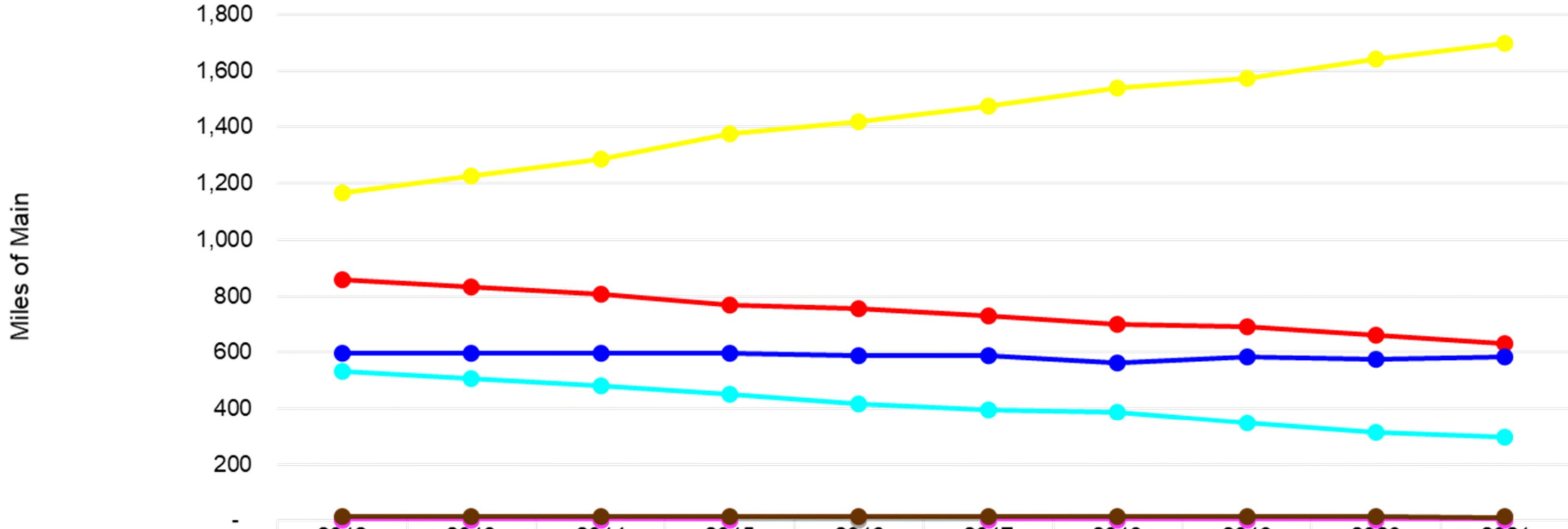
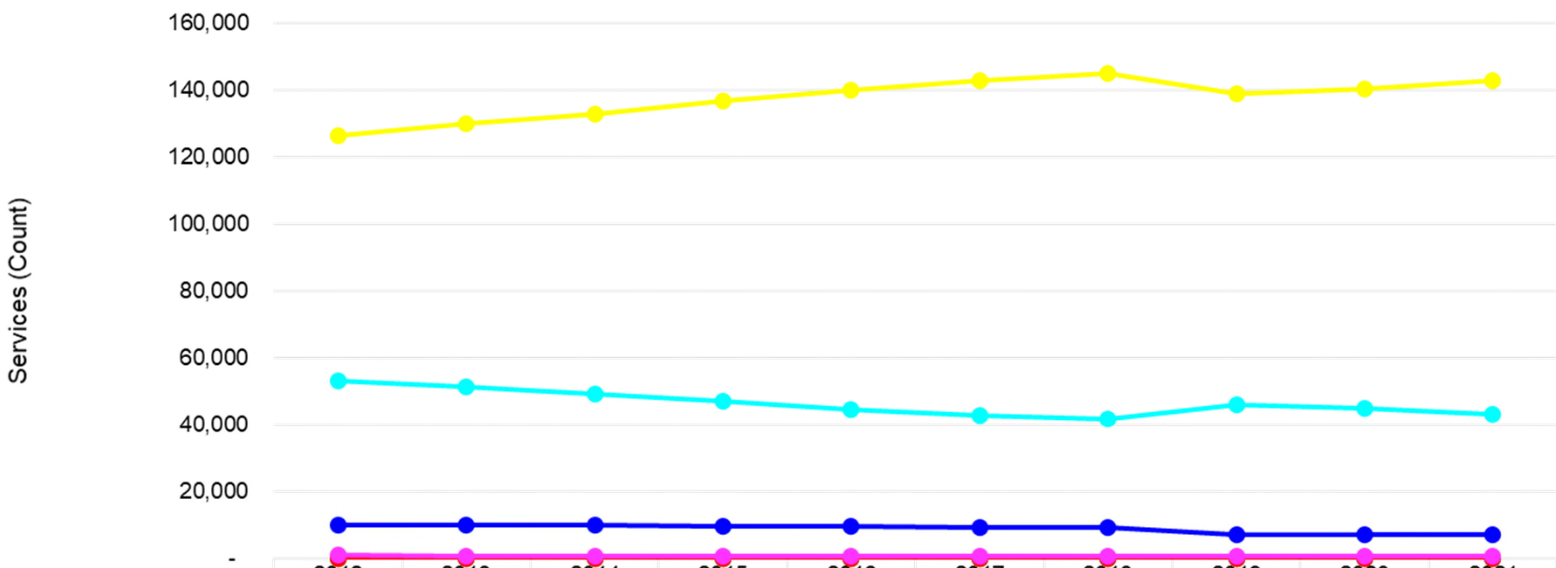


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plastic	1,168	1,227	1,287	1,378	1,417	1,476	1,539	1,572	1,643	1,698
Cast Iron	859	831	806	769	754	730	700	690	660	632
Recond. Cast Iron	-	-	-	-	-	-	-	-	0	-
Steel - Protected	597	596	595	595	590	590	562	582	576	586
Steel - Unprotected	534	508	483	452	416	395	386	349	316	298
Other	-	-	-	-		-	-	0	0	-
Ductile Iron	16	16	16	16	16	16	14	13	13	13

Years

Service Inventory Trend by Material

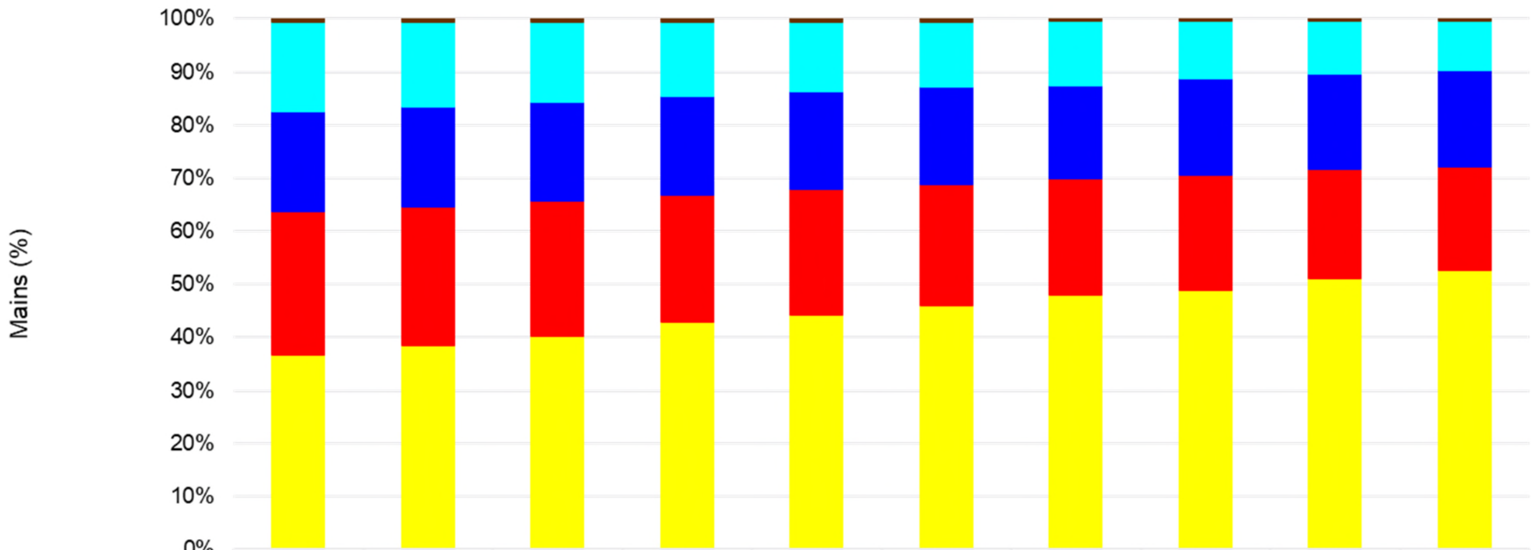
(Count)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plastic	126,474	130,002	133,024	136,700	140,206	142,956	144,929	138,929	140,487	142,839
Copper	208	207	205	202	201	192	189	185	132	71
Cast Iron	189	185	174	137	134	129	127	26	25	25
Steel - Protected	10,285	10,150	9,989	9,800	9,585	9,456	9,334	7,348	7,286	7,153
Steel - Unprotected	53,449	51,387	49,265	47,104	44,806	42,969	41,793	45,992	45,027	43,411
Other	1,085	1,000	958	900	854	803	775	1,011	989	951

Main Inventory Analysis by Material

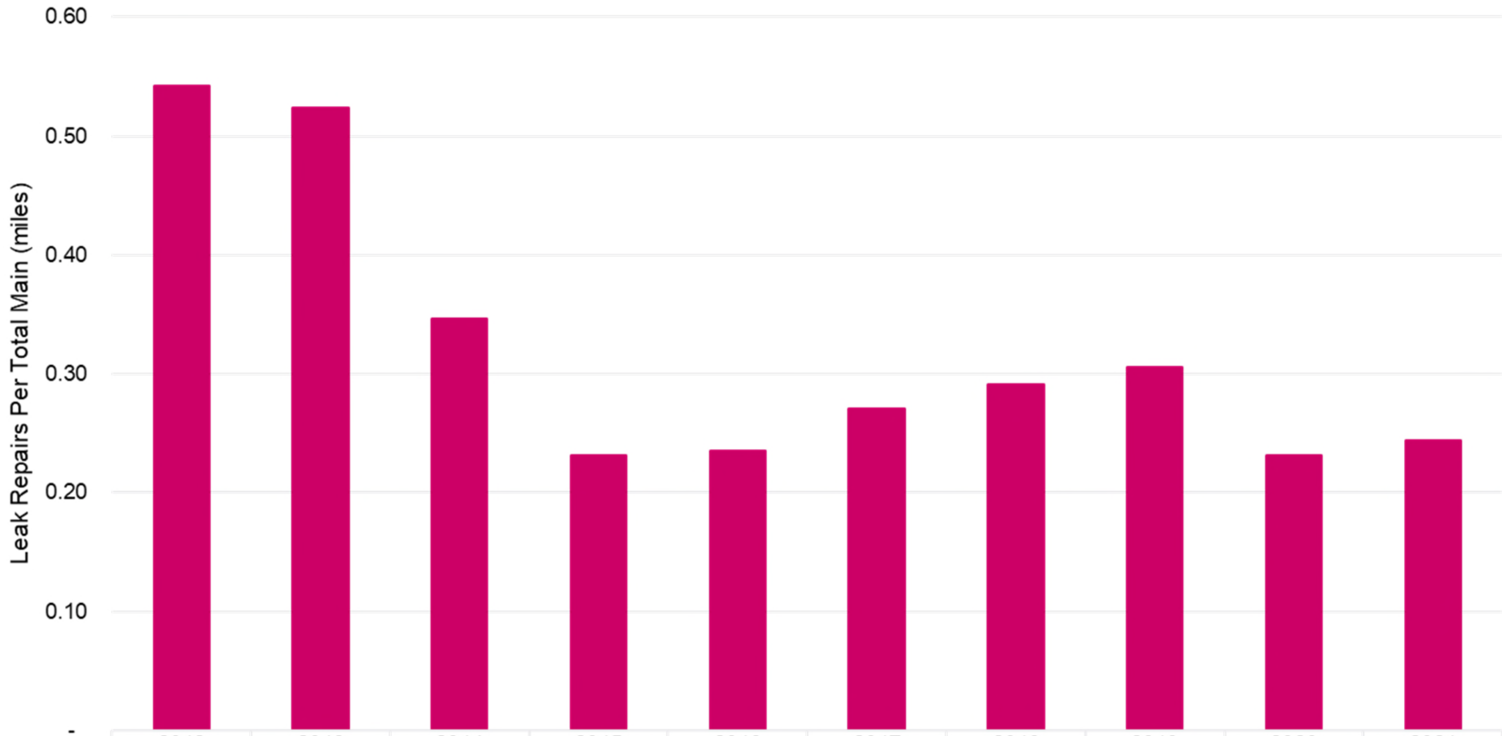
(Percent)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Ductile Iron	1%	1%	1%	0%	1%	0%	0%	0%	0%	0%
Other	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Steel - Unprotected	17%	16%	15%	14%	13%	12%	12%	11%	10%	9%
Steel - Protected	19%	19%	19%	19%	18%	18%	18%	18%	18%	18%
Recond. Cast Iron	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Cast Iron	27%	26%	25%	24%	24%	23%	22%	22%	21%	20%
Plastic	37%	39%	40%	43%	44%	46%	48%	49%	51%	53%

Years

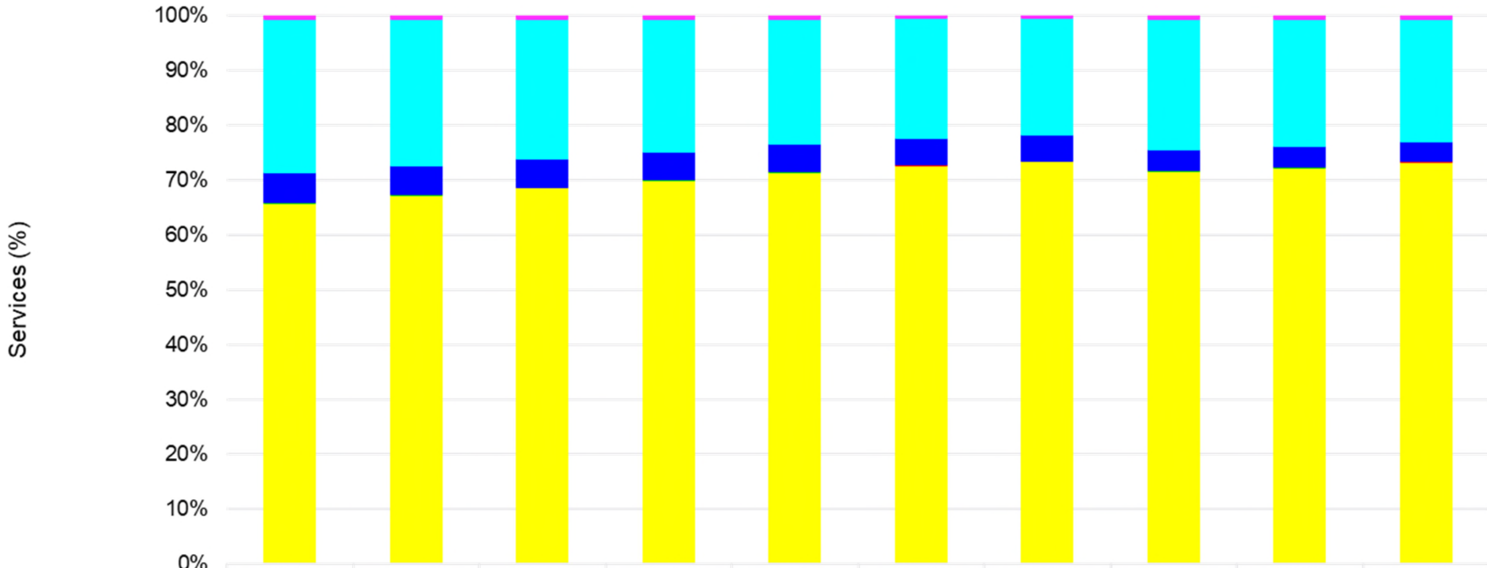
Main Leak Rate
(Including Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	0.54	0.52	0.35	0.23	0.24	0.27	0.29	0.31	0.23	0.24

Service Inventory Analysis by Material

(Percent)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Other	1%	1%	0%	0%	0%	0%	0%	1%	1%	0%
Steel - Unprotected	28%	27%	25%	24%	23%	22%	21%	24%	23%	22%
Steel - Protected	5%	5%	5%	5%	5%	5%	5%	4%	4%	4%
Cast Iron	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Copper	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Plastic	66%	67%	69%	70%	72%	73%	74%	72%	72%	73%

Years

nationalgrid

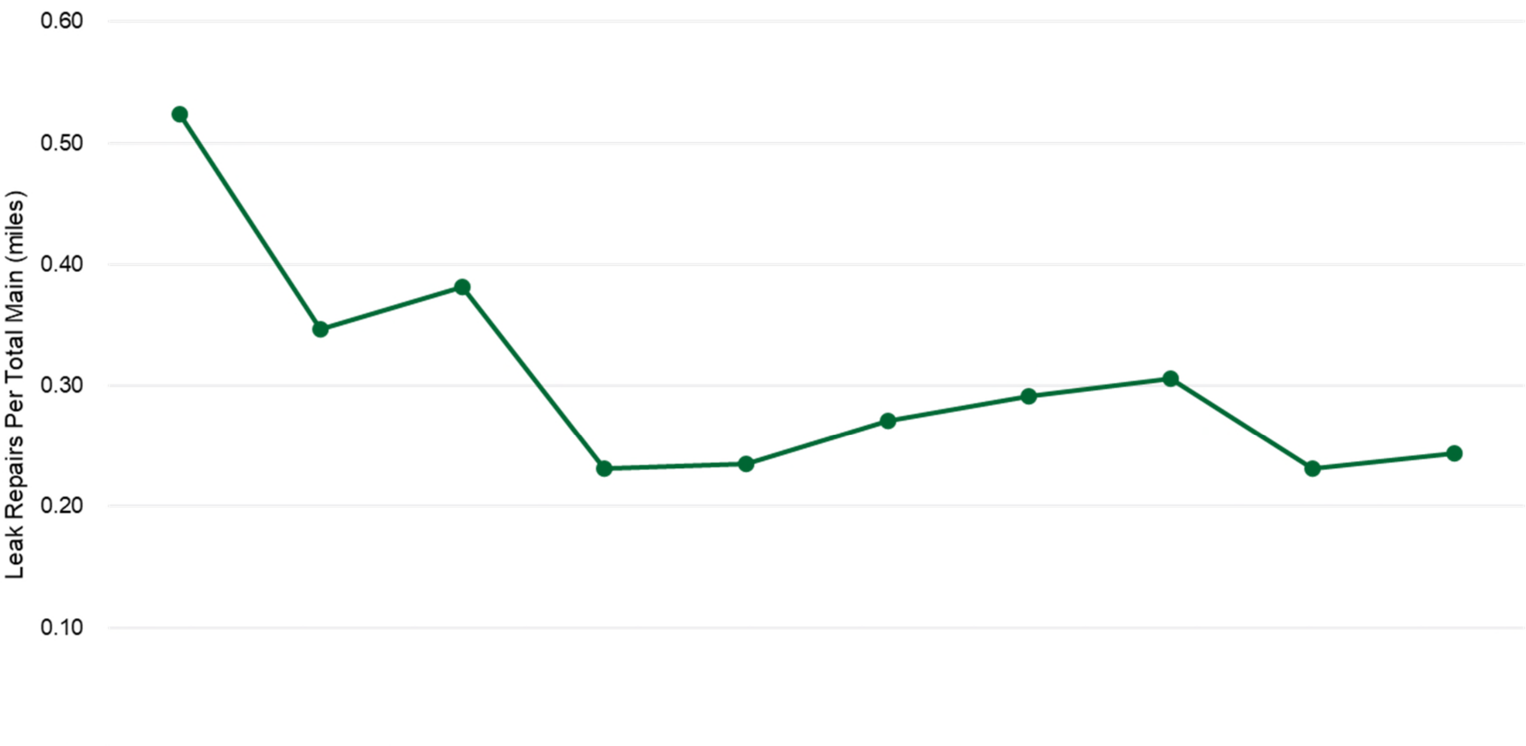
Rhode Island Energy™
a PPL company

15

Archive

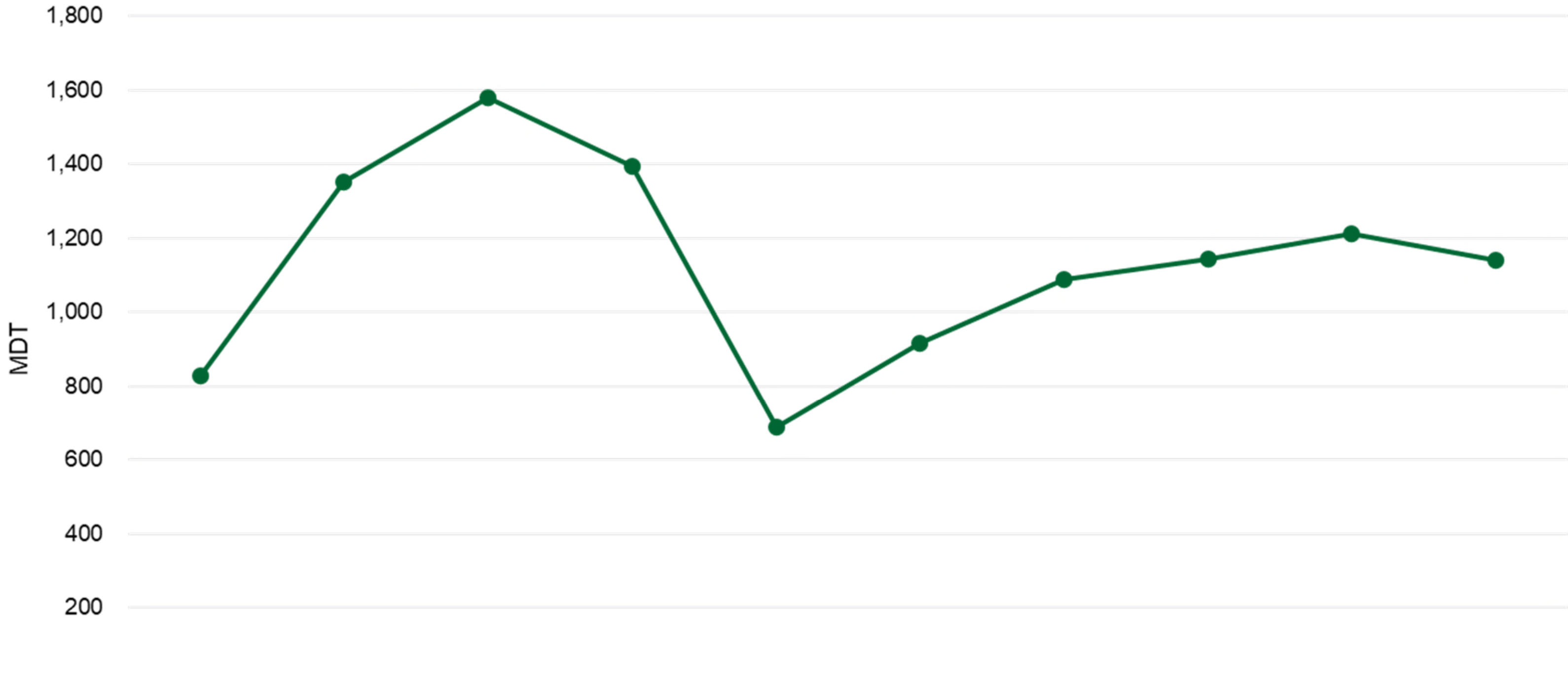
Main Leak Rate

(Including Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	0.52	0.35	0.38	0.23	0.24	0.27	0.29	0.31	0.23	0.24

Gross Unaccounted For Gas

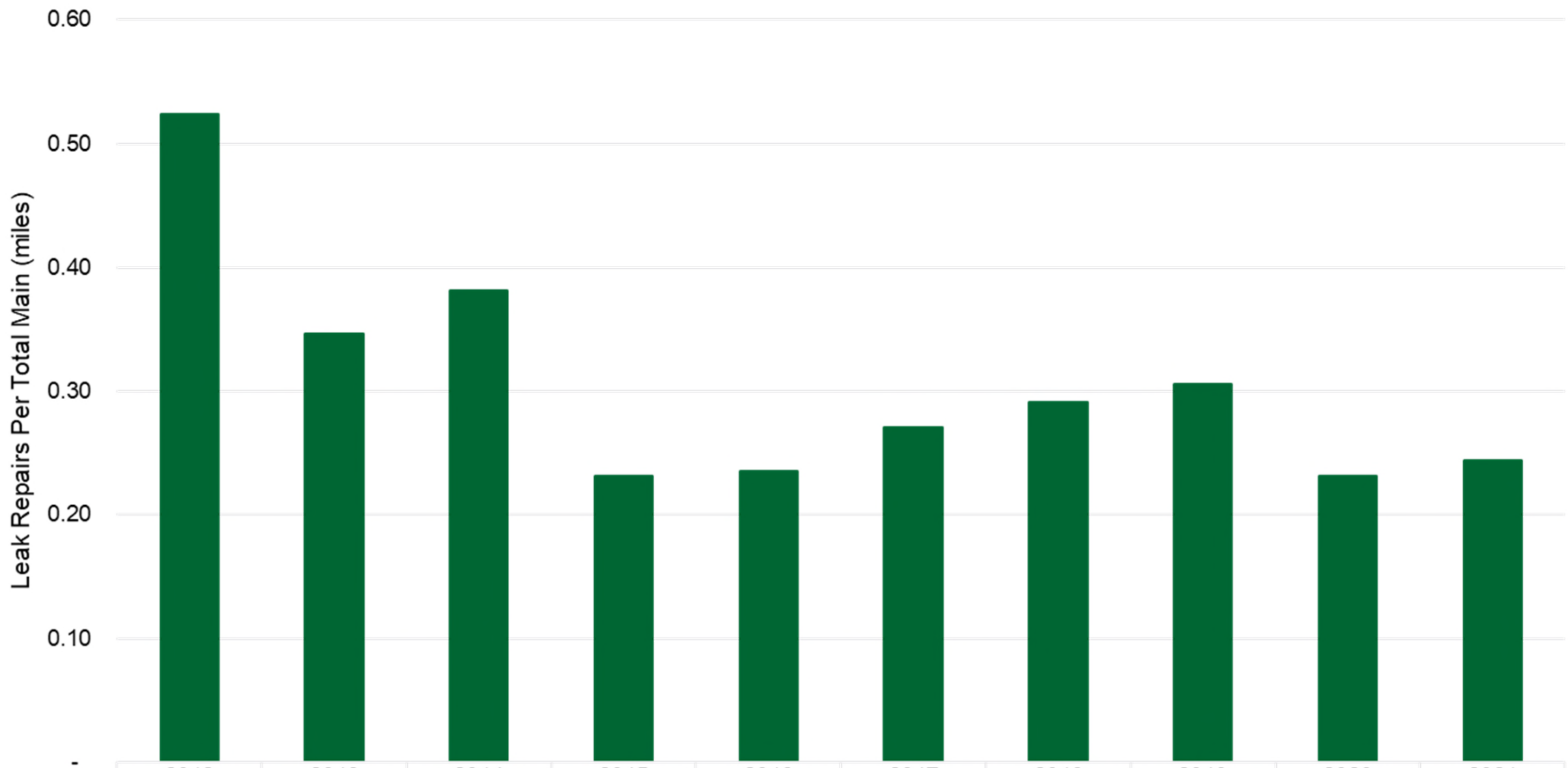


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	828	1,352	1,580	1,395	690	915	1,088	1,146	1,213	1,141

Years

Main Leak Rate

(Including Damages)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RI	0.52	0.35	0.38	0.23	0.24	0.27	0.29	0.31	0.23	0.24

Years

Section 3
Revenue Requirement

Proposed FY 2024 Gas Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Gas ISR Plan
April 2023 – December 2024

Revenue Requirement
FY 2024 Gas ISR Plan
21-Month Proposal

The attached proposed revenue requirement calculations reflect the revenue requirement related to the Company's proposed investment in its Gas ISR Plan for the nine-month period from April 1, 2023 through December 31, 2023 ("CY 2023") and the twelve-month period from January 1, 2024 through December 31, 2024 ("CY 2024"). The Company's prior year Gas ISR Plan for the period April 1, 2022 through March 31, 2023 approved in Docket No. 5210 is referenced in this section as "FY 2023-NG."

As shown on Attachment 1, Page 1, Column (b), the Company's CY 2023 Gas ISR Plan cumulative revenue requirement totals $46,984,604. The revenue requirement consists of the following elements: (1) the revenue requirement of $4,641,664 on CY 2023 proposed non-growth ISR capital investment of $157,130,000, as calculated on Attachment 1, Page 27; (2) the CY 2023 revenue requirement on incremental non-growth ISR capital investment for FY 2018 through FY 2023-NG totaling $34,717,355, as summarized on Attachment 1, Page 1; and (3) property tax expense adjustments of $10,957,033, as shown on Attachment 1, Page 40, in accordance with the property tax recovery mechanism included in the Amended Settlement Agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770. The CY2023 revenue requirement was reduced by $3,331,448 related to the impact of the PPL Rhode Island Holdings, LLC's[1] acquisition of 100 percent of the outstanding shares of common stock of the Company from National Grid USA ("National Grid") on May 25, 2022 (the "Acquisition") on the ISR rate base as described further in the joint pre-filed direct testimony of witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore, and Natalie Hawk. Importantly, the incremental capital investment for the CY 2023 ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4770 for FY 2018 through CY 2023. Incremental non-growth capital investment for this purpose is intended to represent the net change in net plant for non-growth infrastructure investments during the relevant fiscal year and is defined as capital additions plus cost of removal, less annual depreciation expense ultimately embedded in the Company's base distribution rates (excluding depreciation expense attributable to general plant, which is not eligible for inclusion in the Gas ISR Plan).

Additionally, as shown on Attachment 1, Page 1, Columns (c), the Company's CY 2024 Gas ISR Plan cumulative revenue requirement totals $75,244,391. The revenue requirement consists of the following elements: (1) the revenue requirement of $7,813,055 on CY 2024 proposed non-growth ISR capital investment of $189,714,000, as calculated on Attachment 1, Page 31; (2) the CY 2024 revenue requirement on incremental non-growth ISR capital investment for FY 2018 through CY 2023 totaling $57,327,960, as summarized on Attachment

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[1] PPL Rhode Island Holdings, LLC is a wholly owned indirect subsidiary of PPL Corporation.

1, Page 1; and (3) property tax expense adjustments of $14,427,754 as shown on Attachment 1, Page 40, in accordance with the property tax recovery mechanism included in the Amended Settlement Agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770. The CY2024 revenue requirement was reduced by $4,324,378 related to the impact of the Acquisition on the ISR rate base as described further in the joint pre-filed direct testimony of witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore and Natalie Hawk. Importantly, the incremental capital investment for the CY 2024 ISR revenue requirement excludes capital investment embedded in base distribution rates in Docket No. 4770 for FY 2018 through CY 2023. Incremental non-growth capital investment for this purpose is intended to represent the net change in net plant for non-growth infrastructure investments during the relevant fiscal year and is defined as capital additions plus cost of removal, less annual depreciation expense ultimately embedded in the Company's base distribution rates (excluding depreciation expense attributable to general plant, which is not eligible for inclusion in the Gas ISR Plan).

Gas Infrastructure Investment

Incremental Capital Investment

As noted above, Attachment 1, Pages 27 and 31 calculate the revenue requirement of incremental capital investment associated with the Company's CY 2023 and CY 2024 Gas ISR Plan, that is, gas infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. As per the PUC's Order in Docket No. 5099 and the resulting revisions to the Company's Gas tariff, RIPUC NG-GAS No. 101 at Section 3, Schedule A, Sheets 4 and 5, the definition of ISR capital investment changed from "non-growth capital spending" to "non-growth capital investment recorded as in service" effective April 1, 2021. The Company has implemented the plant-in-service methodology to replace the non-growth capital spending method to align with the PUC order and the tariff revision. The proposed CY 2023 and CY 2024 vintage year ISR capital investments represent the non-growth capital investment projected to be in service in CY 2023 and CY 2024. The capital investment for the 21-Month Plan, was obtained from Table 1 in Section 2 of the Plan, and the 21-Month Plan cost of removal is on Page 2 in Section 2. The CY 2023 and CY 2024 revenue requirements also include the incremental capital investment associated with the Company's actual ISR capital investments from FY 2018 through FY 2022 and forecasted ISR capital investments approved in the FY 2023-NG Gas ISR Plan, excluding investments reflected in rate base in Docket No. 4770.

Attachment 1, Page 34 calculates the incremental FY 2018 through FY 2023-NG ISR capital investment and the related incremental cost of removal, incremental retirements, and incremental net operating loss ("NOL") position for the CY 2023 and CY 2024 ISR revenue requirements. The calculations on Pages 34 and 35 compare ISR-eligible capital investment, cost of removal, retirements, and net NOL position for FY 2018 through FY 2023-NG to the corresponding amounts reflected in rate base in Docket No. 4770. 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. Therefore, no estimate of the incremental non-growth capital investment, cost of removal, retirements, or NOL position to be incurred during CY 2023 and CY 2024 were included in Docket No. 4770. Therefore, all CY 2023 and CY 2024 ISR-eligible capital is deemed incremental.

Incremental Capital Investment Calculation

The ISR mechanism was established to allow the Company to recover outside of base distribution rates its costs associated with plant additions incurred to expand its gas infrastructure and improve the reliability and safety of its gas facilities. When new base distribution rates are implemented, as was the case in Docket No. 4770, the Company no longer recovers costs for pre-rate case ISR plant additions through a separate ISR factor. Instead, such costs are recovered through base distribution 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 forecasted ISR plant additions for FY 2018, FY 2019 and five months of FY 2020 (using the level of plant additions approved in the FY 2018 Gas ISR Plan as a proxy for FY 2019 and FY 2020). The effective date of new base distribution rates in Docket No. 4770 was September 1, 2018. Therefore, recovery of the approved FY 2012 through FY 2017 ISR revenue requirement through the ISR factor ended on August 31, 2018, and all future recovery of those ISR plant additions will be through the Company's base distribution rates.

As a result of the implementation of new base distribution rates pursuant to Docket No. 4770 effective September 1, 2018, the cumulative amount of forecasted ISR plant additions were rolled into base distribution rates effective at that date. The CY 2024 revenue requirement for incremental FY 2018 through CY 2024 ISR investments reflect a full year of revenue requirement because none of these incremental investments are included in the Company's rate base in Docket 4770. These incremental fiscal year vintage amounts must remain in the ISR recovery mechanism as provided for in the terms of the approved Amended Settlement Agreement in Docket No. 4770. The current filing is based on the actual ISR investment made during the Company's fiscal years ended March 31, 2018, 2019, 2020, 2021, and 2022 and estimated ISR investment levels for the Company's fiscal year ended March 31, 2023 and CY 2023 and CY 2024, and which are incremental to the levels reflected in rate base in the Company's last base rate case (Docket No. 4770).

