JOINT REBUTTAL TESTIMONY

OF

NICOLE BEGNAL,

KATHY CASTRO,

AND

RYAN CONSTABLE

March 2, 2023

Table of Contents

I. Introduction

Nicole Begnal

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

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

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

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy") as ISR Manager. In my position, I am responsible for the filing and reporting of electric infrastructure, safety, and reliability ("ISR") plans, as well as the electric distribution five-year investment plan.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 23, 2022.

Kathy Castro

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

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

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

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 23, 2022.

<u>Ryan Constable</u>

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

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

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

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 23, 2022.

II. Purpose

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

A. The purpose of this joint rebuttal testimony is for the Company to respond to pre-filed direct testimony submitted in this proceeding on February 23, 2023, by Gregory L. Booth, PE on behalf of the Division of Public Utilities and Carriers ("Division").

Q. How is this joint rebuttal testimony structured?

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

- Major Projects & Area Studies
- Mainline Reclosers
- Reliability
- DER Planning
- Affordability
- Mr. Booth's Recommendations

Q. In addition, to the topics listed above, does the Company have a response to the Division's position on the grid modernization investments contained within the Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability Plan ("FY 24 ISR Plan" or "ISR Plan" or "Plan")[1] and to the Attorney General of the State of Rhode Island's Statement of Position ("AG Position Statement"), dated February 23, 2023?

Yes. The Company disagrees with the Division's position on the grid modernization investments. The reasons why the Public Utilities Commission should reject the Division's position and approve the Company's proposed grid modernization investments are set forth in detail in the Pre-filed Rebuttal Testimony of Wanda Reder. The Company's response to the AG Position Statement is set forth in its Response of The Narragansett Electric Company d/b/a Rhode Island Energy to Position Statement of Attorney General Peter F. Neronha and to Certain Legal Points Raised the Prefiled Direct Testimony of Gregory L. Booth and Exhibit GLB-1, dated March 2, 2023, filed contemporaneously with this joint pre-filed rebuttal testimony.

[1] Unless otherwise noted, when referring to the ISR Plan, the Company is referring to the 12-month spending plan effective April 1, 2023 through March 31, 2024, that is pending before the Public Utilities Commission.

III. Major Projects & Area Studies

Q. Could you briefly summarize your understanding of the Division's concerns regarding major projects and area studies?

A. The Division asserts that its concerns are centered on a perceived lack of justification, under scrutiny, it is more appropriate to describe them as concerns about deviations from previous ISR plan efforts. These "changes" as, the Division describes them, include concerns about (a) the Company's initial presentation of a 21-month investment plan, (b) inclusion of grid modernization investments in the ISR Plan, (c) new programs alleged to be without sufficient justification, (d) acceleration of Area Study investments, and (e) alleged doubling of the historical spending on investments.

Overall, the Division places unnecessary emphasis on maintaining the status quo as opposed to undertaking a thorough analysis of whether the Company has provided the necessary justification to demonstrate that proposed investments in the ISR Plan are reasonably needed to maintain safe and reliable distribution service over the short and long term.

Q. Can you summarize the Company's assessment of the Division's concerns about the initial filing of a 21-month plan?

A. The concerns are unfounded and a distraction. Per the Commission's order and direction following briefing, the Company has submitted supplemental filings presenting a 12-

month plan. The Company recognizes that there may be future procedural issues to resolve, but the Company's initial effort to align the ISR process with its new fiscal year should not be considered unreasonable or even surprising. Nor should that initial effort be an impediment to assessing the substance of the proposed investments, which remain the same as those proposed initially within the 21-month plan, only narrowed to cover what the Company included in the first 12 months of its initial filing.

Q. Can you summarize the Company's assessment of the Division's concerns about the inclusion of grid modernization investments in the ISR Plan?

A. The Division's concerns are unfounded and contrary to the history of the open and transparent development of the grid modernization investments for inclusion in the ISR Plan.

The Company has engaged in discussions about grid modernization that have included the Division since 2018, and the Company's previous plan, originally filed while under National Grid USA ownership and subsequently withdrawn, provided insights into schedules and costs. Rhode Island Energy's Power Sector Transformation committee efforts through 2022 refined, improved, and built upon the substantial grid modernization information previously discussed. Although the Company had not yet filed its proposed Grid Modernization Plan ("GMP") currently the subject of Docket No. 22-56-EL during the 60-day consultation period with the Division, the Company provided the Division with a substantial volume of grid modernization investment information in response to

Division data requests during that period. Thus, the inclusion of grid modernization investments in the ISR Plan was no surprise to the Division, and the Company provided substantial justification for those investments.

The Division now ignores the justification provided and claims that the complete GMP must be approved in a separate regulatory proceeding before any grid modernization investments should be approved through the ISR plan process. This position misunderstands the purpose of the GMP and the nature of the grid modernization investments proposed in the ISR Plan. The Company has explained that it is not seeking approval of the specific GMP investments in Docket No. 22-56-EL, but rather only approval of the filing as satisfying its regulatory obligation to prepare and file the GMP. The Company also has been open and transparent that it intends for the GMP to be a companion document to ISR filings in which it will seek approval for specific grid modernization investments.

Q. Can you summarize the Company's assessment of the Division's concerns about the inclusion of new programs without sufficient justification?

A. The Company presented new programs, such as the Mainline Recloser Enhancement Program, with substantial justification. The Division avoids discussion of the specific data the Company provided in support of these programs. Instead, the Division retreats to arguments that the program information was not submitted at the proper time or demands that the Company take unnecessary engineering steps to claim insufficient support and wrongfully discount the data the Company provided.

Q. Can you summarize the Company's assessment of the Division's concerns about the alleged acceleration of Area Study investments?

A. The Company did not accelerate Area Study investments. Rather, the Company declined to delay these investments as may have occurred in the past under National Grid ownership. Accordingly, the Division's concerns are unfounded.

Q. Can you summarize the Company's assessment of the Division's concerns about the overall increased budget?

A. The increase in the proposed budget is mainly due to (a) the grid modernization investments, which should not be surprising, and (b) area study efforts, which were driven by Division recommendations. The Company has supported all the proposed investments with substantial evidentiary justification demonstrating that they are reasonably needed to maintain safe and reliable distribution service over the short and long term. The Division's concerns about the amount of the budgeted investments are untethered to any rationale as to why incurring those costs would make the investments unnecessary. Accordingly, the Division's concerns on this front are misplaced.

Q. Mr. Booth indicated that "prior to the acquisition [the Company] indicated large capital projects could be eliminated or deferred." Does the Company have a response to this statement?

A. Yes. The Company indicated that large capital projects could be eliminated but not as represented in the Division's testimony. In response to Division 1-7, the Company explained "that the scope of certain projects might be eliminated or adjusted through the grid modernization analysis." This statement was not impacted by the acquisition as implied by the Division. At the time the statement was made, the grid modernization analysis was not complete. Now that the grid modernization analysis is complete, the Company is pursuing modification of certain area study recommendations as described in the Company's response to Division 2-7.

Q. Did the Company indicate prior to acquisition that large capital projects could be deferred?

A. Yes, the Company prior to the acquisition would defer large capital projects accepting system risk. The system risk associated with deferral is no longer acceptable. *See* the Company's response to Division 1-7 and Division 3-4 for additional details.

Q. Mr. Booth recommends that the Company deliver a holistic 10-year Long-Range Plan ("LRP"). Does the Company believe that it should provide an LRP as described by the Division?

A. No, the LRP as described by the Division is not a useful effort. The Company provided a 10-year LRP with useful information as described in the Company's response to Division 1-7. The first 5 years, as already included in the ISR plan, is the complete budget including new business, public requirements, damage failure, and programmatic spend. The second 5 years shows only the area study costs and grid modernization costs. As quoted by the Division, the Company has stated that providing other costs in the second 5-year period is not valuable due to the "unreliable nature of forecasting spend on projects that are unknown and further out in time." For example, it is not relevant to the evaluation of the current ISR Plan to review and evaluate a new business estimate in year 8 of the Division's perception of a 10-year LRP. The Company recognizes the importance of Division and Public Utilities Commission ("PUC" or "Commission") concerns like early obsolescence, duplication of work, non-comprehensive work, and major emerging initiatives like grid modernization, and the Company provided 10-year LRP can be used to satisfy those concerns.

Q. Does the Company agree with Mr. Booth's statements that multi-year projects should be spread over time to minimize project overlap and overall spend and that lengthening "complex project implementation schedules or moderating spend in other discretionary programs in order to maintain reasonable overall budgets" does not compromise necessary reliability programs.

A. No, the Company does not agree with those statements. It is the Company's position that when it identifies a planning criteria violation, the recommended project should proceed on the schedule required by the system need as identified through an engineering analysis like an Area Study. Any delay in project execution, exposes the system to an adverse event actually occurring and thus compromises reliability.

The recent Nasonville event highlights how this risk can materialize. The Company proposed to start the Nasonville project in the FY23 ISR Plan. However, per the Division's recommendations as described in the Prefiled Direct Testimony of Gregory L. Booth, PE, dated February 15, 2022, the Nasonville project was deferred to "modulate annual spend to mitigate dramatic upward pressure on rates…". Although the deferred solution would not have prevented the issue in its entirety, it would have mitigated the reliability impact to customers. Now, in the wake of the event, the Nasonville substation has been temporarily repaired, but system risk still exists and the study recommendation should be progressed diligently. To avoid or mitigate this issue, other projects with similar system risks should likewise progress diligently. Additionally, lengthening project implementation schedules can increase overall project costs due to additional mobilization and demobilization costs, additional overhead, and allowance for funds during construction costs.

Q. Does the Company agree with the Division's statement that "the driving force behind the Company's ISR Plan is not prudent planning and methodically meeting system improvement needs but is instead corporate cash availability."

A. No. The Company's current ISR proposal reflects a focus on prudent planning and methodically meeting system improvement needs. The Company's renewed focus is a departure from the past Division-led efforts focused on cost control. Affordability is important, and the current ISR proposal creates long-term cost affordability through efficient work execution and grid modernization.

Q. Does the Company agree with the Division's statement that "(e)mphasis remains on the need . . . to begin the next cycle of Area Study updates" (page 11, PDF page 13)

A. No. The Company has explained in the past that studies should be conducted as system details dictate. In certain cases, such as the Providence area, past substantial study recommendations focused on addressing asset condition issues resulting in major area reconfigurations over many years. A restudy would serve only to reaffirm the asset condition issues. For this particular area, a restudy is not practical until the reconfigurations are near completion. The Company suggests continued discussion on study status and system needs, but a strict area restudy schedule would be inefficient and wasteful.

Q. Mr. Booth states that the Company will reassess the Northwest Rhode Island ("NWRI") area study as a result of the Nasonville switchgear event. Does the Company plan to reassess the NWRI area study?

A. The Company has no intention to reassess the NWRI study as a result of this failure. The Company is progressing with the plans in the study, which call for the full build out of the substation. Prior to the switchgear failure, the recommended plan called for a new 115kV overhead ("OH") supply with a second transformer and metal clad straight bus and expansion of existing substation facilities at Nasonville #127. Because the switchgear was damaged beyond repair and because the site configuration allows for it, the Company is moving forward with the standard PPL Corporation ("PPL") open-air double-ended substation.

Q. Does the Company believe there was protection device miscoordination during the Nasonville switchgear event?

A. No, the Company is certain that there was no protection device miscoordination during the Nasonville switchgear event. The initial cause of the Nasonville event was a fallen tree on the 41 circuit. The protection scheme operated as designed, and the protective device closest to the fault, a pole top recloser, sensed the fault and operated to clear the fault. The fault current from the fallen tree likely damaged the connection of the 41 breaker C phase terminal. When the fault initiated, the large amount of fault current (and mechanical forces associated with it) caused the breaker connection to the switchgear bus to loosen and the impedance to increase. Once the pole top recloser cleared the fault, normal load current flowed through the connection. The increased impedance, in conjunction with the load current, caused the breaker connection to heat up, arc, and eventually started the fire within the switchgear. As the arc evolved, the West Farnum over current protection scheme operated as designed to clear the fault on the medium voltage switchgear.

Q. Did the Company state that grid modernization investments were the solution to the root cause of Nasonville substation event?

A. No. The Company provided, as an example, the benefit grid modernization investments would have provided in the restoration efforts following an event similar to Nasonville. The use of 20+ MWs of solar generation to avoid extended customer outages and the extended feeder lengths introduced voltage and protection issues that were very difficult to manage over the 5-day restoration period.

For example, voltage dropped below American National Standards Institute limits because of extended feeder length under outage reconfiguration. Approximately half of the devices had remote monitoring to provide visibility into low voltage issues, but the other half did not. Some customers outside the Control Center's voltage visibility reported voltage as low as 96V at their houses. Grid modernization investments would provide more granular voltage visibility along feeders, which would allow operators to respond to more voltage issues before customer complaints or equipment damage occur. Additionally, remote switching of capacitors and regulators would solve voltage issues and distributed energy resources ("DER") dispatch issues without dispatch of line crews. This would be accomplished with an Advanced Distribution Management System ("ADMS") communication system, advanced capacitors and regulators, and real-time loadflow information.

IV. Mainline Reclosers

Q. Does the Company believe that a systemwide protective coordination study is needed to justify the addition of new circuit reclosers?

