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

APPLICATION FOR APPROVAL OF A CHANGE IN ELECTRIC AND GAS BASE DISTRIBUTION RATES

Rebuttal Testimony of:

Kathy Castro

Topic: Electric Capital Spending

Book 3 of 20

May 11, 2026

Submitted to:
Rhode Island Public Utilities Commission
Docket No. 25-45-GE

Submitted by:

Rhode Island Energy™
a PPL company

Rebuttal Testimony of
Kathy Castro

PRE-FILED REBUTTAL TESTIMONY

OF

KATHY CASTRO

Topics: Electric Capital Spending and Staffing

May 11, 2026

SUMMARY

Kathy Castro is Vice President of Distribution for the Company's electric distribution operations. Her rebuttal testimony responds to certain arguments and positions laid out in the direct testimony of Division witnesses William F. Watson, PhD, regarding electric capital spending and joint-owned pole costs, and Dante Mugrace, regarding the vacancy rate within the electric distribution organization.

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I. Introduction

Q. Please state your full name and business address.

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

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

A. I am employed by Rhode Island Energy as Vice President of Distribution for the Company's electric distribution operations.

Q. Are you the same Kathy Castro who submitted direct testimony in this docket on November 26, 2025?

A. Yes.

Q. Has any of your professional experience or qualifications changed since you submitted your direct testimony on November 26, 2025?

A. No.

II. Purpose and Organization of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain arguments and positions laid out in the direct testimony of William F. Watson, PhD, and Dante Mugrace, each submitted on behalf of the Division.

Q. How does your rebuttal testimony respond to Dr. Watson's testimony?

A. I am responding to Dr. Watson's assertion that the Company's request to include the Tiverton and Weaver Hill capital projects is premature and his recommendations regarding joint-owned pole costs. My rebuttal testimony addresses the inaccuracies in Dr. Watsons's testimony and demonstrates that they are based on incomplete information, flawed assumptions, and a fundamental misunderstanding of the Company's operational practices. My testimony also demonstrates that the Company's actions are consistent with the directives issued by the Commission through the Tiverton and Weaver Hill Order.

Q. How does your testimony respond to Mr. Mugrace's testimony?

A. I am responding to Mr. Mugrace's recommendation to increase the electric operations vacancy rate to five percent.

Q. How is your testimony organized?

A. Section I of my rebuttal testimony provides an introduction and background information. Section II discusses the purpose and organization of the rebuttal testimony. Section III responds to Dr. Watson's testimony related to capital spending. Section IV responds to Dr. Watson's testimony on joint pole spending. Section V responds to Mr. Mugrace's testimony on electric operations vacancy rates. Section VI is the conclusion.

III. Overall Comments Regarding Dr. Watson's Testimony

Q. Page 9 of Dr. Watson's testimony states "that capital investments need to be carefully examined to ensure that the utility is not overinvesting or unnecessarily investing capital at the expense of ratepayers." How does the Company ensure that its capital investments are prudent and not excessive at the expense of ratepayers?

A. The Company applies an integrated distribution planning study process uniformly to all distribution area studies and program studies. This process results in comprehensive infrastructure development recommendations having thoroughly defined scopes that facilitate the Company's ability to meet its obligation to provide safe, reliable, and efficient service for customers at reasonable costs. This comprehensive planning process uses reasonable and acceptable guidelines and thresholds for normal equipment loading, contingency equipment loading, voltage criteria, reactive support, and load balancing as well as asset health investigations to identify any system deficiencies. A comprehensive alternatives analysis is completed, followed by a technical review to

ensure that there is no question that the investments being proposed as part of the Company's capital plan are essential to meet the Company's obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.

Q. Page 8 of Dr. Watson's testimony states that Rhode Island Energy has been able to meet its requirements for reliability within the expenditure for capital investments. Why is it misleading to evaluate reliability only through a systemwide average?

A. System wide average metrics are useful for showing overall trends across the grid, but they can hide significant reliability problems in towns or communities because averages flatten performance and mask the extremes. Areas on the system can experience very different reliability even when the utility's overall SAIFI and SAIDI results appear acceptable.