Gas Infrastructure Revenue Requirement

The revenue requirement calculations on incremental gas infrastructure investment for vintage years CY 2023 and CY 2024 are shown on Attachment 1, Page 27 and Page 31, respectively. The revenue requirement calculation incorporates the incremental Gas ISR Plan capital investment, cost of removal, and retirements, which are the basis for determining the two components of the revenue requirement: (1) the return on investment (i.e., average Plan rate base at the weighted average cost of capital) and (2) depreciation expense. The calculation on Page 27 begins with the determination of the depreciable net incremental capital that will be included in the Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in the Plan rate base in determining depreciation expense. Retirements, however, do not affect rate base because 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. Incremental book depreciation expense on Line 13 is computed based on the net depreciable additions from Line 3 at the 2.99 percent composite depreciation rate approved in Docket No. 4770, and as shown on Line 9. 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 7, is combined with the incremental capital investment amount from Line 6 (vintage year ISR Plan allowable capital additions, less non-general plant depreciation expense included in base distribution rates) to arrive at the total incremental investment on Line 8 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 8 and accumulated depreciation on current vintage year investment and accumulated deferred tax reserves as shown on Lines 14 and 19, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 15 through 19, equals the difference between book depreciation and tax depreciation on the capital investment, multiplied by the effective tax rate, net of any tax NOL or NOL utilization. The calculation of tax depreciation is described below. The average rate base before deferred tax proration adjustment is shown on Line 24. This amount then nets with the deferred tax proration adjustment on Line 25 to derive the average ISR rate base on Line 26. This average rate base is multiplied by the pre-tax rate of return approved by the PUC in Docket No. 4770, as shown on Line 27, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 29. Incremental depreciation expense is added to this amount on Line 30. The sum of these amounts reflects the annual revenue requirement associated with the capital investment portion of the Plan on Line 31, which is carried forward to Page 1 as part of the total Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018 through FY 20223-NG incremental Plan capital investment are shown on Pages 2, 6, 10, 15, 19 and 23, respectively. These capital investment revenue requirement amounts are added to the total property tax recovery on Page 1, Lines 12 and 13 to derive the total CY 2023 and CY 2024 Gas ISR Plan revenue requirements (before hold harmless adjustment) of $50,316,051 and $79,568,759, respectively, as shown on Page 1, Line 15.

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. Although, this 21-Month Plan covers forecasted periods for CY 2023 and CY 2024, the ADIT to be included in CY 2023 and CY 2024 reflects the ADIT impact of the Acquisition and the commitments PPL made during the sale 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 net ADIT as of the Acquisition date, at which time PPL began depreciating the new tax basis and started the tracking of book and tax timing differences as if PPL purchased a new asset in the year of the Acquisition. The revenue requirement of each vintage year reflects the elimination of ADIT in the "PPL 5/25/22 – 12-31-2022" 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's Acquisition date as National Grid will have utilized all of the Company's NOLs as a result of the sale. In addition, the tax depreciation calculation for each respective vintage year reflects tax depreciation on the new tax basis that is equivalent to the Company's net book basis as of the Acquisition date. PPL will

[2] *See* Report and Order, Docket No. D-21-09 at 257, Commitment #16 (February 23, 2023).

reflect the impact of any changes to pre-Acquisition computations in its FY 2023-NG reconciliation filing.

Accumulated Deferred Income Tax Proration Adjustment

The Gas 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(l)-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 which 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 CY 2024 proration calculations at Attachment 1, on Pages 4, 5, 8, 9, 12, 13, 17, 18, 21, 22, 25, 26, 29, 30 and 33, respectively, the effects of which are included in each year's respective revenue requirement.

Tax Depreciation Calculation

The tax depreciation calculations for CY 2023 and CY 2024 are provided on Attachment 1, Pages 28 and 32. The tax depreciation amount assumes that a portion of the capital investment, as shown on Lines 1 through 3 of Pages 27 and 31, will be eligible for immediate deduction on the Company's CY federal income tax return. This immediate deductibility is referred to as the capital repairs deduction.[3] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation, as shown on Pages 28 and 32, Lines 7 through 15 for CY 2023 and CY 2024, respectively. In 2010, Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the "2010 Tax Act"), which provided for an extension of bonus depreciation. Specifically, the 2010 Tax Act provided for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 31, 2012. The 50 percent bonus depreciation rate was later extended through December 31, 2013 and then extended further through December 31, 2017 via the Protecting Americans From Tax Hikes (PATH) Act. As noted in the Company's previous Gas ISR filings, the Tax Cuts and Jobs Act of 2017 (the "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 Gas ISR

[3] 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 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 fiscal year 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 Gas ISR Plan.

Plan 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 2017 Tax Act element affecting the Gas ISR Plan revenue requirement is changes to the bonus depreciation rules eliminating bonus depreciation for certain capital investments, including ISR-eligible investments, effective September 28, 2017. Property acquired prior to September 28, 2017 and placed in service in 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 tax return and revised its estimate of FY 2020 bonus depreciation. Starting in FY 2021, the Company can no longer take bonus depreciation. The Company's 21-month revenue requirements include the above impacts of the 2017 Tax Act on vintage FY 2018 through CY 2024 investment.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate. Also, the IRS clarified its tangible property regulations, and, consequently, the Company submitted a §481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. This election was submitted to the PUC, as required under IRS rules, on December 17, 2015. The late partial disposition election was made to protect the Company's deduction of cost of removal ("COR"). Otherwise, the Company would have been required to make a §481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100 percent deductible. The vintage FY 2018 through CY 2024 tax depreciation calculations in this filing include an additional tax deduction related to this change in accounting method. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, the MACRS depreciation, the tax loss on retirements, and the COR. These annual total tax depreciation amounts are carried forward to Line 11 of Page 27 and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for CY 2024 on Page 32 and for FY 2018 through FY 2023-NG investments on Pages 3, 7, 11, 16, 20 and 24, respectively.

The Company continues to monitor for new guidance pertaining to the 2017 Tax Act and any resulting impacts to its pending rate requests. As of this filing, the Company has not yet evaluated the FY 2022 tax return to determine whether any revisions are required to its calculation of accumulated deferred income taxes included in the vintage revenue requirements calculations in this docket. The Acquisition was completed during the period ending March 31, 2023 and will have an impact on tax NOLs utilized in the FY 2023-NG revenue requirement. The Company will reflect the impact of any additional NOL utilization on its deferred federal income taxes included in the calculation of ISR rate base in its FY 2023-NG reconciliation filing.

Federal Net Operating Loss

Tax NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. Tax NOLs do 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 have been generated in recent years by the bonus depreciation and capital repairs tax deductions. In addition to first-year bonus tax depreciation, the Internal Revenue 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, such costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions have 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 the 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 No. 4770, and the calculation of ADIT in this filing includes only the incremental amount of forecasted NOL utilization in the periods which the benefit would be reflected in the Company's federal income tax returns. NOL utilization is an increase to the Company's ADIT and will result in a credit or reduction in the calculation of rate base.

Property Tax Recovery Adjustment

The Property Tax Recovery Adjustment is set forth on Attachment 1, Pages 39 through 41. The method used to recover property tax expense under the Gas ISR Plan was modified by the Amended Settlement Agreement in Docket No. 4323 and continued by the Amended Settlement Agreement in Docket No. 4770. In determining the base on which property tax expense is calculated for purposes of the Plan revenue requirement, the Company includes an amount equal to the base rate allowance for depreciation expense and depreciation expense on incremental Plan plant additions in the accumulated reserve for depreciation that is deducted from plant additions. 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 formula. This provision of the Amended Settlement Agreement in Docket No. 4323 took effect for Plan property tax recovery periods subsequent to the end of the rate year for that docket, or January 31, 2014, and has been continued by the Amended Settlement Agreement in Docket No. 4770. The CY 2023 and CY 2024 revenue requirements include $10,957,033 and $14,427,754, respectively, for the Net Property Tax Recovery Adjustment.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2023-NG (a)	9 Months Calendar Year 2023 (b)	12 Months Calendar Year 2024 (c)
	Operation and Maintenance Expenses			
1	FY 2023 Operation and Maintenance Expense	$0	$0	$0
	Capital Investment:			
2	Actual Revenue Requirement on FY 2018 Incremental Capital Included in ISR Rate Base	$705,341	$269,705	$366,387
3	Actual Revenue Requirement on FY 2019 Incremental Capital Included in ISR Rate Base	$290,803	$304,457	$406,191
4	Actual Revenue Requirement on FY 2020 Incremental Capital Included in ISR Rate Base	$8,490,363	$7,074,206	$9,152,080
5	Actual Revenue Requirement on FY 2021 Incremental Capital Included in ISR Rate Base	$8,578,571	$6,688,317	$8,620,137
6	Actual Revenue Requirement on FY 2022 Incremental Capital Included in ISR Rate Base	$11,111,100	$10,730,055	$13,879,922
7	Forecasted Revenue Requirement on FY 2023-NG Capital Included in ISR Rate Base	$6,439,207	$9,650,614	$12,693,635
8	Forecasted Revenue Requirement on CY 2023 Capital Included in ISR Rate Base (9 Months)		$4,641,664	$12,209,609
9	Forecasted Revenue Requirement on CY 2024 Capital Included in ISR Rate Base (12 Months)			$7,813,055
10	Total Capital Investment Revenue Requirement	$35,615,386	$39,359,018	$65,141,015
11	FY 2023-NG Property Tax Recovery Adjustment	$6,821,584		
12	CY 2023 Property Tax Recovery Adjustment (Dec-23)		$10,957,033	
13	CY 2024 Property Tax Recovery Adjustment (Dec-24)			$14,427,754
14	**Total Capital Investment Component of Revenue Requirement**	**$42,436,970**	**$50,316,051**	**$79,568,769**
15	**Total Revenue Requirement**	**$42,436,970**	**$50,316,051**	**$79,568,769**
16	Per Tax Hold Harmless Adjustment Section 3, Attachment 2, Pages 1 and 2, Line 23		($3,331,448)	($4,324,378)
17	**Total Net Capital Investment Component of Revenue Requiremen**	$42,436,970	$46,984,604	$75,244,391
18	**Incremental Rate Adjustment**		**$4,547,633**	**$28,259,788**

Column Notes:
(a) RIPUC Docket No. 5210, Section 3, Attachment 1, Page 1 of 28, Column (b)

Line Notes for Columns (b) only:
2 Page 2 of 42, Line 35, Col. (i) & (j)
3 Page 6 of 42, Line 30, Col. (h) & (i)
4 Page 10 of 42, Line 35, Col. (g) & (h)
5 Page 15 of 42, Line 35, Col. (f) & (g)
6 Page 19 of 42, Line 35, Col. (e) & (f)
7 Page 23 of 42, Line 35, Col. (e) & (f)
8 Page 27 of 42, Line 31, Col. (a) & (b)
9 Page 31 of 42, Line 29, Col. (a)
10 Sum of Lines 2 through 9
12 Page 40 of 42, Line 93, Col. (g) & (k) × 1,000
14 Sum of Line 10 through Line 13
15 Line 1 + Line 14
16 RIPUC Docket No. 22-54-NG, Section 3, Attachment 2, Pages 1 and 2, Line 23
17 Line 15 + Line 16
18 Line 17 Col (b) - Line 17 Col (a)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on FY 2018 Actual Incremental Gas 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 - 12/31/22 2023 (g)	PPL 1/1/23 - 3/31/23 2023 (h)	9 months Calendar Year Dec-2023 (i)	12 months Calendar Year Dec-2024 (j)
	Depreciable Net Capital Included in ISR Rate Base												
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 34 of 42 , Line 3 ,Col (a)		$4,632,718									
2	Retirements	Page 34 of 42 , Line 9 ,Col (a)		$12,059,428									
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)	($7,426,710)
	Change in Net Capital Included in ISR Rate Base												
4	Capital Included in ISR Rate Base	Line 1		$4,632,718	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718	$4,632,718
7	Cost of Removal	Page 34 of 42 , Line 6 ,Col (a)		$1,941,168									
8	**Net Plant Amount**	Year 1 = Line 6 + Line 7, Then = Prior Year		**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**	**$6,573,886**
	Deferred Tax Calculation:												
9	Composite Book Depreciation Rate		1/	3.38%	3.15%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
10	Number of days		2/						54	221	90		
11	Proration Percentage		2/						14.79%	60.55%	24.66%	75.00%	
12	Tax Depreciation and Year 1 Basis Adjustments	Year 1=Page 3 of 42, Line 30, Col (a); then = Page 3 of 42, Col (e)		$7,820,728	$21,720	$20,089	$18,585	$17,189	$2,353	$213,427	$101,308	$309,553	$380,014
13	Cumulative Tax Depreciation-NG	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12	3/	$7,820,728	$7,842,448	$7,862,538	$7,881,123	$7,898,312	$7,900,664				
14	Cumulative Tax Depreciation-PPL	Year 1 = Line 12; then = Prior Year Line 14 + Current Year Line 12	3/							$213,427	$314,735	$624,288	$1,004,302
14	Book Depreciation	Year 1= Line 3 × Line 9 × 50%; then = Line 3 × Line 9		($125,511)	($234,127)	($222,059)	($222,059)	($222,059)	($32,853)	($134,452)	($54,754)	($166,544)	($222,059)
15	Cumulative Book Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14		($125,511)	($359,638)	($581,697)	($803,756)	($1,025,814)	($1,058,667)	($1,193,119)	($1,247,873)	($1,414,417)	($1,636,476)
16	Cumulative Book / Tax Timer	Columns (a) through (e): Line 13 - Line 15, Then Line 14 - Line 15		$7,946,239	$8,202,087	$8,444,235	$8,684,878	$8,924,126	$8,959,331	$1,406,546	$1,562,608	$2,038,705	$2,640,777
17	Less: Cumulative Book Depreciation at Acquisition	Line 15 Column (f)	3/							($1,058,667)	($1,058,667)	($1,058,667)	($1,058,667)
18	Cumulative Book / Tax Timer - PPL	Line 16 + Line 17								$347,879	$503,941	$980,038	$1,582,110
19	Effective Tax Rate		4/	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Columns (a) through (f): Line 16 * Line 19, Then Line 18 * Line 19		$1,668,710	$1,722,438	$1,773,289	$1,823,824	$1,874,066	$1,881,459	$73,055	$105,828	$205,808	$332,243
21	Less: FY 2018 Federal NOL	-Page 35 of 42, Line 12, Col (g)	3/	($6,051,855)	($6,051,855)	($6,051,855)	($6,051,855)	($6,051,855)	($6,051,855)	$0	$0	$0	$0
22	Excess Deferred Tax	(Line 16 × 31.55% blended FY18 tax rate) - Line 20; then = Prior Year Line 22		$838,328	$838,328	$838,328	$838,328	$838,328	$838,328	$838,328	$838,328	$838,328	$838,328
23	Net Deferred Tax Reserve before Proration Adjustment	Line 20 + Line 21 + Line 22		($3,544,817)	($3,491,089)	($3,440,238)	($3,389,703)	($3,339,461)	($3,332,068)	$911,383	$944,156	$1,044,136	$1,170,571
	ISR Rate Base Calculation:												
24	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886	$6,573,886
25	Accumulated Depreciation	- Line 15		$125,511	$359,638	$581,697	$803,756	$1,025,814	$1,058,667	$1,193,119	$1,247,873	$1,414,417	$1,636,476
26	Deferred Tax Reserve	- Line 23		$3,544,817	$3,491,089	$3,440,238	$3,389,703	$3,339,461	$3,332,068	($911,383)	($944,156)	($1,044,136)	($1,170,571)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$10,244,214	$10,424,613	$10,595,821	$10,767,344	$10,939,161	$10,964,620	$6,855,622	$6,877,603	$6,944,167	$7,039,790
	Revenue Requirement Calculation:												
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = 0; then Average of (Prior + Current Year Line 27)	5/					$10,853,253	$8,908,382	$8,908,382	$8,908,382	$6,910,885	$6,991,978
29	Proration Adjustment	Columns (e) through (i) see Page 4 of 42, Line 41, Column (j) see Page 5 of 42, Line 41						$2,157	$4,860	$4,860	$4,860	$5,474	$4,994
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29						$10,855,409	$8,913,242	$8,913,242	$8,913,242	$6,916,358	$6,996,972
31	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)						8.41%	8.41%	8.41%	8.41%	8.41%	8.41%
32	Proration Percentage	Line 11	2/						14.79%	60.55%	24.66%	75.00%	
33	Return and Taxes	Cols (e) and (j): L 30 * L 31; Cols (f) through (i): L 30 * L 31 * L 32	2/					$912,940	$110,900	$453,870	$184,834	$436,249	$588,445
34	Book Depreciation	Year 1 = N/A; then = Line 14						($222,059)	($32,853)	($134,452)	($54,754)	($166,544)	($222,059)
35	**Annual Revenue Requiremen**	Sum of Lines 33 through 34		**N/A**	**N/A**	**N/A**	**N/A**	**$690,881**	**$78,048**	**$319,418**	**$130,080**	**$269,705**	**$366,387**

1/ 3.38%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.38% × 5 /12 + 2.99% × 7 / 12

2/ Columns (f) through (h) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (i) is prorated for the 9-month calendar year 2023 plan.

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 begin depreciating the new tax basis and start the tracking of book/tax timing differences as if PPL purchased a new asset in the year of acquisition.

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) through (h) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 27, Column (e) and the end of the fiscal year on Line 32, Column (h). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 of 42, Line 1		$4,632,718
2	Capital Repairs Deduction Rate	Per Tax Department	1/	85.43%
3	Capital Repairs Deduction	Line 1 × Line 2		$3,957,731
4				
5				
6	Bonus Depreciation			
7	Plant Additions	Line 1		$4,632,718
8	Less Capital Repairs Deduction	Line 3		$3,957,731
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		$674,987
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$674,987
12	Bonus depreciation 100% category	100% × 15.86%	2/	15.86%
13	Bonus depreciation 50% category	50% × 58.05%	2/	29.03%
14	Bonus depreciation 40% category	40% × 26.35%	2/	10.54%
15	Bonus Depreciation Rate (October 2017 - March 2018)	1 × 50% × 0%	2/	0.00%
16	Total Bonus Depreciation Rate	Line 12 + Line 13 + Line 14 + Line 15		55.43%
17	Bonus Depreciation	Line 11 × Line 16		$374,112
18				
19	Remaining Tax Depreciation			
20	Plant Additions	Line 1		$4,632,718
21	Less Capital Repairs Deduction	Line 3		$3,957,731
22	Less Bonus Depreciation	Line 17		$374,112
23	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 20 - Line 21 - Line 22		$300,875
24	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%
25	Remaining Tax Depreciation	Line 23 × Line 24		$11,283
26				
27	FY18 tax (gain)/loss on retirements	Per Tax Department	3/	$1,536,434
28	Cost of Removal	Page 2 of 42, Line 7		$1,941,168
29				
30	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 17, 25, 27 & 28		$7,820,728

Line No.	(b)	(c)	(d)	(e)	(f)
1	20 Year MACRS Depreciation				
3	MACRS basis:	Line 23, Column (a)		$300,875	
4				Annual	Cumulative
5	Fiscal Year		Prorated		
6	FY Mar-2018	3.750%		$11,283	$7,820,728
7	FY Mar-2019	7.219%		$21,720	$7,842,448
8	FY Mar-2020	6.677%		$20,089	$7,862,538
9	FY Mar-2021	6.177%		$18,585	$7,881,123
10	FY Mar-2022	5.713%		$17,189	$7,898,312
11	FY Mar-2023 (Apr-May 2022)	5.285%	0.782%	$2,353	$7,900,664
12					
13	Book Cost	Line 1, Column (a)		$4,632,718	
14	Cumulative Book Depreciation	- Page 2 of 42, Line 15, Col (f)		$1,058,667	
15	PPL MACRS basis:	Line 13 + Line 14		$5,691,385	
16					
17	FY Mar-2023 (Jun-Dec 2022)	3.750%		$213,427	$213,427
18	FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$101,308	$314,735
19	CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$309,553	$624,288
20	CY 2024	6.677%		$380,014	$1,004,302
21	CY 2025	6.177%		$351,557	$1,355,859
22	CY 2026	5.713%		$325,149	$1,681,007
23	CY 2027	5.285%		$300,790	$1,981,797
24	CY 2028	4.888%		$278,195	$2,259,992
25	CY 2029	4.522%		$257,364	$2,517,356
26	CY 2030	4.462%		$253,950	$2,771,306
27	CY 2031	4.461%		$253,893	$3,025,199
28	CY 2032	4.462%		$253,950	$3,279,148
29	CY 2033	4.461%		$253,893	$3,533,041
30	CY 2034	4.462%		$253,950	$3,786,991
	CY 2035	4.461%		$253,893	$4,040,883
	CY 2036	4.462%		$253,950	$4,294,833
	CY 2037	4.461%		$253,893	$4,548,725
	CY 2038	4.462%		$253,950	$4,802,675
	CY 2039	4.461%		$253,893	$5,056,568
	CY 2040	4.462%		$253,950	$5,310,517
	CY 2041	4.461%		$253,893	$5,564,410
	CY 2042	2.231%		$126,975	$5,691,385
		100.000%		$5,691,385	

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
11 (d) 5.285% / 365 x 54
18 (d) 7.219% / 365 x 90
19 (d) 7.219% / 365 x 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment Pre CY 2024

Line No.				FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
	Deferred Tax Subject to Proration					
1	Book Depreciation	Col (a): Page 2 of 42, Line 14, column (e); Col (b): Page 2 of 42, Line 14, columns (f) through (h); Col (c): Page 2 of 42, Line 14, column (i)		($222,059)	($222,059)	($166,544)
2	Bonus Depreciation			$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 3 of 42, Line 10, column (e); Col (b): - Page 3 of 42, Sum of Lines 11,17,18, column, (e); Col (c): - Page 3 of 42, Line 19, column, (e)		($17,189)	($317,088)	($309,553)
4	FY18 tax (gain)/loss on retirements			$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($239,248)	($539,146)	($476,097)
6	Effective Tax Rate			21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6		($50,242)	($113,221)	($99,980)
	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				
12	Effective Tax Rate					
13	Deferred Tax Reserve	Line 11 × Line 12				
14	Total Deferred Tax Reserve	Line 7 + Line 13		($50,242)	($113,221)	($99,980)
15	Net Operating Loss			$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($50,242)	($113,221)	($99,980)
	Allocation of FY 2018 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($239,248)	($539,146)	($476,097)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($239,248)	($539,146)	($476,097)
20	Total FY 2018 Federal NOL			$0	$0	$0
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		$0	$0	$0
22	Allocated FY 2018 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		($50,242)	($113,221)	($99,980)
		(d)	(e)	(f)	(g)	(h)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23-NG	Apr 1 - Dec 31 2023
26	April	30	91.78%	($3,843)	($8,660)	($9,897)
27	May	31	83.29%	($3,487)	($7,858)	($8,645)
28	June	30	75.07%	($3,143)	($7,083)	($7,433)
29	July	31	66.58%	($2,787)	($6,281)	($6,181)
30	August	31	58.08%	($2,432)	($5,480)	($4,928)
31	September	30	49.86%	($2,088)	($4,705)	($3,716)
32	October	31	41.37%	($1,732)	($3,903)	($2,464)
33	November	30	33.15%	($1,388)	($3,128)	($1,252)
34	December	31	24.66%	($1,032)	($2,326)	
35	January	31	16.16%	($677)	($1,525)	
36	February	28	8.49%	($356)	($801)	
37	March	31	0.00%	$0	$0	
38	Total	365		($22,964)	($51,751)	($44,516)
39	Deferred Tax Without Proration	Line 25		($50,242)	($113,221)	($99,980)
40	Average Deferred Tax without Proration	Line 39 × 50%		($25,121)	($56,610)	($49,990)
41	Proration Adjustment	Line 38 - Line 40		$2,157	$4,860	$5,474

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
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment Post CY 2023

Line No.				CY24 (a)	CY25 (b)
	Deferred Tax Subject to Proration				
1	Book Depreciation	Page 2 of 42 , Line 14		($222,059)	($222,059)
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Page 3 of 42 , Col (e)		($380,014)	($351,557)
4	FY18 tax (gain)/loss on retirements			$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($602,072)	($573,615)
6	Effective Tax Rate			21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6		($126,435)	($120,459)
	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			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 × Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13		($126,435)	($120,459)
15	Net Operating Loss			$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($126,435)	($120,459)
	Allocation of FY 2018 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($602,072)	($573,615)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($602,072)	($573,615)
20	Total FY 2018 Federal NOL			$0	$0
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		$0	$0
22	Allocated FY 2018 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		($126,435)	($120,459)
		(c)	(d)	(e)	(f)
	Proration Calculation	Number of Days in Month	Proration Percentage	CY24	CY25
26	January	31	91.51%	($9,641)	($9,186)
27	February	28	83.84%	($8,833)	($8,416)
28	March	31	75.34%	($7,938)	($7,563)
29	April	30	67.12%	($7,072)	($6,738)
30	May	31	58.63%	($6,177)	($5,885)
31	June	30	50.41%	($5,311)	($5,060)
32	July	31	41.92%	($4,417)	($4,208)
33	August	31	33.42%	($3,522)	($3,355)
34	September	30	25.21%	($2,656)	($2,530)
35	October	31	16.71%	($1,761)	($1,678)
36	November	30	8.49%	($895)	($853)
37	December	31	0.00%	$0	$0
38	Total	365		($58,224)	($55,472)
39	Deferred Tax Without Proration	Line 25		($126,435)	($120,459)
40	Average Deferred Tax without Proration	Line 39 × 50%		($63,218)	($60,230)
41	Proration Adjustment	Line 38 - Line 40		$4,994	$4,758

Column Notes:

(d)	Sum of remaining days in the year (Col (c)) ÷ 366
(e) & (f)	Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on FY 2019 Actual Incremental Gas Capital Investment

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)	NG 4/1/22 - 5/24/2022 2023 (e)	PPL 5/25/22 - 12/31/22 2023 (f)	PPL 1/1/23 - 3/31/23 2023 (g)	9 months Calendar Year Dec-2023 (h)	12 months Calendar Year Dec-2024 (i)
	Depreciable Net Capital Included in ISR Rate Base											
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 34 of 42 , Line 3 ,Col (b)		($914,000)								
2	Retirements	Page 34 of 42 , Line 9 ,Col (b)		($1,368,021)								
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$454,021	$454,021	$454,021	$454,021	$454,021	$454,021	$454,021	$454,021	$454,021
	Change in Net Capital Included in ISR Rate Base											
4	Capital Included in ISR Rate Base	Line 1		($914,000)	$0	$0	$0	$0	$0	$0	$0	$0
5	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		($914,000)	($914,000)	($914,000)	($914,000)	($914,000)	($914,000)	($914,000)	($914,000)	($914,000)
7	Cost of Removal	Page 34 of 42 , Line 6 ,Col (b)		$5,626,564								
8	**Net Plant Amount**	**Line 1 = Line 6+7; Then = Prior Year**		**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**	**$4,712,564**
	Deferred Tax Calculation:											
9	Composite Book Depreciation Rate	As Approved in RIPUC Docket No. 4323 & 4770	1/	3.15%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
10	Number of days		2/					54	221	90		
11	Proration Percentage		2/					14.79%	60.55%	24.66%	75.00%	
12	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 7 of 42, Line 28, Col (a); then = Page 7 of 42, Col (e)		$5,200,130	($8,390)	($7,760)	($7,179)	($982)	($36,146)	($17,158)	($52,426)	($64,359)
13	Cumulative Tax Depreciation-NG	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12	3/	$5,200,130	$5,191,739	$5,183,979	$5,176,799	$5,175,817				
14	Cumulative Tax Depreciation-PPL	Year 1 = Line 12; then = Prior Year Line 14 + Current Year Line 12	3/						($36,146)	($53,303)	($105,729)	($170,088)
15	Book Depreciation	Year 1 = Line 3 × Line 9 × 50%; then = Line 3 × Line 9		$7,157	$13,575	$13,575	$13,575	$2,008	$8,220	$3,347	$10,181	$13,575
16	Cumulative Book Depreciation	Year 1 = Line 15; then = Prior Year Line 16 + Current Year Line 15		$7,157	$20,732	$34,307	$47,883	$49,891	$58,111	$61,458	$71,639	$85,215
17	Cumulative Book / Tax Timer	Columns (a) through (e): Line 13 - Line 16, Then Line 14 - Line 16		$5,192,973	$5,171,007	$5,149,671	$5,128,917	($49,891)	($94,256)	($114,761)	($177,368)	($255,303)
18	Less: Cumulative Book Depreciation at Acquisition	Line 16 Column (e)	3/						$49,891	$49,891	$49,891	$49,891
19	Cumulative Book / Tax Timer - PPL	Line 17 + Line 18							($44,365)	($64,870)	($127,477)	($205,412)
20	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
21	Deferred Tax Reserve	Columns (a) through (e): Line 17 * Line 20, Then Line 19 * Line 20		$1,090,524	$1,085,911	$1,081,431	$1,077,072	($10,477)	($9,317)	($13,623)	($26,770)	($43,136)
22	Add: FY 2019 Federal NOL incremental utilization	Page 34 of 42, Line 12, Col (b)	3/	$286,350	$286,350	$286,350	$286,350	$286,350	$0	$0	$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Line 21 + Line 22		$1,376,874	$1,372,261	$1,367,781	$1,363,422	$275,873	($9,317)	($13,623)	($26,770)	($43,136)
	ISR Rate Base Calculation:											
24	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$4,712,564	$4,712,564	$4,712,564	$4,712,564	$4,712,564	$4,712,564	$4,712,564	$4,712,564	$4,712,564
25	Accumulated Depreciation	- Line 16		($7,157)	($20,732)	($34,307)	($47,883)	($49,891)	($58,111)	($61,458)	($71,639)	($85,215)
26	Deferred Tax Reserve	- Line 23		($1,376,874)	($1,372,261)	($1,367,781)	($1,363,422)	($275,873)	$9,317	$13,623	$26,770	$43,136
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$3,328,533	$3,319,570	$3,310,475	$3,301,259	$4,386,800	$4,663,770	$4,664,728	$4,667,694	$4,670,485
	Revenue Requirement Calculation:											
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 27 ÷ 2; then = (Prior Year Line 27 + Current Year Line 27) ÷ 2	4/				$3,305,867	$3,982,994	$3,982,994	$3,982,994	$4,666,211	$4,669,090
29	Proration Adjustment	Columns (d) through (h) see Page 8 of 42, Line 41, Column (i) see Page 9 of 42, Line 41					($187)	($612)	($612)	($612)	($720)	($646)
25	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29					$3,305,680	$3,982,382	$3,982,382	$3,982,382	$4,665,492	$4,668,444
26	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)					8.41%	8.41%	8.41%	8.41%	8.41%	8.41%
27	Proration Percentage	Line 11	2/					14.79%	60.55%	24.66%	75.00%	
28	Return and Taxes	Cols (d) and (i): L 25 * L 26; Cols (e) through (h): L 25 * L 26 * L 27	2/				$278,008	$49,550	$202,786	$82,583	$294,276	$392,616
29	Book Depreciation	Line 15					$13,575	$2,008	$8,220	$3,347	$10,181	$13,575
30	**Annual Revenue Requiremen**	**Sum of Lines 28 through 29**		**N/A**	**N/A**	**N/A**	**$291,583**	**$51,558**	**$211,006**	**$85,930**	**$304,457**	**$406,191**

1/ 3.38%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.38% × 5 /12 + 2.99% × 7 / 12
2/ Columns (e) through (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. Column (h) is prorated for the 9-month calendar year 2023 plan.
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 begin depreciating the new tax basis and start the tracking of book/tax timing differences as if PPL purchased a new asset in the year of acquisition.
4/ Columns (e) through (g) 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 27, Column (g). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2019 Incremental Capital Investment

Line No.				Fiscal Year 2019 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 6 of 42, Line 1		($914,000)	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	85.18%					
3	Capital Repairs Deduction	Line 1 × Line 2		($778,545)	MACRS basis:	Line 21, Column (a)		($116,227)	
4								Annual	Cumulative
5					Fiscal Year		Prorated		
6	Bonus Depreciation				FY Mar-2019	3.750%		($4,359)	$5,200,130
7	Plant Additions	Line 1		($914,000)	FY Mar-2020	7.219%		($8,390)	$5,191,739
8	Less Capital Repairs Deduction	Line 3		($778,545)	FY Mar-2021	6.677%		($7,760)	$5,183,979
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		($135,455)	FY Mar-2022	6.177%		($7,179)	$5,176,799
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2023 (Apr-May 2022)	5.713%	0.845%	($982)	$5,175,817
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		($135,455)					
12	Bonus Depreciation Rate (30% Eligible)	1 × 30% × 11.65%	2/	3.50%	Book Cost	Line 1, Column (a)		($914,000)	
13	Bonus Depreciation Rate (40% Eligible)	1 × 40% × 26.75%	2/	10.70%	Cumulative Book Depreciation	- Page 6 of 42, Line 16, Col (e)		($49,891)	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		14.20%	PPL MACRS basis:	Line 12 + Line 13		($963,891)	
15	Bonus Depreciation	Line 11 × Line 14		($19,228)					
16					FY Mar-2023 (Jun-Dec 2022)	3.750%		($36,146)	($36,146)
17	Remaining Tax Depreciation				FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	($17,158)	($53,303)
18	Plant Additions	Line 1		($914,000)	CY 2023 (Apr-Dec 2023)	7.219%	5.439%	($52,426)	($105,729)
19	Less Capital Repairs Deduction	Line 3		($778,545)	CY 2024	6.677%		($64,359)	($170,088)
20	Less Bonus Depreciation	Line 15		($19,228)	CY 2025	6.177%		($59,540)	($229,628)
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		($116,227)	CY 2026	5.713%		($55,067)	($284,695)
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	CY 2027	5.285%		($50,942)	($335,637)
23	Remaining Tax Depreciation	Line 21 × Line 22		($4,359)	CY 2028	4.888%		($47,115)	($382,751)
24					CY 2029	4.522%		($43,587)	($426,339)
25	FY19 tax (gain)/loss on retirements	Per Tax Department	3/	$375,698	CY 2030	4.462%		($43,009)	($469,347)
26	Cost of Removal	Page 6 of 42, Line 7		$5,626,564	CY 2031	4.461%		($42,999)	($512,347)
27					CY 2032	4.462%		($43,009)	($555,355)
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25 & 26		$5,200,130	CY 2033	4.461%		($42,999)	($598,355)
					CY 2034	4.462%		($43,009)	($641,363)
					CY 2035	4.461%		($42,999)	($684,363)
					CY 2036	4.462%		($43,009)	($727,371)
					CY 2037	4.461%		($42,999)	($770,371)
					CY 2038	4.462%		($43,009)	($813,379)
					CY 2039	4.461%		($42,999)	($856,379)
					CY 2040	4.462%		($43,009)	($899,387)
					CY 2041	4.461%		($42,999)	($942,387)
					CY 2042	2.231%		($21,504)	($963,891)
						100.000%		($963,891)	

1/ Capital Repairs percentage is the actual result of FY2019 tax return
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY2019 tax return
3/ Actual Loss the actual result of FY2019 tax return
10 (d) 5.713% / 365 x 54
17 (d) 7.219% / 365 x 90
18 (d) 7.219% / 365 x 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment Pre CY 2024

Line No.	**Deferred Tax Subject to Proration**		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 6 of 42, Line 15, column (d); Col (b): Page 6 of 42, Line 15, columns (e) through (g); Col (c): Page 6 of 42, Line 15, column (h)	$13,575	$13,575	$10,181
2	Bonus Depreciation		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 7 of 42, Line 9, column (e); Col (b): - Page 7 of 42, Sum of Lines 10,16,17, column, (e); Col (c): - Page 7 of 42, Line 18, column, (e)	$7,179	$54,286	$52,426
4	FY19 tax (gain)/loss on retirements		$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$20,755	$67,861	$62,607
6	Effective Tax Rate		21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$4,358	$14,251	$13,148
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction				
9	Cost of Removal				
10	Book/Tax Depreciation Timing Difference at 3/31/2019				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	$0
12	Effective Tax Rate		21%	21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$4,358	$14,251	$13,148
15	Net Operating Loss		$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$4,358	$14,251	$13,148
	Allocation of FY 2019 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$20,755	$67,861	$62,607
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$20,755	$67,861	$62,607
20	Total FY 2019 Federal NOL		$0	$0	$0
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0	$0
22	Allocated FY 2019 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	$4,358	$14,251	$13,148