A. The Company does not believe a systemwide protective coordination study is necessary to justify the addition of new circuit reclosers. The purpose of a protective coordination study is to ensure proper timed operation between devices to sectionalize or isolate faulted sections on a system while keeping the unfaulted parts energized. A systemwide study of this magnitude is estimated to take 6 to 12 months and, due to the dynamic nature of the system, upon completion, the results of the study would be stale. A systemwide protective coordination study would be an inefficient use of resources and ultimately provide no benefit to advance this program. Fault current levels and coordination issues are not a driver for any of the proposed investments.

As stated in the Company's response to Division 1-25, in lieu of a statewide study, Rhode Island Energy performs more resource efficient fault current analysis and protective coordination reviews for specific issues and projects. As examples, a distributed generation impact study includes complex coordination issues and certain area studies identify specific localized coordination concerns. The Company reviews these issues and develops recommendations during those studies. Where there are no expected coordination concerns, such as with 2 to 3 reclosers in series on a circuit, the Company performs coordination reviews <u>after</u> device locations are determined, during early stages of execution.

Q. Does Rhode Island Energy believe that it has sufficiently justified the Mainline Recloser Enhancement Program?

A. Yes, as described in the Company's response to Division 1-23, and using the United States Department of Energy ("DOE") Interruption Cost Estimate ("ICE") Calculator, the Company estimated an approximate benefit of $3 million per year for the proposed 100 Reclosers, calculated on the basis of outage reduction. As stated several times over, coordination reviews are not required in order to locate a recloser to achieve this benefit. The Company is not denying the importance and need for a coordination review; it is emphasizing that a systemwide review prior to location identification is neither necessary nor beneficial. In fact, since the Company was rebranded as Rhode Island Energy, the Company has installed 22 reclosers, with the majority commissioned in the last two months. These device locations were identified and then engineering studies were completed on the specific locations in order to set the devices and ensure proper coordination. Since commissioning, seven of these locations have operated or been utilized in response to seven different system faults, resulting in more than 10,000 customer interruptions avoided.

Q. Please explain Rhode Island Energy's position that it has sufficiently justified the grid modernization investment for Advanced Reclosers?

A. The Company performed a reliability analysis to understand the impact of installing reclosers and using them in conjunction with the ADMS-FLISR application that is being made available to Rhode Island customers through ADMS Basic by May 2024. As described in the analysis in Section 6 of the GMP, reliability as measured by SAIFI will improve by up to 30% compared to historical reliability performance. Similar to the Mainline Recloser Enhancement Program, the results of this analysis were run through the DOE ICE Calculator to determine the benefit to customers of reducing the outages they experience. This process identified a net present value of more than $300 million for reduced outage frequency benefits.

Q. Has the Company made new circuit recloser recommendations in past ISR plans without a system protective coordination study?

A. Yes, the Company has made new circuit recloser recommendations in past ISR plans without a system protective coordination study. These include but are not limited to the 2016 Form 3A Recloser Replacement Study and the Distribution Line Recloser Installation Program, the structure of which the Company adopted from Duke Energy. During both of those efforts, the Company completed protective coordination during early engineering stages of project execution – after location identification.

Q. Did the Company complete a system protective coordination study as part of the 2016 Form 3A Recloser Replacement Study NE.

A. No, the Company did not complete a system protective coordination study as part of the 2016 Form 3A Recloser Replacement Study NE. A copy of that study is provided as Exhibit Joint Rebuttal-1.

The purpose of this effort was to eliminate existing Form 3A reclosers, which were exhibiting a variety of problems. The primary means was a 1-to-1 replacement, but the Company did state that it would perform a complete review of field conditions and feeder configurations to determine whether locations should be eliminated, relocated or replaced with another switching device.

The report, however, does not reference a systemwide coordination study being completed to determine whether a recloser would be replaced in kind, eliminated or replaced with another device. In fact, in Section 4.3, the report states that safety/exposure, asset condition, critical customers, and reliability performance were the factors that influenced further direction of engineering review, not a fault current availability or systemwide coordination study.

Q. Did the Company complete a system protective coordination study as part of the Distribution Line Recloser Installation Program?

A. No. A copy of the study performed for this project is attached as <u>Exhibit Joint Rebuttal-2</u>. Specifically, the Design Consideration for Sectionalization of a Circuit (page 6) includes the following:

"1. Examine the structure of the backbone feeder and look for the "T" node locations. A "T" node is a split in the backbone with both significant load and line exposure on both segments beyond the split. A "T" node is a prime candidate for either reclosers or fuses. You will always get a reliability improvement by placing a protective device on both branches of a T. Evaluate the value of protective devices on both branches by using the fundamental law.

2. In general, installing protective devices on both line segments beyond a major "T" node improves reliability. However, the best location for protective devices beyond the "T" node depends on customer count, customer location, and fault probability…."

The excerpt above aligns completely with Rhode Island Energy's statements on proper protective design location identification, which does not require a coordination study. A localized, specific coordination review is necessary <u>after</u> locations have been determined.

Q. How does the Company identify new recloser locations?

A. There are multiple factors that the Company considers when identifying and selecting recloser locations. As described in the Company's response to Division 1-23, the recommended plan proposed to install reclosers prioritized based on feeder length, number of customers, type of customers, and feeder reliability values to reduce mainline fault impacts.

Q. Did the Company state that it believes no study is necessary and that, once it installs a recloser, it will study the individual feeders upon which they are installed?

A. No. As set forth in the Company's response to Division 1-25, and again in response to Division 1-27, unless the Company identifies a complex coordination issue that requires coordination reviews during study phases, like distributed generation interconnections, it typically completes coordination reviews during early stages of execution. The Company stated only that a <u>systemwide</u> study is not necessary and would be an inefficient use of resources.

Q. Does the Company recognize the Institute of Electrical and Electronics Engineers (“IEEE”) as a standards setting organization, and does the Company use the IEEE Guide for Protective Applications to Distribution Lines?

A. Yes, the Company recognizes IEEE as a standards setting organization and uses IEEE standard C37-230, IEEE Guide for Protective Relay Applications and Distribution Lines.

C37-230 provides a review of generally accepted applications and coordination of protection for radial power system distribution lines, which the Company takes into account when completing protection coordination reviews. These include but are not limited to:

- Check for clearing end-of line fault current.
- Overcurrent settings will be set above the load limit of the circuit.
- Overcurrent time dial should be selected for coordination with largest fuse size.
- The detection of ground faults takes priority over coordination.
- Coordination margin will be maintained according to Company procedures.

Personnel at Rhode Island Energy have been incorporating such details into their coordination studies for decades – well prior to the first version of C37-230 in 2007.

Q. Has the Company reviewed protection philosophy with PPL?

A. Yes, the Company has participated in multiple protection philosophy workshops with PPL. These workshops confirmed that both companies are aligned on most topics.

Q. Does the Company need to fully align with PPL on all protection philosophies to advance new recloser locations?

A. No. Any differences in philosophy do not impact the operational value reclosers provide in fault detection and isolation in the immediate or long term.

For example, a fuse save philosophy, like that employed by PPL's Pennsylvania utility, simply gives temporary faults beyond fuses downstream of reclosers a chance to clear. This means more momentary interruptions (which would not be included in system SAIFI statistics) due to more circuit breaker operations but, by design, does not result in more lock-outs. Differences in topology such as circuit lengths and construction types would be the primary reason for applying the fuse blow philosophy in Rhode Island, and may result in a de minimus change in benefits.

But, regardless, benefits from the proposed reclosers will be very significant, and any assertion to the contrary is disingenuous. In fact, National Grid is projecting a 30% improvement with the recloser installations that it is now advancing aggressively in

Massachusetts. The topology of its circuits in Massachusetts are substantially similar to as those in Rhode Island.

V. <u>Reliability</u>

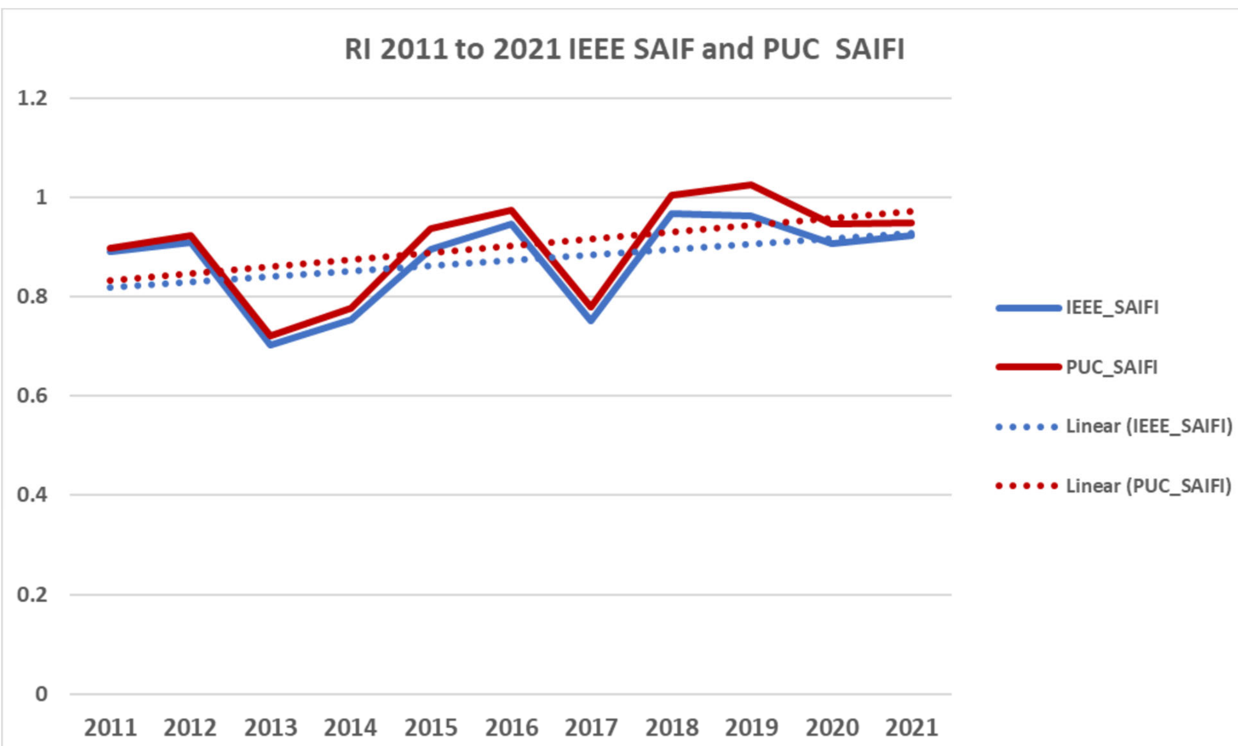
Q. Does the Company agree with Mr. Booth's testimony that the Company has primarily achieved IEEE first quartile results, which is top performance, when ranked against peers across the nation?

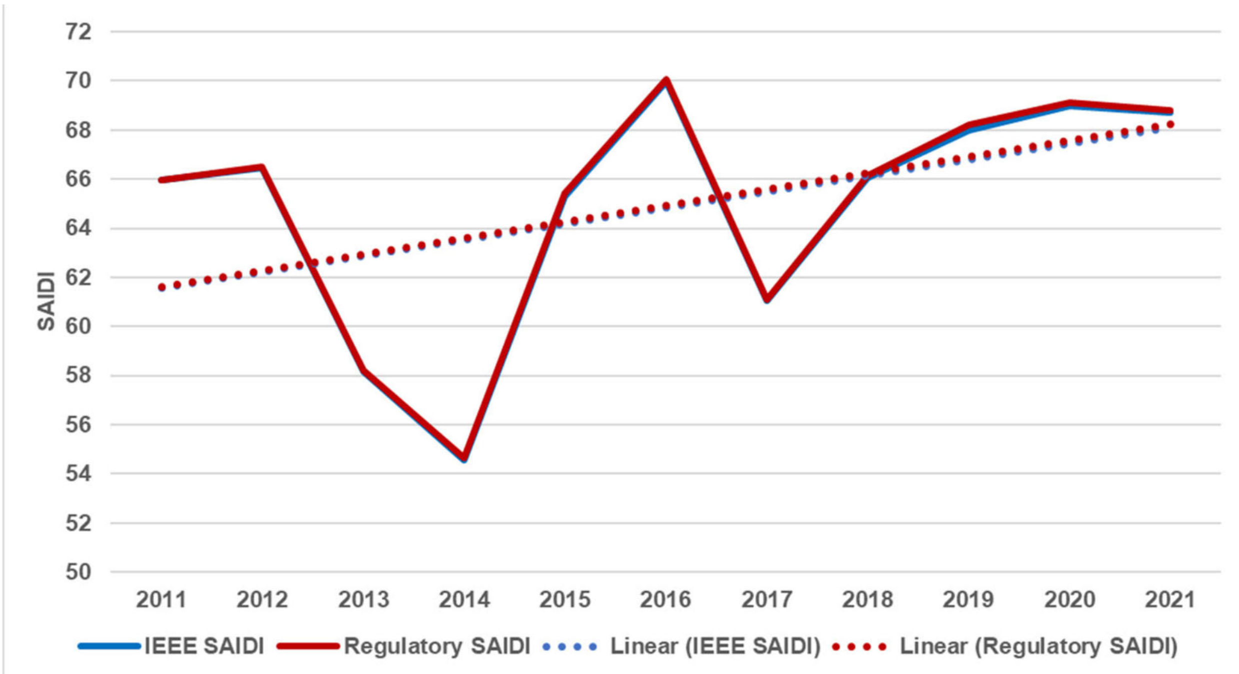
A. No. In recent years, Rhode Island Energy SAIFI consistently has ranked in the 2nd quartile, and although 2021 performance is in the 1st quartile, the Company ranks at the absolute bottom of the 1st quartile. The Company considers its current average performance as 2nd quartile.