Customers do not experience reliability as a calculated average. They experience it in real life, at the moment service is interrupted, whether that is at the kitchen table, in a home office, or when essential needs like heat, internet access, or medical equipment are affected. Also, in a more electrified economy, reliability is not simply a goal or a finish line. It is the minimum expectation. As customers rely on electric service for more aspects of daily life, the consequences of outages become more serious and more disruptive.

If the Company relies only on systemwide reliability averages, it may underinvest in parts of the system where performance is weaker or where targeted improvements are needed due to other drivers. That can obscure the real impact of outages on customers in those areas, who depend on continuous service just like everyone else.

Q. Does the Company believe that historical reliability performance is the only metric or indicator of appropriate capital investments?

A. No. While the Company does review historical system and circuit level reliability performance, it is not the only criteria that is or should be used to define the appropriate expenditure for capital investments. The Company also evaluates equipment loading to thermal (capacity) limits, contingency response capability, voltage performance (ANSI A/B requirements), equipment operating capability, arc flash compliance, reactive compensation performance, asset condition, safety, and environmental issues. All these factors, along with historical reliability performance, make up the Company's planning criteria, which are used to comprehensively study the system. The Company developed the criteria, which have been used since 2011, taking industry standards and risk management into consideration. They are not a checklist but an essential standard that is used to provide a factual structured framework for making decisions.

Q. Can the Company elaborate on the importance of a comprehensive review using all planning criteria?

A. Yes. The Company may be evaluating an area or circuit that historically has experienced acceptable reliability performance but has voltage performance violating ANSI A/B standards. The absence of past reliability issues does not relieve the Company of its obligation to address identified voltage violations. Acceptable voltage ranges are established in the Standards for Electric Utilities (815-RICR-30-00-1), and failure to address known violations may result in adverse customer impacts, including equipment or property damage and the tripping of distributed generation. When distributed generation trips offline due to system conditions, the associated load must instead be supplied by the distribution system, which can increase loading on Company assets. Similarly, the Company has obligations to address known loading, contingency, and other system issues, including those related to asset condition. If asset condition issues are not addressed, assets may fail to operate as intended, potentially escalating into more severe failures and creating safety risks to both the public and Company employees. These risks can range from manhole cover dislodgements to asset failures occurring while Company employees are performing operational work. Additionally, following a system failure, the Company routinely reconfigures the electric distribution system to restore service to as many customers as practicable prior to completing permanent repairs. However, in certain locations, there may be insufficient system contingency capacity or no available Company assets to support such reconfiguration. In those circumstances, affected

customers must remain without electric service until repairs are completed, which in some cases may exceed eight hours or twenty-four hours for severe substation failures.

Q. Does the Company engage in integrated gas-electric planning?

A. Yes, it does. Please refer to Company Witness Leone's rebuttal testimony in response to Mr. Butterworth's recommendations.

Q. Does the Company agree with the implication that reliability investments can wait until performance worsens?

A. No. Waiting until performance declines is a reactive approach that ultimately harms customers. It increases the risk of longer and more frequent outages and leads to higher costs as issues become broader and more difficult to address. Proactive investments, such as replacing aging equipment before failure, help avoid major outages and the added expense of emergency and long-term repair**s.**

Q. In regard to the Tiverton and Weaver Hill projects, page 9 of Dr. Watson's testimony states that "[t]he Division's position is that the Company's request for reimbursement of accelerated system modification costs for the proposed DG Projects interconnections do not meet certain requirements of Rhode Island's Interconnection statutes and tariff because the modifications are not currently necessary and do not comply with the accelerated modification provisions." Does the Company agree?

A. No. The accelerated modifications for which the Company is seeking reimbursement through this rate case are currently necessary. In addition, they were necessary at the time when the Company entered into all applicable interconnection service agreements ("ISAs") for the Tiverton and Weaver Hill projects. The Company's contractual relationships with the interconnecting customers are detailed later in my rebuttal testimony. Furthermore, the Company's actions are aligned with R.I. Gen. Laws § 39-26.3-4.1 (the "Interconnection Statute") and with the regulatory directives set forth in Commission Order No. 25213.