Line No.	Proration Calculation	(d) Number of Days in Month	(e) Proration Percentage	(f) FY22	(g) FY23-NG	(h) Apr 1 - Dec 31 2023
26	April	30	91.78%	$333	$1,090	$1,301
27	May	31	83.29%	$303	$989	$1,137
28	June	30	75.07%	$273	$891	$977
29	July	31	66.58%	$242	$791	$813
30	August	31	58.08%	$211	$690	$648
31	September	30	49.86%	$181	$592	$489
32	October	31	41.37%	$150	$491	$324
33	November	30	33.15%	$120	$394	$165
34	December	31	24.66%	$90	$293	
35	January	31	16.16%	$59	$192	
36	February	28	8.49%	$31	$101	
37	March	31	0.00%	$0	$0	
38	Total	365		$1,992	$6,514	$5,854
39	Deferred Tax Without Proration	Line 25		$4,358	$14,251	$13,148
40	Average Deferred Tax without Proration	Line 39 × 50%		$2,179	$7,125	$6,574
41	Proration Adjustment	Line 38 - Line 40		($187)	($612)	($720)

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
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment Post CY 2023

Line No.			CY24 (a)	CY25 (b)
	Deferred Tax Subject to Proration			
1	Book Depreciation	Page 6 of 42 , Line 15	$13,575	$13,575
2	Bonus Depreciation		$0	$0
3	Remaining MACRS Tax Depreciation	Page 7 of 42 , Col (e)	$64,359	$59,540
4	FY19 tax (gain)/loss on retirements		$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$77,934	$73,115
6	Effective Tax Rate		21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$16,366	$15,354
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction			
9	Cost of Removal			
10	Book/Tax Depreciation Timing Difference at 3/31/2019			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$16,366	$15,354
15	Net Operating Loss		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$16,366	$15,354
	Allocation of FY 2019 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$77,934	$73,115
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$77,934	$73,115
20	Total FY 2019 Federal NOL		$0	$0
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0
22	Allocated FY 2019 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	$16,366	$15,354

Line No.	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24	(f) CY25
26	January	31	91.51%	$1,248	$1,171
27	February	28	83.84%	$1,143	$1,073
28	March	31	75.34%	$1,028	$964
29	April	30	67.12%	$915	$859
30	May	31	58.63%	$800	$750
31	June	30	50.41%	$688	$645
32	July	31	41.92%	$572	$536
33	August	31	33.42%	$456	$428
34	September	30	25.21%	$344	$323
35	October	31	16.71%	$228	$214
36	November	30	8.49%	$116	$109
37	December	31	0.00%	$0	$0
38	Total	365		$7,537	$7,071
39	Deferred Tax Without Proration		Line 25	$16,366	$15,354
40	Average Deferred Tax without Proration		Line 39 × 50%	$8,183	$7,677
41	Proration Adjustment		Line 38 - Line 40	($646)	($606)

Column Notes:
(d) Sum of remaining days in the year (Col (c)) ÷ 366
(e) & (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
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21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on FY 2020 Actual Incremental Gas Capital Investment

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)	NG 4/1/22 - 5/24/2022 2023 (d)	PPL 5/25/22 - 12/31/22 2023 (e)	PPL 1/1/23 - 3/31/23 2023 (f)	9 months Calendar Year Dec-2023 (g)	12 months Calendar Year Dec-2024 (h)
	Depreciable Net Capital Included in ISR Rate Base										
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 34 of 42 , Line 3 ,Col (c)		$105,296,046							
2	Retirements	Page 34 of 42 , Line 9 ,Col (c)		$4,276,135							
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$101,019,911	$101,019,911	$101,019,911	$101,019,911	$101,019,911	$101,019,911	$101,019,911	$101,019,911
	Change in Net Capital Included in ISR Rate Base										
4	Capital Included in ISR Rate Base	Line 1		$105,296,046	$0	$0	$0	$0	$0	$0	$0
5	Depreciation Expense	Page 38 of 42, Line 72(c)		$23,534,853	$0	$0	$0	$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$81,761,193	$81,761,193	$81,761,193	$81,761,193	$81,761,193	$81,761,193	$81,761,193	$81,761,193
7	Cost of Removal	Page 34 of 42 , Line 6 ,Col (c)		$7,055,630						$0	$0
8	**Net Plant Amount**	Line 1 = Line 6+7; Then = Prior Year		**$88,816,823**	**$88,816,823**	**$88,816,823**	**$88,816,823**	**$88,816,823**	**$88,816,823**	**$88,816,823**	**$88,816,823**
	Deferred Tax Calculation:										
9	Composite Book Depreciation Rate	Page 36 of 42, Line 86(e)	1/	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
10	Number of days		2/				54	221	90		
11	Proration Percentage		2/				14.79%	60.55%	24.66%	75.00%	
12	Tax Depreciation and Year 1 Basis Adjustments	Year 1 =Page 11 of 42, Line 28, Col (a); then =Page 11 of 42, Col (e)		$89,531,414	$1,753,362	$1,621,720	$221,959	$3,648,673	$1,731,930	$5,292,008	$6,496,583
13	Cumulative Tax Depreciation-NG	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12	3/	$89,531,414	$91,284,775	$92,906,495	$93,128,454				
14	Cumulative Tax Depreciation-PPL	Year 1 = Line 12; then = Prior Year Line 14 + Current Year Line 12	3/					$3,648,673	$5,380,603	$10,672,611	$17,169,194
15	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$1,510,248	$3,020,495	$3,020,495	$446,868	$1,828,848	$744,780	$2,265,371	$3,020,495
16	Cumulative Book Depreciation	Year 1 = Line 15; then = Prior Year Line 16 + Current Year Line 15		$1,510,248	$4,530,743	$7,551,238	$7,998,106	$9,826,954	$10,571,734	$12,837,105	$15,857,600
17	Cumulative Book / Tax Timer	Columns (a) through (d): Line 13 - Line 16, Then Line 14 - Line 16		$88,021,166	$86,754,032	$85,355,257	$85,130,348	($6,178,281)	($5,191,131)	($2,164,494)	$1,311,594
18	Less: Cumulative Book Depreciation at Acquisition	Line 16 Column (d)	3/					$7,998,106	$7,998,106	$7,998,106	$7,998,106
19	Cumulative Book / Tax Timer - PPL	Line 17 + Line 18						$1,819,825	$2,806,975	$5,833,612	$9,309,700
20	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
21	Deferred Tax Reserve	Columns (a) through (d): Line 17 * Line 20, Then Line 19 * Line 20		$18,484,445	$18,218,347	$17,924,604	$17,877,373	$382,163	$589,465	$1,225,059	$1,955,037
22	Add: FY 2020 Federal NOL utilization	Page 34 of 42, Line 12, Col (c)	3/	($3,063,059)	($3,063,059)	($3,063,059)	($3,063,059)	$0	$0	$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Line 21 + Line 22		$15,421,386	$15,155,288	$14,861,545	$14,814,315	$382,163	$589,465	$1,225,059	$1,955,037
	ISR Rate Base Calculation:										
24	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$88,816,823	$88,816,823	$88,816,823	$88,816,823	$88,816,823	$88,816,823	$88,816,823	$88,816,823
25	Accumulated Depreciation	- Line 16		($1,510,248)	($4,530,743)	($7,551,238)	($7,998,106)	($9,826,954)	($10,571,734)	($12,837,105)	($15,857,600)
26	Deferred Tax Reserve	- Line 23		($15,421,386)	($15,155,288)	($14,861,545)	($14,814,315)	($382,163)	($589,465)	($1,225,059)	($1,955,037)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$71,885,189	$69,130,792	$66,404,039	$66,004,402	$78,607,706	$77,655,624	$74,754,659	$71,004,185
	Revenue Requirement Calculation:										
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Line 27 × Page 14 of 42, Line 16; then = Average of (Prior Year Line 27 + Current Year Line 27/2)	4/			$67,767,415	$72,029,832	$72,029,832	$72,029,832	$76,205,142	$72,879,422
29	Proration Adjustment	Columns (c) through (g) see Page 12 of 42, Line 41, Column (h) see Page 13 of 42, Line 41				($12,608)	$23,274	$23,274	$23,274	$34,797	$28,832
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29				$67,754,807	$72,053,106	$72,053,106	$72,053,106	$76,239,939	$72,908,255
31	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)				8.41%	8.41%	8.41%	8.41%	8.41%	8.41%
32	Proration Percentage	Line 11	2/				14.79%	60.55%	24.66%	75.00%	
33	Return and Taxes	Cols (c) and (h): L 30 * L 31; Cols (d) through (g): L 30 * L 31 * L 32	2/			$5,698,179	$896,499	$3,669,003	$1,494,164	$4,808,834	$6,131,584
34	Book Depreciation	Line 15				$3,020,495	$446,868	$1,828,848	$744,780	$2,265,371	$3,020,495
35	**Annual Revenue Requirement**	Sum of Lines 33 through 34		**N/A**	**N/A**	**$8,718,675**	**$1,343,366**	**$5,497,851**	**$2,238,944**	**$7,074,206**	**$9,152,080**

1/ 2.99%, Composite Book Depreciation Rate of Distirbution Plant approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
2/ Columns (d) through (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. Column (g) is prorated for the 9-month calendar year 2023 plan.
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 begin depreciating the new tax basis and start the tracking of book/tax timing differences as if PPL purchased a new asset in the year of acquisition.
4/ Columns (d) through (f) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 27, Column (c) 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
21-Month Gas ISR Revenue Requirement 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 42, Line 1		$105,296,046		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	76.14%					
3	Capital Repairs Deduction	Line 1 × Line 2		$80,172,409	MACRS basis:	Line 21, Column (a)		$24,288,150	
4								Annual	Cumulative
5					Fiscal Year		Prorated		
6	Bonus Depreciation				FY Mar-2020	3.750%		$910,806	$89,531,414
7	Plant Additions	Line 1		$105,296,046	FY Mar-2021	7.219%		$1,753,362	$91,284,775
8	Less Capital Repairs Deduction	Line 3		$80,172,409	FY Mar-2022	6.677%		$1,621,720	$92,906,495
9	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$25,123,637	FY Mar-2023 (Apr-May 2022)	6.177%	0.914%	$221,959	$93,128,454
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%					
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$25,123,637	Book Cost	Line 1, Column (a)		$105,296,046	
12	Bonus Depreciation Rate 30%, up to December 31, 2019	14.78% × 30% × 75%	2/	3.33%	Cumulative Book Depreciation	- Page 10 of 42, Line 16, Col (d)		($7,998,106)	
13	Bonus Depreciation Rate 0%, after December 31, 2019			0.00%	PPL MACRS basis:	Line 11 + Line 12		$97,297,940	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		3.33%					
15	Bonus Depreciation	Line 11 × Line 14		$835,487	FY Mar-2023 (Jun-Dec 2022)	3.750%		$3,648,673	$3,648,673
16					FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$1,731,930	$5,380,603
17	Remaining Tax Depreciation				CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$5,292,008	$10,672,611
18	Plant Additions	Line 1		$105,296,046	CY 2024	6.677%		$6,496,583	$17,169,194
19	Less Capital Repairs Deduction	Line 3		$80,172,409	CY 2025	6.177%		$6,010,094	$23,179,288
20	Less Bonus Depreciation	Line 15		$835,487	CY 2026	5.713%		$5,558,631	$28,737,919
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$24,288,150	CY 2027	5.285%		$5,142,196	$33,880,116
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	CY 2028	4.888%		$4,755,923	$38,636,039
23	Remaining Tax Depreciation	Line 21 × Line 22		$910,806	CY 2029	4.522%		$4,399,813	$43,035,852
24					CY 2030	4.462%		$4,341,434	$47,377,286
25	FY20 tax (gain)/loss on retirements	Per Tax Department	3/	$557,081	CY 2031	4.461%		$4,340,461	$51,717,747
26	Cost of Removal	Page 10 of 42, Line 7		$7,055,630	CY 2032	4.462%		$4,341,434	$56,059,181
27					CY 2033	4.461%		$4,340,461	$60,399,642
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25 & 26		$89,531,414	CY 2034	4.462%		$4,341,434	$64,741,076
29					CY 2035	4.461%		$4,340,461	$69,081,537
30					CY 2036	4.462%		$4,341,434	$73,422,971
31					CY 2037	4.461%		$4,340,461	$77,763,432
32					CY 2038	4.462%		$4,341,434	$82,104,866
33					CY 2039	4.461%		$4,340,461	$86,445,327
34					CY 2040	4.462%		$4,341,434	$90,786,762
35					CY 2041	4.461%		$4,340,461	$95,127,223
36					CY 2042	2.231%		$2,170,717	$97,297,940
37						100.000%		$97,297,940	

1/ Capital Repairs percentage is the actual result of FY2020 tax return
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY2020 tax return
3/ Actual Loss based on FY2020 tax return
9 (d) 6.177% / 365 x 54
16 (d) 7.219% / 365 x 90
17 (d) 7.219% / 365 x 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investments Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 10 of 42, Line 15, column (c); Col (b): Page 10 of 42, Line 15, columns (d) through (f); Col (c): Page 10 of 42, Line 15, column (g)	$3,020,495	$3,020,495	$2,265,371
2	Bonus Depreciation		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 11 of 42, Line 8, column (e); Col (b): - Page 11 of 42, Sum of Lines 9,15,16, column, (e); Col (c): - Page 11 of 42, Line 17, column, (e)	($1,621,720)	($5,602,562)	($5,292,008)
4	FY20 tax (gain)/loss on retirements	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$1,398,776	($2,582,066)	($3,026,637)
6	Effective Tax Rate		21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$293,743	($542,234)	($635,594)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
9	Cost of Removal	Year 1 = Docket no. 4916, 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			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 × Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13	$293,743	($542,234)	($635,594)
15	Net Operating Loss				
16	Net Deferred Tax Reserve	Line 14 + Line 15	$293,743	($542,234)	($635,594)
	Allocation of FY 2018 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$1,398,776	($2,582,066)	($3,026,637)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$1,398,776	($2,582,066)	($3,026,637)
20	Total FY 2020 Federal NOL	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20			
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$293,743	($542,234)	($635,594)

Line No.	Proration Calculation	(d) Number of Days in Month	(e) Proration Percentage	(f) FY22	(g) FY23-NG	(h) Apr 1 - Dec 31 2023
26	April	30	91.78%	$22,467	($41,472)	($62,917)
27	May	31	83.29%	$20,388	($37,635)	($54,956)
28	June	30	75.07%	$18,376	($33,921)	($47,252)
29	July	31	66.58%	$16,297	($30,083)	($39,291)
30	August	31	58.08%	$14,218	($26,245)	($31,330)
31	September	30	49.86%	$12,206	($22,531)	($23,626)
32	October	31	41.37%	$10,127	($18,693)	($15,665)
33	November	30	33.15%	$8,115	($14,980)	($7,961)
34	December	31	24.66%	$6,036	($11,142)	
35	January	31	16.16%	$3,957	($7,304)	
36	February	28	8.49%	$2,079	($3,838)	
37	March	31	0.00%	$0	$0	
38	Total	365		$134,263	($247,843)	($283,000)
39	Deferred Tax Without Proration	Line 25		$293,743	($542,234)	($635,594)
40	Average Deferred Tax without Proration	Line 39 × 50%		$146,871	($271,117)	($317,797)
41	Proration Adjustment	Line 38 - Line 40		($12,608)	$23,274	$34,797

Column Notes:
(e) Sum of remaining days in the year (Col (d)) ÷ 366
(f), (g) & (h) Current Year Line 25 ÷ 12 × Current Month Col (e)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investments Post CY 2023

Line No.	**Deferred Tax Subject to Proration**			CY24 (a)	CY25 (b)
1	Book Depreciation	Page 10 of 42 , Line 15		$3,020,495	$3,020,495
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Page 11 of 42 , Col (e)		($6,496,583)	($6,010,094)
4	FY20 tax (gain)/loss on retirements	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0		$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($3,476,088)	($2,989,598)
6	Effective Tax Rate			21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6		($729,979)	($627,816)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
9	Cost of Removal	Year 1 = Docket no. 4916, 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			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 × Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13		($729,979)	($627,816)
15	Net Operating Loss				
16	Net Deferred Tax Reserve	Line 14 + Line 15		($729,979)	($627,816)
	Allocation of FY 2018 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($3,476,088)	($2,989,598)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($3,476,088)	($2,989,598)
20	Total FY 2020 Federal NOL	Year 1 = Docket no. 4916, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20			
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($729,979)	($627,816)
	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24	(f) CY25
26	January	31	91.51%	($55,665)	($47,875)
27	February	28	83.84%	($50,998)	($43,861)
28	March	31	75.34%	($45,832)	($39,418)
29	April	30	67.12%	($40,832)	($35,118)
30	May	31	58.63%	($35,666)	($30,674)
31	June	30	50.41%	($30,666)	($26,374)
32	July	31	41.92%	($25,499)	($21,931)
33	August	31	33.42%	($20,333)	($17,487)
34	September	30	25.21%	($15,333)	($13,187)
35	October	31	16.71%	($10,166)	($8,744)
36	November	30	8.49%	($5,167)	($4,443)
37	December	31	0.00%	$0	$0
38	Total	365		($336,157)	($289,111)
39	Deferred Tax Without Proration	Line 25		($729,979)	($627,816)
40	Average Deferred Tax without Proration	Line 39 × 50%		($364,989)	($313,908)
41	Proration Adjustment	Line 38 - Line 40		$28,832	$24,797

Column Notes:
(d) Sum of remaining days in the year (Col (c)) ÷ 366
(e) & (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
ISR Additions April 2019 through March 2020

Line No.	Month No.	Month	FY 2020 ISR Additions	In Rates	Not In Rates	Weight for Days	Weighted Average	Weight for Investment
1			(a)	(b)	(c) = (a) - (b)	(d)	(e) = (d) × (c)	(f)=(c)÷Total(c)
2	1	Apr-19	$12,009,983	$7,764,750	$4,245,233	0.958	$4,068,348	4.03%
3	2	May-19	$12,009,983	$7,764,750	$4,245,233	0.875	$3,714,579	4.03%
4	3	Jun-19	$12,009,983	$7,764,750	$4,245,233	0.792	$3,360,809	4.03%
5	4	Jul-19	$12,009,983	$7,764,750	$4,245,233	0.708	$3,007,040	4.03%
6	5	Aug-19	$12,009,983	$7,764,750	$4,245,233	0.625	$2,653,271	4.03%
7	6	Sep-19	$12,009,983	$0	$12,009,983	0.542	$6,505,407	11.41%
8	7	Oct-19	$12,009,983	$0	$12,009,983	0.458	$5,504,576	11.41%
9	8	Nov-19	$12,009,983	$0	$12,009,983	0.375	$4,503,744	11.41%
10	9	Dec-19	$12,009,983	$0	$12,009,983	0.292	$3,502,912	11.41%
11	10	Jan-20	$12,009,983	$0	$12,009,983	0.208	$2,502,080	11.41%
12	11	Feb-20	$12,009,983	$0	$12,009,983	0.125	$1,501,248	11.41%
13	12	Mar-20	$12,009,983	$0	$12,009,983	0.042	$500,416	11.41%
14		Total	$144,119,796	$38,823,750	$105,296,046		$41,324,429	100.00%
15	**Total Additions September 2019 through March 2020**				**$84,069,881**			
16	**FY 2020 Weighted Average Incremental Rate Base Percentage**						**39.25%**	

Column (a)=Page 34 of 42 , Line 1 ,Col (c)
Column (b)=Page 34 of 42 , Line 2 ,Col (c)
Column (d) = (12.5 - Month No.) ÷ 12
Line 14 = Page 34 of 42 Line 1 Col (c)
Line 15 = Sum of Lines 7(c) through 13(c)
Line 16 = Line 14(e)/Line 14(c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on FY 2021 Actual Incremental Gas Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	NG 4/1/22 - 5/24/2022 2023 (c)	PPL 5/25/22 - 12/31/22 2023 (d)	PPL 1/1/23 - 3/31/23 2023 (e)	9 months Calendar Year Dec-2023 (f)	12 months Calendar Year Dec-2024 (g)
	Depreciable Net Capital Included in ISR Rate Base									
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 34 of 42 , Line 3 ,Col (d)		$110,177,659						
2	Retirements	Page 34 of 42 , Line 9 ,Col (d)		$3,860,987						
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$106,316,672	$106,316,672	$106,316,672	$106,316,672	$106,316,672	$106,316,672	$106,316,672
	Change in Net Capital Included in ISR Rate Base									
4	Capital Included in ISR Rate Base	Line 1		$110,177,659	$0	$0	$0	$0	$0	$0
5	Depreciation Expense	Page 38 of 42, Line 78(c)		$40,700,586	$0	$0	$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$69,477,072	$69,477,072	$69,477,072	$69,477,072	$69,477,072	$69,477,072	$69,477,072
7	Cost of Removal	Page 34 of 42 , Line 6 ,Col (d)		$8,861,636						
8	**Net Plant Amount**	**Line 6 + Line 7**		**$78,338,709**	**$78,338,709**	**$78,338,709**	**$78,338,709**	**$78,338,709**	**$78,338,709**	**$78,338,709**
	Deferred Tax Calculation:									
9	Composite Book Depreciation Rate	Page 36 of 42, Line 86(e)	1/	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
10	Number of days		2/			54	221	90		
11	Proration Percentage		2/			14.79%	60.55%	24.66%	75.00%	
12	Tax Depreciation and Year 1 Basis Adjustments	Year 1 =Page 16 of 42, Line 28, Col (a); then = Page 16 of 42, Col (e)		$63,538,144	$4,232,177	$579,121	$3,935,215	$1,867,944	$5,707,607	$7,006,781
13	Cumulative Tax Depreciation-NG	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12	3/	$63,538,144	$67,770,322	$68,349,442				
14	Cumulative Tax Depreciation-PPL	Year 1 = Line 12; then = Prior Year Line 14 + Current Year Line 12	3/				$3,935,215	$5,803,159	$11,510,765	$18,517,546
15	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$1,589,434	$3,178,868	$470,298	$1,924,740	$783,831	$2,384,151	$3,178,868
16	Cumulative Book Depreciation	Year 1 = Line 15; then = Prior Year Line 16 + Current Year Line 15		$1,589,434	$4,768,303	$5,238,601	$7,163,341	$7,947,171	$10,331,323	$13,510,191
17	Cumulative Book / Tax Timer	Columns (a) through (c): Line 13 - Line 16, Then Line 14 - Line 16		$61,948,710	$63,002,019	$63,110,841	($3,228,126)	($2,144,013)	$1,179,443	$5,007,355
18	Less: Cumulative Book Depreciation at Acquisition	Line 16 Column (c)	3/				$5,238,601	$5,238,601	$5,238,601	$5,238,601
19	Cumulative Book / Tax Timer - PPL	Line 17 + Line 18					$2,010,475	$3,094,588	$6,418,044	$10,245,956
20	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
21	Deferred Tax Reserve	Columns (a) through (c): Line 17 * Line 20, Then Line 19 * Line 20		$13,009,229	$13,230,424	$13,253,277	$422,200	$649,864	$1,347,789	$2,151,651
22	Add: FY 2021 Federal NOL utilization	Page 34 of 42, Line 12, Col (d)	3/	($5,525,796)	($5,525,796)	($5,525,796)	$0	$0	$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Line 21 + Line 22		$7,483,434	$7,704,628	$7,727,481	$422,200	$649,864	$1,347,789	$2,151,651
	ISR Rate Base Calculation:									
24	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$78,338,709	$78,338,709	$78,338,709	$78,338,709	$78,338,709	$78,338,709	$78,338,709
25	Accumulated Depreciation	- Line 16		($1,589,434)	($4,768,303)	($5,238,601)	($7,163,341)	($7,947,171)	($10,331,323)	($13,510,191)
26	Deferred Tax Reserve	- Line 23		($7,483,434)	($7,704,628)	($7,727,481)	($422,200)	($649,864)	($1,347,789)	($2,151,651)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$69,265,841	$65,865,777	$65,372,626	$70,753,168	$69,741,674	$66,659,597	$62,676,867
	Revenue Requirement Calculation:									
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 27 ÷ 2; then = (Prior Year Line 27 + Current Year Line 27) ÷ 2	4/		$67,565,809	$67,803,726	$67,803,726	$67,803,726	$68,200,635	$64,668,232
29	Proration Adjustment	Columns (b) through (f) see Page 17 of 42, Line 41; Column (g) see Page 18 of 42, Line 41			$9,494	$28,875	$28,875	$28,875	$38,210	$31,751
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29			$67,575,303	$67,832,600	$67,832,600	$67,832,600	$68,238,845	$64,699,982
31	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)			8.41%	8.41%	8.41%	8.41%	8.41%	8.41%
32	Proration Percentage	Line 11	2/			14.79%	60.55%	24.66%	75.00%	
33	Return and Taxes	Cols (b) and (g): L 30 * L 31; Cols (c) through (f): L 30 * L 31 * L 32	2/		$5,683,083	$843,986	$3,454,092	$1,406,644	$4,304,165	$5,441,269
34	Book Depreciation	Line 15			$3,178,868	$470,298	$1,924,740	$783,831	$2,384,151	$3,178,868
35	**Annual Revenue Requirement**	**Sum of Lines 33 through 34**		**N/A**	**$8,861,951**	**$1,314,285**	**$5,378,831**	**$2,190,474**	**$6,688,317**	**$8,620,137**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
2/ Columns (c) through (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. Column (f) is prorated for the 9-month calendar year 2023 plan.
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 begin depreciating the new tax basis and start the tracking of book/tax timing differences as if PPL purchased a new asset in the year of acquisition.
4/ Columns (c) through (e) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 27, Column (b) and the end of the fiscal year on Line 27, Column (e). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 15 of 42, Line 1		$110,177,659		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	46.79%					
3	Capital Repairs Deduction	Line 1 × Line 2		$51,552,126	MACRS basis:	Line 21, Column (a)		$58,625,533	
4								Annual	Cumulative
5					Fiscal Year		Prorated		
6	Bonus Depreciation				FY Mar-2021	3.750%		$2,198,457	$63,538,144
7	Plant Additions	Line 1		$110,177,659	FY Mar-2022	7.219%		$4,232,177	$67,770,322
8	Less Capital Repairs Deduction	Line 3		$51,552,126	FY Mar-2023 (Apr-May 2022)	6.677%	0.988%	$579,121	$68,349,442
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		$58,625,533					
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	PPL Acquisition - May 25, 2022				
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$0	Book Cost	Line 1, Column (a)		$110,177,659	
12	Bonus Depreciation Rate ()	Per Tax Department		0.00%	Cumulative Book Depreciation	- Page 15 of 42, Line 16, Col (c)		($5,238,601)	
13	Bonus Depreciation Rate ()	Per Tax Department		0.00%	PPL MACRS basis:	Line 11 + Line 12		$104,939,057	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%					
15	Bonus Depreciation	Line 11 × Line 14		$0	FY Mar-2023 (Jun-Dec 2022)	3.750%		$3,935,215	$3,935,215
16					FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$1,867,944	$5,803,159
17	Remaining Tax Depreciation				CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$5,707,607	$11,510,765
18	Plant Additions	Line 1		$110,177,659	CY 2024	6.677%		$7,006,781	$18,517,546
19	Less Capital Repairs Deduction	Line 3		$51,552,126	CY 2025	6.177%		$6,482,086	$24,999,632
20	Less Bonus Depreciation	Line 15		$0	CY 2026	5.713%		$5,995,168	$30,994,800
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$58,625,533	CY 2027	5.285%		$5,546,029	$36,540,829
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	CY 2028	4.888%		$5,129,421	$41,670,250
23	Remaining Tax Depreciation	Line 21 × Line 22		$2,198,457	CY 2029	4.522%		$4,745,344	$46,415,595
24					CY 2030	4.462%		$4,682,381	$51,097,975
25	FY21 tax (gain)/loss on retirements	Per Tax Department	2/	925,925	CY 2031	4.461%		$4,681,331	$55,779,307
26	Cost of Removal	Page 15 of 42, Line 7		$8,861,636	CY 2032	4.462%		$4,682,381	$60,461,687
27					CY 2033	4.461%		$4,681,331	$65,143,019
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25 & 26		$63,538,144	CY 2034	4.462%		$4,682,381	$69,825,399
29					CY 2035	4.461%		$4,681,331	$74,506,731
30					CY 2036	4.462%		$4,682,381	$79,189,112
31					CY 2037	4.461%		$4,681,331	$83,870,443
32					CY 2038	4.462%		$4,682,381	$88,552,824
33					CY 2039	4.461%		$4,681,331	$93,234,155
34					CY 2040	4.462%		$4,682,381	$97,916,536
35					CY 2041	4.461%		$4,681,331	$102,597,867
36					CY 2042	2.231%		$2,341,190	$104,939,057
37						100.000%		$104,939,057	

1/ Capital Repairs percentage is the actual result of FY2021 tax return
2/ Actual Loss based on FY2021 tax return
8 (d) 6.677% / 365 x 54
16 (d) 7.219% / 365 x 90
17 (d) 7.219% / 365 x 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investments Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 15 of 42, Line 15, column (b); Col (b): Page 15 of 42, Line 15, columns (c) through (e); Col (c): Page 15 of 42, Line 15, column (f)	$3,178,868	$3,178,868	$2,384,151
2	Bonus Depreciation				
3	Remaining MACRS Tax Depreciation	Col (a): - Page 16 of 42, Line 7, column (e); Col (b): - Page 16 of 42, Sum of Lines 8,15,16, column, (e); Col (c): - Page 16 of 42, Line 17, column, (e)	($4,232,177)	($6,382,279)	($5,707,607)
4	FY21 tax (gain)/loss on retirements	Page 16 of 42 , Line 25 ,Col (a)	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,053,309)	($3,203,411)	($3,323,455)
6	Effective Tax Rate		21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	($221,195)	($672,716)	($697,926)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
9	Cost of Removal	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
10	Book/Tax Depreciation Timing Difference at 3/31/2021				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 × Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13	($221,195)	($672,716)	($697,926)
15	Net Operating Loss	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
16	Net Deferred Tax Reserve	Line 14 + Line 15	($221,195)	($672,716)	($697,926)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	($1,053,309)	($3,203,411)	($3,323,455)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($1,053,309)	($3,203,411)	($3,323,455)
20	Total FY 2021 Federal NOL	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20			
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($221,195)	($672,716)	($697,926)

Line No.	Proration Calculation	(d) Number of Days in Month	(e) Proration Percentage	(f) FY22	(g) FY23-NG	(h) Apr 1 - Dec 31 2023
26	April	30	91.78%	($16,918)	($51,452)	($69,088)
27	May	31	83.29%	($15,352)	($46,691)	($60,346)
28	June	30	75.07%	($13,837)	($42,083)	($51,886)
29	July	31	66.58%	($12,272)	($37,322)	($43,144)
30	August	31	58.08%	($10,706)	($32,561)	($34,403)
31	September	30	49.86%	($9,191)	($27,953)	($25,943)
32	October	31	41.37%	($7,626)	($23,192)	($17,201)
33	November	30	33.15%	($6,111)	($18,584)	($8,742)
34	December	31	24.66%	($4,545)	($13,823)	
35	January	31	16.16%	($2,980)	($9,062)	
36	February	28	8.49%	($1,566)	($4,761)	
37	March	31	0.00%	$0	$0	
38	Total	365		($101,103)	($307,484)	($310,753)
39	Deferred Tax Without Proration	Line 25		($221,195)	($672,716)	($697,926)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($110,597)	($336,358)	($348,963)
41	Proration Adjustment	Line 38 - Line 40		$9,494	$28,875	$38,210

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
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investments Post CY 2023

Line No.	Deferred Tax Subject to Proration			CY24 (a)	CY25 (b)
1	Book Depreciation	Page 15 of 42 , Line 15		$3,178,868	$3,178,868
2	Bonus Depreciation				
3	Remaining MACRS Tax Depreciation	Page 16 of 42 , Col (e)		($7,006,781)	($6,482,086)
4	FY21 tax (gain)/loss on retirements	Page 16 of 42 , Line 25 ,Col (a)		$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($3,827,912)	($3,303,217)
6	Effective Tax Rate			21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6		($803,862)	($693,676)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
9	Cost of Removal	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
10	Book/Tax Depreciation Timing Difference at 3/31/2021				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 × Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13		($803,862)	($693,676)
15	Net Operating Loss	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
16	Net Deferred Tax Reserve	Line 14 + Line 15		($803,862)	($693,676)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($3,827,912)	($3,303,217)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($3,827,912)	($3,303,217)
20	Total FY 2021 Federal NOL	Col (a): Docket 4996, R.S. 3, Att. 1R, page 14 Col (a)			
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20			
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($803,862)	($693,676)
		(c)	(d)	(e)	(f)
	Proration Calculation	Number of Days in Month	Proration Percentage	CY24	CY25
26	January	31	91.51%	($61,299)	($52,897)
27	February	28	83.84%	($56,160)	($48,462)
28	March	31	75.34%	($50,471)	($43,553)
29	April	30	67.12%	($44,965)	($38,801)
30	May	31	58.63%	($39,275)	($33,892)
31	June	30	50.41%	($33,770)	($29,141)
32	July	31	41.92%	($28,080)	($24,231)
33	August	31	33.42%	($22,391)	($19,322)
34	September	30	25.21%	($16,885)	($14,570)
35	October	31	16.71%	($11,195)	($9,661)
36	November	30	8.49%	($5,689)	($4,910)
37	December	31	0.00%	$0	$0
38	Total	365		($370,180)	($319,439)
39	Deferred Tax Without Proration	Line 25		($803,862)	($693,676)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($401,931)	($346,838)
41	Proration Adjustment	Line 38 - Line 40		$31,751	$27,399

Column Notes:

(d)	Sum of remaining days in the year (Col (c)) ÷ 366
(e) & (f)	Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on FY 2022 Forecasted Incremental Gas Capital Investment

Line No.				Fiscal Year 2022 (a)	NG 4/1/22 - 5/24/2022 2023 (b)	PPL 5/25/22 - 12/31/22 2023 (c)	PPL 1/1/23 - 3/31/23 2023 (d)	9 months Calendar Year Dec-2023 (e)	12 months Calendar Year Dec-2024 (f)
	Depreciable Net Capital Included in ISR Rate Base								
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 34 of 42 , Line 3 ,Col (e)		$156,694,227					
2	Retirements	Page 34 of 42 , Line 9 ,Col (e)		$6,258,509					
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$150,435,718	$150,435,718	$150,435,718	$150,435,718	$150,435,718	$150,435,718
	Change in Net Capital Included in ISR Rate Base								
4	Capital Included in ISR Rate Base	Line 1		$156,694,227	$0	$0	$0	$0	$0
5	Depreciation Expense	Page 38 of 42, Line 77(c)		$40,954,246	$0	$0	$0	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$115,739,981	$115,739,981	$115,739,981	$115,739,981	$115,739,981	$115,739,981
7	Cost of Removal	Page 34 of 42 , Line 6 ,Col (e)		$10,773,005					
8	**Net Plant Amount**	**Line 6 + Line 7**		**$126,512,985**	**$126,512,985**	**$126,512,985**	**$126,512,985**	**$126,512,985**	**$126,512,985**
	Deferred Tax Calculation:								
9	Composite Book Depreciation Rate	Page 36 of 42, Line 86(e)	1/	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
10	Number of days		2/		54	221	90		
11	Proration Percentage		2/		14.79%	60.55%	24.66%	75.00%	
12	Tax Depreciation and Year 1 Basis Adjustments	Year 1 =Page 20 of 42, Line 28, Col (a); then = Page 20 of 42, Col (e)		$140,549,763	$304,865	$5,766,741	$2,737,322	$8,364,039	$10,267,874
13	Cumulative Tax Depreciation-NG	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12	3/	$140,549,763	$140,854,628				
14	Cumulative Tax Depreciation-PPL	Year 1 = Line 12; then = Prior Year Line 14 + Current Year Line 12	3/			$5,766,741	$8,504,062	$16,868,101	$27,135,975
15	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$2,249,014	$665,462	$2,723,464	$1,109,103	$3,373,521	$4,498,028
16	Cumulative Book Depreciation	Year 1 = Line 15; then = Prior Year Line 16 + Current Year Line 15		$2,249,014	$2,914,476	$5,637,939	$6,747,042	$10,120,563	$14,618,591
17	Cumulative Book / Tax Timer	Columns (a) and (b): Line 13 - Line 16, Then Line 14 - Line 16		$138,300,749	$137,940,153	$128,801	$1,757,020	$6,747,538	$12,517,384
18	Less: Cumulative Book Depreciation at Acquisition	Line 16 Column (b)	3/			$2,914,476	$2,914,476	$2,914,476	$2,914,476
19	Cumulative Book / Tax Timer - PPL	Line 17 + Line 18				$3,043,277	$4,671,496	$9,662,014	$15,431,860
20	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
21	Deferred Tax Reserve	Columns (a) through (b): Line 17 * Line 20, Then Line 19 * Line 20		$29,043,157	$28,967,432	$639,088	$981,014	$2,029,023	$3,240,691
22	Add: FY 2022 Federal NOL utilization	Page 34 of 42 , Line 12 ,Col (e)	3/	$6,564,587	$6,564,587	$0	$0	$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Line 21 + Line 22		$35,607,744	$35,532,019	$639,088	$981,014	$2,029,023	$3,240,691
	ISR Rate Base Calculation:								
24	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$126,512,985	$126,512,985	$126,512,985	$126,512,985	$126,512,985	$126,512,985
25	Accumulated Depreciation	- Line 16		($2,249,014)	($2,914,476)	($5,637,939)	($6,747,042)	($10,120,563)	($14,618,591)
26	Deferred Tax Reserve	- Line 23		($35,607,744)	($35,532,019)	($639,088)	($981,014)	($2,029,023)	($3,240,691)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$88,656,227	$88,066,491	$120,235,958	$118,784,929	$114,363,400	$108,653,704
	Revenue Requirement Calculation:								
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 27 ÷ 2; then = (Prior Year Line 27 + Current Year Line 27) ÷ 2	4/	$44,328,114	$103,720,578	$103,720,578	$103,720,578	$116,574,164	$111,508,552
29	Proration Adjustment	Columns (a) through (e) see Page 21 of 42, Line 41; Column (f) see Page 22 of 42, Line 41		($10,623)	$38,857	$38,857	$38,857	$57,376	$47,858
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$44,317,491	$103,759,435	$103,759,435	$103,759,435	$116,631,540	$111,556,410
31	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)		8.41%	8.41%	8.41%	8.41%	8.41%	8.41%
32	Proration Percentage	Line 11	2/		14.79%	60.55%	24.66%	75.00%	
33	Return and Taxes	Cols (a) and (f): L 30 * L 31; Cols (b) through (d): L 30 * L 31 * L 32	2/	$3,727,101	$1,290,995	$5,283,516	$2,151,658	$7,356,534	$9,381,894
34	Book Depreciation	Line 15		$2,249,014	$665,462	$2,723,464	$1,109,103	$3,373,521	$4,498,028
35	**Annual Revenue Requirement**	**Sum of Lines 33 through 34**		**$5,976,115**	**$1,956,456**	**$8,006,979**	**$3,260,761**	**$10,730,055**	**$13,879,922**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

2/ Columns (b) through (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. Column (e) is prorated for the 9-month calendar year 2023 plan.