Q. Why is it appropriate to use the IEEE reliability standard rather than the Commission standard to assess reliability, in light of Mr. Booth's testimony that the Commission standard is a much more rigorous measure of one minute for outages versus the IEEE five-minute standard.

A. Although the definition of an interruption event used for annual PUC reporting is the loss of service to more than one (1) customer for more than one (1) minute, this is not used for IEEE reporting purposes. The Company must use the IEEE standard definition which excludes interruptions that are less than five (5) minutes in duration to facilitate a comparison with peers.

The following figures provide both Regulatory ("PUC") and IEEE SAIFI and SAIDI measurements since 2011. As can be seen in the SAIFI figure, the Regulatory method of reporting does result in slightly higher values, but, regardless of which method is used, the Company is seeing a negative trend in both indices. This information was provided as part of a supplemental response to Division 1-36 in this docket as part of Attachment DIV 1-36-1.

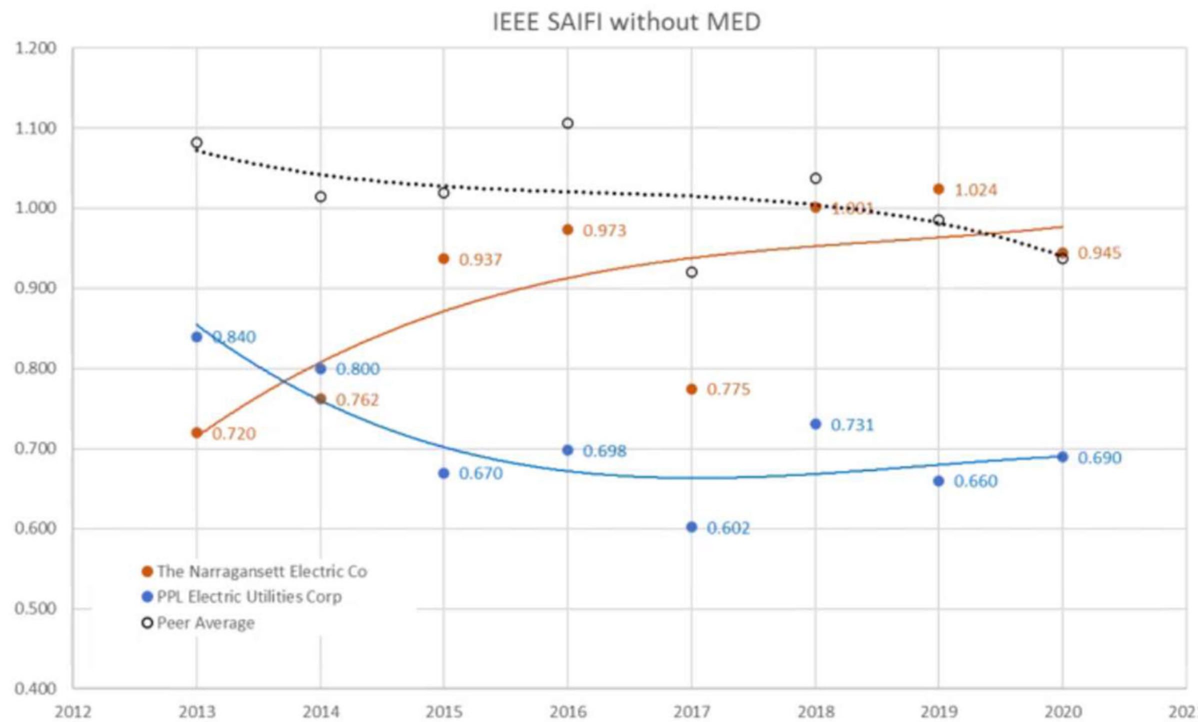




Q. How does the Company compare to PPL Electric Utilities Corporation ("PPL Electric") and other peer utilities?

A. A reliability comparative analysis to PPL Electric and 9 other peer utilities with more than 300,000 electric customers and similar geography concluded that Rhode Island Energy lags in comparison:

- Peers reduced SAIFI by 15%
- PPL Electric has reduced SAIFI by 22%
- Rhode Island Energy has increased SAIFI by 5%



VI. **<u>DER Planning</u>**

Q. Mr. Booth alleges that "RIE is not being forthright in its analysis of DER and the fact that large solar DER is rapidly declining due to the unavailability of land. Large wind projects will be offshore which require significant infrastructure and not GMP to avoid infrastructure. Thus, one of primary arguments for GMP advancement is largely unnecessary." Do you agree with this allegation?

A. No. This position is arguable and unfounded. Although it is impossible to exactly predict DER growth, the first draft of the Executive Climate Change Coordinating Council's ("EC4") Climate Update, which was approved by the EC4 on December 15, 2022,[2] stated: "In an effort to assist with planning future solar photovoltaic ("PV") development within the context of other land-use interests such as conservation, agriculture, and housing development, the Rhode Island Office of Energy Resources ("OER") contracted Synapse Energy Economics to develop an estimate of the likely solar potential available within a number of solar siting categories…. The report finds that in aggregate across all six categories analyzed, technical potential for solar is between 3,390 megawatts ("MW") and 7,340 MW, or 13 to 30 times the amount of solar that is currently installed in Rhode Island. This translates into 5,560 gigawatt-hours ("GWh") to 12,600 GWh of electricity able to be produced." This is in alignment with the forecast Rhode Island Energy used. The GMP forecast considers 5000 megawatts of solar by 2050, roughly at the midpoint of the technical potential identified in the OER report referenced by the EC4. Furthermore, considering the need to make prudent investment decisions in lieu of many forecast uncertainties, Rhode Island Energy used a study approach that would ensure the distribution system would not hinder the State's ability to effectuate the Climate Mandates and, where the resulting investments ready the electric distribution system for any possible future DER adoption rate.

[2] On December 15, 2022, the EC4 approved a final draft of the Rhode Island 2022 Climate Update ("EC4 Climate Update"). A copy may be downloaded at: https://climatechange.ri.gov/act-climate/working-draft-workplan.

VII. Affordability

Q. Mr. Booth indicated that "…the Division did not have sufficient time to fully vet the filing, data request responses, and conduct the necessary evaluation to reach a consensus." Does the Company agree with this statement?

A. No. The Division had sufficient time, as envisioned by R.I. Gen. Laws § 39-1-27.7.1, to fully vet the filing and reach a consensus. Mr. Booth stated that "[t]he maximum level the Division can support is $111.023 million. Any level above this I find excessive and lacking in justification." Booth Testimony 21:4-6. The Company believes Mr. Booth's hard line on spending, without considering the benefits to customers, demonstrates that the Division and the Company were unable to reach a consensus due to philosophical disagreement on spending as opposed to process or timing.

Q. Is the $0.84 monthly increase[3] to customers that will result from approval of the ISR Plan reasonable?

A. Yes. Approval of the ISR Plan places the Company on track to achieve significant benefits for customers. Through the GMP, which supports the grid modernization investments and quantifies the benefits to customers, the Company utilized extensive study methods that are state of the art with a BCA analysis that follows the Docket 4600 framework.

[3] For the typical residential customer using 500 kwh monthly, the bill increase for 12-months equates to $0.84 per month.

Q. Would delay of the grid modernization investments likely result in higher costs for customers over the long term?

A. Yes. With a delay of the grid modernization investments, costs will increase and benefits will be deferred. For costs, the price of materials has been increasing and lead times are getting longer. Delays, therefore, will impact material pricing and complicate supply chain matters. In addition, the avoided costs such as avoided truck rolls from grid modernization will be deferred. In addition to avoided costs, there are many other benefits that would be delayed until grid modernization investments are made, including avoiding infrastructure upgrades and DER enablement.

Q. Mr. Booth indicated that Rhode Island has the 5th highest average retail price of electricity in the United States and that fact should be considered when making large investments. Do you agree?

A. Yes. Affordability is critical to any proposal. Please see Mr. LaBarre's pre-filed direct testimony, page 10 of 10, lines 3-14 for how the Company considered affordability in this case. The Company's testimony is strengthened by the submission of a 12-month spending plan which translates to an increase of only $0.84 per month for a typical customer.

Q. Mr. Booth states that "[t]he Division believes that the nearly 400 percent increase in capital spending on asset condition projects since the early years of the ISR Plan filings will need to be reduced in a carefully planned manner in order to provide budget availability for the pending AMF and GMP programs if and when they are approved." What are your thoughts on this statement?

A. As represented, The Company agrees that capital spending on asset condition projects since the early years of ISR Plan filings has increased over time and is prudent given the age of the Rhode Island Energy assets. However, that investment should not be reduced for the purpose of providing budget availability for pending AMF and GMP programs if they are approved. This approach will never accomplish the modernization that is needed while maintaining reliability and safety. Capital spending on asset condition projects should be determined based on the need for that specific project and not based on the aim of reducing spend in one area to drive spending in another area. In short, any proposed investments should be approved as long as they meet the relevant standard for approval. In the case of investments proposed in ISR plans, that means investments should be approved as long as they are reasonably needed to maintain safe and reliable distribution service over the short and long term.

VIII. Division Recommendations

Q. Mr. Booth sets forth 16 recommendations in his testimony. Has the Company reviewed those recommendations?

A. Yes.

Q. Does the Company agree with Recommendation #1?

A. No, the Company does not agree with Recommendation #1.

Q. Please explain why the Company does not agree with Recommendation #1.

A. The Company suggests this requirement be removed. The Company has submitted substantial information explaining how protective coordination is incorporated into the process of installing reclosers, and how a systemwide study is not beneficial or cost-effective.

Q. Does the Company agree with Recommendation #2?

A. The Company agrees in part with Recommendation #2.

Q. Please explain why the Company agrees in part with Recommendation #2.

A. The Company agrees with supplying a 10-year Long-Range Plan in the manner already provided. The Company's GMP investments are incorporated into the Long-Range Plan.

Q. Please provide the Company's proposed language for Recommendation #2.

A. The Company proposes the following language for Recommendation #2:

"The Company has delivered a 10-year Long-Range Plan as contemplated in previous Recommendations, which includes a summary of the 11 Area Study recommendations. The Company shall provide impacts to the Long-Range Plan as a result of strategic capital investments including AMF and GMP, for Division review by June 1, 2023. The Long-Range Plan shall continue to be adequately supported by Area Studies which include a level of detail that allows stakeholders to sufficiently validate the need, timing, and level of proposed investment."

Q. Does the Company agree with Recommendation #3?

A. The Company does not agree with Recommendation #3.

Q. Please explain why the Company does not agree with Recommendation #3.

A. The Company's stance on promoting transparency as soon as possible remains the same and it will keep the Division informed of substantial changes to the ISR Plan throughout the Plan Year through quarterly reports and review meetings. Although, the Company believes it should not be held to presenting new programs, major projects, or material modifications to existing programs in advance of including programs in the ISR. The Company has an obligation to maintain the safety and reliability of the system and will do what is necessary to operate in such a manner. This recommendation implies a preapproval to spend or not to spend in an imprudent manner and creates a regulatory lag and a challenge for the Company to manage the system. The Company needs the discretion to advance work into the plan that is needed to maintain the safety and reliability of the system and will be held to a prudency review during the reconciliation process.

Q. Please provide the Company's proposed language for Recommendation #3.

A. The Company proposes the following language for Recommendation #3:

"The Company is encouraged to present new programs, major projects, or material modifications to existing programs to the Division prior to including the programs in the ISR Plan. In cases where the Company implements a new program, major project, or material modifications to existing program for immediate or emerging system safety and reliability reasons, the Company shall present that change to the Division in the next quarterly review meeting. The Company shall produce requisite justification at a level of detail to sufficiently validate the need, timing and level of proposed investment, including a benefit-cost analysis."

Q. Does the Company agree with Recommendation #4?

A. The Company does not agree with Recommendation #4.

Q. Please explain why the Company does not agree with Recommendation #4.

A. The Company will keep the Division informed of substantial changes to the ISR Plan throughout the Plan Year through quarterly reports and review meetings. The Company requires discretion to advance work into the plan and subsequent plans that is needed to maintain the safety and reliability of the system and will be held to a prudency review during the reconciliation process. The Company suggests this requirement be deleted as it is covered under the revised Recommendation 3.

Q. Does the Company agree with Recommendation #5?

A. The Company agrees in part Recommendation #5.

Q. Please explain why the Company agrees in part Recommendation #5.

A. The Company adopted the new process of categorizing only work related to failed assets in the nondiscretionary portfolio during FY 2021. All other work is categorized in the asset condition category of the discretionary portfolio. The detailed analysis, review, monitoring and reporting to ensure proper classification continues into FY 2023. Significant improvement in the categorization and documentation of work related to failed asset has been achieved. The Company suggests eliminating this recommendation at the end of FY 2023. The Company will continue to provide the detail for damage/failure in Attachment F as well as the supporting documentation in quarterly reports.

Q. Does the Company agree with Recommendation #6?

A. The Company agrees in part with Recommendation #6.

Q. Please explain why the Company agrees in part with Recommendation #6.

A. The Company agrees with this recommendation and considers it normal course of business and has ensured alignment between the GMP and various planning and project evaluation processes. The Company suggests removing Area Studies and internal Design Criteria as these are not regulatory efforts that need alignment.

Q. Please provide the Company's proposed language for Recommendation #6.

A. The Company proposes the following language for Recommendation #6:

"The Company has developed a Grid Modernization Plan ("GMP") showing alignment between the Long-Range Plan and general ISR investments. This GMP is recognized as enabling greater non-wires alternative capabilities. The Company will continue to align various planning and project evaluation processes, and further grid modernization evaluation in various regulatory efforts including, but is not limited to, the System Reliability Procurement ("SRP") plans, non-wires alternatives ("NWA") and ISR Plan."