Q. Please explain why the accelerated modifications are currently necessary and were necessary at the time when the Company entered into all applicable ISAs.

A. The accelerated modifications were identified in the Company's work plan as necessary capital investments. The Weaver Hill project was referenced in the proposed FY 2022, 2023, 2024, and 2025 Electric ISR Plans. The Tiverton project was referenced in the

proposed 2023, 2024, and 2025 Electric ISR Plans. Both the Tiverton and Weaver Hill projects originated from area studies that identified existing thermal loading and contingency response capability violations, as well as intolerant voltage and reliability concerns affecting customers in Tiverton, Little Compton, West Greenwich, Coventry, and Exeter. The Tiverton Area Study and Central Rhode Island West Area Study were substantially completed in May 2021.

The Company presented substantial evidence in Docket Nos. 23-37-EL and 23-38-EL demonstrating the need for the associated cable and duct bank investments, which provide benefits to both ratepayers and the interconnecting distributed generation ("DG") customers. As reflected in the Company's response to Division 13-28 in this proceeding, these investments are appropriately included for rate recovery.

Q. Page 10 of Dr. Watson's testimony references testimony of Gregory Booth on behalf of the Division stating that "[t]he Division has previously testified that due to lack of demonstrable load growth by existing customers on these circuits, any system modifications that were accelerated associated with these interconnection requests would not be necessary until at least 2035." Does the Company agree that the system modifications were driven solely by load growth?

A. No. As Company witnesses testified in Docket Nos. 23-37-EL and 23-38-EL, projected load growth was not the only driver for proposing these capital investments. Even if the

forecasted load growth does not materialize, the investments remain reasonably necessary to maintain safe and reliable distribution service over both the short and long term. When evaluating a geographic area to determine whether system upgrades are warranted, the Company considers multiple factors, including asset condition, reliability performance, loading levels, contingency loading, and voltage performance. Asset condition assessments focus primarily on substation equipment—such as power transformers, circuit breakers, switches, and protective relays—and take into account historical diagnostic results, repair history, safety concerns, and applicable industry guidance. In addition, the Company reviews each feeder's historical reliability performance to determine compliance with applicable regulatory thresholds. The Company also evaluates existing and forecasted load, contingency loading levels, and voltage performance against its Commission-approved planning criteria, which have been in place since 2011. Once these analyses are completed and system deficiencies are identified, the Company evaluates multiple alternatives to address the identified needs.

The Tiverton 33F6 feeder was initially identified for capital investment for four primary reasons. First, load growth forecasts indicated that three of the four feeders serving the area were projected to become overloaded by 2021. Second, four feeders were identified as having voltage violations using the ANSI A/B standard. Third, the Company identified significant load-at-risk under contingency conditions. Based on observed loads, two out of the four feeders failed the Company's planning criteria for load-at-risk during calendar

year 2024, which is the year before the line extension was completed. Lastly, reliability performance also was a concern, as two of the four feeders exceeded the regulatory thresholds for both SAIFI and SAIDI. While the regulatory thresholds are applied to the system averages, the Company compares circuit level data to identify areas of poor performance and address unacceptable reliability. The Company strives to provide equitable service to all customers, and when it identifies areas with poor reliability, it addresses such concerns.

While the originally forecasted load growth has not materialized to date, the contingency load risk, voltage violations, and reliability underperformance were still present prior to the full build out of the 33F6 feeder, which includes the investments that were identified as accelerated modifications and system improvements.

The Weaver Hill substation project was identified for capital investment for three primary reasons. First, load growth forecasts indicated that two feeders, supplied from two different substations in the area, were expected to experience normal thermal overload conditions. Second, voltage performance on one feeder was projected to fall below the ANSI A/B standard under normal loading conditions. Lastly, four feeders in the area exceeded either the SAIFI or SAIDI reliability performance thresholds. Again, while the originally forecasted load growth has not materialized to date, the voltage violations and reliability underperformance are still present. Further, the Company is seeing requests in

this area that indicate load will increase. The Weaver Hill Substation project, including identified accelerated modifications and system improvements, will comprehensively address both voltage and reliability issues, as well as possible future loading constraints.