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 begin depreciating the new tax basis and start the tracking of book/tax timing differences as if PPL purchased a new asset in the year of acquisition.

4/ Columns (b) through (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 (a) and the end of the fiscal year on Line 27, Column (d). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement 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 19 of 42, Line 1		$156,694,227		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	81.78%					
3	Capital Repairs Deduction	Line 1 × Line 2		$128,149,240	MACRS basis:	Line 21, Column (a)		$28,544,987	
4								Annual	Cumulative
5					Fiscal Year		Prorated		
6	Bonus Depreciation				FY Mar-2022	3.750%		$1,070,437	$140,549,763
7	Plant Additions	Line 1		$156,694,227	FY Mar-2023 (Apr-May 2022)	7.219%	1.068%	$304,865	$140,854,628
8	Less Capital Repairs Deduction	Line 3		$128,149,240					
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		$28,544,987	PPL Acquisition - May 25, 2022				
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Book Cost	Line 1, Column (a)		$156,694,227	
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$0	Cumulative Book Depreciation	- Page 19 of 42, Line 16, Col (b)		($2,914,476)	
12	Bonus Depreciation Rate 30%	Per Tax Department		0.00%	PPL MACRS basis:	Line 10 + Line 11		$153,779,751	
13	Bonus Depreciation Rate 0%	Per Tax Department		0.00%					
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%	FY Mar-2023 (Jun-Dec 2022)	3.750%		$5,766,741	$5,766,741
15	Bonus Depreciation	Line 11 × Line 14		$0	FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$2,737,322	$8,504,062
16					CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$8,364,039	$16,868,101
17	Remaining Tax Depreciation				CY 2024	6.677%		$10,267,874	$27,135,975
18	Plant Additions	Line 1		$156,694,227	CY 2025	6.177%		$9,498,975	$36,634,950
19	Less Capital Repairs Deduction	Line 3		$128,149,240	CY 2026	5.713%		$8,785,437	$45,420,387
20	Less Bonus Depreciation	Line 15		$0	CY 2027	5.285%		$8,127,260	$53,547,647
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$28,544,987	CY 2028	4.888%		$7,516,754	$61,064,401
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	CY 2029	4.522%		$6,953,920	$68,018,322
23	Remaining Tax Depreciation	Line 21 × Line 22		$1,070,437	CY 2030	4.462%		$6,861,653	$74,879,974
24					CY 2031	4.461%		$6,860,115	$81,740,089
25	FY22 tax (gain)/loss on retirements	Per Tax Department	2/	557,081	CY 2032	4.462%		$6,861,653	$88,601,742
26	Cost of Removal	Page 19 of 42, Line 7		$10,773,005	CY 2033	4.461%		$6,860,115	$95,461,856
27					CY 2034	4.462%		$6,861,653	$102,323,509
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25 & 26		$140,549,763	CY 2035	4.461%		$6,860,115	$109,183,623
29					CY 2036	4.462%		$6,861,653	$116,045,276
30					CY 2037	4.461%		$6,860,115	$122,905,391
31					CY 2038	4.462%		$6,861,653	$129,767,043
32					CY 2039	4.461%		$6,860,115	$136,627,158
33					CY 2040	4.462%		$6,861,653	$143,488,810
34					CY 2041	4.461%		$6,860,115	$150,348,925
35					CY 2042	2.231%		$3,430,826	$153,779,751
36						100.000%		$153,779,751	

1/ Capital Repairs percentage is based on a three-year average of FYs 2018, 2019 and 2020 capital repairs rates.
2/ FY 2022 estimated tax loss on retirements is tax department estimate

Column (d), Line 7 = MACRS Rate 7.219% / 365 days x 54 days
Column (d), Line 15 = MACRS Rate 7.219% / 365 days x 90 days
Column (d), Line 16 = MACRS Rate 3.750% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investments Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 19 of 42, Line 15, column (a); Col (b): Page 19 of 42, Line 15, columns (b) through (d); Col (c): Page 19 of 42, Line 15, column (e)	$2,249,014	$4,498,028	$3,373,521
2	Bonus Depreciation				
3	Remaining MACRS Tax Depreciation	Col (a): - Page 20 of 42, Line 6, column (e); Col (b): - Page 20 of 42, Sum of Lines 7,14,15, column, (e); Col (c): - Page 20 of 42, Line 16, column, (e)	($1,070,437)	($8,808,928)	($8,364,039)
4	FY22 tax (gain)/loss on retirements	- Page 20 of 42 , Line 25 ,Col (a)	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$1,178,577	($4,310,900)	($4,990,518)
6	Effective Tax Rate		21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$247,501	($905,289)	($1,048,009)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction				
9	Cost of Removal				
10	Book/Tax Depreciation Timing Difference at 3/31/2022				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 × Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13	$247,501	($905,289)	($1,048,009)
15	Net Operating Loss	- Page 19 of 42 , Line 22 ,Col (a)			
16	Net Deferred Tax Reserve	Line 14 + Line 15	$247,501	($905,289)	($1,048,009)
	Allocation of FY 2022 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5			
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11			
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18			
20	Total FY 2022 Federal NOL	- Page 19 of 42 , Line 22 ,Col (a)÷21%			
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20			
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$247,501	($905,289)	($1,048,009)

Line No.	Proration Calculation	Number of Days in Month (d)	Proration Percentage (e)	FY22 (f)	FY23-NG (g)	Apr 1 - Dec 31 2023 (h)
26	April	30	91.78%	$18,930	($69,240)	($103,742)
27	May	31	83.29%	$17,178	($62,833)	($90,616)
28	June	30	75.07%	$15,483	($56,632)	($77,913)
29	July	31	66.58%	$13,731	($50,225)	($64,786)
30	August	31	58.08%	$11,980	($43,818)	($51,659)
31	September	30	49.86%	$10,284	($37,617)	($38,956)
32	October	31	41.37%	$8,533	($31,210)	($25,830)
33	November	30	33.15%	$6,837	($25,009)	($13,127)
34	December	31	24.66%	$5,086	($18,602)	
35	January	31	16.16%	$3,334	($12,195)	
36	February	28	8.49%	$1,752	($6,407)	
37	March	31	0.00%	$0	$0	
38	Total	365		$113,127	($413,787)	($466,629)
39	Deferred Tax Without Proration	Line 25		$247,501	($905,289)	($1,048,009)
40	Average Deferred Tax without Proration	Line 39 × 0.5		$123,751	($452,644)	($524,004)
41	Proration Adjustment	Line 38 - Line 40		($10,623)	$38,857	$57,376

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
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investments Post CY 2023

Line No.	**Deferred Tax Subject to Proration**		CY24 (a)	CY25 (b)
1	Book Depreciation	Page 19 of 42 , Line 15	$4,498,028	$4,498,028
2	Bonus Depreciation	- Page 20 of 42 , Line 15 ,Col (a)		
3	Remaining MACRS Tax Depreciation	- Page 20 of 42 , Col (e)	($10,267,874)	($9,498,975)
4	FY22 tax (gain)/loss on retirements	- Page 20 of 42 , Line 25 ,Col (a)	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($5,769,846)	($5,000,947)
6	Effective Tax Rate		21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	($1,211,668)	($1,050,199)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction			
9	Cost of Removal			
10	Book/Tax Depreciation Timing Difference at 3/31/2022			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		
12	Effective Tax Rate			
13	Deferred Tax Reserve	Line 11 × Line 12		
14	Total Deferred Tax Reserve	Line 7 + Line 13	($1,211,668)	($1,050,199)
15	Net Operating Loss	- Page 19 of 42 , Line 22 ,Col (a)		
16	Net Deferred Tax Reserve	Line 14 + Line 15	($1,211,668)	($1,050,199)
	Allocation of FY 2022 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		
20	Total FY 2022 Federal NOL	- Page 19 of 42 , Line 22 ,Col (a)÷21%		
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20		
23	Effective Tax Rate			
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23		
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($1,211,668)	($1,050,199)

	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24	(f) CY25
26	January	31	91.51%	($92,397)	($80,084)
27	February	28	83.84%	($84,651)	($73,370)
28	March	31	75.34%	($76,075)	($65,937)
29	April	30	67.12%	($67,776)	($58,744)
30	May	31	58.63%	($59,200)	($51,311)
31	June	30	50.41%	($50,901)	($44,118)
32	July	31	41.92%	($42,325)	($36,685)
33	August	31	33.42%	($33,750)	($29,252)
34	September	30	25.21%	($25,451)	($22,059)
35	October	31	16.71%	($16,875)	($14,626)
36	November	30	8.49%	($8,576)	($7,433)
37	December	31	0.00%	$0	$0
38	Total	365		($557,976)	($483,619)
39	Deferred Tax Without Proration	Line 25		($1,211,668)	($1,050,199)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($605,834)	($525,099)
41	Proration Adjustment	Line 38 - Line 40		$47,858	$41,480

Column Notes:
(d) Sum of remaining days in the year (Col (c)) ÷ 366
(e) & (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on FY 2023-NG Forecasted Incremental Gas Capital Investment

Line No.				NG 4/1/22 - 5/24/2022 2023 (a)	PPL 5/25/22 - 12/31/22 2023 (b)	PPL 1/1/23 - 3/31/23 2023 (c)	Total Fiscal Year 2023 (d)	9 months Calendar Year Dec-2023 (e)	12 months Calendar Year Dec-2024 (f)
	Depreciable Net Capital Included in ISR Rate Base								
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 34 of 42 , Line 3 ,Col (f)		$24,103,825	$98,647,134	$40,173,041	$162,924,000		
2	Retirements	Page 34 of 42 , Line 9 ,Col (f)		1,426,106	5,836,472	2,376,844	$9,639,422		
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$22,677,718	$92,810,662	$37,796,197	$153,284,578	$153,284,578	$153,284,578
	Change in Net Capital Included in ISR Rate Base								
4	Capital Included in ISR Rate Base	Line 1		$24,103,825	$98,647,134	$40,173,041	$162,924,000	$0	$0
5	Depreciation Expense	Page 38 of 42, Line 77(c)		$6,058,984	$24,796,955	$10,098,307	$40,954,246		
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$18,044,840	$73,850,180	$30,074,734	$121,969,754	$121,969,754	$121,969,754
7	Cost of Removal	Page 34 of 42 , Line 6 ,Col (f)		$649,627	$2,658,660	$1,082,712	$4,391,000		
8	**Net Plant Amount**	**Line 6 + Line 7**		**$18,694,468**	**$76,508,840**	**$31,157,446**	**$126,360,754**	**$126,360,754**	**$126,360,754**
	Deferred Tax Calculation:								
9	Composite Book Depreciation Rate	Page 36 of 42, Line 86(e)	1/	2.99%	2.99%	2.99%	2.99%	2.99%	2.99%
10	Proration Percentage		2/					75.00%	
11	Tax Depreciation and Year 1 Basis Adjustments	Col (a) = Page 24 of 42, Column (a), Line 28; Col (b) = Page 24 of 42, Col (b), Lines 19,25,26 + Col (i), Line 18; Col (c) = Page 24 of 42, Co (c), Lines 19,25,26 + Col (i), Line 19, Then remaining years from Page 24 of 42, Col (i)		$18,262,218	$75,630,997	$31,037,446	$124,930,661	$3,149,730	$4,297,143
12	Cumulative Tax Depreciation-NG	Year 1 = Line 11, Column (a); then = zero	3/				$18,262,218		
13	Cumulative Tax Depreciation-PPL	Year 1 = Line 11, Columns (b) and (c); then = Prior Year Line 13 + Current Year Line 11	3/				$106,668,444	$109,818,173	$114,115,316
14	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$339,032	$1,387,519	$565,053	$2,291,604	$3,437,407	$4,583,209
15	Cumulative Book Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14					$2,291,604	$5,729,011	$10,312,220
16	Book / Tax Timer	Line 11 - Line 14 except column (d) = sum of Cols (a) through (c)		$17,923,186	$74,243,478	$30,472,393	$122,639,057	($287,677)	($286,066)
17	Cumulative Book / Tax Timer -NG	Line 16, Column (a), then = zero					$17,923,186		
18	Cumulative Book / Tax Timer - PPL	Line 16, Columns (b) and (c), then = Prior Year Line 18 + Current Year Line 16					$104,715,871	$104,428,194	$104,142,128
19	Cumulative Book / Tax Timer - Total	Line 17 + Line 18					$122,639,057	$104,428,194	$104,142,128
20	Effective Tax Rate						21.00%	21.00%	21.00%
21	Deferred Tax Reserve	Line 19 × Line 20					$25,754,202	$21,929,921	$21,869,847
22	Add: FY 2023-NG Federal NOL utilization	Page 34 of 42 , Line 12 ,Col (f)	3/				$0	$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Line 21 + Line 22					$25,754,202	$21,929,921	$21,869,847
	ISR Rate Base Calculation:								
24	Cumulative Incremental Capital Included in ISR Rate Base	Line 8					$126,360,754	$126,360,754	$126,360,754
25	Accumulated Depreciation	- Line 15					($2,291,604)	($5,729,011)	($10,312,220)
26	Deferred Tax Reserve	- Line 23					($25,754,202)	($21,929,921)	($21,869,847)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26					$98,314,947	$98,701,822	$94,178,687
	Revenue Requirement Calculation:								
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 26 ÷ 2; then = (Prior Year Line 26 + Current Year Line 26) ÷ 2	4/				$49,157,474	$98,508,384	$96,440,254
29	Proration Adjustment	Page 25 of 42, Line 41 & Page 26 of 42, Line 41					$16,869	($3,307)	($2,373)
30	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28					$49,174,342	$98,505,077	$96,437,881
31	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)					8.41%	8.41%	8.41%
32	Proration	Line 10	2/					75.00%	
33	Return and Taxes	Columns (d) and (f): Line 30 * Line 31; Column (e): Line 30 * Line 31 * Line 32	2/				$4,135,562	$6,213,208	$8,110,426
34	Book Depreciation	Line 14					$2,291,604	$3,437,407	$4,583,209
35	**Annual Revenue Requirement**	**Sum of Lines 33 through 34**					**$6,427,167**	**$9,650,614**	**$12,693,635**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

2/ Columns (a) through (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. Column (d) is prorated for the 9-month calendar year 2023 plan.

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 begin depreciating the new tax basis and start the tracking of book/tax timing differences as if PPL purchased a new asset in the year of acquisition.

4/ Column (d) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Lines 30, Column (a) through (c) and the end of the fiscal year on Line 26, Column (d). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2023-NG Incremental Capital Investments

Line No.				Apr 1-May 24, 2022 2023-NG (a)	PPL May 25-Dec 31, 2022 FY 2023 (b)	PPL Jan 1-Mar 31, 2023 FY 2023 (c)
	Capital Repairs Deduction					
1	Plant Additions	Page 23 of 42, Line 1		$24,103,825	$98,647,134	$40,173,041
2	Capital Repairs Deduction Rate	Per Tax Department	1/	71.43%	71.43%	71.43%
3	Capital Repairs Deduction	Line 1 × Line 2		$17,217,362	$70,463,648	$28,695,603
4						
5						
6	Bonus Depreciation					
7	Plant Additions	Line 1		$24,103,825	$98,647,134	$40,173,041
8	Less Capital Repairs Deduction	Line 3		$17,217,362	$70,463,648	$28,695,603
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		$6,886,463	$28,183,486	$11,477,438
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	0.00%	0.00%
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$0	$0	$0
12	Bonus Depreciation Rate 1	Per Tax Department		0.00%	0.00%	0.00%
13	Bonus Depreciation Rate 2	Per Tax Department		0.00%	0.00%	0.00%
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%	0.00%	0.00%
15	Bonus Depreciation	Line 11 × Line 14		$0	$0	$0
16						
17	Remaining Tax Depreciation					
18	Plant Additions	Line 1		$24,103,825	$98,647,134	$40,173,041
19	Less Capital Repairs Deduction	Line 3		$17,217,362	$70,463,648	$28,695,603
20	Less Bonus Depreciation	Line 15		$0	$0	$0
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$6,886,463	$28,183,486	$11,477,438
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	3.75%	3.75%
23	Remaining Tax Depreciation	Line 21 × Line 22		$258,242	$1,056,881	$430,404
24						
25	FY23 tax (gain)/loss on retirements	Per Tax Department	2/	136,986	560,629	228,310
26	Cost of Removal	Page 23 of 42, Line 7		$649,627	$2,658,660	$1,082,712
27						
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25 & 26		$18,262,218	$74,739,818	$30,437,030
29						
30	Reconcilation of MACRS Tax Depreciation:					
31	Apr 1 -May 24, 2022 Plant Additions	Line 1, Column			$24,103,825	
32	Cumulative Book Depreciaiton through May 24, 2022	, Line 19, Col			($339,032)	
33	2022 Plant Additions (Net Book) through Acquisition	Line 31 + Line 32			$23,764,793	
34	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%	7.219%
35	Remaining Tax Depreciation	Line 33 * Line 34	3/		$891,180	$1,715,580
36	2023 Proration Applied to Tax Year 2022 Additions	90 Days / 365 Days				24.658%
37	Jan-Mar 2023 Tax Depreciation on 2022 Additions	Line 35 * Line 36	4/			$423,020
38						
39	MACRS Basis in Apr-Dec 2022 Plant Additions	Line 20, Column (a)			$28,183,486	
40	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%	7.219%
41	Tax Depreciation on 2022 Additions	Line 39 * Line 40	3/		$1,056,881	$2,034,566
42	2023 Proration Applied to Tax Year 2022 Additions	90 Days / 365 Days				24.658%
43	Jan-Mar 2023 Tax Depreciation on 2022 Additions	Line 41 * Line 42	4/			$501,674
44						
45	MACRS Basis in Jan-Mar 2023 Plant Additions	Line 21, Column (c)				$11,477,438
46	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946				3.750%
47	Tax Depreciation on 2023 Additions	Line 45 * Line 46				$430,404
48	Proration Applied to Tax Year 2023 Additions	90 Days / 365 Days				24.658%
49	Jan-Mar 2023 Tax Depreciation on 2023 Additions	Line 47 * Line 48	4/			$106,127
50		Sum of Lines 35, 41, Column (a)				
51	Total MACRS Tax Depreciation	Sum of Lines 37, 43, 49, Column (b)			$1,948,060	$1,030,821

(d)	(e)	(f)	(g)	(h)	(i)	(j)
20 Year MACRS Depreciation						
MACRS basis:	Line 21, Column (a)				$6,886,463	
					Annual	Cumulative
Fiscal Year					MACRS	Tax Depr
FY Mar-2023 (Apr-May 2022)	3.750%				$258,242	$18,262,218
PPL Acquisition - May 25, 2022						
Book Cost	Line 1, Column (a)				$24,103,825	
Cumulative Book Depreciation	- Page 23 of 42, Line 14, Col (a)				($339,032)	
MACRS basis from Acquisition:	Line 9(i) + Line 10(i)				$23,764,793	
MACRS basis (Jun-Dec 2022)	Line 21, Column (b)				$28,183,486	
Total MACRS Basis in 2022	Line 11(i) + Line 12(i)				$51,948,279	
MACRS basis (Jan-Mar 2023)	Line 21, Column (c)				$11,477,438	
Total MACRS Basis	Line 13(i) + Line 14(i)				$63,425,717	
	2022 Additions	2023 Additions	2022 Proration	2023 Proration		
FY Mar-2023 (Jun-Dec 2022)	3.750%				$1,948,060	$75,630,997
FY Mar-2023 (Jan-Mar 2023)	7.219%	3.750%	1.780%	0.925%	$1,030,821	$106,668,444
CY 2023 (Apr-Dec 2023)	7.219%	3.750%	5.439%	2.825%	$3,149,730	$109,818,173
CY 2024	6.677%	7.219%			$4,297,143	$114,115,316
CY 2025	6.177%	6.677%			$3,975,194	$118,090,510
CY 2026	5.713%	6.177%			$3,676,767	$121,767,276
CY 2027	5.285%	5.713%			$3,401,173	$125,168,449
CY 2028	4.888%	5.285%			$3,145,814	$128,314,264
CY 2029	4.522%	4.888%			$2,910,118	$131,224,382
CY 2030	4.462%	4.522%			$2,836,942	$134,061,324
CY 2031	4.461%	4.462%			$2,829,536	$136,890,860
CY 2032	4.462%	4.461%			$2,829,941	$139,720,801
CY 2033	4.461%	4.462%			$2,829,536	$142,550,337
CY 2034	4.462%	4.461%			$2,829,941	$145,380,277
CY 2035	4.461%	4.462%			$2,829,536	$148,209,813
CY 2036	4.462%	4.461%			$2,829,941	$151,039,754
CY 2037	4.461%	4.462%			$2,829,536	$153,869,290
CY 2038	4.462%	4.461%			$2,829,941	$156,699,231
CY 2039	4.461%	4.462%			$2,829,536	$159,528,767
CY 2040	4.462%	4.461%			$2,829,941	$162,358,708
CY 2041	4.461%	4.462%			$2,829,536	$165,188,244
CY 2042	2.231%	4.461%			$1,670,975	$166,859,218
CY 2043		2.231%			$256,062	$167,115,280
	100.00%	100.00%			$63,425,717	

Column (g), Line 19 = MACRS Rate 7.219% / 365 days x 90 days
Column (g), Line 20 = MACRS Rate 7.219% / 365 days x 275 days
Column (h), Line 19 = MACRS Rate 3.750% / 365 days x 90 days
Column (h), Line 20 = MACRS Rate 3.750% / 365 days x 275 days

1/ Capital Repairs percentage is based on a five-year average of FYs 2017 through 2021 capital repairs rates.
2/ FY 2023 estimated tax loss on retirements is based on most recent actual loss on retirement
3/
4/

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2023-NG Incremental Capital Investments Pre CY 2024

Line No.	Deferred Tax Subject to Proration		4/1/22 - 5/24/2022 FY Mar-2023 (a)	5/25/22 - 12/31/22 FY Mar-2023 (b)	1/1/23 - 3/31/23 FY Mar-2023 (c)	9 Months Dec-2023 (d)
1	Book Depreciation	Page 23 of 42, Line 14, columns (a) through (e)	$339,032	$1,387,519	$565,053	$3,437,407
2	Bonus Depreciation	- Page 24 of 42 , Line 15 ,Col (a)	$0	$0	$0	
3	Remaining MACRS Tax Depreciation	- Page 24 of 42 ,column (i), Lines 6,18,19,20	($258,242)	($1,948,060)	($1,030,821)	($3,149,730)
4	FY23-NG tax (gain)/loss on retirements	- Page 24 of 42 , Line 25 ,Col (a)	($136,986)	($560,629)	($228,310)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($56,197)	($1,121,170)	($694,078)	$287,677
6	Effective Tax Rate		21%	21%	21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	($11,801)	($235,446)	($145,756)	$60,412
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 24 of 42 , Line 3 ,Col (a)	($17,217,362)	($70,463,648)	($28,695,603)	
9	Cost of Removal	- Page 23 of 42 , Line 7 ,Col (a)	($649,627)	($2,658,660)	($1,082,712)	
10	Book/Tax Depreciation Timing Difference at 3/31/2022					
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($17,866,989)	($73,122,308)	($29,778,315)	$0
12	Effective Tax Rate		21%	21%	21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	($3,752,068)	($15,355,685)	($6,253,446)	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($3,763,869)	($15,591,130)	($6,399,203)	$60,412
15	Net Operating Loss	- Page 23 of 42 , Line 22 ,Col (a)	$0			
16	Net Deferred Tax Reserve	Line 14 + Line 15	($3,763,869)	($15,591,130)	($6,399,203)	$60,412
	Allocation of FY 2023-NG Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	($56,197)	($1,121,170)	($694,078)	$287,677
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($17,866,989)	($73,122,308)	($29,778,315)	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($17,923,186)	($74,243,478)	($30,472,393)	$287,677
20	Total FY 2023-NG Federal NOL	- Page 23 of 42 , Line 22 ,Col (a)÷21%	$0	$0	$0	$0
21	Allocated FY 2023-NG Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0	$0	$0
22	Allocated FY 2023-NG 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	($11,801)	($235,446)	($145,756)	$60,412

Line No.	Proration Calculation	(e) Number of Days in Month	(f) Proration Percentage	(g) 4/1/22 - 5/24/2022	(h) 5/25/22 - 12/31/22	(i) 1/1/23 - 3/31/23	(j) 9 Months
26	April	30	91.78%	($903)	($18,008)	($11,148)	$5,980
27	May	31	83.29%	($819)	($16,341)	($10,116)	$5,224
28	June	30	75.07%	($738)	($14,729)	($9,118)	$4,491
29	July	31	66.58%	($655)	($13,062)	($8,086)	$3,735
30	August	31	58.08%	($571)	($11,396)	($7,055)	$2,978
31	September	30	49.86%	($490)	($9,783)	($6,057)	$2,246
32	October	31	41.37%	($407)	($8,117)	($5,025)	$1,489
33	November	30	33.15%	($326)	($6,504)	($4,027)	$757
34	December	31	24.66%	($242)	($4,838)	($2,995)	
35	January	31	16.16%	($159)	($3,172)	($1,963)	
36	February	28	8.49%	($84)	($1,666)	($1,032)	
37	March	31	0.00%	$0	$0	$0	
38	Total	365		($5,394)	($107,617)	($66,622)	$26,899
39	Deferred Tax Without Proration	Line 25		($11,801)	($235,446)	($145,756)	$60,412
40	Average Deferred Tax without Proration	Line 39 × 0.5		($5,901)	($117,723)	($72,878)	$30,206
41	Proration Adjustment	Line 38 - Line 40		$507	$10,106	$6,256	($3,307)

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2023-NG Incremental Capital Investments Post CY 2023

Line No.	**Deferred Tax Subject to Proration**		(a) CY24	(b) CY25
1	Book Depreciation	Page 23 of 42 , Line 15	$4,583,209	$4,583,209
2	Bonus Depreciation	- Page 24 of 42 , Line 15 ,Col (a)		
3	Remaining MACRS Tax Depreciation	- Page 24 of 42 , Col (e)	($4,297,143)	($3,975,194)
4	FY23-NG tax (gain)/loss on retirements	- Page 24 of 42 , Line 25 ,Col (a)		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$286,066	$608,015
6	Effective Tax Rate		21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$60,074	$127,683
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 24 of 42 , Line 3 ,Col (a)		
9	Cost of Removal	- Page 23 of 42 , Line 7 ,Col (a)		
10	Book/Tax Depreciation Timing Difference at 3/31/2022			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$60,074	$127,683
15	Net Operating Loss	- Page 23 of 42 , Line 22 ,Col (a)		
16	Net Deferred Tax Reserve	Line 14 + Line 15	$60,074	$127,683
	Allocation of FY 2023-NG Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$286,066	$608,015
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$286,066	$608,015
20	Total FY 2023-NG Federal NOL	- Page 23 of 42 , Line 22 ,Col (a)÷21%	$0	$0
21	Allocated FY 2023-NG Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0
22	Allocated FY 2023-NG 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	$60,074	$127,683

Line No.	**Proration Calculation**	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24	(f) CY25
26	January	31	91.51%	$4,581	$9,737
27	February	28	83.84%	$4,197	$8,920
28	March	31	75.34%	$3,772	$8,017
29	April	30	67.12%	$3,360	$7,142
30	May	31	58.63%	$2,935	$6,238
31	June	30	50.41%	$2,524	$5,364
32	July	31	41.92%	$2,098	$4,460
33	August	31	33.42%	$1,673	$3,556
34	September	30	25.21%	$1,262	$2,682
35	October	31	16.71%	$837	$1,778
36	November	30	8.49%	$425	$904
37	December	31	0.00%	$0	$0
38	Total	365		$27,664	$58,798
39	Deferred Tax Without Proration		Line 25	$60,074	$127,683
40	Average Deferred Tax without Proration		Line 39 × 0.5	$30,037	$63,842
41	Proration Adjustment		Line 38 - Line 40	($2,373)	($5,043)

Column Notes:
(d) Sum of remaining days in the year (Col (c)) ÷ 366
(e) & (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on CY 2023 (9-Months) Forecasted Incremental Gas Capital Investment

Line No.				9 months Calendar Year Dec-2023 (a)	12 months Calendar Year Dec-2024 (b)
	Depreciable Net Capital Included in ISR Rate Base				
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Section 2, Table 1		$157,130,000	
2	Retirements	Line 1 x 3-year average actual retirement rate FY20 - FY20		$7,889,491	
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$149,240,509	$149,240,509
	Change in Net Capital Included in ISR Rate Base				
4	Capital Included in ISR Rate Base	Line 1		$157,130,000	$0
5	Depreciation Expense	Page 38 of 42, Line 77(c)		$40,954,246	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$116,175,754	$116,175,754
7	Cost of Removal	Section 2, Page 2		$8,217,000	
8	**Net Plant Amount**	**Line 6 + Line 7**		**$124,392,754**	**$124,392,754**
	Deferred Tax Calculation:				
9	Composite Book Depreciation Rate	Page 36 of 42, Line 86(e)	1/	2.99%	2.99%
10	Proration Percentage		2/	75.00%	
11	Tax Depreciation and Year 1 Basis Adjustments	Year 1 =Page 28 of 42, Line 28, Col (a); then = Page 28 of 42, Col (d)		$137,796,042	$2,066,393
12	Cumulative Tax Depreciation-PPL	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$137,796,042	$139,862,435
13	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% x Line 10; then = Line 3 × Line 9	2/	$1,673,359	$4,462,291
14	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$1,673,359	$6,135,650
15	Cumulative Book / Tax Timer	Line 11 - Line 13		$136,122,683	$133,726,785
16	Effective Tax Rate			21.00%	21.00%
17	Deferred Tax Reserve	Line 15 × Line 16		$28,585,763	$28,082,625
18	Add: CY 2023 Federal NOL utilization	Page 34 of 42 , Line 12 ,Col (e)		$0	$0
19	Net Deferred Tax Reserve before Proration Adjustment	Line 17 + Line 18		$28,585,763	$28,082,625
	ISR Rate Base Calculation:				
20	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$124,392,754	$124,392,754
21	Accumulated Depreciation	- Line 14		($1,673,359)	($6,135,650)
22	Deferred Tax Reserve	- Line 19		($28,585,763)	($28,082,625)
23	Year End Rate Base before Deferred Tax Proration	Sum of Lines 20 through 22		$94,133,631	$90,174,478
	Revenue Requirement Calculation:				
24	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 23 ÷ 2; then = (Prior Year Line 23 + Current Year Line 23) ÷ 2		$47,066,815	$92,154,055
25	Proration Adjustment	Page 29 of 42 & Page 30 of 42		($6,898)	($33,753)
26	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24		$47,059,918	$92,120,302
27	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)		8.41%	8.41%
28	Proration Percentage	Line 10		75.00%	
29	Return and Taxes	Col (a): Line 26 × Line 27 × Line 28; then = Line 26 × Line 27	2/	$2,968,304	$7,747,317
30	Book Depreciation	Line 13		$1,673,359	$4,462,291
31	**Annual Revenue Requirement**	**Sum of Lines 29 through 30**		**$4,641,664**	**$12,209,609**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
2/ Calendar Year December 2023 is prorated for 9 months.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on CY 2023 (9-Months) Incremental Capital Investments

Line No.				Dec-23 Fiscal Year 2023 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 27 of 42, Line 1		$157,130,000	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	81.78%				
3	Capital Repairs Deduction	Line 1 × Line 2		$128,505,628	MACRS basis:		$28,624,372	
4							Annual	Cumulative
5					Calendar Year			
6	Bonus Depreciation				2023	3.75%	$1,073,414	$137,796,042
7	Plant Additions	Line 1		$157,130,000	2024	7.22%	$2,066,393	$139,862,435
8	Less Capital Repairs Deduction	Line 3		$128,505,628	2025	6.68%	$1,911,249	$141,773,685
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		$28,624,372	2026	6.18%	$1,768,127	$143,541,812
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	2027	5.71%	$1,635,310	$145,177,123
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$0	2028	5.29%	$1,512,798	$146,689,921
12	Bonus Depreciation Rate 30%	Per Tax Department		0.00%	2029	4.89%	$1,399,159	$148,089,080
13	Bonus Depreciation Rate 0%	Per Tax Department		0.00%	2030	4.52%	$1,294,394	$149,383,474
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%	2031	4.46%	$1,277,219	$150,660,694
15	Bonus Depreciation	Line 11 × Line 15		$0	2032	4.46%	$1,276,933	$151,937,627
16					2033	4.46%	$1,277,219	$153,214,846
17	Remaining Tax Depreciation				2034	4.46%	$1,276,933	$154,491,779
18	Plant Additions	Line 1		$157,130,000	2035	4.46%	$1,277,219	$155,768,999
19	Less Capital Repairs Deduction	Line 3		$128,505,628	2036	4.46%	$1,276,933	$157,045,932
20	Less Bonus Depreciation	Line 15		$0	2037	4.46%	$1,277,219	$158,323,152
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$28,624,372	2038	4.46%	$1,276,933	$159,600,085
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	2039	4.46%	$1,277,219	$160,877,304
23	Remaining Tax Depreciation	Line 21 × Line 22		$1,073,414	2040	4.46%	$1,276,933	$162,154,238
24					2041	4.46%	$1,277,219	$163,431,457
25	CY23 tax (gain)/loss on retirements	Per Tax Department	2/	-	2042	4.46%	$1,276,933	$164,708,390
26	Cost of Removal	Page 27 of 42, Line 7		$8,217,000	2043	2.23%	$638,610	$165,347,000
27						100.00%	$28,624,372	
28	Total Tax Depreciation and Repairs Deductior	Sum of Lines 3, 15, 23, 25 & 26		$137,796,042				