Q. Does the Company agree with Recommendation #7?

A. The Company agrees in part with Recommendation #7.

Q. Please explain why the Company agrees in part with Recommendation #7.

A. For the first point, the traditional elements are included in the Company's area studies as applicable. For example, criticality rankings are utilized in the Company's programs not in studies. The Company works to ensure there is no redundancy in area studies and recommendations. The Company included state initiatives in the second point to ensure initiatives such as the Act on Climate are considered in current and future study plans. The fourth point regarding the evaluation of potential incremental investments is included in the Grid Modernization Plan, which was filed on December 30, 2022. The second to last point related to NWA evaluation has been completed within the individual area studies. For the last point, areas are defined by distinct geographical and electrical boundaries that have minimal overlap. Should the Company determine that multiple areas have common system solutions those areas are combined and studied closely together, for example Blackstone Valley North and North Central RI. An analysis of the overall system in a holistic manner is conducted when the issues impact the entire system. For example, the Company is performing a state-wide review to analyze forecasted system impacts of load and generation in the Grid Modernization analysis. The analysis is informed by the Area Study solutions and in certain scenarios identified Area Study solutions may be revised so that the most optimal plan will be executed.

Q. Please provide the Company's proposed language for Recommendation #7.

A. The Company proposes the following language for Recommendation #7:

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

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

- When necessary, the Company will explain any overlap or correlation between the 11 Area Studies to ensure no duplication in investments or recommendations."

Q. Does the Company agree with Recommendation #8?

A. The Company agrees in part with Recommendation #8.

Q. Please explain why the Company agrees in part with Recommendation #8.

A. The Company takes several factors into consideration when sequencing projects including, need identified in the study, availability of resources, materials, outage constraints and funding. The Company agrees in principle with the recommendation of developing a system Capacity Load Study and with supplying a 10-year Long Range Plan in the manner already provided. The Company takes several factors into consideration when sequencing projects including, need identified in the study, availability of resources, materials, outage constraints and funding. However, with the completion of both Area Studies and the Long-Range Plan, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.

Q. Please provide the Company's proposed language for Recommendation #8.

A. The Company proposes the following language for Recommendation #8:

"The Company shall continue to develop its annual System Capacity Load Review in order to increase the level of support and transparency for the capital budget. The

Company shall submit a report with updates on System Capacity Load Review, modeling activities, holistic system long-range plan development and revision of each current and future planned Area Study status within the FY 2025 ISR Plan Proposal."

Q. Does the Company agree with Recommendation #9?

A. The Company does not agree with Recommendation #9.

Q. Please explain why The Company does not agree with Recommendation #9.

A. The Company will continue to manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects and report on large projects in Attachment G of the quarterly reports. If, however, a need arises, the Company believes that it should be able to advance a project and be held to a prudency review during the annual reconciliation process.

Q. Please provide the Company's proposed language for Recommendation #9.

A. The Company proposes the following language for Recommendation #9:
"The Company shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects and provide quarterly budget and project management reports."

Q. Does the Company agree with Recommendation #10?

A. Yes.

Q. Does the Company agree with Recommendation #11?

A. Yes. The Company agrees with this recommendation and will continue to report on Level I projects repaired and Damage/Failure in the quarterly reports.

Q. Does the Company agree with Recommendation #12?

A. The Company agrees with the recommendation of providing transparency for the future years spend. However, with the completion of both Area Studies and the Long-Range Plan, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.

Q. Please provide the Company's proposed language for Recommendation #12.

A. The Company proposes the following language for Recommendation #12:
"The Company shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided within the FY 2025 ISR Plan Proposal filing."

Q. Does the Company agree with Recommendation #13?

A. The Company agrees with the recommendation of providing transparency for the future years spend. However, with the completion of both Area Studies and the Long-Range Plan, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.

Q. Please provide the Company's proposed language for Recommendation #13.

A. The Company proposes the following language for Recommendation #13:

"The Company shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan within the FY 2025 ISR Plan Proposal filing."

Q. Does the Company agree with Recommendation #14?

A. The Company agrees with the recommendation of providing transparency for the future years spend. However, with the completion of both Area Studies and the Long-Range Plan, however, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.

Q. Please provide the Company's proposed language for Recommendation #14.

A. The Company proposes the following language for Recommendation #14:

"The Company shall continue to submit its detailed substation capacity expansion plans and load projections and include an evaluation of proposed projects against the Company's Long Range Plan within the FY 2025 ISR Plan Proposal filing."

Q. Does the Company agree with Recommendation #15?

A. The Company does not agree with Recommendation #15.

Q. Please explain why the Company does not agree with Recommendation #15.

A. The changes to the vegetation management program are meant to improve reliability for all PPL Companies by targeting risk across the network. To demonstrate the impact of the program, it was shown that for three consecutive years it yielded a 15% to 18% improvement for PPL Electric Utilities. While this speaks to the credibility of the program that the Company will be deploying at RIE, this does not infer that it will be the same result. Measurement of program effectiveness is an important component of vegetation management. However, separation of Cycle Clearing Program and Enhanced Tree Management Program does not support understanding the effectiveness of an overall program.

Q. Please provide the Company's proposed language for Recommendation #15.

A. The Company proposes the following language for Recommendation #15:

"The Company is in the process of making changes to the Vegetation Management Program. The Company is discussing how to best complete a cost-benefit analysis for the overall program to track SAIFI improvement while normalizing weather. The new measurement(s) will be provided within the FY 2025 ISR Plan Proposal filing."

Q. Does the Company agree with Recommendation #16?

A. No, the Company does not agree with Recommendation #16.

Q. Please explain why the Company does not agree with Recommendation #16.

A. The Company recommends removing this recommendation. The Company complied with this recommendation from Docket 5209 and provided a personnel update as part of the FY 2024 Pre-Filing submitted on September 9, 2022 as this was a transitional period from National Grid to Rhode Island Energy. The Company also provided documentation of Company guidelines, standards and processes that affect distribution planning in response to Division 1-35.

IX. Conclusion

Q. Does this conclude this joint rebuttal testimony?

A. Yes.

nationalgrid

Form 3A Recloser Replacement Study NE

Emilio Agustin

March 14, 2016

Reviewed by [illegible] 3/14/16

Approved by [illegible] 3/24/16

Table of Contents **Page**

1. Executive Summary

This study documents the need for the replacement of Cooper pole top reclosers (PTRs) equipped with Form 3A controls (Form 3A Reclosers) in New England. There are 200 identified locations over 8 districts in Massachusetts and Rhode Island. The replacements will be scheduled over a 5 year period.

The purpose of this program is to address multiple issues and concerns with in service Form 3A Reclosers in regards to operations, maintenance, safety, reliability, and asset condition. These units have been in service for more than 25 years and are exhibiting a variety of problems including but not limited to; battery charging circuit problems, battery failures, and exterior deterioration/rust, all of which have caused multiple malfunctions.

The intention of this program is to eliminate all Form 3A Reclosers from service. The primary means of doing so will be a one for one replacement with a standard recloser (presently a G&W Viper). However, before individual replacements are completed, Field Engineering will complete a review of field conditions and current feeder configurations. Results of this review will determine if elimination of a Form 3A Recloser will be addressed with one for one replacement, one for multiple replacement, or replacement with another switching device (ex. load break switch).

A Criticality Scoring Model (CSM) was developed for this program and it was used to produce a prioritized recloser replacement list. This list will be used for budgeting, work planning, and to provide direction for the further engineering review which will provide the development of specific replacement recommendations. The quality of the data evaluated in the model varied across the service territory and is expected to improve over time. As such, the candidate list will be refreshed as needed to consider recent recloser failures and system data.

2. Introduction

2.1 Purpose

In an effort to improve system service reliability, National Grid has, over the course of several decades, very successfully deployed thousands of line reclosers on its distribution feeders. Line reclosers are devices that sense and interrupt fault current and, after prescribed time delays, re-energize the line. This reduces the frequency of permanent interruptions resulting from system faults that are temporary in nature. In addition, reclosers significantly limit outage exposure when they operate to clear permanent faults since customers ahead of the line recloser installation will not experience an outage.

This study focuses on performance concerns that have developed with some of the earliest reclosers installed by the Company (Cooper reclosers equipped with Form 3A controls) located in MA and RI.

2.2 Problem

Operational, maintenance, safety, reliability and asset condition concerns exist with the Cooper Form 3A Reclosers. The specifics are detailed below:

2.2.1 Operational Problems and Worker Safety

These reclosers have been exhibiting battery charging circuit problems, causing battery failures. The battery in a recloser control is needed during normal operations. A dead battery prevents device operation (tripping) in response to system fault conditions because the main circuit path goes through the battery and battery charging circuit. Charging circuit problems have required additional procedures to be put in place when work is being done downstream of a Form 3A Recloser. In these situations, workers complete recloser battery checks before work commences. This inspection procedure adds time to all these jobs.

Additionally, construction Standards have changed significantly since most of these units were installed. Many do not have a shunt or in-line disconnects making switching and tagging or bypassing a faulty unit very difficult.

2.2.2 Maintenance problems

Form 3A Reclosers are oil filled. As unit failure frequency has increased, so have the occasions involving a release of oil. The modern replacement units are maintenance free solid dielectric with no such environmental concerns.

Additionally, maintenance and repair issues with these aging units are currently problematic. Form 3A controls are incompatible with all other newer Cooper controls (4C, 5, etc.), and when a unit fails the repair time is very lengthy because there is only one vendor in the U.S. that works on them.

2.2.3 System Reliability

Since Form 3A Reclosers were the first reclosers used by the company, they were placed in locations on feeders that would derive the greatest benefit from their functionality. As such, control failures can often result in very significant and disruptive outages impacting "critical customers" (hospitals & public safety facilities) and large numbers of customers.

Fault restoration procedures are complicated with these reclosers. Dead batteries and/or blown control fuses make the units unusable to a switch person. This extends outage times, and also increases the customer minutes interrupted (CMI). The lack of targets (phase identification), or fault info compared to modern devices, increases the time to isolate the problem in the feeder and further increases CMI. Device repair complexities have led to units being left inoperable for long periods of time. This negates all the benefits that this switching and protective device would have provided the circuit and its customers.

Additionally, load readings for maintenance switching or annual circuit analysis are not available on these devices. Therefore, operators and engineers rely on load estimates to make decisions instead of actual values.

2.2.4 Limited functionality

Form 3A reclosers lack the modern functionality which has become essential to system operators and the engineering groups. They have no over current target indications or load readings so they can't provide critical information during emergency situations. They have limited protection settings making it hard to coordinate with the station breakers, upstream or downstream reclosers and main line fuses. Additionally, they have sparse control interfaces (a few LED's and toggle switches), they lack modern controls like Supervisory Control and Data Acquisition (SCADA) which allows remote open/close and data sharing, telemetered loads, modern TCCs (Time Current Curves), fault value reports, computer interfaces, and logging functions.

Form 3A Reclosers are also not directionally independent, so the units will only close when energized from the normal source side, limiting switching options during both normal and contingency switching operations.

2.2.5 Age and Asset Condition

Form 3A reclosers were last installed as new in the early 1990's. As such, almost all units have been in service in excess of 25 years. Control boxes (mostly installed at street level) have been exposed for all this time to the environment and road salt, and corrosion has become a significant concern. Lastly, these reclosers were not built with 23 or 35kV insulators, as current PTR installation standards dictate, making them more susceptible to faults caused by animal contacts. These faults cause large customer interruptions and can damage equipment.

2.3 Scope

This program will cover the replacement of the 200 Form 3A Reclosers presently in service in the NE area over a 5 year period.

3. Background

National Grid uses reclosers to improve customer reliability, provide load side fault protection and to enhance worker safety. These units are basically over current protective devices, and their general function is to sense and interrupt fault current, re-energize the line if the fault is of temporary nature, and sectionalize faulted sections of distribution circuits.

In our systems we have numerous reclosers from different vintages and models from at least two different manufactures. Form 3A Cooper Reclosers were installed as early as the 1980's. Although innovative at that time, they are now considered outdated. These units have been in operation for more than 25 years and have all the operational concerns detailed in Section 2.2.

Feeder sizes and customers downstream from these units have changed through the years.

4. Program Description

4.1 Infrastructure Development

National Grid's Distribution Construction Standards have changed considerably over the last 35 years. For example, current standards for switch installations require the use of an H1 class pole, bypass disconnects and a sectionalizing switch. Many Form 3A Recloser installations occurred prior to these requirements. An initial review with the data available from EMS and GIS provided an assessment of what are the current construction conditions are at each field location. This provided a possible construction scope which we used to estimate the program cost. Actual work required however, won't be determined until after complete review by Distribution Field Engineering. A complete review of each circuit location and configuration will be performed including a visual inspection to validate priority. When replaced, the following three possible construction scenarios will result from this review, in addition to adhering to the latest construction standards:

Scenario 1 - Review determines the need for a single pole top recloser, either on the same location or a different position on the feeder.

Scenario 2 - Review determines the need to install more than one recloser to optimally sectionalize the circuit.

Scenario 3 - Review determines that there is no need for a recloser given existing circuit configuration and that installation of a load break switch will be adequate for operational needs.