Q. Since the load has not materialized, and normal thermal constraints are no longer a driver, are the preferred solutions identified in the area studies, and also identified as system improvements and accelerated modifications for the interconnection projects, still prudent?

A. Yes because the preferred solutions in the area studies fully address the issues identified. As stated above, neither project was driven solely by load growth. Even if forecasted load growth does not materialize, both investments remained necessary to address load at risk, reliability, and voltage performance issues. These deficiencies cannot be effectively or efficiently resolved through alternative solutions.

Q. On Page 10 of Dr. Watson's testimony, he answers "No" in response to the question on Page 9 asking whether the Tiverton and Weaver Hill projects are fully in service. Is Dr. Watson's answer accurate?

A. No. Tiverton is fully in service. The DG project connected in December 2023, and distribution customers were picked up on the 33F6 circuit in ISR FY 2025. A portion of the supply line that will serve the Weaver Hill Substation is fully in service. The Weaver Hill project consists of three customer-owned DG projects and one Company project. The

three customer-owned DG projects connected on 12/30/2022, 12/29/2023, and 12/9/2025. The Company project in service date is expected to be in ISR FY 2030.

Q. Is the Company seeking cost recovery for all costs associated with the Tiverton and Weaver Hill projects?

A. No. The Company seeks cost recovery only for the accelerated system modification and system improvement costs associated with DG projects that are fully in service and for which payments have already been made to the customer. These projects include Tiverton, Weaver Hill Nooseneck, and Weaver Hill Robin Hollow, but not the Weaver Hill Studley Solar project.

Q. On Page 10 of Dr. Watson's testimony, he references Schedule 11 in the Company's response to Division 13-31 and Schedule 5A and Schedule 5B in the Company's response to Division 13-32, where these responses indicate that both Tiverton and Weaver Hill would be completed in FY 2028. Can you explain why Tiverton is already completed, and whether the Weaver Hill completion is still expected for FY 2028?

A. The reconciliation and negotiation process to determine interconnecting customer reimbursement amounts for accelerated system modifications includes calculating depreciation from the date the assets were placed into service to the date the investments would have otherwise been required, as determined by the Commission. This calculation

reflects a point-in-time assumption based on the most recent project schedule. At the time of the analysis, both the Tiverton line extension and the Weaver Hill substation projects were planned to be placed into service in FY 2028, which is reflected in the Company's responses to Division 13-31 and Division 13-32.

The Tiverton feeder addition was initially identified as a system need in the FY 2023 Electric ISR Plan, with no associated spending proposed at that time. The project was subsequently included in the FY 2024 and FY 2025 ISR Plans with proposed expenditures through FY 2029. During construction activities in FY 2025, the project team determined that completing the full line extension within the same year would be more efficient. Completing the work in FY 2025, as identified in the Company's response to DIV 13-29, allowed the Company to avoid multiple construction mobilizations, reduce costs associated with repeated permitting activities, and mitigate exposure to future labor and material cost escalation, thereby lowering the overall project cost. Finally, the solution addressed the existing voltage, reliability, and contingency issues identified in the area study.

As identified in the Company's response to Division 13-30, the Weaver Hill substation project is currently in detailed engineering, with an expected in service date of FY 2030. This shift from the previously assumed FY 2028 timeframe reflects recent schedule

adjustments resulting from new information identified during the substation land assessment process.

Q. Could you summarize the Company's contractual relationships with the interconnecting customers associated with the projects seeking cost recovery?