1/ Capital Repairs percentage is based on a three-year average of FYs 2018, 2019 and 2020 capital repairs rates.
2/ CY 2023 estimated tax loss on retirements is tax department estimate

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on CY 2023 (9-Months) Incremental Capital Investments Pre CY 2024

Line No.	Deferred Tax Subject to Proration		(a) 9 Months Dec-2023
1	Book Depreciation	Page 27 of 42 , Line 15	$1,673,359
2	Bonus Depreciation	- Page 28 of 42 , Line 15 ,Col (a)	
3	Remaining MACRS Tax Depreciation	- Page 28 of 42 , Col (d)	($1,073,414)
4	CY23 tax (gain)/loss on retirements	- Page 28 of 42 , Line 25 ,Col (a)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$599,945
6	Effective Tax Rate		21%
7	Deferred Tax Reserve	Line 5 × Line 6	$125,989
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 28 of 42 , Line 3 ,Col (a)	
9	Cost of Removal	- Page 27 of 42 , Line 7 ,Col (a)	
10	Book/Tax Depreciation Timing Difference at 3/31/2022		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$125,989
15	Net Operating Loss	- Page 27 of 42 , Line 18 ,Col (a)	
16	Net Deferred Tax Reserve	Line 14 + Line 15	$125,989
	Allocation of CY 2023 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$599,945
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$599,945
20	Total CY 2023 Federal NOL	- Page 27 of 42 , Line 18 ,Col (a)÷21%	$0
21	Allocated CY 2023 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0
22	Allocated CY 2023 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	$125,989

	Proration Calculation	(e) Number of Days in Month	(f) Proration Percentage	(j) 9 Months
26	April	30	89.09%	$12,472
27	May	31	77.82%	$10,894
28	June	30	66.91%	$9,366
29	July	31	55.64%	$7,788
30	August	31	44.36%	$6,210
31	September	30	33.45%	$4,683
32	October	31	22.18%	$3,105
33	November	30	11.27%	$1,578
34	December	31	0.00%	
35	January		0.00%	
36	February		0.00%	
37	March		0.00%	
38	Total	275		$56,097

39	Deferred Tax Without Proration	Line 25	$125,989
40	Average Deferred Tax without Proration	Line 39 × 0.5	$62,994
41	Proration Adjustment	Line 38 - Line 40	($6,898)

Column Notes:
(f) Sum of remaining days in the year (Col (h)) divided by 365
Current Year Line 25 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on CY 2023 (9-Months) Incremental Capital Investments Post CY 2023

Line No.	**Deferred Tax Subject to Proration**		(a) CY24
1	Book Depreciation	Page 27 of 42 , Line 15	$6,135,650
2	Bonus Depreciation	- Page 28 of 42 , Line 15 ,Col (a)	
3	Remaining MACRS Tax Depreciation	- Page 28 of 42 , Col (d)	($2,066,393)
4	CY23 tax (gain)/loss on retirements	- Page 28 of 42 , Line 25 ,Col (a)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$4,069,257
6	Effective Tax Rate		21%
7	Deferred Tax Reserve	Line 5 × Line 6	$854,544
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 28 of 42 , Line 3 ,Col (a)	
9	Cost of Removal	- Page 27 of 42 , Line 7 ,Col (a)	
10	Book/Tax Depreciation Timing Difference at 3/31/2022		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$854,544
15	Net Operating Loss	- Page 27 of 42 , Line 18 ,Col (a)	
16	Net Deferred Tax Reserve	Line 14 + Line 15	$854,544
	Allocation of FY 2023 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$4,069,257
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$4,069,257
20	Total CY 2023 Federal NOL	- Page 27 of 42 , Line 18 ,Col (a)÷21%	$0
21	Allocated CY 2023 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0
22	Allocated CY 2023 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	$854,544

	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24
26	January	31	91.51%	$65,164
27	February	28	83.84%	$59,701
28	March	31	75.34%	$53,653
29	April	30	67.12%	$47,800
30	May	31	58.63%	$41,752
31	June	30	50.41%	$35,899
32	July	31	41.92%	$29,851
33	August	31	33.42%	$23,802
34	September	30	25.21%	$17,949
35	October	31	16.71%	$11,901
36	November	30	8.49%	$6,048
37	December	31	0.00%	$0
38	Total	365		$393,519
39	Deferred Tax Without Proration	Line 25		$854,544
40	Average Deferred Tax without Proration	Line 39 × 0.5		$427,272
41	Proration Adjustment	Line 38 - Line 40		($33,753)

Column Notes:
(d) Sum of remaining days in the year (Col (h)) divided by 366
Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
21-Month Revenue Requirement on CY 2024 (Dec-24) Forecasted Incremental Gas Capital Investment

Line No.				12 months Calendar Year Dec-2024 (a)
	Depreciable Net Capital Included in ISR Rate Base			
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Section 2, Table 1		$189,714,000
2	Retirements	Line 1 x 3-year average actual retirement rate FY20 - FY22		$9,525,532
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$180,188,468
	Change in Net Capital Included in ISR Rate Base			
4	Capital Included in ISR Rate Base	Line 1		$189,714,000
5	Depreciation Expense	Page 38 of 42, Line 77(c)		$40,954,246
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$148,759,754
7	Cost of Removal	Section 2, Page 2		$10,111,000
8	**Net Plant Amount**	**Line 6 + Line 7**		**$158,870,754**
	Deferred Tax Calculation:			
9	Composite Book Depreciation Rate	Page 36 of 42, Line 86(e)	1/	2.99%
10	Tax Depreciation	Year 1 =Page 32 of 42, Line 28, Col (a); then = Page 32 of 42, Col (d)		$166,560,808
11	Cumulative Tax Depreciation-PPL	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$166,560,808
12	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$2,693,818
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$2,693,818
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$163,866,990
15	Effective Tax Rate			21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$34,412,068
17	Add: CY 2024 Federal NOL utilization	Page 34 of 42 , Line 12 ,Col (e)		$0
18	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17		$34,412,068
	ISR Rate Base Calculation:			
19	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$158,870,754
20	Accumulated Depreciation	- Line 13		($2,693,818)
21	Deferred Tax Reserve	- Line 18		($34,412,068)
22	Year End Rate Base before Deferred Tax Proration	Sum of Lines 19 through 21		$121,764,868
	Revenue Requirement Calculation:			
23	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 22 ÷ 2; then = (Prior Year Line 22 + Current Year Line 22) ÷ 2		$60,882,434
24	Proration Adjustment	Page 33 of 42		($11,594)
25	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24		$60,870,840
26	Pre-Tax ROR	Page 42 of 42, Line 30, Column (e)		8.41%
27	Return and Taxes	Line 25 × Line 26		$5,119,238
28	Book Depreciation	Line 12		$2,693,818
29	**Annual Revenue Requirement**	**Sum of Lines 27 through 28**		**$7,813,055**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on CY 2024 (Dec-24) Incremental Capital Investments

Line No.				Calendar Year 2024 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 31 of 42, Line 1		$189,714,000	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	81.78%				
3	Capital Repairs Deduction	Line 1 × Line 2		$155,153,801	MACRS basis:		$34,560,199	
4							Annual	Cumulative
5					Calendar Year			
6	Bonus Depreciation				2024	3.75%	$1,296,007	$166,560,808
7	Plant Additions	Line 1		$189,714,000	2025	7.22%	$2,494,901	$169,055,709
8	Less Capital Repairs Deduction	Line 3		$155,153,801	2026	6.68%	$2,307,584	$171,363,293
9	Plant Additions Net of Capital Repairs Deduction	Line 7 - Line 8		$34,560,199	2027	6.18%	$2,134,783	$173,498,077
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	2028	5.71%	$1,974,424	$175,472,501
11	Plant Eligible for Bonus Depreciation	Line 9 × Line 10		$0	2029	5.29%	$1,826,507	$177,299,007
12	Bonus Depreciation Rate 30%	Per Tax Department		0.00%	2030	4.89%	$1,689,303	$178,988,310
13	Bonus Depreciation Rate 0%	Per Tax Department		0.00%	2031	4.52%	$1,562,812	$180,551,122
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%	2032	4.46%	$1,542,076	$182,093,198
15	Bonus Depreciation	Line 11 × Line 14		$0	2033	4.46%	$1,541,730	$183,634,929
16					2034	4.46%	$1,542,076	$185,177,005
17	Remaining Tax Depreciation				2035	4.46%	$1,541,730	$186,718,735
18	Plant Additions	Line 1		$189,714,000	2036	4.46%	$1,542,076	$188,260,811
19	Less Capital Repairs Deduction	Line 3		$155,153,801	2037	4.46%	$1,541,730	$189,802,542
20	Less Bonus Depreciation	Line 15		$0	2038	4.46%	$1,542,076	$191,344,618
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$34,560,199	2039	4.46%	$1,541,730	$192,886,348
22	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%	2040	4.46%	$1,542,076	$194,428,424
23	Remaining Tax Depreciation	Line 21 × Line 22		$1,296,007	2041	4.46%	$1,541,730	$195,970,155
24					2042	4.46%	$1,542,076	$197,512,231
25	CY24 tax (gain)/loss on retirements	Per Tax Department	2/	-	2043	4.46%	$1,541,730	$199,053,961
26	Cost of Removal	Page 31 of 42, Line 7		$10,111,000	2044	2.23%	$771,038	$199,825,000
27						100.00%	$34,560,199	
28	Total Tax Depreciation and Repairs Deductior	Sum of Lines 3, 15, 23, 25 & 26		$166,560,808				

1/ Capital Repairs percentage is based on a three-year average of FYs 2018, 2019 and 2020 capital repairs rates.
2/ FY 2022 estimated tax loss on retirements is tax department estimate

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on CY 2024 (Dec-24) Incremental Capital Investments Post CY 20

Line No.	Deferred Tax Subject to Proration		(a) CY24
1	Book Depreciation	Page 23 of 42 , Line 14 ,Col (a) and Col (e)	$2,693,818
2	Bonus Depreciation	- Page 24 of 42 , Line 15 ,Col (a)	
3	Remaining MACRS Tax Depreciation	- Page 24 of 42 , Col	($1,296,007)
4	CY24 tax (gain)/loss on retirements	- Page 24 of 42 , Line 25 ,Col (a)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$1,397,810
6	Effective Tax Rate		21%
7	Deferred Tax Reserve	Line 5 × Line 6	$293,540
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 24 of 42 , Line 3 ,Col (a)	
9	Cost of Removal	- Page 23 of 42 , Line 7 ,Col (a)	
10	Book/Tax Depreciation Timing Difference at 3/31/2022		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$293,540
15	Net Operating Loss	- Page 23 of 42 , Line 22 ,Col (a)	
16	Net Deferred Tax Reserve	Line 14 + Line 15	$293,540
	Allocation of CY 2024 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$1,397,810
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$1,397,810
20	Total CY 2024 Federal NOL	- Page 23 of 42 , Line 22 ,Col (a)÷21%	$0
21	Allocated CY 2024 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0
22	Allocated CY 2024 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	$293,540

Line No.	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24
26	January	31	91.51%	$22,384
27	February	28	83.84%	$20,508
28	March	31	75.34%	$18,430
29	April	30	67.12%	$16,419
30	May	31	58.63%	$14,342
31	June	30	50.41%	$12,331
32	July	31	41.92%	$10,254
33	August	31	33.42%	$8,176
34	September	30	25.21%	$6,166
35	October	31	16.71%	$4,088
36	November	30	8.49%	$2,078
37	December	31	0.00%	$0
38	Total	365		$135,176

39	Deferred Tax Without Proration	Line 25	$293,540
40	Average Deferred Tax without Proration	Line 39 × 0.5	$146,770
41	Proration Adjustment	Line 38 - Line 40	($11,594)

Column Notes:
(d) Sum of remaining days in the year (Col (h)) divided by 365
Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
FY 2018 - FY 2023-NG Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2018 (a)	Actual Fiscal Year 2019 (b)	Actual Fiscal Year 2020 (c)	Actual Fiscal Year 2021 (d)	Plan Fiscal Year 2022 (e)	Plan Fiscal Year 2023-NG (f)
	Capital Investment							
1	ISR-eligible Capital Investment	Col (a)=Docket No. 4678 FY18 ISR Reconciliation Filing; Col (b)=Docket No. 4781 FY19 ISR Reconciliation Filing; Col (c)=Docket No. 4916 FY20 ISR Reconciliation Filing; Col (d)=Docket No. 4996 FY21 ISR Reconciliation Filing; Col (e)=Docket No. 5099 FY22 ISR Plan Filing	$97,809,718	$92,263,000	$144,119,796	$110,177,659	$156,694,227	$162,924,000
2	ISR-eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770 Schedule MAL-11-Gas Page 5, Col (a)=Lines 1(a) + 1(b); Col(b)=Lines 1(c) + 1(d); Col(c)= Line 1(e); Col(d) = Line 1(h) + 1(j)	$93,177,000	$93,177,000	$38,823,750	$0	$0	$0
3	Incremental ISR Capital Investment	Line 1 - Line 2	$4,632,718	($914,000)	$105,296,046	$110,177,659	$156,694,227	$162,924,000
	Cost of Removal							
4	ISR-eligible Cost of Removal	Col (a)=Docket No. 4678 FY18 ISR Reconciliation Filing; Col (b)=Docket No. 4781 FY19 ISR Reconciliation Filing; Col (c)=Docket No. 4916 FY20 ISR Reconciliation Filing; Col (d)=Docket No. 4996 FY21 ISR Reconciliation Filing; Col (e)=Docket No. 5099 FY22 ISR Plan Filing	$8,603,224	$11,583,085	$10,161,508	$9,975,152	$11,244,351	$4,391,000
5	ISR-eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L23+L42×7÷12+Docket 4678 Page 2, Line 7x3÷12; Col(b)=[P1]L42×5÷12+[P2]L18×7÷12; Col (c)=[P2]L18×5÷12+L39×7÷12; Col (d) = [P2] L39×5÷12+L60×7÷12; Col (e)= [P2] L60×5÷12	$6,662,056	$5,956,522	$3,105,878	$1,113,515	$471,346	$0
6	Incremental Cost of Removal	Line 4 - Line 5	$1,941,168	$5,626,564	$7,055,630	$8,861,636	$10,773,005	$4,391,000
	Retirements							
7	ISR-eligible Retirements	Col (a)=Docket No. 4678 FY18 ISR Reconciliation Filing; Col (b)=Docket No. 4781 FY19 ISR Reconciliation Filing; Col (c)=Docket No. 4916 FY20 ISR Reconciliation Filing; Col (d)=Docket No. 4996 FY21 ISR Reconciliation Filing; Col (e)=Docket No. 5099 FY22 ISR Plan Filing;	$24,056,661	$6,531,844	$8,395,321	$5,337,792	$6,883,634	$19,586,882
8	ISR-eligible Retirements per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L24+L43×7÷12+ Docket 4678 Page 2, Line 2x3÷12; Col(b)=[P1]L43×5÷12+[P2]L19×7÷12 Col (c)=[P2]L19×5÷12+L40×7÷12; Col (d) = [P2]L40×5÷12+L61×7÷12; Col (e)= L61×5÷12	$11,997,233	$7,899,865	$4,119,186	$1,476,805	$625,125	$0
9	Incremental Retirements	Line 7 - Line 8	$12,059,428	($1,368,021)	$4,276,135	$3,860,987	$6,258,509	$19,586,882
	(NOL)/ NOL Utilitization							
10	ISR (NOL)/NOL Utilization Per ISR	Page 35 of 42, Line 12	($6,051,855)	$1,091,119	$0	$2,072,387	$10,722,358	$0
11	ISR NOL Utilization Per Docket 4770	Schedule 11-Gas Page 11, Docket No. 4770: Col (a)= L40×5÷12; Col (b) = L40×5÷12+L48×7÷12 ; Col (c) = P11,L48×5÷12+P12,L39×7÷12; Col (d) = P12,L39×5÷12+P12,L49×7÷12 ; Col (e)= P12,L49×5÷12	$0	$804,769	$3,063,059	$7,598,182	$4,157,771	$0
12	Incremental (NOL)/NOL Utilization	Line 10 - Line 11	($6,051,855)	$286,350	($3,063,059)	($5,525,796)	$6,564,587	$0

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement 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		$29,439,421					$5,223,437	$20,453,237	$16,078,372	$5,085,206	$7,746,916	$0
2	Excess DIT amortization							$0	$0	($1,470,238)	($1,470,238)	($1,470,238)	$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
3	Total Base Rate Plant DIT Provision							$24,514,347.17	$17,043,594	$8,195,453.84	$5,167,632	$2,615,282.52	$0
4	Incremental FY 18	$2,507,039	$2,560,766	$2,611,618	$2,662,153	$2,712,395	$2,719,788	$2,507,039	$53,728	$50,851	$50,535	$50,242	$7,393
5	Incremental FY 19		$1,090,524	$1,085,911	$1,081,431	$1,077,072	($10,477)	$0	$1,090,524	($4,613)	($4,480)	($4,358)	($1,087,550)
6	Incremental FY 20			$18,484,445	$18,218,347	$17,924,604	$17,877,373	$0	$0	$18,484,445	($266,098)	($293,743)	($47,231)
7	Incremental FY 21				$13,009,229	$13,230,424	$13,253,277			$0	$13,009,229	$221,195	$22,853
8	Incremental FY 22					$29,043,157	$28,967,432					$29,043,157	($75,725)
9	Incremental FY 23						$3,763,869						$3,763,869
10	TOTAL Plant DIT Provision	$2,507,039	$3,651,291	$22,181,974	$34,971,160	$63,987,652	$66,571,261	$27,021,386	$18,187,846	$26,726,137	$17,956,818	$31,631,775	$2,583,609
11	NOL (Utilization)							$6,051,855	($1,091,119)	$0	($2,072,387)	($10,722,358)	$0
12	Lesser of NOL or DIT Provision							$6,051,855	($1,091,119)	$0	($2,072,387)	($10,722,358)	$0

Line Notes:
1(b) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 2 of 23, Line 29, Col (e) minus Col (b)
1(g) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 3 plus Line 4
1(h) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 7
1(i) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 50
1(j) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 41
1(k) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 51
1(l) RIPUC Docket Nos. 4770/4780 third rate year ends at Aug 31, 2021
2 RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 52
3 Col (f) = Line 1(b) × 25% + Line 1(f) + Line 1(g) × 7/12; Col (g) = Line 1(g) × 5/12 + Line 1(h) × 7/12 + Line (2(g) x 5/12 + Line 2(h) × 7/12; Col (h) = Line 1(h) × 5/12 + Line 1(i) × 7/12 + Line (2(h) x 5/12 + Line 2(i)
4(a)-9(f) Cumulative DIT plus Deferred Income Tax (Page 2, Line 16 + Line 18; Page 5, Line 16; Page 8, Line 16; Page 12, Line 16; Page 15, Line 16)
4(g)-9(m) Year over year change in cumulative DIT shown in Cols (a) through (f)
10 Sum of Lines 3 through 9
11 Col (f)~(g) = Docket no. 4916 FY 20 ISR Rec, Att. MAL-1, p.19, L. 8; Col (h) ~Col (j) Per Tax Department
12 Lesser of Line 9 or Line 10
12 Lesser of Line 9 or Line 10

The Narragansett Electric Company
d/b/a Rhode Island Energy
ISR Depreciation Expense per Rate Case RIPUC Docket No. 4770

	Account No.	Account Title	Test Year 1/ June 30, 2017 (a)	ARO Adjustment (b)	Adjustments June 30, 2017 (c)	Adjusted Balance (d) = (a) + (b) + (c)	Proposed Rate (e)	Depreciation Expense (f) = (d) x (e)
		Intangible Plant						
1	302.00	Franchises And Consents	$213,499	$0	$0	$213,499	0.00%	$0
2	303.00	Misc. Intangible Plant	$25,427	$0	$0	$25,427	0.00%	$0
3	303.01	Misc. Int Cap Software	$19,833,570	$0	$9,991,374	$29,824,944	0.00%	$0
4								
5		Total Intangible Plant	$20,072,496	$0	$9,991,374	$30,063,870		$0
6								
7		Production Plant						
8								
9	304.00	Production Land Land Rights	$364,912	$0	$0	$364,912	0.00%	$0
10	305.00	Prod. Structures & Improvements	$2,693,397	$0	$0	$2,693,397	15.05%	$405,356
11	307.00	Production Other Power	$46,159	$0	$0	$46,159	7.16%	$3,305
12	311.00	Production LNG Equipme	$3,167,445	$0	$0	$3,167,445	11.40%	$361,089
13	320.00	Prod. Other Equipment	$1,106,368	$0	$0	$1,106,368	6.69%	$74,016
14								
15		Total Production Plant	$7,378,281	$0	$0	$7,378,281		$843,766
16								
17		Storage Plant						
18								
19	360.00	Stor Land & Land Rights	$261,151	$0	$0	$261,151	0.00%	$0
20	361.03	Storage Structures Improvements	$3,385,049	$0	$0	$3,385,049	0.99%	$33,512
21	362.04	Storage Gas Holders	$4,606,338	$0	$0	$4,606,338	0.04%	$1,843
22	363.00	Stor. Purification Equipment	$13,891,210	$0	$0	$13,891,210	3.37%	$468,134
23								
24		Total Storage Plant	$22,143,748	$0	$0	$22,143,748		$503,488
25								
26		Distribution Plant						
27								
28	374.00	Dist. Land & Land Rights	$956,717	$0	$0	$956,717	0.00%	$0
29	375.00	Gas Dist Station Structure	$10,642,632	$0	$0	$10,642,632	1.15%	$122,390
30	376.00	Distribution Mains	$46,080,760	$0	$0	$46,080,760	3.61%	$1,663,515
31	376.03	Dist. River Crossing Main	$695,165	$0	$0	$695,165	3.61%	$25,095
32	376.04	Mains - Steel And Other - Sl	$4,190	$0	$0	$4,190	0.00%	$0
33	376.06	Dist. District Regulator	$14,213,837	$0	$0	$14,213,837	3.61%	$513,120
34	376.11	Gas Mains Steel	$57,759,572	$0	$0	$57,759,572	3.31%	$1,908,954
35	376.12	Gas Mains Plastic	$382,797,443	$0	$0	$382,797,443	2.70%	$10,316,391
36	376.13	Gas Mains Cast Iron	$5,556,209	$0	$0	$5,556,209	8.39%	$465,888
37	376.14	Gas Mains Valves	$222,104	$0	$0	$222,104	3.61%	$8,018
38	376.15	Propane Lines	$0	$0	$0	$0	3.61%	$0
39	376.16	Dist. Cathodic Protect	$1,569,576	$0	$0	$1,569,576	3.61%	$56,662
40	376.17	Dist. Joint Seals	$63,067,055	$0	$0	$63,067,055	4.63%	$2,920,005
41	377.00	T&D Compressor Sta Equipment	$248,656	$0	$0	$248,656	1.07%	$2,661
42	377.62	1/ 5360-Tanks ARO	$299	($299)	$0	$0	0.00%	$0
43	378.10	Gas Measur & Reg Sta Equipment	$19,586,255	$0	$0	$19,586,255	2.08%	$407,394
44	378.55	Gas M&Reg Sta Eqp RTU	$372,772	$0	$0	$372,772	6.35%	$23,671
45	379.00	Dist. Measur. Reg. Gs	$11,033,164	$0	$0	$11,033,164	2.22%	$244,936
46	379.01	Dist. Meas. Reg. Gs Eq	$1,399,586	$0	$0	$1,399,586	0.00%	$0
47	380.00	Gas Services All Sizes	$331,205,854	$0	$0	$331,205,854	3.05%	$10,101,779
48	381.10	Sml Meter& Reg Bare Co	$26,829,565	$0	$0	$26,829,565	1.76%	$472,200
49	381.30	Lrg Meter& Reg Bare Co	$15,779,214	$0	$0	$15,779,214	1.76%	$277,714
50	381.40	Meters	$9,332,227	$0	$0	$9,332,227	0.96%	$89,589
51	382.00	Meter Installations	$675,201	$0	$0	$675,201	3.66%	$24,712
52	382.20	Sml Meter& Reg Installation	$43,145,998	$0	$0	$43,145,998	3.66%	$1,579,144
53	382.30	Lrg Meter&Reg Installation	$2,524,025	$0	$0	$2,524,025	3.66%	$92,379
54	383.00	Dist. House Regulators	$937,222	$0	$0	$937,222	0.67%	$6,279
55	384.00	T&D Gas Reg Installs	$1,216,551	$0	$0	$1,216,551	1.56%	$18,978
56	385.00	Industrial Measuring And Regulating Station Equipment	$540,187	$0	$0	$540,187	4.18%	$22,580
57	385.01	Industrial Measuring And Regulating Station Equipment	$255,921	$0	$0	$255,921	0.00%	$0
58	386.00	Other Property On Customer Premises	$271,765	$0	$0	$271,765	0.23%	$625
59	386.02	Dist. Consumer Prem Equipment	$110,131	$0	$0	$110,131	0.00%	$0
60	387.00	Dist. Other Equipment	$930,079	$0	$0	$930,079	2.15%	$19,997
61	388.00	1/ ARO	$5,736,827	($5,736,827)	$0	$0	0.00%	$0
62								
63		Total Distribution Plant	$1,055,696,761	($5,737,126)	$0	$1,049,959,635	2.99%	$31,384,677
64								
65		General Plant						
66								
67	389.01	General Plant Land Lan	$285,357	$0	$0	$285,357	0.00%	$0
68	390.00	Structures And Improvements	$7,094,532	$0	$0	$7,094,532	3.12%	$221,349
69	391.01	Gas Office Furniture & Fixture	$274,719	$0	$0	$274,719	6.67%	$18,324
70	394.00	General Plant Tools Shop (Fully Dep)	$26,487	$0	$0	$26,487	0.00%	$0
71	394.00	General Plant Tools Shop	$5,513,613	$0	$0	$5,513,613	5.00%	$275,681
72	395.00	General Plant Laboratory	$221,565	$0	$0	$221,565	6.67%	$14,778
73	397.30	Communication Radio Site Specific	$387,650	$0	$0	$387,650	5.00%	$19,383
74	397.42	Communication Equip Tel Site	$63,481	$0	$0	$63,481	20.00%	$12,696
75	398.10	Miscellaneous Equipment (Fully Dep)	$1,341,386	$0	$0	$1,341,386	0.00%	$0
76	398.10	Miscellaneous Equipment	$2,789,499	$0	$0	$2,789,499	6.67%	$186,060
77	399.10	1/ ARO	$342,146	($342,146)	$0	$0	0.00%	$0
78								
79		Total General Plant	$18,340,436	($342,146)	$0	$17,998,289	4.16%	$748,271
80								
81		Grand Total - All Categories	$1,123,631,722	($6,079,273)	$9,991,374	$1,127,543,823	3.05%	$33,480,202
82							2.97%	
83		Other Utility Plant Assets						
84			Line 63		Total Distribution Plant	$1,049,959,635	2.99%	$31,384,677
85			Line 73 + Line 74		Communication Equipment	$451,132	7.11%	$32,079
86					Total ISR Tangible Plant	$1,050,410,767	2.99%	$31,416,756
					Non ISR Assets	$77,133,057		

Lines 1 through 81 - per RIPUC Docket No. 4770 Compliance filing dated August 16, 2018 , Compliance Attachment 2, Schedule 6-GAS, Pages 3 & 4

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
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
Gas ISR Depreciation Expense

Line No	Description		Reference	Amount	Less non-ISR eligible Plant	ISR Amount
				(a)	(b)	(c)
1	Total Company Rate Year Depreciation		Sum of Page 2, Line 16 and Line 17	$39,136,909		
2	Total Company Test Year Depreciation		Per Company Books	$33,311,851		
3	Less: Reserve adjustments		Page 4, Line 29, Col (b) + Col (c)	($15,649)		
4	Adjusted Total Company Test Year Depreciation Expense		Line 2 + Line 3	$33,296,202		
5	Depreciation Expense Adjustmen		Line 1 - Line 4	$5,840,707		
6						
7				Per Book		
8	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount		
9	Total Gas Utility Plant 06/30/17		Page 4, Line 27, Col (d)	$1,405,994,678	($77,133,057)	$1,328,861,622
10	Less Non Depreciable Plant		Sum of Page 3, Line 5, Col (d) and Page 4, Line 25, Col (e)	($308,514,725)		($308,514,725)
11	Depreciable Utility Plant 06/30/17		Line 9 + Line 10	$1,097,479,953	($77,133,057)	$1,020,346,897
12						
13	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-GAS, Page 3, Line 4	$19,592,266		$19,592,266
14	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 13 x Retirement Rate	($1,345,989)		($1,345,989)
15	Depreciable Utility Plant 08/31/17		Line 11 + Line 13 + Line 14	$1,115,726,231	($77,133,057)	$1,020,346,897
16						
17	Average Depreciable Plant for Year Ended 08/31/17		(Line 11 + Line 15)/2	$1,106,603,092		$1,106,603,092
18						
19	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		
20						
21	Book Depreciation Reserve 06/30/17		Page 5, Line 72, Col (d)	$357,576,825		$357,576,825
22	Plus: Book Depreciation Expense		Line 17 x Line 19	$6,233,864		$6,233,864
23	Less: Net Cost of Removal/(Salvage)	2/	Line 13 x Cost of Removal Rate	($1,014,879)		($1,014,879)
24	Less: Retired Plant		Line 14	($1,345,989)		($1,345,989)
25	Book Depreciation Reserve 08/31/17		Sum of Line 21 through Line 24	$361,449,821		
26						
27	Depreciation Expense 12 Months Ended 08/31/18					
28	Total Utility Plant 08/31/17		Line 9 + Line 13 + Line 14	$1,424,240,956	($77,133,057)	$1,347,107,900
29	Less Non Depreciable Plant		Line 10	($308,514,725)		($308,514,725)
30	Depreciable Utility Plant 08/31/17		Line 28 + Line 29	$1,115,726,231		$1,038,593,175
31						
32	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-GAS, Page 3, Line 11	$115,710,016		$115,710,016
33	Less: Plant Retired in 12 Months Ended 08/31/18		Line 32 x Retirement rate	($7,949,278)		($7,949,278)
34	Depreciable Utility Plant 08/31/18		Sum of Line 30 through Line 33	$1,223,486,969		$1,146,353,912
35						
36	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 30 + Line 34)/2	$1,169,606,600		$1,092,473,543
37						
38	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		3.38%
39						
40	Book Depreciation Reserve 08/31/17		Line 25	$361,449,821		
41	Plus: Book Depreciation 08/31/18		Line 36 x Line 38	$39,532,703		$36,925,606
42	Less: Net Cost of Removal/(Salvage)		Line 32 x Cost of Removal Rate	($5,993,779)		
43	Less: Retired Plant		Line 33	($7,949,278)		
44	Book Depreciation Reserve 08/31/18		Sum of Line 40 through Line 43	$387,039,467		

1/ 3 year average retirement over plant addition in service FY 15 ~ FY17 — 6.87% Retirements
2/ 3 year average Cost of Removal over plant addition in service FY 15 ~ FY17 — 5.18% COR

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No		Description		Reference	Amount (a)	Less non-ISR eligible Plant (b)	ISR Amount (c)
1		Rate Year Depreciation Expense 12 Months Ended 08/31/19:					
2		Total Utility Plant 08/31/18		Page 1, Line 28 + Line 32 + Line 33	$1,532,001,694	($77,133,057)	$1,454,868,637
3		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
4		Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,223,486,969		$1,146,353,912
5							
6		Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-GAS, Page 3, Line 35	$114,477,000	($1,348,000)	$113,129,000
7		Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($7,864,570)	$92,608	($7,771,962)
8							
9		Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,330,099,399	($78,388,449)	$1,251,710,950
10							
11		Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,276,793,184		$1,199,032,431
12							
13		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
14							
15		Book Depreciation Reserve 08/31/18		Page 1, Line 44	$387,039,467		$0
16		Plus: Book Depreciation Expense		Line 11 x Line 13	$38,950,409		$35,851,070
17		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
18		Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($5,929,909)		$0
19		Less: Retired Plant		Line 7	($7,864,570)		$0
20		Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$412,381,898		$36,037,570
21							
22		Rate Year Depreciation Expense 12 Months Ended 08/31/20:					
23		Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$1,638,614,124	($78,388,449)	$1,560,225,675
24		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
25		Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,330,099,399		$1,251,710,950
26							
27		Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-GAS, Page 5, Line 11(i)	$21,017,630	($750,000)	$20,267,630
28		Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($1,443,911)	$51,525	($1,392,386)
29							$0
30		Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,349,673,118	($79,086,924)	$1,270,586,194
31							
32		Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,339,886,258		$1,261,148,572
33							
34		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
35							
36		Book Depreciation Reserve 08/31/20		Line 20	$412,381,898		$0
37		Plus: Book Depreciation Expense		Line 32 x Line 34	$40,875,154		$37,708,342
38		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
39		Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($1,088,713)		$0
40		Less: Retired Plant		Line 28	($1,443,911)		$0
41		Book Depreciation Reserve 08/31/20		Sum of Line 36 through Line 40	$450,910,927		$37,894,842
42							
43		Rate Year Depreciation Expense 12 Months Ended 08/31/21:					
44		Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$1,658,187,843	($79,086,924)	$1,579,100,919
45		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
46		Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,349,673,118		$1,270,586,194
47							
48		Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-GAS, Page 5, Line 11(l)	$21,838,436	($750,000)	$21,088,436
49		Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($1,500,301)	$51,525	($1,448,776)
50							
51		Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,370,011,253	($79,785,399)	$1,290,225,854
52							
53		Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,359,842,185		$1,280,406,024
54							
55		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
56							
57		Book Depreciation Reserve 08/31/20		Line 41	$450,910,927		$0
58		Plus: Book Depreciation Expense		Line 53 x Line 55	$41,483,938		$38,284,140
59		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
60		Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($1,131,231)		$0
61		Less: Retired Plant		Line 49	($1,500,301)		$0
62		Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$489,949,834		$38,470,640
63							
64	1/	3 year average retirement over plant addition in service FY 15 ~ FY17		0.0687	Retirements		
65	2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17		0.0518	COR		
66							
67		Book Depreciation RY2		Line 37 (a) + Line 38 (b)			$41,061,654
68		Less: General Plant Depreciation (assuming add=retirement)		Page 10, Line 79(f)			($748,271)
69		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
70		Total					$40,345,462
71		7 Months					x7/12
72		FY 2020 Depreciation Expense					$23,534,853
73							
74		Book Depreciation RY3		Line 58 (a) + Line 59 (b)			$41,670,438
75		Less: General Plant Depreciation		Page 10, Line 79(f)			($748,271)
76		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
77		Total					$40,954,246
78		FY 2021 Depreciation Expense		5 Months of RY 2 and 7 Months of RY 3			$40,700,586