New recloser installations require a ground mesh installation when control boxes are installed within 8 feet from the ground. A ground mesh installation is expensive and often complex, requiring additional permitting and most of the existing locations do not have them. Installing recloser controls above 8 feet also reduces the threat from vandalism and unintended sidewalk issues, such as; damage from motor vehicle accidents or municipal equipment when performing work in or near the sidewalks. The new Viper Recloser's remote control features and the minimum maintenance requirements actually reduce the need for direct access to the control box. Locations with limited access, like ROW's and rural areas, obviously present less installation complexities and therefore reduce the costs of ground mesh installations. Therefore, the Operation's departments in each area are encouraged to avoid ground level installations. A decision to install a ground level installation must weigh the operational benefits with the installation cost, scope and maintenance increases.

4.2 Identification

This program has identified 200 Form 3A Reclosers that are still in operation inside our NE service territory. The EMS and GIS systems were used to identify these units. Table 1 below shows the existing locations per state and districts:

Table 1: Cooper Form 3A Recloser locations

Massachusetts		**Rhode Island**	
Central	61	Capital	19
West	27	Coastal	19
North Shore	2		
Merrimack Valley	18		
South East	50		
South Shore	4		
Total	**162**	**Total**	**38**

Existing locations include substations , Rights-of-Way, private driveways to businesses, parking lots, main roads and side streets. These units could have one large customer or large portions of feeders downstream of their installation location. EMS & GIS were used to not only obtain the location but also other physical unit data that was used in the prioritization process, including; % Feeder Load, Customer Count, Pole Ownership (SO, JO), Pole Size and Set Date, Station Breaker, and Location (ROW, Street, Private property).

The Business Services customer database was also queried to obtain the "critical customer" data for the distribution feeders that have an in service Form 3A Recloser. Reclosers with "critical customers" downstream of them where given special consideration and a higher value under the prioritization criteria due to the high sensitivity of these customers.

4.3 Prioritization

A CSM was developed for this program and it was used to produce a prioritized recloser replacement list. This list will be used for budgeting, work planning, and to provide direction for further engineering review which will provide the development of specific replacement recommendations. The quality of the data evaluated in the model varied across our territories and is expected to improve over time. As such, the candidate list will be refreshed as needed to consider recent, recloser failures and system data.

Our CMS includes standardized weighting factors; Safety/Exposure (30%), Asset Condition (20%), Customer (40%) and Reliability/Performance (10%) as shown in Appendix 1.

The detailed criterion and its relative impact in the CSM is shown in Appendix 2.

The data is weighted exponentially by level as shown at the top of the tables found in Appendix 2, with most risk assigned the highest level and score. In the Excel based scoring tool used for this program, the weighting of each data set and the criteria for each level within the data set can be altered, and are shown in red in the scoring matrices. This allows scoring to be varied depending on the availability of data. In this case, the Customer category was the biggest driver ensuring reclosers on feeders with large and "critical customer" exposure are addressed first. Other main drivers considered in the evaluation are; location of unit, existing construction versus current construction standards, if the unit serves as a Station Breaker, existing pole size and age, pole ownership and if device is on a Worst Performing Feeder.

The final outcome from this prioritization model is a list of reclosers to be replaced, in order of priority from 1 to 200, to be used by Program Management in the decision making when deciding when and what reclosers to be replaced in years 1 to 5 of the program.

4.3.1 Resource Considerations

Other Departments
The volume of work proposed in this program requires additional resources from Engineering, Program Management, and Operations.

Verizon & Special Equipment
In addition to National Grid resources, resources from our joint pole owner (typically Verizon) will also be required. Verizon sets poles in multiple locations around the NE area as assigned through our Joint Owner Pole (JO) Agreement. Replacement of PTRs often requires the replacement of one or more poles for equipment and line clearances. Notification and documentation to the JO should be expedited to prevent construction delays due to pole setting needs.

Additionally, recently updated construction standards, Section 4 – Storm Hardening, require the use of Class H1 poles for the installation of new PTRs and load breaks. Verizon has informed National Grid they will not be installing class H1 poles or poles larger than 50 feet in their maintenance areas. Hence, our crews will have to install all H1 class poles for the PTRs. Distribution Design has created an internal process to expedite this procedure. They send a manually created 605 Form to Verizon indicating our intent to replace an existing pole with an H1 pole, and therefore we do not wait for the rejection process to complete before releasing the job to construction. National Grid then charges Verizon a set fee per our JO Agreement. Operations also has to manage equipment concerns when installing H1 class poles. The diameter of H1 pole butts require our pole setting digger trucks to use 24 inch augers which are larger than the standard 18 inch augers our vehicle use today. Some operating districts may need to purchase the larger augers or existing 18 inch augers can be used and the holes would need to be manually widened during the installation.

Outages
The replacement of PTRs usually does not require a main line outage to perform the work, but a small portion of Form 3A Reclosers feed single commercial customers and therefore will

require an outage. Coordination with these commercial customers will be required to setup the outages.

Grid Mod
National Grid's future Grid Modernization projects will require field switching devices that are capable of sensing voltage and current, and are equipped with special communication features. Units installed by this replacement effort should have the ability to be modified as required, and be compatible with any technology we are currently adopting. Today's construction standards call for the use of modern Viper reclosers which offer multiple alternatives for communications, provide readings for voltage and current, and are reasonably flexible to allow some future modifications, so they are the best choice for replacement at this time.

Radios
In August 2012, AT&T announced support for the 2G cellular technology will reach its end-of-life by the end of 2016. In addition, Sensus will also be upgrading PowerVista to a new system called Automation Control. Therefore, National Grid will be required to visit approximately 1900 reclosers in the field to upgrade the radios and firmware to retain remote communications. A team from multiple departments has been initiated to look at possible solutions and an implementation plan. New reclosers installed within this project will need to have the latest preferred NGrid communications equipment.

Equipment Availability
Implementation of this project will create a higher demand for PTRs than usual. These devices are already in high demand for existing commercial service and infrastructure jobs, including Distributed Generation projects that are emerging all over our service territory. Given this concurrent demand and the required manufacturer three to five month lead time, continuous coordination will be required with Supply Chain and the CDC.

Project Management
There are many coordination complexities associated with this PTR replacement process that will demand proper and prior planning. Distribution Control Center commissioning process requires documentation to be submitted in advance for planning and review. Coordination between Distribution Planning and Distribution Design is required to ensure all drawings and documents are completed and submitted as required. Execution strategies for this recloser replacement program should consider the use of a dedicated Project Manager following a beginning to end process that will identify handoff points to key players (Distribution Design, Planning, Operations, PTO, and Control Center) throughout the complete life cycle. The coordination required between multiple groups for each install has proven reclosers to be one of our most complex distribution line installations. A project managed approach may improve the priority placed on program execution and would enable the leveraging of lessons learned as initial reclosers are replaced.

4.3.2 Objectives and Benefits

The main objective of this program is to replace all Cooper Form 3A Reclosers in the distribution system.

The reasons for this replacement program are detailed in Section 2.2 and are summarized below:

- Battery and charging circuit problems
- In-Line battery design which makes battery required for unit operation
- Requires additional operating procedures
- Potential for environmental issues w/loss of oil
- Long vendor repair times
- Ground level control box deterioration (severe rusting)

The benefits anticipated from this replacement program are also detailed in Section 2.2 and are again summarized below:

- New installation will be in accordance with the latest construction standards
    - H1 Poles meeting highest storm rating
    - Increased pole spacing for increased worker protection and less animal contacts
    - Bypass/Shunt & In-Line disconnects for improved maintenance
- Improved information and data sharing shortens outage and switching times and increases data accuracy
- Additional and robust protection setting options provides improved coordination which leads to fewer CMI
- Directionally independent devices which provide more flexibility when switching and also leads to lower CMI
- Full remote operation shortens outage and switching times and greatly decreases the amount of times a remote unit must be field visited
- Less required maintenance
- Creating this program to replace existing Form 3A PTRs with today's modern Viper solid Dielectric models will provide a standard, efficient and repeatable process to replace this type of aging infrastructure
- This replacement program will also provide an opportunity to study our system for optimal application of the reclosers on these feeders

4.3.3 Costs

Recloser replacements will be scheduled over a 5 year period, with quantities distributed evenly throughout 8 districts in both MA and RI. Replacement costs for each location will depend on the existing installation type and the results of Planning Engineer's review. Table 2 below shows the different possible construction cost for each scenario:

Table 2: Estimated Construction Cost

Estimate Name	Cap	O&M	Rem	Total
Recloser Study MA Isolation Switch Install	$ 5,527.20	$ 276.36	$ 276.00	$ 6,079.56
Recloser Study MA Isolation Switch Install and Pole	$ 7,926.00	$ 396.30	$ 714.00	$ 9,036.30
Recloser Study MA Replace Rec	$ 47,860.80	$ 2,393.04	$ 3,662.40	$ 53,916.24
Recloser Study MA Replace Rec and Pole	$ 50,505.60	$ 2,525.28	$ 4,100.40	$ 57,131.28
Recloser Study MA Replace Rec and Pole plus 2 poles	$ 57,052.80	$ 2,852.64	$ 5,424.00	$ 65,329.44
Recloser Study MA Replace Rec with LB	$ 25,729.20	$ 1,286.46	$ 3,662.40	$ 30,678.06
Recloser Study MA Replace Rec with LB and Pole	$ 28,374.00	$ 1,418.70	$ 4,100.40	$ 33,893.10
Recloser Study RI Isolation Switch Install	$ 5,968.80	$ 298.44	$ 303.60	$ 6,570.84
Recloser Study RI Isolation Switch Install and Pole	$ 8,563.20	$ 428.16	$ 790.80	$ 9,782.16
Recloser Study RI Replace Rec	$ 50,504.40	$ 2,525.22	$ 4,045.20	$ 57,074.82
Recloser Study RI Replace Rec and Pole	$ 53,354.40	$ 2,667.72	$ 4,532.40	$ 60,554.52
Recloser Study RI Replace Rec and Pole plus 2 poles	$ 60,426.00	$ 3,021.30	$ 5,997.60	$ 69,444.90
Recloser Study RI Replace Rec with LB	$ 27,216.00	$ 1,360.80	$ 4,045.20	$ 32,622.00
Recloser Study RI Replace Rec with LB and Pole	$ 30,064.80	$ 1,503.24	$ 4,532.40	$ 36,100.44

Based on all the available system information discussed in section 4.2 and 4.3, each recloser location was matched with an installation scenario shown above to create a preliminary estimate. These were distributed over a 5 year period to show the replacement of all 200 Form 3A reclosers which will cost a total of $12.152M. Individual work requests (WRs) will be initiated per recloser location under two funding projects, one for MA and one for RI. The projects will be sanctioned on an annual basis. The next table (3) shows the estimated breakdown of annual costs:

Table 3: Five year Cost Forecast

State	Area	Qty	YR1	YR2	YR3	YR4	YR5	Total
MA	Central	61	13	12	12	12	12	**61**
MA	West	27	6	6	5	5	5	**27**
	Total	**88**	**19**	**18**	**17**	**17**	**17**	
	Central		**$ 802,771.00**	**$ 749,707.00**	**$ 734,738.00**	**$ 693,241.00**	**$ 720,703.00**	**$ 3,701,160.00**
	West		**$ 341,996.00**	**$ 356,032.00**	**$ 304,508.00**	**$ 274,734.00**	**$ 263,782.00**	**$ 1,541,052.00**
	Total		**$ 1,144,767.00**	**$ 1,105,739.00**	**$ 1,039,246.00**	**$ 967,975.00**	**$ 984,485.00**	**$ 5,242,212.00**
MA	North Shore	2	1	1	0	0		**2**
MA	Merrimack Valley	18	4	4	4	4	2	**18**
	Total	**20**	**5**	**5**	**4**	**4**	**2**	**20**
	North Shore		**$ 62,476.00**	**$ 62,476.00**				**$ 124,952.00**
	Merrimack Valley		**$ 249,902.00**	**$ 277,404.00**	**$ 231,080.00**	**$ 238,950.00**	**$ 54,606.00**	**$ 1,051,942.00**
	Total		**$ 312,378.00**	**$ 339,880.00**	**$ 231,080.00**	**$ 238,950.00**	**$ 54,606.00**	**$ 1,176,894.00**
MA	Southeast	50	10	10	10	10	10	**50**
MA	South Shore	4	2	2	0	0		**4**
	Total	**54**	**12**	**12**	**10**	**10**	**10**	**54**
	Southeast		**$ 606,982.00**	**$ 625,526.00**	**$ 606,982.00**	**$ 551,489.00**	**$ 496,566.00**	**$ 2,887,545.00**
	South Shore		**$ 117,852.00**	**$ 124,951.00**				**$ 242,803.00**
	Total		**$ 724,834.00**	**$ 750,477.00**	**$ 606,982.00**	**$ 551,489.00**	**$ 496,566.00**	**$ 3,130,348.00**
RI	Capital	19	4	4	4	4	3	**19**
RI	Coastal	19	4	4	4	4	3	**19**
	Total	**38**	**8**	**8**	**8**	**8**	**6**	**38**
	Capital		**$ 294,577.00**	**$ 281,886.00**	**$ 270,011.00**	**$ 231,350.00**	**$ 168,263.00**	**$ 1,246,087.00**
	Coastal		**$ 291,240.00**	**$ 303,115.00**	**$ 279,365.00**	**$ 281,886.00**	**$ 200,906.00**	**$ 1,356,512.00**
	Total		**$ 585,817.00**	**$ 585,001.00**	**$ 549,376.00**	**$ 513,236.00**	**$ 369,169.00**	**$ 2,602,599.00**
	Overall	**200**	**44**	**43**	**39**	**39**	**35**	**200**
	MA		**$ 2,181,979.00**	**$ 2,196,096.00**	**$ 1,877,308.00**	**$ 1,758,414.00**	**$ 1,535,657.00**	**$ 9,549,454.00**
	RI		**$ 585,817.00**	**$ 585,001.00**	**$ 549,376.00**	**$ 513,236.00**	**$ 369,169.00**	**$ 2,602,599.00**
	Total		**$ 2,767,796.00**	**$ 2,781,097.00**	**$ 2,426,684.00**	**$ 2,271,650.00**	**$ 1,904,826.00**	**$ 12,152,053.00**

5. Conclusions and Recommendations

It is recommended that the Company pursue a program to replace all existing Form 3A Cooper reclosers in the NE area over a 5 year construction period.