A. Yes. On July 21, 2021, the Company and Green Development, LLC ("Green") entered into an Interconnection Services Agreement ("ISA") for purposes of interconnecting Green's 11,791 kW photovoltaic systems located at 390 Brayton Road, Tiverton, RI 02878 ("Tiverton Projects") to the Company's electric power system ("EPS"). In September 2023, the ISA was amended to identify the scope of work change to reflect the customer procurement of the cable. The ISA includes construction of a dedicated circuit (33F6) out of the Tiverton Substation and the installation of approximately 21,000 feet of a manhole and duct system with 3 conductor 1000 kcmil SCU EPR cable (the "Tiverton Phase 1 Investments"). The Tiverton Phase 1 Investments were completed in December 2023 and serve the Tiverton Projects. In December 2024, the Company and Green reached an agreement identifying the Accelerated System Modification and System Improvement costs and executed an ISA addendum which included the costs incurred by the customer and reimbursement payment terms.

On July 22, 2020, the Company and Green entered into an Interconnection Services Agreement ("Green ISA") for purposes of interconnecting Green's 20,000 kW

photovoltaic systems located at 899 Nooseneck Hill Road, West Greenwich, RI 02817 ("Nooseneck Projects") to the Company's EPS, which was amended by the Company and Green on December 9, 2021, and December 16, 2022. The Green ISA includes construction of approximately 17,000 feet of a manhole and duct bank system along Division Street and Nooseneck Hill Road, West Greenwich and the installation of approximately 17,000 feet of three conductor 1000 kcmil EPR insulated Cu cable to extend the 3310 line ("Green Development System Investments"). In April 2025, the Company and Green reached an agreement identifying the Accelerated System Modification and System Improvement costs and executed an ISA addendum which included the costs incurred by the customer and reimbursement payment terms.

In addition, on May 16, 2022, the Company and Revity Energy LLC ("Revity") entered Interconnection Services Agreements ("Revity ISAs") for purposes of interconnecting Revity's 40.7 MW photovoltaic systems located at 18 Weaver Hill Road, West Greenwich, RI 02817 ("Robin Hollow Project") to the Company's EPS, which were amended by the Company and Revity on July 29, 2022, and April 26, 2023. In August 2025, the Company and Green reached an agreement identifying the Accelerated System Modification and System Improvement costs and executed an ISA addendum which included the costs incurred by the customer and reimbursement payment terms.

Q. At this time, are there any items in dispute between the Company and the interconnecting customers?

A. No. The Company and the interconnecting customers have come to a mutual agreement and understanding of the contractual expectations for cost responsibility for identified Accelerated System Modification and System Improvements, including a final set of cost calculations. The cost schedules can be found in the Company's responses to Division 13-31 and Division 13-32.

Q. What are the impacts for cost recovery of the requested capital investments in this case associated with Weaver Hill and Tiverton?

A. Please see Company Witness Briggs' rebuttal testimony, specifically Schedule SAB-11-ELEC-R, Page 11 for the schedule of the impacts to the revenue requirement for Weaver Hill and Tiverton investments.

Q. Why did the Company include these project costs in this distribution rate case?

A. The Commission's Order in Docket Nos. 23-37-EL and 23-38-EL envisioned a scenario in which cost recovery would be litigated through a distribution rate case. The Order provides that "[w]hile the Commission declines to grant the Company's requests in the Petition, it is without prejudice to the Company seeking recovery of costs relating to this matter in its next distribution rate case, **after the Company carries out the Commission directives specified herein**." Emphasis added.

Q. Has the Company carried out the Commission directives specified in the Final Report and Order in Docket Nos.23-27-EL and 23-38-EL?

A. Yes.

Q. Did the Company comply with the directive to negotiate in good faith and execute an amended ISA or an addendum to a completed ISA that attempts to comply with the intent of Section 5.4(c) of the Interconnection Tariff with the relevant interconnecting customers involved with the Tiverton Project and the Weaver Hill Project to reimburse the customers for:

a. the costs incurred by the customers who self-built portions of the interconnection that constitute System Improvements and

b. the appliable portion of the costs of any Accelerated System Modifications self-built by the customers, calculated as the total cost incurred less the depreciated value of the modification as of the time that the Company can reasonably show that the modification would have been in service had the interconnecting customer not requested the System Modification?

A. Yes. The Company completed negotiations with the two developers for the three interconnection projects associated with costs in this rate case. The ISA addendum completed dates are shown below.