The Narragansett Electric Company
d/b/a Rhode Island Energy
Forecasted CY 2024 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		End of FY 2018	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	Adjustment	End of FY 2019
1	Plant In Service	$1,195,705	$92,263	$24,845	$117,108		($6,844)		$0	$1,305,969
2	Accumulated Depr	$414,713				$40,858	($6,844)	($6,123)		$442,604
3	Net Plant	$780,992								$863,364
4	Property Tax Expense	$22,678								$23,283
5	Effective Prop tax Rate	2.90%								2.70%
		End of FY 2019	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	Adjustment	End of FY 2020
6	Plant In Service	$1,305,969	$144,120	$22,074	$166,193		($8,567)		$0	$1,463,595
7	Accumulated Depr	$442,604				$41,588	($8,567)	($10,162)		$465,463
8	Net Plant	$863,364								$998,132
9	Property Tax Expense	$23,283								$25,959
10	Effective Prop tax Rate	2.70%								2.60%
		End of FY 2020	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	Adjustment	End of FY 2021
11	Plant In Service	$1,463,595	$110,178	$97,667	$207,844		($5,766)		($26,386)	$1,639,288
12	Accumulated Depr	$465,463				$45,652	($5,766)	($11,566)	($32,599)	$461,185
13	Net Plant	$998,132								$1,178,103
14	Property Tax Expense	$25,959								$28,846
15	Effective Prop tax Rate	2.60%								2.45%
		End of FY 2021	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	Adjustment	End of FY 2022
16	Plant In Service	$1,639,288	$156,694	$29,406	$186,100		($7,443)			$1,817,945
17	Accumulated Depr	$461,185				$51,439	($7,443)	($11,244)		$493,937
18	Net Plant	$1,178,103								$1,324,008
19	Property Tax Expense	$28,846								$33,631
20	Effective Prop tax Rate	2.45%								2.54%
		End of FY 2022	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	Adjustment	End of FY 2023-NG
21	Plant In Service	$1,817,945	$162,924	$22,074	$184,998		($9,639)			$1,993,303
22	Accumulated Depr	$493,937				$55,711	($9,639)	($4,391)		$535,618
23	Net Plant	$1,324,008								$1,457,686
24	Property Tax Expense	$33,631								$35,713
25	Effective Prop tax Rate	2.54%								2.45%
		End of FY 2023-NG	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	Adjustment	End of CY 2023
26	Plant In Service	$1,993,303	$157,130	$29,406	$186,536		($7,889)			$2,171,950
27	Accumulated Depr	$535,618				$58,772	($7,889)	($8,217)		$578,283
28	Net Plant	$1,457,686								$1,593,667
29	Property Tax Expense	$35,713								$40,479
30	Effective Prop tax Rate	2.45%								2.54%
		Dec-2023 End of FY 2022	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	Adjustment	End of CY 2024
31	Plant In Service	$2,171,950	$189,714	$29,406	$219,120		($9,526)			$2,381,545
32	Accumulated Depr	$578,283				$62,417	($9,526)	($10,111)		$621,064
33	Net Plant	$1,593,667								$1,760,481
34	Property Tax Expense	$40,479								$44,716
35	Effective Prop tax Rate	2.54%								2.54%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Forecasted CY 2024 ISR Property Tax Recovery Adjustment
Forecasted CY 2024 ISR Property Tax Recovery Adjustment (Continued) 1

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Cumulative Increm. ISR Prop. Tax for FY2018				Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 month				Cumulative Increm. ISR Prop. Tax for FY2019		
36	Incremental ISR Additions			$97,810				$92,263				($914)	
37	Book Depreciation: base allowance on ISR eligible plant			($24,356)				($24,356)				$0	
38	Book Depreciation: current year ISR additions			($1,246)				($1,449)				($7)	
39	COR			$8,603				$11,583				$5,627	
40	Net Plant Additions			$80,811				$78,041				$4,705	
41	RY Effective Tax Rate			3.06%				3.06%				2.92%	
										7 mos		1.70%	
42	ISR Year Effective Tax Rate		2.90%				2.70%						
43	RY Effective Tax Rate		3.06%	-0.15%			3.06%	-0.36%			2.70%		
44	RY Effective Tax Rate 5 mos for FY 2019					5 month		-0.15%			2.92%	-0.22%	
45	RY Net Plant times 5 mo rate	7 month	$458,057	-0.15%	($694)		$458,057	-0.15%	($684)			-0.13% 7 mos	
46	FY 2014 Net Adds times ISR Year Effective Tax rate	7 month	$6,343	2.90%	$184		$5,950	1.12%	$67		$919,892	* -0.13%	($1,203)
47	FY 2015 Net Adds times ISR Year Effective Tax rate	7 month	$42,913	2.90%	$1,246		$39,920	1.12%	$449				$0
48	FY 2016 Net Adds times ISR Year Effective Tax rate		$59,527	2.90%	$1,729		$55,693	1.12%	$626		$6,934	1.57%	$109
49	FY 2017 Net Adds times ISR Year Effective Tax rate		$58,883	2.90%	$1,710		$56,076	1.12%	$630		$4,705	1.57%	$74
50	FY 2018 Net Adds times ISR Year Effective Tax rate		$80,810	2.90%	$2,347		$77,664	1.12%	$873				
51	FY 2019 Net Adds times ISR Year Effective Tax rate						$78,041	1.12%	$877				
52	Total ISR Property Tax Recovery				$6,521				$2,837				($1,020)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			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			$105,296				$110,178				$156,694	
54	Book Depreciation: base allowance on ISR eligible plant			$0				$0				($23,890)	
55	Book Depreciation: current year ISR additions			($1,510)				($1,589)				($2,249)	
56	COR			$7,056				$8,862				$10,773	
57	Net Plant Additions			$110,841				$117,450				$141,328	
58													
59	RY Effective Tax Rate			2.96%				3.02%				3.05%	
60	Property Tax Recovery on Growth and non-ISR												
61	ISR Year Effective Tax Rate		2.60%				2.45%				2.54%		
62	RY Effective Tax Rate		2.96%	-0.36%			3.02%	-0.57%			3.05%	-0.51%	
63	RY Effective Tax Rate 7 mos for FY 2019			-0.36%				-0.57%				-0.51%	
64	RY Net Plant times Rate Difference	7 month	$908,586	* -0.36%	($3,246)		$889,353	* -0.57%	($5,080)		$881,383	* -0.51%	($4,486)
65	Growth and non-ISR Incremental times rate difference		($20,407)	* -0.36%	$73		($41,336)	* -0.57%	$236		($51,615)	* -0.51%	$263
66	FY 2018 Net Incremental times rate difference		$7,156	* 2.6%	$186		$7,378	* 2.45%	$181		$7,600	* 2.54%	$193
67	FY 2019 Net Incremental times rate difference		$4,692	* 2.6%	$122		$4,678	* 2.45%	$115		$4,665	* 2.54%	$118
68	FY 2020 Net Incremental times rate difference		$110,841	* 2.6%	$2,882		$107,821	* 2.45%	$2,642		$104,800	* 2.54%	$2,662
69	FY 2021 Net Incremental times rate difference						$117,450	* 2.45%	$2,878		$114,271	* 2.54%	$2,902
70	FY 2022 Net Adds times rate difference										$141,328	* 2.54%	$3,590
71	Total ISR Property Tax Recovery				$17				$970				$5,242
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Cumulative Increm. ISR Prop. Tax for FY2023-NG				Cumulative Increm. ISR Prop. Tax for CY2023				Cumulative Increm. ISR Prop. Tax for CY2024		
72	Incremental ISR Additions			$162,924				$157,130				$189,714	
73	Book Depreciation: base allowance on ISR eligible plant			($40,954)				($40,954)				($40,954)	
74	Book Depreciation: current year ISR additions			($2,292)				($1,673)				($2,694)	
75	COR			$4,391				$8,217				$10,111	
76	Net Plant Additions			$124,069				$122,719				$156,177	
77													
78	RY Effective Tax Rate			3.05%				3.05%				3.05%	
79	Property Tax Recovery on Growth and non-ISR												
80	ISR Year Effective Tax Rate		2.45%				2.54%				2.54%		
81	RY Effective Tax Rate		3.05%	-0.60%			3.05%	-0.51%			3.05%	-0.51%	
82	RY Effective Tax Rate 7 mos for FY 2019			-0.60%				-0.51%				-0.51%	
83	RY Net Plant times Rate Difference		$881,383	* -0.6%	($5,279)		$881,383	* -0.51%	($4,486)		$881,383	* -0.51%	($4,486)
84	Growth and non-ISR Incremental times rate difference		($51,615)	* -0.6%	$309		($51,615)	* -0.51%	$263		($51,615)	* -0.51%	$263
85	FY 2018 Net Incremental times rate difference		$7,822	* 2.45%	$192		$7,988	* 2.54%	$203		$8,210	* 2.54%	$209
86	FY 2019 Net Incremental times rate difference		$4,651	* 2.45%	$114		$4,641	* 2.54%	$118		$4,627	* 2.54%	$118
87	FY 2020 Net Incremental times rate difference		$101,780	* 2.45%	$2,494		$99,515	* 2.54%	$2,528		$96,494	* 2.54%	$2,451
88	FY 2021 Net Incremental times rate difference		$111,092	* 2.45%	$2,722		$108,708	* 2.54%	$2,761		$105,529	* 2.54%	$2,680
89	FY 2022 Net Adds times rate difference		$136,830	* 2.45%	$3,352		$133,457	* 2.54%	$3,390		$128,959	* 2.54%	$3,276
90	FY 2023-NG Net Adds times rate difference		$124,069	* 2.45%	$3,040		$120,632	* 2.54%	$3,064		$116,049	* 2.54%	$2,948
91	CY 2023 Net Adds times rate difference						$122,719	* 2.54%	$3,117		$118,257	* 2.54%	$3,004
92	CY 2024 Net Adds times rate difference										$156,177	* 2.54%	$3,967
93	Total ISR Property Tax Recovery				$6,943				$10,957				$14,428

The Narragansett Electric Company
d/b/a Rhode Island Energy
Forecasted CY 2024 ISR Property Tax Recovery Adjustment
Forecasted CY 2024 ISR Property Tax Recovery Adjustment (Continued) 2

Line Notes	
1(a) - 5(i)	Docket No. 4781 Attachment MAL-2, Page 10 of 13, 1(a) to 5(h)
6(i) - 10(i)	Docket No. 4916 Attachment MAL-1, Page 17 of 20, 6(a) to 10(h)
11(a) - 15(i)	Docket No. 4996 Attachment MAL-1, Page 20 of 22, 11(a) to 15(i)
16(a) - 20(a)	11(i) - 15(i)
16(b)	Page 34 of 42 , Line 1 ,Col (e)÷1000
16(c)	Docket No. 5099, Section 3, Att. 1 (C), Page 23, 16 (c)
16(d)	Docket No. 5099, Section 3, Att. 1 (C), Page 23, 16 (d)
16(f)	Docket No. 5099, Section 3, Att. 1 (C), Page 23, 16 (f)
16(i)	Line 16(a) + (d) + (f)
17(e)	P25, (L58+L59)+(P2, L3 (a)+P5, L3 (a)+P8, L3 (a)+P12, L3 (a))÷1000×3.05%+Inc (L1(c)+L6(c)+L11(c))×0.0416+ P15, L3 (a)×0.5×3.05%÷1000+ L16(c)×0.5×0.0416
17(f)	=16(f)
17(g)	Docket No. 5099, Section 3, Att. 1 (C), Page 23, 17 (g)
17(i)	Line 17(a) + (e) + (f) + (g)
18(i)	Line 16(i) - 17(i)
19(i)	Line 18(h) × 20(h)
20(i)	Docket No. 5099, Section 3, Att. 1 (C), Page 23, 20 (h)
21(a) - 25(a)	16(i) - 20(i)
21(b)	Page 23 of 42 , Line 1 ,Col (d)÷1000
21(c)	Line 6(c)
21(d)	Line 16(b) + 16(c)
21(f)	- Page 23 of 42 , Line 2 ,Col (d)÷1000
21(i)	Line 21 (a) + (d) + (f)
22(e)	Page 38, (Line 58 + Line 59) + (Page 2 , Line 3, Col (a) + Page 6 , Line 3, Col (a) + Page 10 , Line 3, Col (a) + Page 15 , Line 3, Col (a) + Page 19 , Line 3, Col (a))÷1000 × 3.05%+ Incremental (L1(c)+L6(c)+L11(c)+L16(c))×3.05% + Page 23 , Line 3, Col (a)+ L21(c))×0.5×3.05%÷1000
22(f)	=21(f)
22(g)	- Page 23 of 42 , Line 7 ,Col (d)÷1000
22(i)	Line 22 (a) + (e) + (f) + (g)
23(i)	Line 21(i) - 22(i)
24(i)	Line 23(i) × 25(i)
25(i)	=20(a) most recent actual property tax rate
26(a) - 30(a)	21(i) - 25(i)
26(b)	Page 27 of 42 , Line 1 ,Col (a)÷1000
26(c)	Line 16(c)
26(d)	Line 26(b) + 26(c)
26(f)	- Page 27 of 42 , Line 2 ,Col (a)÷1000
26(i)	Line 26 (a) + (d) + (f)
27(e)	Page 38, (Line 58 + Line 59) + (Page 2 , Line 3, Col (a) + Page 6 , Line 3, Col (a) + Page 10 , Line 3, Col (a) + Page 15 , Line 3, Col (a) + Page 19 , Line 3, Col (a))÷1000 × 3.05%+ Incremental (L1(c)+L6(c)+L11(c)+L16(c))×3.05% + Page 23 , Line 3, Col (a)+ L21(c))×0.5×3.05%÷1000
27(f)	=26(f)
27(g)	- Page 27 of 42 , Line 7 ,Col (a)÷1000
27(i)	Line 27 (a) + (e) + (f) + (g)
28(i)	Line 26(i) - 27(i)
29(i)	Line 28(i) × 30(i)
30(i)	=20(i) most recent actual property tax rate

Line Notes	
31(a) - 35(a)	26(i) - 30(i)
31(b)	Page 31 of 42 , Line 1 ,Col (a)÷1000
31(c)	Line 16(c)
31(d)	Line 31(b) + 31(c)
31(f)	- Page 31 of 42 , Line 2 ,Col (a)÷1000
31(i)	Line 31 (a) + (d) + (f)
32(e)	Page 38, (Line 58 + Line 59) + (Page 2 , Line 3, Col (a) + Page 6 , Line 3, Col (a) + Page 10 , Line 3, Col (a) + Page 15 , Line 3, Col (a) + Page 19 , Line 3, Col (a))÷1000 × 3.05%+ Incremental (L1(c)+L6(c)+L11(c)+L16(c))×3.05% + Page 23 , Line 3, Col (a)+ L21(c))×0.5×3.05%÷1000
32(f)	=31(f)
32(g)	- Page 31 of 42 , Line 7 ,Col (a)÷1000
32(i)	Line 32 (a) + (e) + (f) + (g)
33(i)	Line 31(i) - 32(i)
34(i)	Line 33(i) × 35(i)
35(i)	=20(i) most recent actual property tax rate
36(a) - 52(h)	Docket No. 4781 Rec, Attachment MAL-1, Page 29 of 35, 82(e) to 107(k)
53(a)-71 (c)	Docket No. 4781 Rec, Attachment MAL-2, Page 10 of 13, 31(a) to 50 (c)
53(e) -71(g)	Docket No. 4916 Rec, Attachment MAL-1, Page 18 of 20, 28(e) to 48 (g)
53(j)	Page 19 of 42, Line 4(a)÷1000
54(j)	- (Page 38 of 42, Line 77(c) ×7÷12)÷1000
55(j)	- Page 19 of 42, Line 15(a)÷1000
56(j)	Page 19 of 42, Line 7(a)÷1000
57(j)	Sum of Lines 53(j) through 56(j)
59(j)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P3, L15, Col (e) ÷ 64(j)
61(i)	=20(i)
62(i)	=59(j)
62(j)	61(i)-62(i)
63(j)	=62(j)
64(i)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: 64(a) × 5÷12 + (Sch 6-G, P2, L30 - L41 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)) × 7÷12000
64(k)	64(i)×63(j)
65(i)	= - Rate Case, Docket 4770, Compliance, Revised Rebuttal Att. 1: Sch 11-G, P5, L3(e)+L3(i)+L7(e)+L7(i)+L3(l)+L7(l)")
65(k)	65(i)×63(j)
66(i)	Line 66(e) - Page 2 of 42, Line 14(e)÷1000
66(k)	=66(i)×61(i)
67(i)	Line 67(e) - Page 6 of 42, Line 15(d)÷1000
67(k)	=67(i)×61(i)
68(i)	Line 68(e) - Page 10 of 42, Line 15(c)÷1000
68(k)	=68(i)×61(i)
69(i)	Line 69(e) - Page 15 of 42, Line 15(c)÷1000
69(k)	=69(i)×61(i)

Line Notes	
70(i)	57(j)
70(k)	=70(i)×61(i)
71(k)	sum of 64(k) through 70(k)
72(b)	Page 23 of 42, Line 4(a)÷1000
73(b)	- Page 23 of 42, Line 5(a)÷1000
74(b)	- Page 23 of 42, Line 14(a)÷1000
75(b)	Page 23 of 42, Line 7(a)÷1000
76(b)	Sum of Lines 72(b) through 75(b)
78(b)	59(j)
80(a)	25(i)
81(a)	78(b)
81(b)	80(a)-81(a)
82(b)	81(b)
83(a)	64(i)
83(c)	83(a)×82(b)
84(a)	65(i)
84(c)	84(a)×82(b)
85(a)	Line 66(i) - (Page 2 of 42, Line 14(f) through (h))÷1000
85(c)	=85(a)×80(a)
86(a)	Line 67(i) - (Page 6 of 42, Line 15(e) through (g))÷1000
86(c)	=86(a)×80(a)
87(a)	Line 68(i) - (Page 10 of 42, Line 15(d) through (f))÷1000
87(c)	=87(a)×80(a)
88(a)	Line 69(i) - (Page 15 of 42, Line 15(c) through (e))÷1000
88(c)	=88(a)×80(a)
89(a)	(Line 70(i) - (Page 19 of 42, Line 15(b) through (d))÷1000
89(c)	=89(a)×80(a)
90(a)	=76(b)
90(c)	=90(a)×80(a)
93(c)	sum of 83(c) through 90(c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Gas ISR Revenue Requirement Plan
Calculation of Weighted Average Cost of Capital

Line No.						
1	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013					
2		(a)	(b)	(c)	(d)	(e)
3		Ratio	Rate	Weighted Rate	Taxes	Return
4	Long Term Debt	49.95%	5.70%	2.85%		2.85%
5	Short Term Debt	0.76%	0.80%	0.01%		0.01%
6	Preferred Stock	0.15%	4.50%	0.01%		0.01%
7	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
8		100.00%		7.54%	2.51%	10.05%
9						
10	(d) - Column (c) x 35% divided by (1 - 35%)					
11						
12						
13	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018					
14		(a)	(b)	(c)	(d)	(e)
15		Ratio	Rate	Weighted Rate	Taxes	Return
16	Long Term Debt	49.95%	5.70%	2.85%		2.85%
17	Short Term Debt	0.76%	0.80%	0.01%		0.01%
18	Preferred Stock	0.15%	4.50%	0.01%		0.01%
19	Common Equity	49.14%	9.50%	4.67%	1.24%	5.91%
20		100.00%		7.54%	1.24%	8.78%
21	(d) - Column (c) x 21% divided by (1 - 21%)					
22						
23	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
24		(a)	(b)	(c)	(d)	(e)
25		Ratio	Rate	Weighted Rate	Taxes	Return
26	Long Term Debt	48.35%	4.98%	2.41%		2.41%
27	Short Term Debt	0.60%	1.76%	0.01%		0.01%
28	Preferred Stock	0.10%	4.50%	0.00%		0.00%
29	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
30		100.00%		7.15%	1.26%	8.41%
31	(d) - Column (c) x 21% divided by (1 - 21%)					
32						
33	FY18 Blended Rate		Line 8(e) × 75% + Line 20(e) × 25%			9.73%
34						
35	FY19 Blended Rate		Line 20 x 5 ÷ 12 + Line 30 x 7 ÷ 12			8.56%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Impact of Elimination of ADIT and Hold Harmless Commitment for the 21-Month Gas Plan
CY 2023 - April 2023 - December 2023

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		**4.980%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / (Lines 2 + 3) * Line 7 + Line 3 / (Lines 2 + 3) * Line 8	**4.941%**	
10	Cost of Equity		**9.275%**	
11	Revenue WACC (pre-tax)	Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6	**8.4100%**	
12	WACC (after-tax)	(Line 9 * Line 5) + (Line 10 * Line 6)	**7.149%**	
13	Rate Base - PPL (after purchase)	Page 3. Line 8, Column (c)	$278,397,938	9-Month April-December 2023
14	Rate Base - NG (before sale)	Page 3. Line 8, Column (f)	$238,785,005	9-Month April-December 2023
15	**Deferred Taxes / Hold Harmless**	**Lines 13 - 14**	**$39,612,934**	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
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 shown on Line 30 is the revenue credit reflected on Line 23.

			9-Month April to December 2023 (CY 2023)			
			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	278,397,938	278,397,938	-	
17	ADIT Adjustment	- Line 15	-	(39,612,934)	39,612,934	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**278,397,938**	**238,785,005**	**39,612,934**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	6,746,502	5,786,550	959,952	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	13,156,008	11,284,054	1,871,954	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	3,497,167	2,999,559	497,608	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**23,399,676**	**20,070,162**	**3,329,514**	
23	Revenue Adjustment for 9 Month CY 2023	- Line 15 * Line 11	(3,331,448)	-	(3,331,448)	Note 1
24	**Total Revenue**	**Lines 22 + 23**	**20,068,229**	**20,070,162**	**(1,934)**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	5,786,550	5,786,550	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	2,999,153	2,999,559	(406)	
27	**Net Income**	**Lines 24 - 25 - 26**	**11,282,526**	**11,284,054**	**(1,528)**	

	Impact of Transaction		
28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	12,532,589
29	Cash Tax Benefit at 21%	Line 28 * Line 1	2,631,844
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	3,331,448

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
d/b/a Rhode Island Energy
Impact of Elimination of ADIT and Hold Harmless Commitment for the 21-Month Gas Plan
CY 2024 - January 2024 - December 2024

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		**4.980%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	**4.941%**	
10	Cost of Equity		**9.275%**	
11	Revenue WACC (pre-tax)	Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6	**8.4100%**	
12	WACC (after-tax)	(Line 9 * Line 5) + (Line 10 * Line 6)	**7.149%**	
13	Rate Base - PPL (after purchase)	Page 3. Line 16, Column (c)	$357,267,944	12-Month CY 2024
14	Rate Base - NG (before sale)	Page 3. Line 16, Column (f)	$305,848,473	12-Month CY 2024
15	**Deferred Taxes / Hold Harmless**	**Lines 13 - 14**	**$51,419,471**	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

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 shown on Line 30 is the revenue credit reflected on Line 23.

			12-Month January to December 2024 (CY 2024)			
			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	357,267,944	357,267,944	-	
17	ADIT Adjustment	- Line 15	-	(51,419,471)	51,419,471	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**357,267,944**	**305,848,473**	**51,419,471**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	8,657,783	7,411,719	1,246,064	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	16,883,099	14,453,214	2,429,885	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	4,487,912	3,841,994	645,919	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**30,028,794**	**25,706,926**	**4,321,867**	
23	Revenue Adjustment for 12 Month CY 2024	- Line 15 * Line 11	(4,324,378)	-	(4,324,378)	Note 1
24	**Total Revenue**	**Lines 22 + 23**	**25,704,416**	**25,706,926**	**(2,510)**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	7,411,719	7,411,719	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	3,841,466	3,841,994	(527)	
27	**Net Income**	**Lines 24 - 25 - 26**	**14,451,231**	**14,453,214**	**(1,983)**	

	Impact of Transaction		
28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	16,267,896
29	Cash Tax Benefit at 21%	Line 28 * Line 1	3,416,258
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	4,324,378

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
d/b/a Rhode Island Energy
Average ISR Rate Base after Deferred Tax Proration

		Post-Acquisition (a)	Prorated (b)	Post-Acquisition Prorated for 9 months (c)		No Acquisition (d)	Prorated (e)	No Acquisition Prorated for 9 months (f)	
1	**9 Months 2023**								
2	FY 2018	6,916,358	75%	5,187,269		11,177,572	75%	8,383,179	
3	FY 2019	4,665,492	75%	3,499,119		3,288,364	75%	2,466,273	
4	FY 2020	76,239,939	75%	57,179,954		62,652,180	75%	46,989,135	
5	FY 2021	68,238,845	75%	51,179,134		61,224,689	75%	45,918,517	
6	FY 2022	116,631,540	75%	87,473,655		83,120,508	75%	62,340,381	
7	FY 2023	98,505,077	75%	73,878,808		96,916,693	75%	72,687,520	
8		371,197,251		278,397,938	Page 1, Line 13	318,380,006		238,785,005	Page 1, Line 14
9	**CY 2024**								
10	FY 2018	6,996,972	100%	6,996,972		11,327,969	100%	11,327,969	
11	FY 2019	4,668,444	100%	4,668,444		3,280,250	100%	3,280,250	
12	FY 2020	72,908,255	100%	72,908,255		60,279,470	100%	60,279,470	
13	FY 2021	64,699,982	100%	64,699,982		58,282,576	100%	58,282,576	
14	FY 2022	111,556,410	100%	111,556,410		79,620,172	100%	79,620,172	
15	FY 2023	96,437,881	100%	96,437,881		93,058,037	100%	93,058,037	
16		357,267,944		357,267,944	Page 2, Line 13	305,848,473		305,848,473	Page 2, Line 14
17	Total 21-Month Plan	728,465,195		635,665,883		624,228,480		544,633,478	

Section 4
Rate Design & Bill Impacts

Section 4
Rate Design & Bill Impacts

Proposed FY 2024 Gas Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Gas ISR Plan
April 2023 – December 2024

Rate Design & Bill Impacts
FY 2024 Gas ISR Plan
21-Month Proposal

For purposes of rate design, the 21-Month Plan revenue requirement associated with total net capital investment is allocated to rate classes based upon the most recent rate base allocator approved in the Amended Settlement Agreement in Docket No. 4770. For each rate class, the allocated revenue requirement is divided by the applicable fiscal year (21-month period) forecasted therm deliveries to arrive at a per-therm factor unique to each rate class.

The proposed rate design and associated estimated typical bill impacts are provided in Section 4. The estimated bill impact of the Gas ISR Plan for the average Residential Heating customer, using 845 therms annually, would be an annual increase of $113.88, or 6.6%, from current bills.

	FY 2024 (21-Month) Revenue Requirement	Rate Class	Rate Base Allocator (%)	Allocation to Rate Class ($)	Throughput (dth)	ISR Factor (dth)	ISR Factor (therm)	Uncollectible %	ISR Factor (therm)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)									
(2)	$122,228,995	Residential Total	66.59%	$81,392,288	30,744,949	$2.6473	$0.2647	1.91%	$0.2698
(3)		Small	8.04%	$9,827,211	3,667,874	$2.6792	$0.2679	1.91%	$0.2731
(4)		Medium	12.23%	$14,948,606	9,034,738	$1.6545	$0.1654	1.91%	$0.1686
(5)		Large LL	5.57%	$6,808,155	4,362,918	$1.5604	$0.1560	1.91%	$0.1590
(6)		Large HL	2.25%	$2,750,152	2,310,145	$1.1904	$0.1190	1.91%	$0.1213
(7)		XL-LL	0.97%	$1,185,621	1,991,070	$0.5954	$0.0595	1.91%	$0.0606
(8)		XL-HL	4.35%	$5,316,961	10,028,706	$0.5301	$0.0530	1.91%	$0.0540
(9)		Total	100.00%	$122,228,995	62,140,401				

(a) Line 1: 9 Months (Calendar Year 2023) and 12 Months (Calendar Year 2024) Revenue Requirement (Section 3: Attachment 1, Page 1, Line 17, Columns (b) and (c)):

Total Net Capital Investment Component of Revenue Requirement (9 Months (Calendar Year 2023)):	$46,984,604
Total Net Capital Investment Component of Revenue Requirement (12 Months (Calendar Year 2024)):	$75,244,391
Total Net Capital Investment Component of Revenue Requirement (21 Months (FY 2024)):	$122,228,995

(c) Docket 4770, RI 2017 Rate Case, Compliance Attachment 14 (August 16, 2018), Schedule 2, Page 1 & 2, Line 15 (Rate Class divided by Total Company)
(d) Column (a) Line 1 * Column (c)
(e) Page 2, Column (v)
(f) Column (d) / Column (e), truncated to 4 decimal places
(g) Column (d) / (Column (e)*10), truncated to 4 decimal places
(h) Docket 4770, RI 2017 Rate Case, Compliance Attachment 2 (August 16, 2018), Schedule 22, Page 7, Line 15
(i) Column (g) / (1- Column (h)), truncated to 4 decimal places

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Forecasted Throughput April 2023 - December 2024

		Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	Res-NH	32,722	17,627	14,729	12,134	11,633	11,842	14,932	23,404	34,731
(2)	Res-H	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	1,470,815	2,633,843
(3)	Small	285,844	124,997	64,421	54,187	43,242	41,803	54,616	147,547	313,165
(4)	Medium	667,083	324,894	238,769	169,312	160,551	164,298	206,272	436,093	711,633
(5)	Large LL	341,713	146,391	78,951	43,570	40,707	44,919	84,532	243,208	400,299
(6)	Large HL	130,842	106,321	90,157	86,340	80,386	86,450	87,945	108,040	131,565
(7)	X-Large LL	132,000	52,699	28,048	23,460	24,151	28,280	68,293	150,950	184,851
(8)	X-Large HL	506,318	459,948	423,059	419,512	430,465	433,813	445,403	494,428	545,481
(9)		4,413,877	2,084,669	1,512,071	1,262,205	1,224,455	1,258,101	1,560,062	3,074,485	4,955,567

		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
		(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
(1)	Res-NH	43,448	47,295	38,266	31,196	16,815	13,747	11,279	10,809	11,015	13,974	22,390	33,227	467,216
(2)	Res-H	3,549,689	3,971,935	3,065,501	2,349,331	863,518	581,746	459,826	439,149	452,699	606,221	1,490,373	2,668,228	30,277,734
(3)	Small	449,257	540,931	407,327	289,224	126,889	64,893	54,552	43,510	42,044	54,914	148,943	315,569	3,667,874
(4)	Medium	913,591	1,030,866	832,596	682,836	337,321	248,386	178,318	169,413	173,115	214,908	448,585	725,898	9,034,738
(5)	Large LL	512,504	555,075	433,286	345,753	148,606	79,530	43,863	40,960	45,179	84,994	245,509	403,372	4,362,918
(6)	Large HL	154,028	167,116	153,378	134,268	109,569	93,550	89,718	81,602	87,678	89,120	109,228	132,845	2,310,145
(7)	X-Large LL	222,248	205,311	171,792	133,561	53,497	28,254	23,618	24,301	28,443	68,666	152,378	186,269	1,991,070
(8)	X-Large HL	577,956	579,793	544,481	507,341	460,953	424,183	420,597	431,578	434,914	446,472	495,427	546,583	10,028,706
(9)		6,422,720	7,098,322	5,646,626	4,473,510	2,117,167	1,534,289	1,281,772	1,241,321	1,275,087	1,579,269	3,112,833	5,011,991	62,140,401

Source: Company Forecast

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Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

						Difference due to:					
(1)											
(2)	Annual	Proposed	Current				DAC				
(3)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(4)											
(5)	548	$1,257.59	$1,183.75	$73.84	6.2%	$0.00	$0.00	$71.62	$0.00	$0.00	$2.22
(6)	608	$1,375.27	$1,293.32	$81.95	6.3%	$0.00	$0.00	$79.49	$0.00	$0.00	$2.46
(7)	667	$1,490.98	$1,401.08	$89.90	6.4%	$0.00	$0.00	$87.20	$0.00	$0.00	$2.70
(8)	726	$1,606.69	$1,508.85	$97.84	6.5%	$0.00	$0.00	$94.90	$0.00	$0.00	$2.94
(9)	785	$1,722.30	$1,616.53	$105.77	6.5%	$0.00	$0.00	$102.60	$0.00	$0.00	$3.17
(10)	845	$1,839.98	$1,726.11	$113.88	6.6%	$0.00	$0.00	$110.46	$0.00	$0.00	$3.42
(11)	905	$1,957.68	$1,835.72	$121.96	6.6%	$0.00	$0.00	$118.30	$0.00	$0.00	$3.66
(12)	964	$2,073.33	$1,943.42	$129.91	6.7%	$0.00	$0.00	$126.01	$0.00	$0.00	$3.90
(13)	1,023	$2,189.02	$2,051.14	$137.88	6.7%	$0.00	$0.00	$133.74	$0.00	$0.00	$4.14
(14)	1,082	$2,304.71	$2,158.92	$145.79	6.8%	$0.00	$0.00	$141.42	$0.00	$0.00	$4.37
(15)	1,142	$2,422.37	$2,268.53	$153.85	6.8%	$0.00	$0.00	$149.23	$0.00	$0.00	$4.62

Residential Heating Low Income:

							Difference due to:					
(16)												
(17)	Annual	Proposed	Current				Low Income	DAC				
(18)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(19)												
(20)	548	$933.09	$877.72	$55.38	6.3%	$0.00	($17.91)	$0.00	$71.62	$0.00	$0.00	$1.66
(21)	608	$1,020.26	$958.80	$61.46	6.4%	$0.00	($19.87)	$0.00	$79.49	$0.00	$0.00	$1.84
(22)	667	$1,105.96	$1,038.53	$67.42	6.5%	$0.00	($21.80)	$0.00	$87.20	$0.00	$0.00	$2.02
(23)	726	$1,191.64	$1,118.26	$73.38	6.6%	$0.00	($23.73)	$0.00	$94.90	$0.00	$0.00	$2.20
(24)	785	$1,277.27	$1,197.94	$79.33	6.6%	$0.00	($25.65)	$0.00	$102.60	$0.00	$0.00	$2.38
(25)	845	$1,364.45	$1,279.05	$85.41	6.7%	$0.00	($27.62)	$0.00	$110.46	$0.00	$0.00	$2.56
(26)	905	$1,451.62	$1,360.15	$91.47	6.7%	$0.00	($29.57)	$0.00	$118.30	$0.00	$0.00	$2.74
(27)	964	$1,537.24	$1,439.81	$97.43	6.8%	$0.00	($31.50)	$0.00	$126.01	$0.00	$0.00	$2.92
(28)	1,023	$1,622.94	$1,519.54	$103.41	6.8%	$0.00	($33.44)	$0.00	$133.74	$0.00	$0.00	$3.10
(29)	1,082	$1,708.63	$1,599.29	$109.35	6.8%	$0.00	($35.36)	$0.00	$141.42	$0.00	$0.00	$3.28
(30)	1,142	$1,795.78	$1,680.40	$115.38	6.9%	$0.00	($37.31)	$0.00	$149.23	$0.00	$0.00	$3.46

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2022

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Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

(31)								Difference due to:				
(32)	Annual	Proposed	Current				DAC					
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$459.93	$440.47	$19.45	4.4%	$0.00	$0.00	$18.87	$0.00	$0.00	$0.58
(36)	158	$486.85	$465.52	$21.33	4.6%	$0.00	$0.00	$20.69	$0.00	$0.00	$0.64
(37)	172	$513.81	$490.58	$23.23	4.7%	$0.00	$0.00	$22.53	$0.00	$0.00	$0.70
(38)	189	$546.49	$520.98	$25.51	4.9%	$0.00	$0.00	$24.74	$0.00	$0.00	$0.77
(39)	202	$571.49	$544.25	$27.25	5.0%	$0.00	$0.00	$26.43	$0.00	$0.00	$0.82
(40)	220	$606.06	$576.41	$29.65	5.1%	$0.00	$0.00	$28.76	$0.00	$0.00	$0.89
(41)	238	$640.70	$608.61	$32.09	5.3%	$0.00	$0.00	$31.13	$0.00	$0.00	$0.96
(42)	251	$665.72	$631.88	$33.85	5.4%	$0.00	$0.00	$32.83	$0.00	$0.00	$1.02
(43)	268	$698.38	$662.26	$36.11	5.5%	$0.00	$0.00	$35.03	$0.00	$0.00	$1.08
(44)	282	$725.30	$687.30	$38.00	5.5%	$0.00	$0.00	$36.86	$0.00	$0.00	$1.14
(45)	297	$754.18	$714.17	$40.01	5.6%	$0.00	$0.00	$38.81	$0.00	$0.00	$1.20

Residential Non-Heating Low Income:

(46)								Difference due to:				
(47)	Annual	Proposed	Current				Low Income	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$342.28	$327.69	$14.59	4.5%	$0.00	($4.72)	$0.00	$18.87	$0.00	$0.00	$0.44
(51)	158	$362.24	$346.24	$16.00	4.6%	$0.00	($5.17)	$0.00	$20.69	$0.00	$0.00	$0.48
(52)	172	$382.19	$364.77	$17.42	4.8%	$0.00	($5.63)	$0.00	$22.53	$0.00	$0.00	$0.52
(53)	189	$406.38	$387.26	$19.13	4.9%	$0.00	($6.19)	$0.00	$24.74	$0.00	$0.00	$0.57
(54)	202	$424.91	$404.47	$20.44	5.1%	$0.00	($6.61)	$0.00	$26.43	$0.00	$0.00	$0.61
(55)	220	$450.50	$428.27	$22.24	5.2%	$0.00	($7.19)	$0.00	$28.76	$0.00	$0.00	$0.67
(56)	238	$476.14	$452.07	$24.07	5.3%	$0.00	($7.78)	$0.00	$31.13	$0.00	$0.00	$0.72
(57)	251	$494.66	$469.28	$25.38	5.4%	$0.00	($8.21)	$0.00	$32.83	$0.00	$0.00	$0.76
(58)	268	$518.86	$491.77	$27.09	5.5%	$0.00	($8.76)	$0.00	$35.03	$0.00	$0.00	$0.81
(59)	282	$538.79	$510.29	$28.50	5.6%	$0.00	($9.22)	$0.00	$36.86	$0.00	$0.00	$0.86
(60)	297	$560.15	$530.15	$30.01	5.7%	$0.00	($9.70)	$0.00	$38.81	$0.00	$0.00	$0.90

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2022

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Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

(61)						Difference due to:					
(62)	Annual	Proposed	Current				DAC				
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(64)											
(65)	830	$1,854.49	$1,743.52	$110.97	6.4%	$0.00	$0.00	$107.64	$0.00	$0.00	$3.33
(66)	919	$2,019.09	$1,896.18	$122.91	6.5%	$0.00	$0.00	$119.22	$0.00	$0.00	$3.69
(67)	1,010	$2,187.45	$2,052.40	$135.05	6.6%	$0.00	$0.00	$131.00	$0.00	$0.00	$4.05
(68)	1,099	$2,352.17	$2,205.18	$146.99	6.7%	$0.00	$0.00	$142.58	$0.00	$0.00	$4.41
(69)	1,187	$2,514.96	$2,356.25	$158.71	6.7%	$0.00	$0.00	$153.95	$0.00	$0.00	$4.76
(70)	1,277	$2,681.42	$2,510.67	$170.75	6.8%	$0.00	$0.00	$165.63	$0.00	$0.00	$5.12
(71)	1,367	$2,847.84	$2,665.09	$182.75	6.9%	$0.00	$0.00	$177.27	$0.00	$0.00	$5.48
(72)	1,456	$3,012.48	$2,817.81	$194.67	6.9%	$0.00	$0.00	$188.83	$0.00	$0.00	$5.84
(73)	1,544	$3,175.35	$2,968.92	$206.43	7.0%	$0.00	$0.00	$200.24	$0.00	$0.00	$6.19
(74)	1,635	$3,343.74	$3,125.11	$218.63	7.0%	$0.00	$0.00	$212.07	$0.00	$0.00	$6.56
(75)	1,725	$3,510.25	$3,279.57	$230.68	7.0%	$0.00	$0.00	$223.76	$0.00	$0.00	$6.92

C & I Medium:

(76)						Difference due to:					
(77)	Annual	Proposed	Current				DAC				
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(79)											
(80)	6,907	$12,104.06	$11,496.65	$607.41	5.3%	$0.00	$0.00	$589.19	$0.00	$0.00	$18.22
(81)	7,650	$13,292.02	$12,619.30	$672.72	5.3%	$0.00	$0.00	$652.54	$0.00	$0.00	$20.18
(82)	8,391	$14,476.41	$13,738.53	$737.88	5.4%	$0.00	$0.00	$715.74	$0.00	$0.00	$22.14
(83)	9,136	$15,667.49	$14,864.07	$803.42	5.4%	$0.00	$0.00	$779.32	$0.00	$0.00	$24.10
(84)	9,880	$16,857.03	$15,988.21	$868.81	5.4%	$0.00	$0.00	$842.75	$0.00	$0.00	$26.06
(85)	10,623	$18,045.01	$17,110.86	$934.15	5.5%	$0.00	$0.00	$906.13	$0.00	$0.00	$28.02
(86)	11,366	$19,233.03	$18,233.53	$999.51	5.5%	$0.00	$0.00	$969.52	$0.00	$0.00	$29.99
(87)	12,111	$20,424.14	$19,359.09	$1,065.05	5.5%	$0.00	$0.00	$1,033.10	$0.00	$0.00	$31.95
(88)	12,855	$21,613.59	$20,483.15	$1,130.44	5.5%	$0.00	$0.00	$1,096.53	$0.00	$0.00	$33.91
(89)	13,596	$22,798.01	$21,602.41	$1,195.61	5.5%	$0.00	$0.00	$1,159.74	$0.00	$0.00	$35.87
(90)	14,340	$23,987.56	$22,726.53	$1,261.03	5.5%	$0.00	$0.00	$1,223.20	$0.00	$0.00	$37.83

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2022

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Rhode Island Energy
Infrastructure, Safety, and Reliability (ISR) Filing
Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

						Difference due to:					
(91)											
(92)	Annual	Proposed	Current				DAC				
(93)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(94)											
(95)	37,587	$61,244.94	$58,423.97	$2,820.97	4.8%	$0.00	$0.00	$2,736.34	$0.00	$0.00	$84.63
(96)	41,634	$67,571.41	$64,446.70	$3,124.71	4.8%	$0.00	$0.00	$3,030.97	$0.00	$0.00	$93.74
(97)	45,683	$73,901.39	$70,472.80	$3,428.60	4.9%	$0.00	$0.00	$3,325.74	$0.00	$0.00	$102.86
(98)	49,731	$80,229.98	$76,497.58	$3,732.40	4.9%	$0.00	$0.00	$3,620.43	$0.00	$0.00	$111.97
(99)	53,777	$86,554.94	$82,518.90	$4,036.04	4.9%	$0.00	$0.00	$3,914.96	$0.00	$0.00	$121.08
(100)	57,825	$92,883.55	$88,543.67	$4,339.88	4.9%	$0.00	$0.00	$4,209.68	$0.00	$0.00	$130.20
(101)	61,873	$99,212.11	$94,568.41	$4,643.70	4.9%	$0.00	$0.00	$4,504.39	$0.00	$0.00	$139.31
(102)	65,920	$105,538.50	$100,591.09	$4,947.41	4.9%	$0.00	$0.00	$4,798.99	$0.00	$0.00	$148.42
(103)	69,967	$111,865.65	$106,614.49	$5,251.15	4.9%	$0.00	$0.00	$5,093.62	$0.00	$0.00	$157.53
(104)	74,016	$118,195.65	$112,640.62	$5,555.03	4.9%	$0.00	$0.00	$5,388.38	$0.00	$0.00	$166.65
(105)	78,063	$124,522.08	$118,663.32	$5,858.76	4.9%	$0.00	$0.00	$5,683.00	$0.00	$0.00	$175.76

C & I HLF Large:

						Difference due to:					
(106)											
(107)	Annual	Proposed	Current				DAC				
(108)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(109)											
(110)	41,956	$58,537.65	$56,751.27	$1,786.38	3.1%	$0.00	$0.00	$1,732.79	$0.00	$0.00	$53.59
(111)	46,471	$64,569.94	$62,591.32	$1,978.62	3.2%	$0.00	$0.00	$1,919.26	$0.00	$0.00	$59.36
(112)	50,991	$70,608.36	$68,437.33	$2,171.03	3.2%	$0.00	$0.00	$2,105.90	$0.00	$0.00	$65.13
(113)	55,507	$76,641.89	$74,278.56	$2,363.33	3.2%	$0.00	$0.00	$2,292.43	$0.00	$0.00	$70.90
(114)	60,028	$82,681.62	$80,125.80	$2,555.82	3.2%	$0.00	$0.00	$2,479.15	$0.00	$0.00	$76.67
(115)	64,545	$88,716.34	$85,968.17	$2,748.16	3.2%	$0.00	$0.00	$2,665.72	$0.00	$0.00	$82.44
(116)	69,062	$94,751.13	$91,810.67	$2,940.46	3.2%	$0.00	$0.00	$2,852.25	$0.00	$0.00	$88.21
(117)	73,583	$100,790.87	$97,657.89	$3,132.98	3.2%	$0.00	$0.00	$3,038.99	$0.00	$0.00	$93.99
(118)	78,099	$106,824.35	$103,499.10	$3,325.25	3.2%	$0.00	$0.00	$3,225.49	$0.00	$0.00	$99.76
(119)	82,619	$112,862.80	$109,345.11	$3,517.69	3.2%	$0.00	$0.00	$3,412.16	$0.00	$0.00	$105.53
(120)	87,137	$118,899.71	$115,189.63	$3,710.08	3.2%	$0.00	$0.00	$3,598.78	$0.00	$0.00	$111.30

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2022

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Rhode Island Energy
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Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

(121)						Difference due to:					
(122)	Annual	Proposed	Current				DAC				
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(124)											
(125)	233,835	$295,921.37	$291,702.70	$4,218.67	1.4%	$0.00	$0.00	$4,092.11	$0.00	$0.00	$126.56
(126)	259,019	$327,124.57	$322,451.54	$4,673.03	1.4%	$0.00	$0.00	$4,532.84	$0.00	$0.00	$140.19
(127)	284,197	$358,320.98	$353,193.72	$5,127.26	1.5%	$0.00	$0.00	$4,973.44	$0.00	$0.00	$153.82
(128)	309,381	$389,524.19	$383,942.56	$5,581.63	1.5%	$0.00	$0.00	$5,414.18	$0.00	$0.00	$167.45
(129)	334,562	$420,723.97	$414,688.07	$6,035.90	1.5%	$0.00	$0.00	$5,854.82	$0.00	$0.00	$181.08
(130)	359,745	$451,926.07	$445,435.79	$6,490.28	1.5%	$0.00	$0.00	$6,295.57	$0.00	$0.00	$194.71
(131)	384,928	$483,128.13	$476,183.54	$6,944.59	1.5%	$0.00	$0.00	$6,736.25	$0.00	$0.00	$208.34
(132)	410,110	$514,329.05	$506,930.16	$7,398.89	1.5%	$0.00	$0.00	$7,176.92	$0.00	$0.00	$221.97
(133)	435,293	$545,531.16	$537,677.93	$7,853.23	1.5%	$0.00	$0.00	$7,617.63	$0.00	$0.00	$235.60
(134)	460,471	$576,727.53	$568,420.05	$8,307.48	1.5%	$0.00	$0.00	$8,058.26	$0.00	$0.00	$249.22
(135)	485,655	$607,930.72	$599,168.93	$8,761.79	1.5%	$0.00	$0.00	$8,498.94	$0.00	$0.00	$262.85

C & I HLF Extra-Large:

(136)						Difference due to:					
(137)	Annual	Proposed	Current				DAC				
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(139)											
(140)	486,528	$549,943.82	$538,106.64	$11,837.19	2.2%	$0.00	$0.00	$11,482.07	$0.00	$0.00	$355.12
(141)	538,924	$608,502.38	$595,390.42	$13,111.96	2.2%	$0.00	$0.00	$12,718.60	$0.00	$0.00	$393.36
(142)	591,320	$667,060.16	$652,673.41	$14,386.75	2.2%	$0.00	$0.00	$13,955.15	$0.00	$0.00	$431.60
(143)	643,718	$725,620.72	$709,959.16	$15,661.56	2.2%	$0.00	$0.00	$15,191.71	$0.00	$0.00	$469.85
(144)	696,109	$784,173.33	$767,237.06	$16,936.27	2.2%	$0.00	$0.00	$16,428.18	$0.00	$0.00	$508.09
(145)	748,506	$842,732.94	$824,521.86	$18,211.07	2.2%	$0.00	$0.00	$17,664.74	$0.00	$0.00	$546.33
(146)	800,903	$901,292.51	$881,806.60	$19,485.91	2.2%	$0.00	$0.00	$18,901.33	$0.00	$0.00	$584.58
(147)	853,294	$959,845.05	$939,084.49	$20,760.56	2.2%	$0.00	$0.00	$20,137.74	$0.00	$0.00	$622.82
(148)	905,692	$1,018,405.66	$996,370.29	$22,035.37	2.2%	$0.00	$0.00	$21,374.31	$0.00	$0.00	$661.06
(149)	958,088	$1,076,963.44	$1,053,653.25	$23,310.19	2.2%	$0.00	$0.00	$22,610.88	$0.00	$0.00	$699.31
(150)	1,010,485	$1,135,523.01	$1,110,937.99	$24,585.02	2.2%	$0.00	$0.00	$23,847.47	$0.00	$0.00	$737.55

Note: Bill Impacts are based on rates approved and currently in effect as of November 1, 2022

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JOINT PRE-FILED DIRECT TESTIMONY

OF

STEPHANIE A. BRIGGS

JEFFREY D. OLIVEIRA

ANDREW W. ELMORE

AND

NATALIE HAWK

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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 your responsibilities within 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 (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 ("PUC")?

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, and most recently in the Company's Advanced Metering Functionality Business Case, Docket No. 22-49-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 your responsibilities within 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 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 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 testified before the PUC in support of the Company's filings in several proceedings as follows: 2022 Last Resort Service Rate Filing, Docket No. 4978; 2022 Renewable Energy Growth Factor Filing, Docket No. 22-04-REG; 2022 Annual Retail Rate Filing Docket 5234; Joint Petition of National Grid and the Rhode Island Division of Public Utilities and Carriers ("Division") filed February 23, 2022 relating to the Storm Contingency Fund Replenishment, Docket No. 4686; 2021 Distribution Adjustment Charge Filing, Docket No. 5165; 2021 Pension Adjustment Factor Filing, Docket No. 5179; 2020 Distribution Adjustment Charge Filing, Docket No. 5040; 2020 Pension Adjustment Factor Filing, Docket No. 5054; 2019 Distribution Adjustment Charge Filing, Docket No. 4955; 2019 Pension Adjustment Factor Filing,, Docket No. 4958; 2018 Distribution Adjustment Charge Filing, Docket No. 4846; 2018 Pension Adjustment Factor Filing, Docket No. 4855; and again in Docket No. 4686, in support of the Joint Proposal and Settlement submitted by the Company and the Division dated September 25, 2017 pertaining to the operation of the Storm Contingency Fund. I have also submitted pre-filed testimony to the Massachusetts Department of Public Utilities on behalf of the Company's affiliates, Massachusetts Electric Company and Nantucket

Electric Company, as a revenue requirement witness in annual pension adjustment mechanism proceedings.

__**Andrew W. Elmore**__

Q. Please state your full name and business address.

A. My name is Andrew W. Elmore, and my business address is 2 North 9th Street, Allentown, Pennsylvania 18049.

Q. Please state your position and your responsibilities within that position.

A. I am employed by the Services Corporation as the Vice President - Tax. The Services Corporation provides, among other things, tax services to PPL and its subsidiary companies, including Rhode Island Energy. My current duties include responsibility for, and oversight of, all tax matters of the PPL group of companies.

Q. Please describe your education and professional experience

A. In 1989, I received a Bachelor of Arts degree in French and Political Science from the University of Massachusetts in Boston. In 1993, I obtained a law degree from the University of Kentucky College of Law. I was formerly a member of the Rhode Island Bar Association and am currently a member of the Massachusetts Bar Association. In 1993, I joined the law firm of Powers, Kinder and Kenney, based in Providence Rhode Island, as an associate. I then joined Arthur Andersen as an International Tax Consultant in 1996. In turn, I joined the firm Deloitte & Touche as an International Tax Manager in 2000. In 2004, I accepted a position at United Technologies Corporation as an International Tax Manager. I subsequently worked as the Director of International Tax for Zimmer Corporation in Indiana from 2006 until 2011, at which time I joined PPL as the Director of International Tax. In 2016, I assumed the role of Director of Tax Planning and Compliance. I was then promoted to the position of Vice President – Tax in 2020.

Q. Have you previously filed testimony or testified before the PUC or any other jurisdiction?

A. No.

<u>Natalie Hawk</u>

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. No.

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 3 of the proposed fiscal year ("FY") 2024 21-Month Gas ISR Plan ("Gas ISR Plan" or "Plan"), which covers the period April 1, 2023 through December 31, 2024. Section 3, Attachment 1 describes the calculation of the Company's revenue requirement for the nine-month period from April 1, 2023 through December 31, 2023 ("CY 2023") and the twelve-month period from January 1, 2024 through December 31, 2024 ("CY 2024"). The revenue requirement is based on the 21-month Gas ISR Plan capital investment described in the joint pre-filed direct testimony of Company Witnesses Nathan Kocon and Laeyeng Hunt. The Company's FY 2023 Gas ISR Plan for the period April 1, 2022 through March 31, 2023 approved in Docket No. 5210 is referenced in this section as "FY 2023-NG."

III. Gas ISR Plan Revenue Requirement

Q. Please summarize the revenue requirement for the Company's 21-Month FY 2024 Gas ISR Plan.

A. As shown in Attachment 1, Page 1, Column (b), the Company's CY 2023 Gas ISR Plan revenue requirement totals $46,984,604, or an incremental $4,547,633 over the amount currently being billed for the Gas ISR Plan. The Plan's revenue requirement consists of the following elements: (1) the revenue requirement of $4,641,664 comprised of the Company's return, taxes and depreciation expense associated with CY 2023 proposed non-growth ISR incremental capital investment in gas utility infrastructure of $157,130,000, as calculated on Attachment 1, Page 27; (2) the CY 2023 revenue requirement on incremental non-growth ISR capital investment for FY 2018 through FY 2023-NG totaling $34,717,355; (3) CY 2023 property tax expense of $10,957,033, as shown on Attachment 1 at Page 40, in accordance with the property tax recovery mechanism included in the Amended Settlement Agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770; and (4) a reduction to the revenue requirement of $3,331,448 for the CY 2023 Hold Harmless adjustment. Importantly, the incremental capital investment for the CY 2023 ISR revenue requirement excludes capital investment embedded in base distribution rates in Docket No. 4770 for FY 2018 through FY 2023-NG. Incremental non-growth capital investment for this purpose is intended to represent the net change in net plant for non-growth infrastructure investments during the relevant fiscal year and is defined as capital additions plus cost of removal, less annual depreciation expense ultimately embedded in the Company's base distribution rates (excluding depreciation expense attributable to general plant, which is not eligible for inclusion in the Gas ISR Plan). Additionally, as shown in Attachment 1, Page 1, Column (c), the Company's CY 2024 Gas ISR Plan revenue requirement totals $75,244,391, or an incremental $28,259,788 over the CY 2023 revenue requirement. The Plan's revenue requirement consists of the following elements: (1) the revenue requirement of $7,813,055 comprised of the Company's return, taxes and depreciation expense associated with CY 2024 proposed non-growth

ISR incremental capital investment in gas utility infrastructure of $189,714,000, as calculated on Attachment 1, Page 31; (2) the CY 2024 revenue requirement on incremental non-growth ISR capital investment for FY 2018 through CY 2023 totaling $57,327,960; (3) CY 2024 property tax expense of $14,427,754, as shown on Attachment 1 at Page 40, in accordance with the property tax recovery mechanism included in the Amended Settlement Agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770; and (4) a reduction to the revenue requirement of $4,324,378 for the CY 2024 Hold Harmless adjustment. Importantly, the incremental capital investment for the CY 2024 ISR revenue requirement excludes capital investment embedded in base distribution rates in Docket No. 4770 for FY 2018 through CY 2023. Incremental non-growth capital investment for this purpose is intended to represent the net change in net plant for non-growth infrastructure investments during the relevant fiscal year and is defined as capital additions plus cost of removal, less annual depreciation expense ultimately embedded in the Company's base rates (excluding depreciation expense attributable to general plant, which is not eligible for inclusion in the Gas ISR Plan).

Q. Did the Company calculate the 21-Month Gas ISR Plan revenue requirement in the same fashion as calculated in the previous ISR factor submissions?

A. Yes. Per the PUC's Order in the FY 2022 Gas ISR Plan, Docket No. 5099 and the resulting revisions to the Company's Gas tariff, RIPUC NG-GAS No. 101 at Section 3, Schedule A, Sheets 4 and 5, the definition of ISR capital investment changed from "non-growth capital spending" to "non-growth capital investment recorded as in service" effective April 1, 2021. The Company has since reflected the impact of this change in its FY 2021 and FY 2022 ISR Gas reconciliations, FY 2023-NG Gas ISR Plan and now its FY 2024 21-month Gas ISR Plan revenue requirements. For the FY 2021 transition year, the vintage year FY 2021 ISR Plan capital investment is calculated as the difference between FY 2021 ISR Plan actual capital spending and the cumulative ISR Plan capital spending included in the Construction Work in Progress ("CWIP") balance as of March 31, 2021. The CY 2023 and CY 2024 ISR vintage year ISR capital investments reflect the ISR Plan capital investment projected to be in-service in the respective vintage year.

Q. Please explain the increase of CY 2023 Gas ISR Plan revenue requirement over the amount currently being billed for Gas ISR Plan.

A. As mentioned above, the Company's CY 2023 Gas ISR Plan revenue requirement is $4,547,633 higher than the FY 2023-NG Gas ISR Plan revenue requirement. Of the total $46,984,604 CY 2023 revenue requirement, $34,717,355 in capital investment revenue requirement and $7,839,961 in property tax recovery adjustment are associated with incremental non-growth ISR Plan capital investment for FY 2018 through FY 2023-NG, which the PUC has approved in previous Gas ISR Plan or reconciliation filings. The increase in the CY 2023 revenue requirement compared to the approved FY 2023-NG Plan revenue requirement on that same investment totals $120,345 and is caused by the net impact of increase related to the half-year convention applied in the year of service in the FY 2023-NG plan, the higher estimated property tax rate in CY 2023 compared to the estimated FY 2023-NG property tax rate, an increase to vintage rate base affected by the sale as described below, offset by the proration to account for the fact that CY 2023 is only a nine-month revenue requirement compared to FY 2023-NG which was a 12-month period. As a result, the CY 2023 revenue requirement on vintage year FY 2023-NG incremental non-growth ISR capital investment increased by $3,211,407 from the FY 2023-NG revenue requirement on the same investment. The CY 2023 proposed incremental non-growth ISR capital investment and the resulting increase in property tax expense due to the fact that incremental investment accounts for $7,758,737 of the CY 2023 revenue requirement over the FY 2023-NG revenue requirement. Lastly, the total CY 2023 revenue requirement was reduced for the tax hold harmless adjustment of $3,331,448.

Q. Please explain the increase of CY 2024 Gas ISR Plan revenue requirement over the CY 2023 proposed revenue requirement.

A. As mentioned above, the Company's CY 2024 Gas ISR Plan revenue requirement is $28,259,788 higher than the CY 2023 Gas ISR Plan revenue requirement. Of the total $75,244,391 CY 2024 revenue requirement, $57,327,960 in capital investment revenue requirement and $10,460,839 in property tax recovery adjustment are associated with incremental non-growth ISR Plan capital investment for FY 2018 through CY 2023. The increase in the CY 2024 revenue requirement compared to the proposed CY 2023 plan revenue requirement on that same investment totals $17,472,768 and is mainly caused by the impact of the half-year convention applied in the year of service in the CY 2023 plan and an increase in that CY 2024 is a 12-month revenue requirement compared to only a nine-month revenue requirement for CY 2023. As a result, the CY 2024 revenue requirement on vintage year CY 2023 incremental non-growth ISR capital investment increased by $7,567,945 from the CY 2023 revenue requirement on the same investment. The CY 2024 proposed incremental non-growth ISR capital investment and the resulting increase in property tax expense due to that incremental investment accounts for $11,779,949 of the CY 2024 revenue requirement over the CY 2023 revenue requirement. The CY 2024 revenue requirement increase was offset by a reduction to the CY 2024 revenue requirement for $992,930 for the tax hold harmless adjustment over the CY 2023 adjustment amount.

Q. What are the impacts of the sale of the Company to PPL Rhode Island on the 21-Month Gas ISR Plan revenue requirement calculations?

A. As indicated above, on May 25, 2022, PPL Rhode Island, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of Company from National Grid. 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 $39,612,934 for CY 2023 and $51,419,471 for CY 2024. Consequently, the increase in rate base ultimately increases the return on rate base recoverable through the ISR mechanism. The expected impact to the 21-month Gas ISR Plan revenue requirement would be an increase of approximately $3,331,448 in CY 2023 and $4,324,378 in CY 2024 as shown on Section 3, Attachment 1, Page 1, Line 16 and shown in detail on Section 3, Attachment 2. The expected increase to the FY 2023-NG Gas ISR revenue requirement will be reflected in the Company's FY 2023-NG Gas ISR reconciliation to be filed by August 1, 2023.

Q. How does the Company propose to address the above increases to the revenue requirements on the FY 2024 Gas 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.[1] The Company is proposing to reduce the CY 2023 and CY 2024 revenue requirements by the calculated hold harmless amounts as shown on Section 3, Attachment 1, Page 1, Line 16. 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 Gas ISR Plan revenue requirements reflecting the actual tax deductions or NOLs generated or utilized as submitted in its tax return. The Company will revise the revenue requirement in this filing to reflect the actual tax repair deductibility percentages and NOL utilization on vintage FY 2022 ISR Plan capital investment per the Company's filed FY 2022 federal income tax return.

Q. Please describe any changes to the presentation of the revenue requirements calculations because of the Acquisition.

A. Because of the §338 election, the Acquisition 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 the Acquisition. To reflect these

[1] *See* Report and Order, Docket No. D-21-09 at 257, commitment #16 (February 23, 2023).

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-NG were separated into three columns in Section 3, Attachment 1, Pages 2,6,10,15,19 and 23. The first FY 2023 column labeled as "NG, 4/1/22-5/24/22", reflects the 55 days of National Grid ownership during FY 2023. The second FY 2023 column labeled as "PPL, 5/25/22-12/31/22" reflects the period from acquisition date through December 31, 2022, which represents the first year 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 third FY 2023 column labeled "PPL, 1/1/23-3/31/23, representing January 1 through March 31, 2023, fall under a new tax return year for PPL in which tax depreciation is calculated for the 2023 calendar year and prorated to the first three months of 2023 in the FY 2023 plan. Once the impacts of the sale are reflected in the FY 2023 plan year, the calculations can be rolled forward into future years (i.e., the 21-month plan) to compute the proper rate base and revenue requirement.

Q. As a result of the Acquisition, are there any changes to the Company's policies regarding capitalizing expenditures for plant, property, and equipment used for regulatory reporting purposes that affect the revenue requirement or rate impacts presented in this filing?

A. There is no impact on this filing. The Company is continuing to capitalize to the same thresholds as when it was owned by National Grid, pending further review to determine whether to make any changes to the capitalization policy thresholds, which also depend on the systems cutover.

Q. Please describe the process that PPL is undertaking to review the policies regarding capitalizing expenditures for plant, property, and equipment used for regulatory reporting purposes.

A. The capitalization policies primarily and directly impacting the Property Plant and Equipment (PPE) amount capitalized can be broken down into three main types:

1) Retirement unit, also known as property unit, listing: This identifies those items (such as poles) which are individually capitalized upon replacement. Below this level, items (such as attaching hardware) are expensed when individually replaced. This listing is integrated with the compatible units used by the work management systems as well as substation and gas equipment estimating processes. PPL will analyze the retirement unit listing as part of the process to implement a new work management system for Rhode Island Energy.

2) Software: National Grid's software capitalization threshold is $250,000, while PPL's software capitalization threshold is $50,000. PPL would propose to eventually move to a common threshold to make future software project management of integrated systems easier. At this time, as part of the effort to transition the Company from National Grid to PPL systems to exit the Transition Services Agreement ("TSA"),

PPL is expensing all transitional software projects for Rhode Island Energy, so there is no current impact on Rhode Island Energy regarding the software capitalization threshold. The expense is being recorded so that there is not impact to Rhode Island Energy customers.

3) General property, such as small tools and equipment, excluding software: See accompanying table for threshold differences between PPL and National Grid regarding small tools and equipment. In general, National Grid's capitalization thresholds are higher than PPL's. National Grid typically uses $500 to $2,500 thresholds for gas and electric, respectively. PPL uses thresholds ranging from $200 to $500, depending on types of equipment. PPL would use existing National Grid processes for procurement of these items in CY 2023, until PPL's supply chain systems are implemented. Afterwards, PPL would propose utilizing common thresholds for acquisition of general property such as small tools and equipment, to make most efficient use of common supply chain processes. Note that these types of materials are most frequently acquired based upon replacement needs, thus it is difficult to identify what is going to be incurred in advance and the future impact of decreasing the thresholds is unknown at this time.

	POLICY OR PROCESS	**CURRENT (INTERIM) TREATMENT FOR RHODE ISLAND ENERGY**	**FUTURE TREATMENT FOR RHODE ISLAND ENERGY**
1	Retirement Unit (RU) Catalog (replacement of retirement unit is capital)	The Company has an existing RU catalog under National Grid (NG)	During 2023, continue to use existing NG RU catalog. During the design phase of the work management system implementation, PPL will evaluate whether to continue using the existing catalog or have the Company utilize PPL's RU catalog.
2	Software projects (capital)	NG applies a $250K threshold	PPL utilizes a $50K threshold for capitalization and plans to apply that threshold to RIE.
3	Software as a Service (SAAS) – cloud implementation costs	Not significant	Per FERC guidance, implementation costs will continue to be capitalized consistent with ASC 350.
4	Pre-capitalized materials (meters and line transformers)	Capitalized at purchase	No change
5	General Property – office furniture and computer equipment	Capital thresholds of $2,500 for electric and $500 for gas.	Utilize PPL's current threshold of $200 for both gas and electric, which supports use of a consistent and centralized purchases process.
6	General Property – Stores, tools, lab, communication and general plant equipment	Capital threshold of $2,500 for electric and $500 for gas	Utilize PPL's threshold of $500 for both gas and electric, which supports use of a consistent and centralized purchasing process.
7	Standby Emergency Capital Spares	Assets placed in-service as backups directly related to assets served (no more spares than assets being backed up)	No change
8	Capital Clearing Overheads	Where possible, costs are directly charged to capital projects, but where impractical, costs directly related to capital process are allocated to capital projects	Based on our discussions with NG, the PPL process to be utilized for the Company is similar. The biggest change is that PPL applies capital clearing overhead to cost of removal, while NG does not.
9	A&G Overheads	A portion of A&G that is deemed directly related to capital is allocated to capital projects.	Based on our discussions with NG, the PPL process to be utilized for the Company is similar.
10	Leasehold Improvements	Capital Threshold – follows general plant thresholds	Will continue to follow general plant thresholds, based upon revised levels above.

Q. What is the timeline for implementing changes to the Company's policies regarding capitalizing expenditures for plant, property, and equipment used for regulatory reporting purposes that could impact this filing or future ISR plan-related filings?

A. The current target is end of CY 2023; however, that target date depends on cutover of numerous complex systems.

Q. Please explain how any changes to the capitalization policies will affect the Company's ISR plan-related reconciliation filings, revenue requirements, and rate impacts for future ISR plan filings.

A. As indicated above, the earliest the Company expects any changes to the capitalization policies is CY 2024. To the extent that any changes to thresholds occur during CY 2024 and impact the Gas ISR Plan capitalization amounts included in the CY 2024 revenue requirement, the differences would be captured during the CY 2024 Gas ISR Reconciliation filing, which compares the actual ISR capitalized amounts to the forecasted ISR Plan capital. Assuming that the review and capitalization changes are known before the Company files its CY 2025 Gas ISR Plan, the revenue requirement in the CY 2025 Gas ISR Plan would reflect these changes.

IV. Conclusion

Q. Does this conclude your testimony?

A. Yes.

**Testimony of
Peter Blazunas**

DIRECT TESTIMONY

OF

PETER R. BLAZUNAS

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Peter R. Blazunas and my business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. By whom are you employed and in what capacity?

A. I am a Project Manager for Concentric Energy Advisors, Inc. ("Concentric"), a management consulting firm. I am testifying on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company").

Q. Please provide your educational background and professional experience.

A. I received a Bachelor of Arts degree in Economics from the University of Dayton in 2009 and a Master of Arts degree in Economics from the University of Akron in 2011. I began my career with FirstEnergy Corp. in 2012 as a State Regulatory Analyst in the Ohio Rates and Regulatory Affairs Department. In July 2017, I joined the Potomac Electric Power Company ("Pepco") Regulatory Strategy and Revenue Policy team of the Regulatory Affairs Department of Pepco Holdings Inc. as a Senior Rate Analyst. In November 2018, I assumed the position of Manager of Rate Administration for Pepco. In that role, I was responsible for the development of electric rates, including tariff surcharges, for Pepco's Maryland and District of Columbia jurisdictions, and also participated in the development of Pepco's policies and practices with respect to rate design and assisted with regulatory compliance matters, including tariff administration and periodic filings. I left Pepco in January 2021 and assumed my current role at Concentric in October 2021.

Q. Have you previously testified before the Rhode Island Public Utility Commission (“PUC”)?

A. Yes. I have submitted pre-filed testimony before the PUC in support of the Company’s Renewable Energy (RE) Growth Program Factor filing in Docket No. 22-04-REG, the Company’s Gas Revenue Decoupling Mechanism (RDM) Reconciliation filing in Docket No. 22-13-NG, the Company’s Distribution Adjustment Charge (DAC) in Docket No. 22-13-NG, the Company’s Electric Infrastructure, Safety, and Reliability (ISR) Plan Annual Reconciliation filing in Docket No. 5098, and the Company’s Gas Cost Recovery (GCR) Filing in Docket No. 22-20-NG.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 4 of the Fiscal Year (“FY”) 2024 Gas Infrastructure, Safety, and Reliability (“ISR”) Plan (“Gas ISR Plan” or “Plan”), which describes the calculation of the proposed FY 2024 ISR factors and the customer bill impacts of the proposed ISR factors.

II. Rate Design

Q. Please summarize the rate design used to develop the ISR factors presented as part of this filing.

A. The proposed rate design for the Company's 21-month FY 2024 GAS ISR Plan for the period April 2023 through December 2024 is based on the revenue requirement of cumulative incremental capital investment in excess of capital investment that has been reflected in rate base in the Company's most recent general rate case in Docket No. 4770 and property tax expense as described in Section 3 of the ISR Plan. Furthermore, the revenue requirement used in the development of the Company's proposed rate design includes reductions for the hold harmless amounts described in the Direct Testimony of Company Witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore, and Natalie Hawk. The Company has allocated the revenue requirement associated with the capital investment to each rate class based on the rate base allocator approved by the PUC in the Amended Settlement Agreement in Docket No. 4770.[1] The billing determinants used in the Company's proposed rate design are for the twenty-one month period April 2023 through December 2024 and come from the throughput forecast utilized in the Company's 2022-23 Gas Cost Recovery filing in Docket No. 22-20-NG. The forecasted throughput is compiled by rate class and summarized as set forth in Section 4, Attachment 1, Page 2 of the proposed Gas ISR Plan. As shown in Section 4,

[1] In Docket No. 5099, the PUC approved the Company's proposal to combine the allocated revenue requirements for the Residential Heating and Residential Non-Heating rate classes, thereby deriving one ISR factor applicable to all residential customers, until the Company's next Rate Case filing.

Attachment 1, Page 1, the Company divided the allocated rate class revenue requirement, as multiplied by the rate base allocator, by the forecasted throughput for each rate class to develop separate ISR factors per rate class on a per-therm basis. The Company then adjusted each rate class's ISR factor to reflect the 1.91 percent uncollectible factor from the Amended Settlement Agreement in Docket No. 4770.

III. ISR Factors

Q. What are the ISR factors proposed by the Company?

A. The ISR factors proposed by the Company are shown in the table below and in the Gas ISR Plan at Section 4, Attachment 1.

Table 3-1 FY 2024 (April 2023 – December 2024) ISR factors per rate class

Rate Class	ISR Rate* ($/therm)
Residential	$0.2698
Small C&I	$0.2731
Medium C&I	$0.1686
Large Low Load	$0.1590
Large High Load	$0.1213
XL-Low Load	$0.0606
XL-High Load	$0.0540

*Rates include uncollectible allowance.

The Residential factors noted above apply to Residential Heating customers, Residential Non-Heating customers, as well as to customers of both of the Residential Low-Income rate classes.