Field Engineering will perform an engineering review of each recloser location and provide construction recommendations in the first year. Individual WRs created under each project will be managed according to complexity and a Program or Project Manager will track the progress.

6. Factors Requiring Program Review

It is not expected that the work required by the program will require further technical reviews.

We will however assess the average cost of these replacements at the end of the first construction year to refine our estimates. We will review the optimal amount of yearly spend with the Resource Planning Department every year through our resanctioning process. As the budget is managed throughout the year by Resource Planning and Investment Planning, they may dictate spending levels that may slightly decrease or increase the actual length of this proposed five year construction program. DAMs input into this process will ensure that the intent of this program is not compromised.

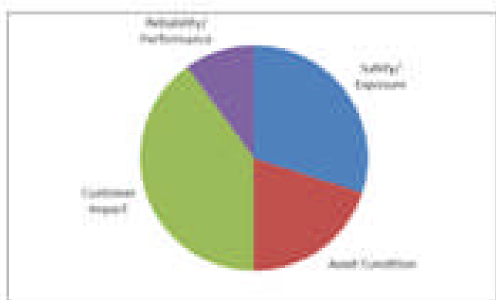
Furthermore, the weighting factors in the CSM developed in this study will be re-evaluated as necessary, as more information becomes available, such that the DAM Department can ensure that the most critical PTRs are being addressed first.

7. Appendices

Appendix 1 - Criticality Scoring Model – Input Data Weighting

Prioritization – Input Data Weighting

- Safety/Exposure Impact: 30%
  What is the risk of potential injury in case of an event?
- Asset Condition: 20%
  What is the current state of the asset and what is the likelihood/rate for continued deterioration?
- Customer Impact: 40%
  How is the customer (and how many) impacted by an event?
- Reliability/Performance: 10%
  How does the asset perform and what is the likelihood/rate for continued performance degradation?



Appendix 2 - Block Scoring Matrix for Identifying System Improvement

Recloser Scoring

Category	Data Source	Weight	Level 1 1	Level 2 20	Level 3 100	Level 4 400	Level 5 1000
Safety/Exposure		**25.0%**					
ROW/Street	GIS	8.0%	na	na	Street	ROW	na
Construction Standards	GIS/EMS	8.0%	na	na	Yes	No	na
Station Breaker	GIS/EMS	9.0%	na	na	na	No	Yes
Asset Condition		**15.0%**					
Pole Size	GIS	7.5%	50 ft	45 ft	40 ft	35 ft	30 ft
Pole Set Year/Age	GIS	7.5%	na	1-10 Years	10-30 Yrs (2006)	30-50 Yrs (1986)	50+ Yrs (1966)
Customer		**30.0%**					
%Feeder Load	EMS	8.0%	na	0-50%	50-75%	75-90%	>90%
# Customer	Analytical Group	8.0%	na	na	0-1000	>1000	>2000
Critical Facilities	CF Table	14.0%	na	na	None	Tier 2	Tier 1
Reliability/Performace		**30.0%**					
SO/JO	GIS	2.5%	na	JO	SO	na	na
Verizon/ Ngrid Set	GIS	2.5%	na	na	None	Verizon	Ngrid
Worst Performing Feeder 2015	Reliability	10.0%	No	na	na	na	Yes
Coordination Problem	Reliability	15.0%	No	na	na	na	Yes

Appendix 3 – Prioritization Table

"Large format spreadsheet attached separately"

SECTIONALIZATION PROJECT SPECIFICATIONS - 2005

CHANGES FOR 2005

(1) The UNIT COST for saving a customer fault on laterals has been changed to $25 per CUSTOMER FAULT SAVED. The UNIT COST for backbone feeders and other main lines, including recloser subfeeders, remains at $10 per CUSTOMER FAULT SAVED.

(2) The spreadsheet for spot coordination has been modified to align with currrent asset management methodology. This methodology results in more aggressive future O&M savings where fuse saving opportunities exist.

SECTIONALIZATION PROJECT SPECIFICATIONS

"Sectionalization of Distribution Circuits" is an Outage Prevention Project that improves the reliability of distribution circuits by reducing the fault exposure of backbone feeders and recloser subfeeders. This reduction of exposure is accomplished by adding and/or re-configuring a small number of protective devices on backbone feeders and/or recloser subfeeders.

Scope – ALL distribution circuits on the Duke Distribution System are being evaluated for sectionalization. Sectionalization includes backbone feeders, and large recloser subfeeders on every circuit.

Timeline – The goal is to complete all work by the end of 2005. During 2001, every circuit was evaluated for sectionalization and classified based on cost. Circuit classifications are shown in Appendix VI.

ENGINEERING TASKS

There are 2 main engineering tasks:

1. Design the sectionalization of circuits to be done in each calendar year. This design work should be complete by June 1 each year.

2. Engineer the actual work - This work will be done as each circuit is due for sectionalization per the established work plan.

ENGINEERING TEAMS

ESD and Field Engineer – The engineering for most circuits is done by two engineers, one using the circuit analysis tool, and one doing the field work. These tasks cannot be completely separated. These engineers should work closely together.

PLANNING AND DESIGN

Each convenient geographic location will set up an engineering team to review all circuits in that location. Work tasks are as follows:

1. Design the sectionalization for circuits to be sectionalized during the calendar year. The target date for completion of this design work for each year is June 1.

2. Promptly update the region spreadsheet with any new information derived from these design activities.

3. Keep a record of the quantity, size, and type of line reclosers, electronic recloser panels, by-pass switches, etc. needed for each circuit. This information is needed for budget and supply chain decisions.

4. Promptly keep records of the engineering work on file for assessment, including class 1 circuits (no work needed).

MANAGER OF SECTIONALIZATION

Each region shall designate a project manager for Sectionalization. The manager will be responsible for reporting completed sectionalizations to General Office R&I each month by using the R&I Measures Spreadsheet and the Region Sectionalization Spreadsheet until the project is complete.

RULES FOR SECTIONALIZATION

1. **<u>The Fundamental Law of Sectionalization</u> shall be used to evaluate the placement of protective devices on a circuit. The law may be applied from the largest device (station breaker) to the smallest device (fuse). The fundamental law takes precedence over all "rules of thumb" or general sectionalization rules used in 2001 and 2002. See Appendix I, II, and III for details. Also, see Spot Coordination Guidelines (Appendix VII) for added value of reclosers associated with downstream temporary faults.**

2. ONELINE submissions for sectionalized circuits are required when installing larger fuses or any recloser changes on the circuit, or for significant changes in fault currents due to relocation of protective devices. **Allow sufficient lead time for necessary modifications to station breaker relay settings.**

1. A Sectionalization job must change the line exposure of the backbone feeder or recloser subfeeder(s) of a circuit, or initiate Spot Coordination on the circuit.

2. The sectionalization project shall be confined to backbone feeders and subfeeders served by 140 Amp reclosers or larger.

3. A review of the reliability value of every recloser on the circuit is required. Remove reclosers that are not justified by the fundamental law.

3. Fuses on lateral taps shall be added or relocated if the cost can be justified by the fundamental law of sectionalization.

4. Sectionalization of subfeeders served by reclosers sized 100 Amps or smaller is optional. Theory and experience show little benefit in sectionalizing these smaller subfeeders.

4. Do not report a circuit as "complete" until all sectionalization work is finished on the circuit. If there is more than one sectionalization work request for the circuit, do not report the circuit complete until the last work request is complete.

5. Do not report Class 1 circuits as "complete" until you have verified that there is nothing to be done on the circuit. Class 1 circuits are subject to be assessed the same as any other circuit.

6. New protective device locations shall be placed in ATLAS within 2 weeks of final construction.

7. It is required that new reclosers be placed in the Recloser Maintenance Application within 4 weeks of final construction.

5. **DO NOT** sectionalize beyond fuses.

6. Completing a full circuit study or coordination on a sectionalized circuit is not required. However, the following over current protection items should be addressed if there is a problem:

    a. Lockout coordination between devices.

    b. Spot coordination to preserve or implement fuse savings where possible. See spot coordination guidelines, Appendix VII.

    c. Properly sized UG Riser fuses (or sectionalizers).

Contact Lee Taylor if you have questions about these rules or need exceptions to these rules. Reasonable economic and operational exceptions to these rules will be taken into account during assessment of sectionalization jobs.

DESIGN CONSIDERATIONS FOR SECTIONALIZATION OF A CIRCUIT

1. Examine the structure of the backbone feeder and look for the "T" node locations. A "T" node is a split in the backbone with both significant load and line exposure on both segments beyond the split. A "T" node is a prime candidate for either reclosers or fuses. You will always get a reliability improvement by placing a protective device on both branches of a T. Evaluate the value of protective devices on both branches by using the fundamental law.

2. In general, installing protective devices on both line segments beyond a major "T" node improves reliability. However, the best location for protective devices beyond the "T" node depends on customer count, customer location, and fault probability. Here are 2 examples.

   a. One line segment beyond a "T" node is 336 AAC, clear of trees, and there are a large number of customers within ½ mile of the "T". For this segment, evaluate the value of a line recloser placed **beyond** the large group of customers. The other segment is 1/0 HWLW, and there are only a few short taps and transformers within ½ mile of the "T". The fundamental law will probably show that the protective device for this line segment should be positioned very close to the "T" point.

   b. There is an existing set of line reclosers about 1 mile down the line from a circuit backbone "T" node. The conductor on the backbone is 336 AAC. Beyond the "T" the conductor reduces to #2ACSR. In addition, there are only a few customers between "T" point and the existing recloser location. The reclosers were placed farther out on the line to save money because fault currents near the "T" would require vacuum reclosers. In this case, the fundamental law will likely show that there is a large benefit to relocating the reclosers close to the "T" point, even if you have to use vacuum units.

3. In some cases, the reliability of a circuit can be improved by INCREASING the exposure of a feeder. This improvement works by moving a line recloser just beyond a large grouping of customers. By moving the line reclosers, these customers are now protected from the line exposure beyond the recloser. The fundamental law will confirm if moving the reclosers farther out has a benefit.

4. The fundamental law will usually show that lightly loaded, long circuit ties should be fused. To preserve tie capability, solid bypass switches can be installed, but are not required.

5. Many circuits have large unfused “taps” with a moderate customer count and load. Here are 2 solutions:

    a. Consider fusing these segments with larger fuses such as 140K’s. Installing large fuses rather than line reclosers is applicable where permanent faults are predominant, such as underground taps, exposure to trees, exposure to traffic accidents, and areas with retrofitted transformers. Another variation is to examine the number of fuses in series on such large taps and eliminate one level. For example, you may find a 100T followed by a 50T followed by a 20K. In this case, move the 100T (or 140K) back to the main line and make either the old 100T or 50T location a solid blade.

    b. Consider using a line recloser. This solution is applicable if momentary faults are predominant in the lines beyond the recloser, such as a circuit with un-retrofitted transformers. See Appendix VII (Spot Coordination Guidelines – Example #6) to evaluate whether a fuse or recloser is more appropriate.

6. Circuits without major “T” nodes are basically radial “line” circuits and offer fewer opportunities for improvement. “Line” circuits can sometimes be improved by adding a line recloser at the mid-point or fusing the last portion of the backbone. Do not install 2 line reclosers in series unless justified by the fundamental law.

7. Circuits with major loads or customer counts near the end of the circuit offer fewer opportunities for sectionalization. Be careful to fully justify sectionalization work on such circuits.

8. Sectionalization beyond line reclosers is largely a matter of adding fuses to exposed line segments that do not have a large customer count. Adding line reclosers beyond line reclosers should always be evaluated using the fundamental law of sectionalization.

9. The last section of the backbone feeder should be evaluated for fusing.

Appendix I

The Fundamental Law of Sectionalization

"The number of CUSTOMER FAULTS SAVED by any protective device is the product of the customers protected upsteam times the line mileage downsteam. The VALUE of the protective device is given by the product of the customer faults saved times the UNIT COST for saving a customer fault [currently $10 per CUSTOMER FAULT SAVED on backbones and main feeders, including recloser subfeeders, and $25 per CUSTOMER FAULT SAVED on laterals - 1/1/2005]."

[Note: A reclosing device (or saved fuse) sometimes has a significant additional value over a single shot device (unsaved fuse). See Appendix VII for calculation of this additional value.]

<u>Discussion</u> - The Fundamental Law of Sectionalization is used to calculate the relation between the reliability and the cost of a protective device. It should be used in all decisions involving installation, removal, or maintenance of a protective device. **This law takes precedence over all the general rules that govern Declared Circuits, Sectionalization, or anything else.**

Example: In general, you need to save 20 customer faults (i.e. spend $500) to install a set of 3 fuses on an existing arm for a tap. You need to save 8 customer faults (spend $200) to install a single phase fuse. If you have to do more work, (i.e. spend more money), then you need to have a higher CFS value.