1. Tiverton - 12/27/2024
2. Nooseneck (Weaver Hill) - 4/17/2025

3. Robin Hollow (Weaver Hill) - 8/22/2025.

Q. Did the Company comply with the directive to complete negotiations by

i. no later than thirty days from the issuance date of the Order regarding the Tiverton Project and

ii. no later than thirty days from the later to occur of the issuance date of the Order or completion of final accounting regarding the Weaver Hill Project?

A. Yes. The Company completed negotiations with the two developers for the three interconnection projects associated with costs in this rate case. The ISA addendum completed dates are shown below.

1. Tiverton - 12/27/2024
2. Nooseneck (Weaver Hill) - 4/17/2025
3. Robin Hollow (Weaver Hill) - 8/22/2025

Q. Did the Company comply with the directive that if agreement(s) are reached with any or all of the interconnecting customers, the Company shall make the relevant reimbursement payments to the customers within ten business days of executing each reimbursement agreement or within ten business days of any final accounting needed to confirm the amounts owed under the terms of the agreement(s), whichever is later?

A. Yes. The reimbursement payments were made by the Company on the following dates:

1. Tiverton – 12/31/2024
2. Nooseneck (Weaver Hill) – 5/1/2025
3. Robin Hollow (Weaver Hill) – 8/29/2025

Q. Did the Company comply with the directive that any payment(s) made to the relevant customers shall be final and not subject to any further conditions relating to cost recovery by the Company?

A. Yes.

Q. Did the Company comply with the directive that if an agreement cannot be reached with any or all of the interconnecting customers within the applicable deadlines specified for each project, the Company shall make final offers to reimburse such customers? If so, any such unaccepted final offers shall be filed with the Commission no later than thirty days after rejection of the final offers.

A. The Company satisfied this directive by reaching an agreement with all interconnecting customers.

Q. Did the Company comply with the directive that after final reimbursement payments are made by the Company to the relevant interconnecting customers, the Company may seek cost recovery relating to the relevant payments in the Company's next distribution rate case filing, but cost recovery of the reimbursement payments may not be sought through the ISR cost recovery mechanism?

A. Yes. The Company has included the relevant interconnecting customers payments as part of this ongoing distribution rate case filing.

Q. In conclusion, does the Company believe that rate recovery for the costs associated with the capital investments that are in service for the Weaver Hill and Tiverton projects is appropriate?

A. Yes. As explained above, the investments deemed Accelerated System Modifications by the Company in this case are in fact benefiting both the interconnecting customers and other customers, and the System Improvements are benefitting customers. These investments were planned and accelerated due to an interconnection request.

IV. Costs for Jointly Owned Poles

Q. Can you summarize Dr. Watson's testimony on the Joint Ownership Agreement ("JOA") with Verizon?

A. Dr. Watson recommends updating the amounts charged to Verizon under the JOA for pole placement, replacement, and relocation based on his assertion that electric customers are subsidizing Verizon for these costs.

Q. What is the JOA?

A. The JOA is a negotiated agreement that governs how the Company and Verizon jointly own, maintain, and replace poles, including safety and construction standards, notice/billing processes, and allocation of costs and risk. In addition to allocating costs, the JOA gives the Company control over the installation of poles, either for deteriorated

poles or reliability upgrades, allowing for efficient scheduling to replace facilities as needed.

Q. What does the Company charge Verizon for its share of covered pole placement, replacement, or relocation costs?

A. The Company charges Verizon $1,240 per pole when the work is required by the Company or Verizon. If the work is required by a third-party attacher, the third-party attacher pays the costs, and no amounts are charged to Verizon or incurred by ratepayers.

Q. What is the $1,240 intended to cover?

A. It reflects Verizon's 50 percent share of typical pole material and installation labor for the pole itself. It does not include the cost for either party to attach or transfer its own facilities. Each party bears its own attachment/transfer costs.

Q. How does $1,240 compare to the Company's actual pole-setting costs?

A. In 2026, the average estimated cost to install a 45-foot, class 3 pole is $2,452.78. Fifty percent of that is $1,226.39. The JOA rate is $1,240, which reflects slightly more than 50 percent of the average costs for a typical pole placement.