IV. Bill Impacts

Q. What is the impact of the proposed ISR factors on customers' bills?

A. For the average Residential Heating customer using 845 therms annually, the proposed FY 2024 ISR factors result in an annual bill increase of $113.88 or 6.6 percent,[2] as shown in the proposed Gas ISR Plan at Section 4, Attachment 2. The annual impact of the proposed ISR factors for all rate classes is set forth in Section 4, Attachment 2 of the Plan.

V. Tariff Modifications

Q. Is the Company proposing modifications to the ISR provisions of its gas tariff, RIPUC RIE-GAS No. 101?

A. Yes. Attachment PRB-1 provides a clean and redline version of the Company's gas tariff, RIPUC RIE-GAS No.101.

Q. Please describe the nature of the changes the Company is proposing to the gas tariff, RIPUC RIE-GAS No. 101.

A. The Company is proposing modifications to the ISR Plan (Section 3.2) provision of the Distribution Adjustment Charge ("DAC") (Section 3) of its gas tariff effective April 1, 2023, to reflect the fact that the Company is proposing a one-time twenty-one month plan for the period April 1, 2023, through December 31, 2024, as compared to the twelve-

[2] The bill impact includes the Rhode Island Gross Earnings Tax of three percent.

month plans covering the period April through March that it has proposed historically. Furthermore, it is the Company's intent to move to twelve-month plans covering the period January through December beginning January 1, 2025. Consequently, the ISR Plan provision of the DAC will need to be modified again to reflect this change.

Q. As a result of its one-time proposal for a twenty-one month plan, is the Company presently proposing any modifications to the ISR Plan provision of the DAC with respect to the Reconciliation Mechanism?

A. No, not at this time. The current language in the tariff properly accounts for the fact that the Company's next adjustment to the ISR reconciliation factor will be filed as a part of its initial DAC filing on August 1, 2023, with an effective date of November 1, 2023, through October 31, 2024, and will reconcile the fiscal year 2023 (April 2022 – March 2023) ISR plan presently in effect. As a part of its August 1, 2023, filing to adjust the ISR reconciliation factor the Company will, however, include a proposal, including tariff language related to the timing of filing and effective dates, with respect to the reconciliation of the one-time FY 2024 twenty-one month plan and the twelve-month plans thereafter.

VI. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment PRB-1

Distribution Adjustment Clause Tariff (RIPUC RIE-GAS No.101) – Redlined and Clean

THE NARRAGANSETT ELECTRIC COMPANY

Rhode Island Public Utilities Commission Tariff

RIPUC RIE-GAS No. 101

DISTRIBUTION ADJUSTMENT CLAUSE

1.0 GENERAL

1.1 Purpose:

The purpose of the Distribution Adjustment Clause ("DAC") is to establish procedures that allow the Company, subject to the jurisdiction of the PUC, to annually adjust its rates for firm sales and transportation in order to recover, credit, or reconcile the following:

(1) the system pressure costs;
(2) the costs of the Infrastructure, Safety, and Reliability Plan;
(3) the amortization of the most recent ten years of Environmental Response costs;
(4) Pension costs and Post-retirement Benefits Other than Pensions expenses;
(5) to credit any Service Quality Performance penalties;
(6) any over or under collections of revenue under the Revenue Decoupling mechanism;
(7) the previous year DAC items;
(8) any Earnings Sharing;
(9) any Residential Assistance costs; and
(10) the net revenue received for Storm Restoration services provided in other jurisdictions.

Any costs recovered through the application of the Distribution Adjustment Charge shall be identified and explained fully in the annual Distribution Adjustment Charge filing.

1.2 Applicability:

The Distribution Adjustment Charge will be applied to sales and transportation volumes under each of the Company's firm rate schedules.

The Company will make annual DAC filings and its annual Reconciliation filings based on actual costs and volumes available at the time of filing as well as forecasts of applicable costs and volumes through October of that year. With the exception of the Infrastructure, Safety and Reliability component described in Item 3.2.2, the Distribution Adjustment Charge shall become effective with consumption as of November 1 each year.

Unless otherwise notified by the PUC, the Company shall submit the Distribution Adjustment Charge filings no later than 90 days before they are scheduled to take effect, provided however that the Revenue Decoupling Adjustment component of the

DISTRIBUTION ADJUSTMENT CLAUSE

Distribution Adjustment Charge filing will be made July 1 annually. The Annual Reconciliation filing will be made by August 1 of each year.

2.0 DISTRIBUTION ADJUSTMENT CHARGE:

The Distribution Adjustment Charge will consist of an annual System Pressure factor, an Advanced Gas Technology factor, an Infrastructure, Safety, and Reliability factor, an Environmental Response Cost factor, a Pension Adjustment Mechanism factor, a Service Quality Performance factor, a Revenue Decoupling Adjustment factor, and a Reconciliation of deferred account balance factor, an Earnings Sharing Mechanism factor, a Low Income Discount Recovery Factor, a Storm Net Revenue Factor and an Arrearage Management Adjustment Factor. The Distribution Adjustment Charge is calculated as follows:

DAC = SP+ISR+ERCF+PAF+SQP+RDA+AMAF+R+ESM+LIDRF+SNR

Where:

DAC	Distribution Adjustment Charge applicable to all firm throughput.
SP	System Pressure factor. See Item 3.1 for calculation.
ISR	Infrastructure, Safety, and Reliability factor. See Item 3.2 for calculation.
ERCF	Environmental Response Cost Factor. See Item 3.3 for calculation.
PAF	Pension Adjustment Factor. See Item 3.4 for calculation.
SQP	Service Quality Performance Factor. See Item 3.5 for calculation.
RDA	Revenue Decoupling Adjustment factor. See Item 3.6 for calculation.
AMAF	Arrearage Management Adjustment Factor. See Item 3.7 for calculation.
LIDRF	Low Income Discount Recovery Factor. See Item 3.8 for calculation.
SNRF	Storm Net Revenue Factor. See Item 3.9 for calculation.
R	Reconciliation of deferred account balances as of October 31. See Item 4.0 for calculation.
ESM	Earnings Sharing Mechanism Factor. See Item 5.0 for calculation.

DISTRIBUTION ADJUSTMENT CLAUSE

The Distribution Adjustment Charge, excluding the RDA, shall be increased by the uncollectible expense percentage approved in the most recent general rate case.

3.0 DISTRIBUTION ADJUSTMENT CALCULATIONS

3.1 System Pressure Factor:

The System Pressure factor shall be computed in a manner that identifies and includes all fixed and variable gas supply costs required on an annual basis to maintain pressure within the Company's distribution system and shall identify and consider all gas supply costs that are required to maintain pressure for all portions of the Company's distribution system. The System Pressure factor shall also include a reallocation of fixed gas costs incurred to meet peak hour requirements from the Company's GCR to the DAC:

$$SP = \frac{(GCSP \times SP\%) + GCPH}{Dt_T}$$

Where:

SP	System Pressure Amount.
GCSP	Forecasted Gas Costs associated with supply used to maintain system pressures, including both demand and commodity costs.
SP%	Percent of supply used to maintain system pressures, as established in the most recent general rate case or DAC proceeding.
GCPH	Forecasted fixed Gas Costs incurred to meet the peak hour requirements.
Dt_T	Forecasted annual firm throughput.

3.2 Infrastructure, Safety and Reliability Plan:

3.2.1 Gas Infrastructure, Safety, and Reliability Plan Filing:

DISTRIBUTION ADJUSTMENT CLAUSE

In compliance with R.I.G.L. Section 39-1-27.7.1, no later than January 1 of each year, the Company shall submit to the PUC a Gas Infrastructure, Safety, and Reliability Plan (Gas ISR Plan) for the upcoming fiscal year (April to subsequent ~~March~~December) for review and approval within 90 days. The Gas ISR Plan shall include the upcoming fiscal year's forecasted capital investment on its gas distribution system infrastructure and may include any other costs relating to maintaining safety and reliability that have been mutually agreed upon by the Division and the Company.

3.2.2 Infrastructure, Safety and Reliability Factor:

Effective each April 1, the Company shall recover through a change in Distribution Adjustment Charge rates the Cumulative Revenue Requirement on the Adjusted Cumulative Non-growth Capital Investment as approved by the PUC in the Company's annual gas infrastructure, safety, and reliability filings less the amount included in rate base for base rate purposes. For purposes of this section, non-growth capital shall exclude general plant (FERC Accts 389 through 399). The Cumulative Revenue Requirement shall mean the return and taxes on year-end Adjusted Cumulative Non-growth Capital Investment, at a rate equal to the pre-tax weighted average cost of capital as approved by the PUC in the most recent general rate case, plus the annual depreciation net of depreciation expense attributable to general plant that was approved by the PUC in the Company's most recent general rate case adjusted, if appropriate, by later proceedings related to capital, plus the annual municipal property tax recovery mechanism.

The Adjusted Cumulative Non-growth Capital Investment shall mean the cumulative actual non-growth capital investment recorded as in service since the end of the Company's rate year in its most recent general rate case, reflecting any difference between Actual Non-Growth Investment and Forecasted Non-Growth Investment for any period during which Forecasted Non-Growth Investment has not been reconciled to Actual Non-Growth Investment including through the end of the Company's rate year in its last general rate case. Cumulative Revenue Requirements will reflect Adjusted Cumulative Non-Growth Capital Investment as defined above plus the associated retirements, cost of removal, accumulated depreciation, and accumulated deferred taxes.

All accumulated Gas ISR investments will be eligible for inclusion in rate base recovery through new rates set in the next general rate case.

The Company shall allocate the Cumulative Revenue Requirements to its rate classes based on the rate base allocation approved by the PUC in the Company's most recent general rate case. Any other costs, including Operation and Maintenance expenses

DISTRIBUTION ADJUSTMENT CLAUSE

mutually agreed upon by the Division and the Company shall be allocated on a per unit basis.

3.2.3 Infrastructure, Safety and Reliability Factor: Reconciliation Mechanism:

The Company shall include an annual reconciliation mechanism associated with the ISR Factor designed to reconcile the actual Cumulative Revenue Requirements and any associated costs approved for recovery through this mechanism to the actual billed revenue for the prior fiscal year. As part of its annual DAC filing, the Company shall submit by August 1 a reconciliation factor (either positive or negative) related to the ISR Factor recoveries and actual Cumulative Revenue Requirements and any associated costs approved for recovery through this mechanism to take effect annually for the twelve months beginning November 1 each year.

3.3 Environmental Response Cost Factor (ERCF):

$$ERCF = \frac{\frac{\sum ERCyr_x}{10} - ERC_{EMB}}{Dt_T}$$

Where:

ERC	Environmental Response Costs as defined in Section 1, Schedule B Definitions
$\sum ERCyr_x$	The sum of Environmental Response Costs, incurred in the most recent twelve month period ended March 31.
ERC_{EMB}	Environmental Response Costs funding embedded in base rates, \$1,310,000.
Dt_T	Forecasted annual firm throughput

In order to limit the bill impacts that could potentially result from the incurrence of environmental remediation costs, the ERC factor, calculated as described above, shall be limited to an increase of no more than $0.10 per dekatherm in any annual DAC filing. If this limitation results in the Company recovering less than the amount that would otherwise be eligible for recovery in a particular year, then beginning on the date that the proposed ERC factor becomes effective, carrying costs shall accrue to the Company on the portion of the environmental remediation costs not included in

DISTRIBUTION ADJUSTMENT CLAUSE

the ERC factor as a result of this limitation. Such carrying costs shall accrue through the year in which such amount, together with accumulated carrying costs, are recovered from ratepayers. Any amounts so deferred shall be incorporated into the ERC factor in succeeding years consistent with the $0.10 per dekatherm ERC factor annual increase limitation. Such carrying charges shall accrue at the Interest on Deferred Balance rate specified in Section 1, Schedule B of the Company's Definition section above.

3.4 Pension Adjustment Factor:

The Pension Adjustment Factor shall recover or refund the prior fiscal year's reconciliation of the Company's actual Pension and Post-retirement Benefits Other Than Pension (PBOP) expenses to the Company's Pension and PBOP expense allowance included in distribution base rates, including interest at the rate of interest paid on customer deposits. The recoverable actual Pension and PBOP shall reflect expense recorded on the Company's books of account pursuant to the Financial Accounting Standards Board ("FASB") Accounting Standards Codification Topic 715, Compensation—Retirement Benefits, as amended in March 2017 in a FASB Accounting Standards Update (formerly Statement of Financial Accounting Standards ("SFAS") 87 and SFAS 106) associated with pension and PBOP. The PAF will be computed on an annual basis for the twelve months ended March 31 and will be based on the difference in the Company's actual Pension and PBOP expense for the prior twelve month period ended March 31 and the distribution base rate allowance, plus carrying charges at the weighted average cost of capital on the cumulative five quarter average underfunding of the Pension and PBOP Minimum Funding Obligation for the fiscal year ended March 31. The Minimum Funding Obligation will be equal to the amount of Pension and PBOP costs collected from customers during the fiscal year, plus the amounts of Pension and PBOP costs capitalized during the year. The amount collected from customers during the fiscal year would include (1) Pension and PBOP allowance included in base rates, and (2) amounts collected or refunded through the PAF. For the purpose of determining its Minimum Funding Obligation and the carrying costs that apply to that obligation, the Company shall be permitted to combine the funding of pensions and PBOPs, thereby offsetting, any deficiencies in PBOPs funding with any excess pension funding, or conversely offsetting any deficiencies in pension funding with any excess PBOP funding. The Company will be required to accrue and defer carrying charges on only the net unfunded pension/PBOP amount.

3.5 Service Quality Performance Factor:

The Service Quality Performance (SQP) Factor will be used for crediting to customers any penalties reflected in the Company's annual Service Quality Report.

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3.6 Revenue Decoupling Adjustment Factor:

The Revenue Decoupling Adjustment (RDA) Factor shall be a credit or surcharge determined for all Residential rate classes and Small and Medium C&I rate classes as the sum of the March 31 deferral ending balances for each rate class divided by the forecasted total annual firm throughput for those rate classes. The March deferral ending balance for each rate class shall result from the monthly calculation of the difference between the Target Revenue-per-Customer and the Actual Revenue-Per-Customer for each twelve months ending March 31. The deferral balance will be calculated as follows:

$$RDAF = \frac{\sum_{RC}(AEB_{M-1} + DIFF_M + INT_M)}{Dt_{RC}}$$

Where:

RDAF — Revenue Decoupling Adjustment Factor

$\sum_{RC}$ — The sum of the March 31 deferral ending balances for each of the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I.

AEB_{M-1} — Account Ending Balance for prior month

$DIFF_M$ — Current month Difference

$$= (RPC_{TM} - RPC_{AM}) \times CUST_M$$

RPC_{TM} — Target Revenue-per-Customer based on class specific revenue per customer targets established in the most recent general rate case. The target for Low-Income classes will reflect non-discounted revenue. Low-income class revenue and customers will be included with non-discounted revenue and customers for the purposes of setting the target.

RPC_{AM} — Actual Revenue-per-Customer for current month calculated as actual base revenue divided by number of

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customers in the current month. Revenue for Low-Income classes will reflect non-discounted revenue.

$CUST_M$ Number of customers in current month

INT_M Interest on average monthly balance based on the Bank of America Prime minus 200 basis points.

Dt_{RC} Forecasted annual firm throughput for the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I.

3.7 Arrearage Management Adjustment Factor (AMAF):

In compliance with R.I.G.L. §39-2-1(d)(2), the Company shall surcharge customers allowable amounts forgiven through the Arrearage Management Plan (AMP) over the prior calendar year as described in Section 7, Schedule C, Item 9.0 through the AMAF.

$$AMAF = \frac{AMPC}{Dt_T}$$

Where:

AMPC Allowable arrearage management plan costs the Company may recover from firm customers in accordance with R.I.G.L. § 39-2-1(d)(2) and described in Section 7, Schedule C, Item 9.0.

Dt_T Forecasted annual firm throughput

3.8 Low Income Discount Recovery Factor (LIDRF):

The Low Income Discount Recovery Factor shall be determined annually based upon the total amount of low income discount applied to eligible customer bills. The low income discount percentages are as follows:

- Residential Assistance Non-Heating, Rate 11: 25% with an additional 5% for a total of 30% for those customers receiving benefits through Medicaid, General Public Assistance, and/or the Rhode Island Works Program (formerly known as the Family Independence Program).

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- Residential Assistance Heating, Rate 13: 25% with an additional 5% for a total discount of 30% for those customers receiving benefits through Medicaid, General Public Assistance, and/or the Rhode Island Works Program.

$$LIDRF = \frac{LIDC}{Dt_T}$$

Where:

LIDC Annual low income discounts provided to eligible low income customers which the Company may recover from firm customers.

Dt_T Forecasted annual firm throughput excluding Rate 11 and Rate 13 forecasted annual throughput.

3.9 Storm Net Revenue Factor (SNRF):

The Storm Net Revenue Factor shall credit customers the value of services performed by the Company's employees in other jurisdictions, including those outside of PPL Corporation's operating companies' service territories, in accordance with the provisions of the Amended Settlement Agreement ("ASA") in Docket No. 4770. In accordance with the ASA, the Company will credit customers 75 percent of the Storm Net Revenue received by the Company.

$$SNRF = \frac{SNR \times 75\%}{Dt_T}$$

Where:

SNR The proceeds received or cost reductions achieved for base labor and non-incremental labor overhead costs on all labor (i.e., not just base labor) charged for storm restoration services provided to other utilities, whether affiliated or non-affiliated, less an amount equal to 55.18 percent, which is the labor capitalization rate set in the Company's general rate case.

Dt_T Forecasted annual firm throughput

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4.0 DEFERRED DISTRIBUTION ADJUSTMENT COST ACCOUNT:

The Distribution Adjustment Cost Account shall include annual reconciliation for the twelve month period for the revenues and costs for the System Pressure factor, ISR factor, Environmental Response Costs factor, Pension Adjustment factor, SQP factor, RDA factor, ESM factor, AMAF, LIDRF, SNRF, and a Previous Reconciliation factor, including a true-up for any prior year's forecasted revenues and costs. Base rate related items (Pension Adjustment factor and Environmental Response Cost factor) will be reconciled only for those non-Revenue Decoupling rate classes (Large and Extra Large high load and low load factor rate classes). For each reconciliation component, a monthly rate based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning and ending balance shall also apply.

5.0 EARNINGS SHARING MECHANISM:

The Earnings Sharing Mechanism Credit ("ESMC") will be filed on May 1 and will reflect a 12-month period ending December 31. For purposes of calculating earnings to be shared, the Company will be allowed to include its 50% share of net merger synergies resulting from the National Grid/KeySpan transactions, or $2,450,000. Calculation of the ESMC is as follows:

$$ESMC = \frac{ESMF}{Dt_T}$$

Where:

ESMF — Earnings Sharing Mechanism Fund is defined as customers' share of earnings subject to sharing and will be based on the return on equity authorized by the PUC in a general rate case or as otherwise authorized by the PUC. For FY 18, the annual earnings over 9.5% return on equity, up to and including 100 basis points, being shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of 9.5% return on equity shall be shared 75% to customers and 25% to the Company. For all subsequent ESMC, the annual earnings over 9.275% return on equity, and up to and including 100 basis points (i.e., 10.275%), will be shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of 9.275% return on equity (i.e., exceeding 10.275%) shall be shared 75% to customers and 25% to the Company. The Company's share of any shared earnings will be retained by Company and not reflected in any earnings report.

Dt_T — Forecasted annual firm throughput

THE NARRAGANSETT ELECTRIC COMPANY

Rhode Island Public Utilities Commission Tariff

RIPUC RIE-GAS No. 101

DISTRIBUTION ADJUSTMENT CLAUSE

1.0 GENERAL

1.1 Purpose:

The purpose of the Distribution Adjustment Clause ("DAC") is to establish procedures that allow the Company, subject to the jurisdiction of the PUC, to annually adjust its rates for firm sales and transportation in order to recover, credit, or reconcile the following:

(1) the system pressure costs;
(2) the costs of the Infrastructure, Safety, and Reliability Plan;
(3) the amortization of the most recent ten years of Environmental Response costs;
(4) Pension costs and Post-retirement Benefits Other than Pensions expenses;
(5) to credit any Service Quality Performance penalties;
(6) any over or under collections of revenue under the Revenue Decoupling mechanism;
(7) the previous year DAC items;
(8) any Earnings Sharing;
(9) any Residential Assistance costs; and
(10) the net revenue received for Storm Restoration services provided in other jurisdictions.

Any costs recovered through the application of the Distribution Adjustment Charge shall be identified and explained fully in the annual Distribution Adjustment Charge filing.

1.2 Applicability:

The Distribution Adjustment Charge will be applied to sales and transportation volumes under each of the Company's firm rate schedules.

The Company will make annual DAC filings and its annual Reconciliation filings based on actual costs and volumes available at the time of filing as well as forecasts of applicable costs and volumes through October of that year. With the exception of the Infrastructure, Safety and Reliability component described in Item 3.2.2, the Distribution Adjustment Charge shall become effective with consumption as of November 1 each year.

Unless otherwise notified by the PUC, the Company shall submit the Distribution Adjustment Charge filings no later than 90 days before they are scheduled to take effect, provided however that the Revenue Decoupling Adjustment component of the

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Distribution Adjustment Charge filing will be made July 1 annually. The Annual Reconciliation filing will be made by August 1 of each year.

2.0 DISTRIBUTION ADJUSTMENT CHARGE:

The Distribution Adjustment Charge will consist of an annual System Pressure factor, an Advanced Gas Technology factor, an Infrastructure, Safety, and Reliability factor, an Environmental Response Cost factor, a Pension Adjustment Mechanism factor, a Service Quality Performance factor, a Revenue Decoupling Adjustment factor, and a Reconciliation of deferred account balance factor, an Earnings Sharing Mechanism factor, a Low Income Discount Recovery Factor, a Storm Net Revenue Factor and an Arrearage Management Adjustment Factor. The Distribution Adjustment Charge is calculated as follows:

DAC = SP+ISR+ERCF+PAF+SQP+RDA+AMAF+R+ESM+LIDRF+SNR

Where:

DAC	Distribution Adjustment Charge applicable to all firm throughput.
SP	System Pressure factor. See Item 3.1 for calculation.
ISR	Infrastructure, Safety, and Reliability factor. See Item 3.2 for calculation.
ERCF	Environmental Response Cost Factor. See Item 3.3 for calculation.
PAF	Pension Adjustment Factor. See Item 3.4 for calculation.
SQP	Service Quality Performance Factor. See Item 3.5 for calculation.
RDA	Revenue Decoupling Adjustment factor. See Item 3.6 for calculation.
AMAF	Arrearage Management Adjustment Factor. See Item 3.7 for calculation.
LIDRF	Low Income Discount Recovery Factor. See Item 3.8 for calculation.
SNRF	Storm Net Revenue Factor. See Item 3.9 for calculation.
R	Reconciliation of deferred account balances as of October 31. See Item 4.0 for calculation.
ESM	Earnings Sharing Mechanism Factor. See Item 5.0 for calculation.

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The Distribution Adjustment Charge, excluding the RDA, shall be increased by the uncollectible expense percentage approved in the most recent general rate case.

3.0 DISTRIBUTION ADJUSTMENT CALCULATIONS

3.1 System Pressure Factor:

The System Pressure factor shall be computed in a manner that identifies and includes all fixed and variable gas supply costs required on an annual basis to maintain pressure within the Company's distribution system and shall identify and consider all gas supply costs that are required to maintain pressure for all portions of the Company's distribution system. The System Pressure factor shall also include a reallocation of fixed gas costs incurred to meet peak hour requirements from the Company's GCR to the DAC:

$$SP = \frac{(GCSP \times SP\%) + GCPH}{Dt_T}$$

Where:

SP — System Pressure Amount.

GCSP — Forecasted Gas Costs associated with supply used to maintain system pressures, including both demand and commodity costs.

SP% — Percent of supply used to maintain system pressures, as established in the most recent general rate case or DAC proceeding.

GCPH — Forecasted fixed Gas Costs incurred to meet the peak hour requirements.

Dt_T — Forecasted annual firm throughput.

3.2 Infrastructure, Safety and Reliability Plan:

3.2.1 Gas Infrastructure, Safety, and Reliability Plan Filing:

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In compliance with R.I.G.L. Section 39-1-27.7.1, no later than January 1 of each year, the Company shall submit to the PUC a Gas Infrastructure, Safety, and Reliability Plan (Gas ISR Plan) for the upcoming fiscal year (April to subsequent December) for review and approval within 90 days. The Gas ISR Plan shall include the upcoming fiscal year's forecasted capital investment on its gas distribution system infrastructure and may include any other costs relating to maintaining safety and reliability that have been mutually agreed upon by the Division and the Company.

3.2.2 Infrastructure, Safety and Reliability Factor:

Effective each April 1, the Company shall recover through a change in Distribution Adjustment Charge rates the Cumulative Revenue Requirement on the Adjusted Cumulative Non-growth Capital Investment as approved by the PUC in the Company's annual gas infrastructure, safety, and reliability filings less the amount included in rate base for base rate purposes. For purposes of this section, non-growth capital shall exclude general plant (FERC Accts 389 through 399). The Cumulative Revenue Requirement shall mean the return and taxes on year-end Adjusted Cumulative Non-growth Capital Investment, at a rate equal to the pre-tax weighted average cost of capital as approved by the PUC in the most recent general rate case, plus the annual depreciation net of depreciation expense attributable to general plant that was approved by the PUC in the Company's most recent general rate case adjusted, if appropriate, by later proceedings related to capital, plus the annual municipal property tax recovery mechanism.

The Adjusted Cumulative Non-growth Capital Investment shall mean the cumulative actual non-growth capital investment recorded as in service since the end of the Company's rate year in its most recent general rate case, reflecting any difference between Actual Non-Growth Investment and Forecasted Non-Growth Investment for any period during which Forecasted Non-Growth Investment has not been reconciled to Actual Non-Growth Investment including through the end of the Company's rate year in its last general rate case. Cumulative Revenue Requirements will reflect Adjusted Cumulative Non-Growth Capital Investment as defined above plus the associated retirements, cost of removal, accumulated depreciation, and accumulated deferred taxes.

All accumulated Gas ISR investments will be eligible for inclusion in rate base recovery through new rates set in the next general rate case.

The Company shall allocate the Cumulative Revenue Requirements to its rate classes based on the rate base allocation approved by the PUC in the Company's most recent general rate case. Any other costs, including Operation and Maintenance expenses

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mutually agreed upon by the Division and the Company shall be allocated on a per unit basis.

3.2.3 Infrastructure, Safety and Reliability Factor: Reconciliation Mechanism:

The Company shall include an annual reconciliation mechanism associated with the ISR Factor designed to reconcile the actual Cumulative Revenue Requirements and any associated costs approved for recovery through this mechanism to the actual billed revenue for the prior fiscal year. As part of its annual DAC filing, the Company shall submit by August 1 a reconciliation factor (either positive or negative) related to the ISR Factor recoveries and actual Cumulative Revenue Requirements and any associated costs approved for recovery through this mechanism to take effect annually for the twelve months beginning November 1 each year.

3.3 Environmental Response Cost Factor (ERCF):

$$ERCF = \frac{\frac{\sum ERCyr_x}{10} - ERC_{EMB}}{Dt_T}$$

Where:

ERC	Environmental Response Costs as defined in Section 1, Schedule B Definitions
$\sum ERCyr_x$	The sum of Environmental Response Costs, incurred in the most recent twelve month period ended March 31.
ERC_{EMB}	Environmental Response Costs funding embedded in base rates, \$1,310,000.
Dt_T	Forecasted annual firm throughput

In order to limit the bill impacts that could potentially result from the incurrence of environmental remediation costs, the ERC factor, calculated as described above, shall be limited to an increase of no more than \$0.10 per dekatherm in any annual DAC filing. If this limitation results in the Company recovering less than the amount that would otherwise be eligible for recovery in a particular year, then beginning on the date that the proposed ERC factor becomes effective, carrying costs shall accrue to the Company on the portion of the environmental remediation costs not included in

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the ERC factor as a result of this limitation. Such carrying costs shall accrue through the year in which such amount, together with accumulated carrying costs, are recovered from ratepayers. Any amounts so deferred shall be incorporated into the ERC factor in succeeding years consistent with the $0.10 per dekatherm ERC factor annual increase limitation. Such carrying charges shall accrue at the Interest on Deferred Balance rate specified in Section 1, Schedule B of the Company's Definition section above.

3.4 Pension Adjustment Factor:

The Pension Adjustment Factor shall recover or refund the prior fiscal year's reconciliation of the Company's actual Pension and Post-retirement Benefits Other Than Pension (PBOP) expenses to the Company's Pension and PBOP expense allowance included in distribution base rates, including interest at the rate of interest paid on customer deposits. The recoverable actual Pension and PBOP shall reflect expense recorded on the Company's books of account pursuant to the Financial Accounting Standards Board ("FASB") Accounting Standards Codification Topic 715, Compensation—Retirement Benefits, as amended in March 2017 in a FASB Accounting Standards Update (formerly Statement of Financial Accounting Standards ("SFAS") 87 and SFAS 106) associated with pension and PBOP. The PAF will be computed on an annual basis for the twelve months ended March 31 and will be based on the difference in the Company's actual Pension and PBOP expense for the prior twelve month period ended March 31 and the distribution base rate allowance, plus carrying charges at the weighted average cost of capital on the cumulative five quarter average underfunding of the Pension and PBOP Minimum Funding Obligation for the fiscal year ended March 31. The Minimum Funding Obligation will be equal to the amount of Pension and PBOP costs collected from customers during the fiscal year, plus the amounts of Pension and PBOP costs capitalized during the year. The amount collected from customers during the fiscal year would include (1) Pension and PBOP allowance included in base rates, and (2) amounts collected or refunded through the PAF. For the purpose of determining its Minimum Funding Obligation and the carrying costs that apply to that obligation, the Company shall be permitted to combine the funding of pensions and PBOPs, thereby offsetting, any deficiencies in PBOPs funding with any excess pension funding, or conversely offsetting any deficiencies in pension funding with any excess PBOP funding. The Company will be required to accrue and defer carrying charges on only the net unfunded pension/PBOP amount.

3.5 Service Quality Performance Factor:

The Service Quality Performance (SQP) Factor will be used for crediting to customers any penalties reflected in the Company's annual Service Quality Report.

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3.6 Revenue Decoupling Adjustment Factor:

The Revenue Decoupling Adjustment (RDA) Factor shall be a credit or surcharge determined for all Residential rate classes and Small and Medium C&I rate classes as the sum of the March 31 deferral ending balances for each rate class divided by the forecasted total annual firm throughput for those rate classes. The March deferral ending balance for each rate class shall result from the monthly calculation of the difference between the Target Revenue-per-Customer and the Actual Revenue-Per-Customer for each twelve months ending March 31. The deferral balance will be calculated as follows:

$$RDAF = \frac{\sum_{RC}(AEB_{M-1} + DIFF_M + INT_M)}{Dt_{RC}}$$

Where:

RDAF — Revenue Decoupling Adjustment Factor

$\sum_{RC}$ — The sum of the March 31 deferral ending balances for each of the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I.

AEB_{M-1} — Account Ending Balance for prior month

$DIFF_M$ — Current month Difference

$= \quad (RPC_{TM} - RPC_{AM}) \times CUST_M$

RPC_{TM} — Target Revenue-per-Customer based on class specific revenue per customer targets established in the most recent general rate case. The target for Low-Income classes will reflect non-discounted revenue. Low-income class revenue and customers will be included with non-discounted revenue and customers for the purposes of setting the target.

RPC_{AM} — Actual Revenue-per-Customer for current month calculated as actual base revenue divided by number of

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customers in the current month. Revenue for Low-Income classes will reflect non-discounted revenue.

$CUST_M$ Number of customers in current month

INT_M Interest on average monthly balance based on the Bank of America Prime minus 200 basis points.

Dt_{RC} Forecasted annual firm throughput for the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I.

3.7 Arrearage Management Adjustment Factor (AMAF):

In compliance with R.I.G.L. §39-2-1(d)(2), the Company shall surcharge customers allowable amounts forgiven through the Arrearage Management Plan (AMP) over the prior calendar year as described in Section 7, Schedule C, Item 9.0 through the AMAF.

$$AMAF = \frac{AMPC}{Dt_T}$$

Where:

AMPC Allowable arrearage management plan costs the Company may recover from firm customers in accordance with R.I.G.L. § 39-2-1(d)(2) and described in Section 7, Schedule C, Item 9.0.

Dt_T Forecasted annual firm throughput

3.8 Low Income Discount Recovery Factor (LIDRF):

The Low Income Discount Recovery Factor shall be determined annually based upon the total amount of low income discount applied to eligible customer bills. The low income discount percentages are as follows:

- Residential Assistance Non-Heating, Rate 11: 25% with an additional 5% for a total of 30% for those customers receiving benefits through Medicaid, General Public Assistance, and/or the Rhode Island Works Program (formerly known as the Family Independence Program).

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- Residential Assistance Heating, Rate 13: 25% with an additional 5% for a total discount of 30% for those customers receiving benefits through Medicaid, General Public Assistance, and/or the Rhode Island Works Program.

$$LIDRF = \frac{LIDC}{Dt_T}$$

Where:

LIDC — Annual low income discounts provided to eligible low income customers which the Company may recover from firm customers.

Dt_T — Forecasted annual firm throughput excluding Rate 11 and Rate 13 forecasted annual throughput.

3.9 Storm Net Revenue Factor (SNRF):

The Storm Net Revenue Factor shall credit customers the value of services performed by the Company's employees in other jurisdictions, including those outside of PPL Corporation's operating companies' service territories, in accordance with the provisions of the Amended Settlement Agreement ("ASA") in Docket No. 4770. In accordance with the ASA, the Company will credit customers 75 percent of the Storm Net Revenue received by the Company.

$$SNRF = \frac{SNR \times 75\%}{Dt_T}$$

Where:

SNR — The proceeds received or cost reductions achieved for base labor and non-incremental labor overhead costs on all labor (i.e., not just base labor) charged for storm restoration services provided to other utilities, whether affiliated or non-affiliated, less an amount equal to 55.18 percent, which is the labor capitalization rate set in the Company's general rate case.

Dt_T — Forecasted annual firm throughput

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4.0 DEFERRED DISTRIBUTION ADJUSTMENT COST ACCOUNT:

The Distribution Adjustment Cost Account shall include annual reconciliation for the twelve month period for the revenues and costs for the System Pressure factor, ISR factor, Environmental Response Costs factor, Pension Adjustment factor, SQP factor, RDA factor, ESM factor, AMAF, LIDRF, SNRF, and a Previous Reconciliation factor, including a true-up for any prior year's forecasted revenues and costs. Base rate related items (Pension Adjustment factor and Environmental Response Cost factor) will be reconciled only for those non-Revenue Decoupling rate classes (Large and Extra Large high load and low load factor rate classes). For each reconciliation component, a monthly rate based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning and ending balance shall also apply.

5.0 EARNINGS SHARING MECHANISM:

The Earnings Sharing Mechanism Credit ("ESMC") will be filed on May 1 and will reflect a 12-month period ending December 31. For purposes of calculating earnings to be shared, the Company will be allowed to include its 50% share of net merger synergies resulting from the National Grid/KeySpan transactions, or $2,450,000. Calculation of the ESMC is as follows:

$$ESMC = \frac{ESMF}{Dt_T}$$

Where:

ESMF — Earnings Sharing Mechanism Fund is defined as customers' share of earnings subject to sharing and will be based on the return on equity authorized by the PUC in a general rate case or as otherwise authorized by the PUC. For FY 18, the annual earnings over 9.5% return on equity, up to and including 100 basis points, being shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of 9.5% return on equity shall be shared 75% to customers and 25% to the Company. For all subsequent ESMC, the annual earnings over 9.275% return on equity, and up to and including 100 basis points (i.e., 10.275%), will be shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of 9.275% return on equity (i.e., exceeding 10.275%) shall be shared 75% to customers and 25% to the Company. The Company's share of any shared earnings will be retained by Company and not reflected in any earnings report.

Dt_T — Forecasted annual firm throughput