To decide if a tap should be fused on a circuit with 2,100 customers, use the Fundamental Law of Sectionalization. If you have a 3 phase tap 50 feet or longer, then you should install a set of fuses. The formula is 2100 X 50/5280 X $25 = $497. If you have a single phase span 20 feet or longer, then you can put up a fuse. The formula is 2100 X 20/5280 X $25 = $199. However, if the tap pole has to be reframed just to accommodate the fuses, then the cost may exceed the benefit, and the fuses are not justified.

As usual, if the fault probability is higher, then a shorter span may need protection; or you may be justified to spend additional money. If you are already set up on a pole for some other reason, then less value is needed. For example, if you are changing out a pole, then it does not cost $200 to install a cutout…it only costs the value of the material plus enough labor to install the cutout. Refer to Appendix II for values required to install various protective devices.

The Fundamental Law of Sectionalization can be used in all scenarios; declared circuits, sectionalization, recloser maintenance, outage follow up, BE, etc. to either justify installing a protective device or to justify NOT installing a protective device.

Appendix II

Estimated Costs to save Customer Faults

How much to spend for a given customer fault reduction?

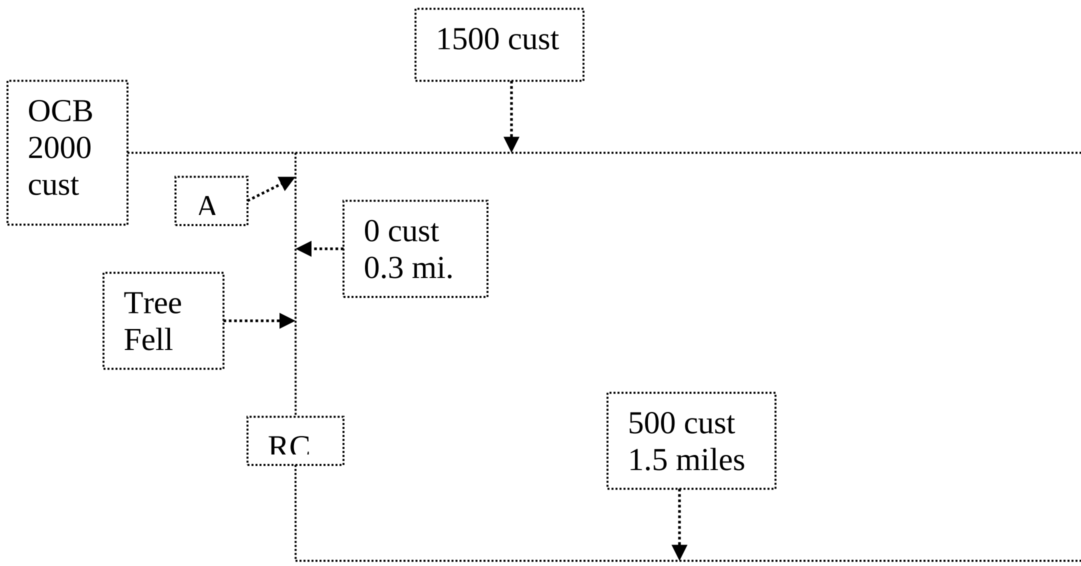
Try to spend < $10 / customer fault reduced!

Using the standard of a 750 customer fault reduction justifying the installation of a 3 phase hydraulic recloser, the minimum customer fault reduction for other protective devices can be calculated as follows:

Activity	Approx Cost	Minimum Customer Faults Saved	
Install Fuse (1)	$ 200	8	
Install Fuses (3)	$ 500	20	
Install Hyd RC	$ 7,500	750	
Install Vac RC	$ 9,500	950	
Install Elec RC	$ 20,000	2000	
Relocate RC	$ 3,750	375	
Relocate RC & up to vacuum RC	$ 5,750	575	(Upgrade to Vacuum due to higher I fault)
Sectionalizer (1)	$ 900	90	
Power Fuse SMU (3)	$ 1,250	50	
Power Fuse SMU (1)	$ 450	18	
Remove Hydraulic & I: Electronic RC	$ 14,000	1400	
Install D Recloser	$ 15,000	1500	

These estimates included changing single cross arm to a double arm and dead ending the primary on an existing pole. Pole costs not included. Estimates are approximate and are intended to give a “feel” for what is justified in sectionalization work. These numbers are subject to change as more information becomes available.

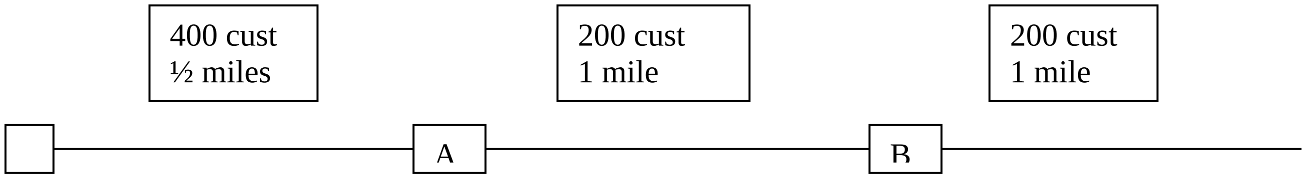
Appendix III Application of the FUNDAMENTAL LAW



1. A tree fell on the backbone before the recloser shown above. What is the value of the existing recloser? **ANSWER**: 1500 customers protected times 1.5 line miles = 2,250 customer faults saved or $22,500. Therefore, this recloser is justified based on either the chart in Appendix IV or the actual estimated cost.

2. What is our budget for moving the recloser to point A? **ANSWER**: The value of a recloser at A without the existing recloser is 1500 X 1.8 = 2,700 customer faults saved or $27,000. The value of the existing recloser (without one at A) is 2,250 customer faults saved which you can spend $22,500. Therefore, you can eliminate 450 customer faults (2,700 – 2,250) by moving the recloser from its' existing location to location A, and you can spend up to $4,500 to move it. Therefore, in most cases you should move the recloser. If there are special circumstances that will make the move cost more than $4,500, then the move would not be justified.

3. Can you add a recloser at A and leave the recloser at B? **Answer: NO.** The value of a recloser at A if there is already one at B is 1,500 X 0.3 = 450 or $4500, which not enough to justify a second recloser.



1. What is the value of a recloser at A only? Answer: 400 X 2 = 800 ($8,000)

2. What is the value of a recloser at B only?   Answer 600 X 1 = 600 ($6,000)

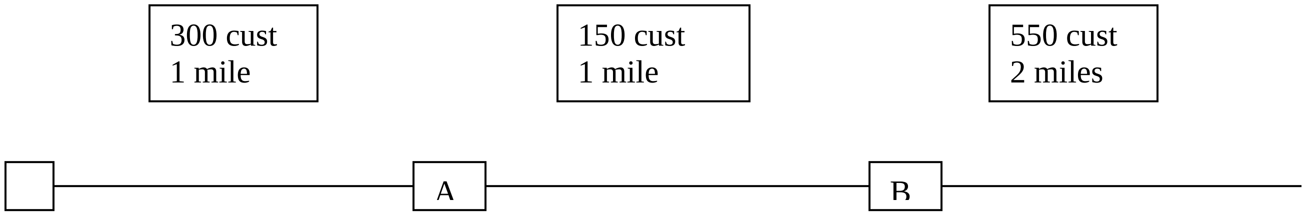
3. What is the value of a recloser at A if there is already a recloser at B? Answer: 400 X 1 = 400 ($4,000)

4. What is the value of a recloser at B if there is already a recloser at A? Answer: 200 X 1 = 200 ($2,000)

5. If there is already a recloser at B, should you relocate it to A? **Answer: NO**. The value at A only is 800 and the value at B only is 600, so you only gain 200 customer faults by moving the recloser from A to B. You cannot move a set of reclosers for only $2,000 (see Appendix IV).

6. If there is already a recloser at B, and it is time to do maintenance on the recloser at B, can you justify moving it to A? **Answer: Probably YES**. Since you already have to install and remove a set of reclosers, it is likely that you can spend less that $2,000 to move them to another location.

7. Can you justify placing reclosers at both A and B? **Answer: NO.** The exception would be in cases where the fault probability is four times normal.



1. What is the value of a recloser at A only? Answer: 300 X 3 = 900 customer faults saved or $9,000 budget.

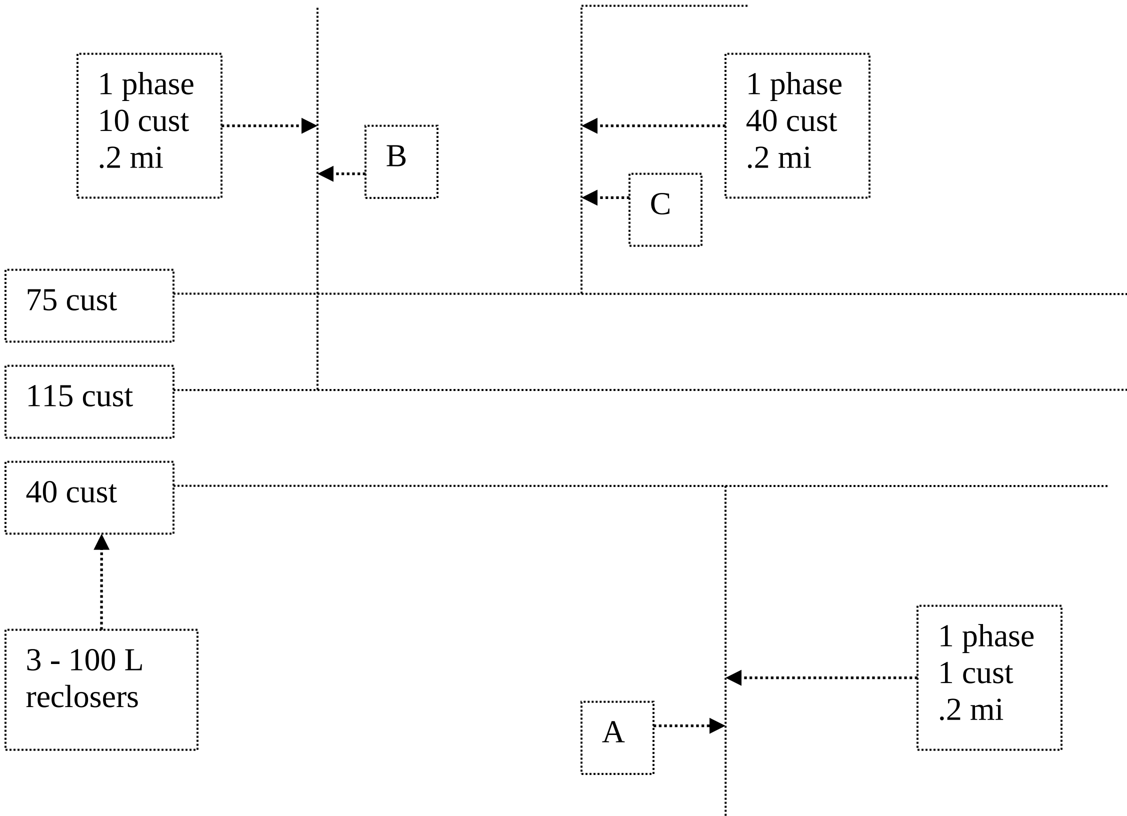
2. What is the value of a recloser at B only? Answer: 450 X 2 = 900 customer faults saved or $9,000 budget.

3. What is the value of a recloser at A if there is already a recloser at B? Answer: 300 X 1 = 300 customer faults saved or $3,000 budget.

4. What is the value of a recloser at B if there is already a recloser at A? Answer: 150 X 2 = 300 customer faults saved or $3,000 budget.

5. Can you justify placing reclosers at both A and B? **Answer: NO.** After placing one recloser, you only get an incremental increase of 300 customer faults saved for the second recloser. You cannot install a set of reclosers for $3,000, so it is not justified.

6. Should you move a recloser to B if it is at A? **Answer: ABSOLUTELY NOT**. Since site A and site B have the same value for customer faults saved, then you gain nothing by moving from one site to the other.



Each single phase tap shown above is 4 spans long (average span is 268 ft.)

1. On which tap or taps can you justify installing a fuse if you are doing sectionalization? Answer: B is worth (115-10) X 0.2 = 21 ($525) which is well worth doing. A is worth (40-1) X 0.2 = 7.8 , a $195 budget, so it is justified. C is worth only (75-40) X 0.2 = 7, a $175 budget, technically not worth doing.

2. On which tap or taps can you justify installing a fuse if you are doing outage follow up because a fault occurred on the unfused tap? Answer: You can justify doing follow up on any of them, because to follow up on a small outage, you would have to have 4 outages in the past year. Therefore, the fault probability is at least 4 times normal, so the number of faults saved is much higher than normal. For example, C was saving only 7 customer faults under the normal calculation, but if the fault probability is 4 times as high, then the value is 28 or $700. You can afford to install a fuse for that amount, so it is justified.

3. On which tap or taps can you justifying installing a fuse if you are already working on the tap pole for some reason? **Answer: All of them.** You only need enough money to pay for the cutout and enough labor to install it. All other costs for travel, set up, work zone, etc. are already paid.

Appendix IV - MEGA CIRCUITS AND T-CIRCUITS

IDENTIFICATION

A “Mega-Circuit” is any circuit with more than 2,100 customers. In 2001, more than 200 circuits on the system qualify for this category, which is an increase of over 118% since 1991.

A T-Circuit is defined as a distribution circuit with a major T-node within 1000 feet of the station breaker. Many Mega-Circuits are also T-Circuits.