Q. Do you agree that ratepayers are subsidizing Verizon for each pole placement, replacement, or relocation?

A. No. The JOA payment is designed to reflect 50 percent of typical pole-setting costs, and the Company's cost comparison shows the $1,240 rate is generally consistent with that split.

Q. What analysis does Dr. Watson rely on to conclude that the Company is subsidizing Verizon?

A. Dr. Watson does not analyze actual pole-setting costs. Instead, he relies on changes in a FERC account and assumes that overall increases translate to higher pole placement/replacement/relocation costs on a like-for-like basis, without supporting that assumption.

Q. What does Dr. Watson recommend?

A. He recommends increasing Verizon's contribution under the JOA, requiring updates at least every three years, and directing the Company to file updated costs in the FY 2028 ISR proceeding.

Q. Can the Company unilaterally change the amount it charges Verizon under the JOA?

A. No. The JOA is a negotiated agreement, and Verizon can decline proposed changes.

Q. Would Dr. Watson's recommendations change the rates set in this case?

A. No. Any change would be prospective and would depend on Verizon's agreement. It would not change base distribution rates set in this proceeding.

Q. Does the Company agree with Dr. Watson's recommendations?

A. The Company agrees with the general premise that each party should bear an appropriate share of costs for jointly owned assets. The Company does not agree that Mr. Watson's specific recommendations are necessary or appropriate to achieve that. The JOA is an important tool for coordinating pole work and supporting safe and timely reliability and deteriorated-pole replacements, and the Company already initiated discussions with Verizon to revisit the JOA in January of this year. The Company believes that it is best positioned to negotiate any changes to the JOA, and that the Commission's general oversight into the prudency of the Company's costs provides appropriate oversight to ensure ratepayers are protected. The Company also believes that the ISR process is the more appropriate forum to address any prospective updates related to pole costs under the JOA, rather than this rate proceeding.

V. Vacancy Rates

Q. Can you summarize Mr. Mugrace's testimony on the vacancy rate ratio?

A. Mr. Mugrace recommends increasing the proposed vacancy rate to five percent as compared to the Company's proposed vacancy rate of 2.5 percent, based on his calculation of the average vacancy rate over calendar years 2023 to 2025.

Q. Does the Company agree with Mr. Mugrace's recommendation?

A. No. The Company experienced higher vacancies during the Test Year than normal. The rates in 2022 and 2023 of two percent and one percent are more in line with the expected vacancy rate moving forward.

Q. Why did the Company experience periods of higher vacancies during the Test Year?

A. In certain departments, such as overhead and underground lines, hiring occurs in groups, allowing the Company to eliminate the need to repeat training, which spans multiple years for individuals. Therefore, the Company waits until it has a certain number of vacancies before filling those positions. A class of apprentices is hired for these departments, saving time as multiple-year progression training is started and administered in groups. Since the end of the Test Year, the Company has filled four underground line positions and eight overhead line positions, which is an appropriate class size conducive to efficient training in each discipline. Also, the nature of certain vacant positions, such as Distribution System Operators and System Consultants, posed challenges in finding

qualified candidates. The Company actively recruited for those six positions throughout 2025, only filling three with qualified candidates after the Test Year.

VI. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

APPLICATION OF THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY FOR APPROVAL OF A CHANGE IN ELECTRIC AND GAS BASE DISTRIBUTION RATES PURSUANT TO R.I. GEN. LAWS §§ 39-3-10 AND 39-3-11	:	RIPUC Docket No. 25-45-GE

AFFIDAVIT OF KATHY CASTRO

Kathy Castro does attest and swear to the following:

I, Kathy Castro, certify that the attached pre-filed rebuttal testimony and related schedules, submitted on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy, which bear my name, were prepared by me or under my supervision and control and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this __ day of May, 2026.

Kathy Castro
Digitally signed by Kathy Castro
Date: 2026.05.08 11:44:36 -04'00'

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