PREVENTION AND ELIMINATION

T-Circuits and Mega Circuits can be split into separate circuits if justified by the fundamental law of sectionalization.

Appendix V - OTHER REASONS TO INSTALL A LINE RECLOSER

The methods shown in this document calculate the relative reliability benefits of protective devices based on permanent fault sectionalization. Here are other reasons to install a recloser at a particular location on a circuit.

- To protect an important customer from sustained outages. To use the fundamental law, the important customer is converted to “customer equivalents”. Use 14 KVAC (KVA connected) or 5 KVAD (KVA actual peak demand) to convert the important customer to customer equivalents. Example: An important customer is served from a 1500 KVA transformer. This customer is equivalent to 107 regular customers (1500/14 = 107)…or you may use the peak demand. If the customer’s peak demand is 1050, then that customer is equivalent to 210 regular customers. (1050/5 = 210). For very large customers served by “customer stations” on transmission or F-bay substations on distribution, the favored method of conversion is 5 KVAD (actual peak demand).

- To protect portions of the backbone feeder where the lowest unprotected 3 phase bolted fault is less than 2.3 times the setting of the 51XYZ relays; or where the lowest unprotected phase to ground fault is less than 2.0 times the 51G relay.

- To protect unprotected portions of recloser subfeeders where the maximum bolted line to ground fault is less than 1.5 times the minimum interrupting rating of the upstream recloser.

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- For operating concerns such as “ride time” and rough terrain. However, these reclosers must be justified by a business case. Where protective devices have been used in the past for troubleshooting the location of faults, but there is not sufficient “Fundamental Law” justification, use OH fault indicators instead.

- For subfeeders that have a lot of temporary faults, where there is justification for fuse savings. See Appendix VII for details.

- If installation of a recloser is required by the Distribution Manual. [Example: Electronic recloser on a heavily loaded three phase UG loop.]

Appendix VI - CIRCUIT CLASSIFICATIONS

There were 9 classifications for sectionalization. These classifications were used to design the original project and are given here for information purposes only. Currently, there is no requirement that the circuit classifications recorded in the region spreadsheets be changed, even if the circuit has been re-classified.

1. **Type 1** - Circuit requires no work.
2. **Type 2** - Circuit requires additional fuses only, or relocation of fuses only.
3. **Type 3** - Circuit requires additional line reclosers, or relocation of reclosers. May also require some fuse work.
4. **Type 4** - Circuit requires splitting into 2 or more circuits. This classification puts the circuit into another category known as “Mega-Circuit Elimination” which is outside the scope of the Sectionalization Project. Nevertheless, these circuits must be correctly classified to avoid duplication of efforts.
5. Designated as a type “43” – Mega Circuit that cannot be split yet, but still requires sectionalization by line reclosers.
6. Designated as a type “42” – Mega Circuit that cannot be split yet, but still requires sectionalization by fuses only.
7. **Type 5** - Circuit has less than 2,100 customers, but has a major T node within 1000 ft. of substation, and best solution is to add a station breaker.
8. Designated as a type “53” – A type 5 that cannot be split yet, but still requires sectionalization by line reclosers.
9. Designated as a type “52” - A type 5 that cannot be split yet, but still requires sectionalization by fuses.

Appendix VII - Spot Coordination Guidelines

General – Spot coordination is used to implement fuse savings where fuse savings does not currently exist, or where the addition, change-out, or removal of a line recloser has resulted in either a loss or gain of fuse savings. Here is an overview of the business case for preserving or implementing fuse savings.

1. For every customer fault per year that can be prevented, Duke Power can spend $50. [This cost is based on the actual average number of faults per mile per year on the system of 0.20. This cost is equivalent to the Fundamental Law which uses $10 per fault, but an assumed fault rate of 1.0 per mile, used for convenience of calculation.]
2. If an outage call-out can be prevented, Duke Power will spend funds to avoid this cost. These O&M savings provides most of the cost benefit associated with Spot Coordination.

Fault Current - The justification depends on the fault current being low enough to enable fuse savings. **The station breaker and the backbone feeder are therefore outside the scope of Spot Coordination**. Some areas beyond the first downstream recloser are also outside scope because the fault currents are too high.

Faults per Line Mile – Technically, we are dealing with "sustained faults that should be temporary" or "TS faults" (temporary faults that end up as sustained outages). TS faults should actually be temporary outages, not sustained. In scenarios that involve gaining or losing fuse savings, for circuits that have not been retrofitted (transformer retrofitted), use 0.8 faults per mile. If the circuit has been retrofitted, use 0.2 faults per mile.

SCENARIOS:

1. **Series recloser beyond first recloser - Removing a recloser.** Often, series reclosers cannot be justified by the Fundamental Law and are removed. In these cases, if you can lose fuse savings the downstream fuses should be changed to fuses that can be saved by the remaining upstream recloser if justified by the table shown in the tab "Limits to justify resized fuse" in the spreadsheet "SCP – Spot Coordination 04022005.XLS". For purposes of this calculation, use 0.2 faults per mile for retrofitted circuits, and 0.8 faults per mile for unretrofitted circuits. The spreadsheet shows which taps should be re-fused.

2. **Increasing the size of a recloser** - In this case, with favorable fault levels, you may lose fuse savings that already exist. The downstream fuses should be changed to fuses that can be saved by the remaining upstream recloser if justified by the table shown in the tab "Limits to justify resized fuse" in the spreadsheet "SCP – Spot Coordination

04022005.XLS". For purposes of this calculation, you should use 0.2 faults per mile for retrofitted circuits, and 0.8 faults per mile for unretrofitted circuits.

3. **No recloser work is planned, but the existing fuses are too small to be saved** - These fuses should be changed to fuses that can be saved by the upstream recloser if justified by the table shown in the tab "Limits to justify resized fuse" in the spreadsheet "SCP – Spot Coordination 04022005.XLS". For purposes of this calculation, you can use 0.2 faults per mile for retrofitted circuits, and 0.8 faults per mile for unretrofitted circuits.

4. **First Recloser beyond the OCB – Adding a recloser.** In this case, with favorable fault levels, you may be able to obtain fuse savings where it was not possible before. In this case, the recloser has additional value above the value given by the Fundamental Law. This value can be calculated using the "Additional value of recloser" tab in the spreadsheet "SCP – Spot Coordination 04022005.XLS". You must enter the tap mileage, number of customers served, and number of phases for each tap. For purposes of this calculation, you can use 0.2 faults per mile for retrofitted circuits, and 0.8 faults per mile for unretrofitted circuits. The spreadsheet shows which taps should be re-fused. The cost and benefits of re-fusing these taps comprise the "additional value" given the recloser.

5. **First Recloser beyond the OCB – Removing a recloser.** In this case, with favorable fault levels, you may lose fuse savings that already exist. In this case, the recloser has additional value above the value given by the Fundamental Law. This value can be calculated using the "Additional value of recloser" tab in the spreadsheet "SCP – Spot Coordination 04022005.XLS". For purposes of this calculation, you should use 0.2 faults per mile for retrofitted circuits, and 0.8 faults per mile for unretrofitted circuits.

6. **Evaluation of a recloser versus a fuse off the backbone feeder** – In this case, you could be either contemplating replacing a recloser with a fuse or the reverse. In addition to the evaluation of taps shown in scenarios 1 and 2 above, you should consider the main line beyond the protective device. Temporary faults on the main line will become permanent faults with a fuse. Therefore, the recloser has additional value over the fuse. In the "general parameters" tab of the SCP Spot Coordination 04022005.xls spreadsheet, put a "yes" in the "evaluate recloser vs. fuse" parameter. Add the line miles of the main line and the customers on the main line to the table given in the tab "additional value of a recloser."

REBUTTAL TESTIMONY

OF

WANDA REDER

March 2, 2023

Table of Contents

I. Introduction

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

A. My name is Wanda Reder. My business address is 34W676 Country Club Road, Wayne, Illinois 60184.

Q. Are you the same Wanda Reder who filed pre-filed direct testimony in this docket?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 22, 2022, on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy"). For additional information on my professional experience, please see Exhibit WR-1.

II. Purpose

Q. What is the purpose of this rebuttal testimony?

A. The purpose of this testimony is to respond to pre-filed direct testimony submitted in this proceeding on February 23, 2023 by Gregory L. Booth, PE on behalf of the Division of Public Utilities and Carriers ("Division") and the position memorandum submitted by the Rhode Island Attorney General Peter F. Neronha ("AG") on February 23, 2023.

III. Summary of Position

Q. Could you briefly summarize your rebuttal points?

A. Yes. My testimony: (a) reinforces the justification the Company previously provided for the proposed increase in capital spend and potential impact on customer bills, (b) provides the facts regarding the pre-filing consultation process with the Division and further explains the justification for approval of grid modernization expenditures in the Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability Plan ("FY 24 ISR Plan" or "ISR Plan" or "Plan")[1] before the Grid Modernization Plan ("GMP") docket has been completed, and (d) the explains the appropriate process for protective device coordination studies and the reasons a systemwide study is not only unnecessary but inappropriate before approving investments in reclosers. This rebuttal testimony also highlights the support for the Company's position that these investments are necessary because reliability is declining in Rhode Island and that added visibility and control from the proposed grid modernization investments would offer improved operational and restoration capability as evidenced by the recovery efforts for the Nasonville event. All this demonstrates the urgency to make the grid modernization investments and there is no reason to delay the grid modernization investments until the review and approval of Advanced Metering Functionality ("AMF") is complete or until the full GMP has been vetted in Docket No. 22-56-EL has been reviewed and approved.

[1] Unless otherwise noted, when referring to the ISR Plan, I am referring to the 12-mnth spending plan effective April 1, 2023 through March 31, 2024 that is pending before the Public Utilities Commission ("PUC").

Q. Could you summarize your rebuttal testimony on each of these issues?

A. Yes. First, with respect to the increase in capital spending and impact on customer bills to accomplish the grid modernization as proposed in the ISR Plan, the evidence demonstrates that the bill impact to customers is modest and will bring about tangible benefits that far exceed the costs.

Second, with respect to the justification for the grid modernization investments proposed in the FY 2024 Electric ISR Plan, the functionality is necessary to modernize a traditional grid to successfully operate in a world of increased complexity.

Third, with respect to the timing of the filings and the interrelationship with the AMF Business Case and the GMP, the review and consultation process with the Division not only complied with statutory requirements, but the Company also provided the Division with substantial information about the development of the ISR and GMP that went above and beyond the minimum levels required by statute. And, although the acquisition of The Narragansett Electric Company by PPL Rhode Island Holdings, LLC ("PPL") resulted in some additional attention on the time period that would be covered by the FY 2024 Electric ISR Plan, the Company's construct of using the GMP as a companion document to support grid modernization investments that would be proposed in the ISR Plan was and is not new. In fact, National Grid contemplated that construct in its Grid Modernization Plan filing developed from 2018 – 2020.

Fourth, with respect to whether protection coordination studies are necessary before approving investments in reclosers, a systemwide protection coordination study is not customary prior to determining whether to procure and where to locate reclosers, and, in fact, is not prudent to execute before installation because of the dynamic nature of the system. Rather, timely localized studies are appropriate prior to installation to avoid staleness.

Fifth, the Company disagrees with the Division's assessment of the need for investments to reverse negative reliability trends and improve operational visibility for reliability and safety, as well as how the proposed grid modernization investments would improve the Company's ability to respond to events effectively and efficiently like the one that occurred at the Nasonville substation. This disagreement stems from a difference in perspective between having the responsibility for affordability and the responsibility to keep the lights on. The Company takes the responsibility to keep the lights on seriously, and to meet its obligation to provide safe and reliable service it must transition from the fix on fail mentality represented by the Division's position. Maintaining that status quo would eventually degrade the system to the point that the cost and service impacts to recover would far surpass those necessary to make grid modernization investments to prevent those future failures. This has been learned the hard way by many other utilities. Given the many challenges before the Company now, (i.e. resources, supply chain, operational, interconnections, enabling Climate Mandates) coupled with the opportunity to realize immediate benefit from grid modernization investments with or without AMF, the Company must start now.

Q. Do you have any concerns about relying on the Division's consultant, Gregory Booth's evaluation, analysis and testimony regarding grid modernization investments?

A. Yes. Mr. Booth lacks experience in grid modernization. Although Mr. Booth has an extensive CV, his operational background and experience evaluating and implementing modern-day integrated grid-modernization portfolios is lacking. For example, in Mr. Booth's evaluation, he cited reliability as the only driver for grid modernization investments missing the key factors outlined in the report by the U.S. Department of Energy ("DOE") entitled Quadrennial Technology Review an Assessment of Energy Technologies and Research Opportunities.[2] The DOE report states, "a modern grid must be more flexible, robust, and agile. It must have the ability to dynamically optimize grid operations and resources, rapidly detect and mitigate disturbances, integrate diverse generation sources (on both the supply and demand sides), integrate demand response and energy-efficiency resources, enable consumers to manage their electricity use and participate in markets, and provide strong protection against physical and cyber risks." As the report states, "[t]he characteristics of the future grid will be distinctly different from

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[2] U.S. Department of Energy QUADRENNIAL TECHNOLOGY REVIEW AN ASSESSMENT OF ENERGY TECHNOLOGIES AND RESEARCH OPPORTUNITIES, Chapter 3: Enabling Modernization of the Electric Power System, September 2015 Chapter 3: Enabling Modernization of the Electric Power System (energy.gov)

those of the current system." The approach that Mr. Booth recommends is short sighted; he underappreciates the operational risks associated with emerging grid complexity, which will result in further performance degradation and limit the State's ability to effectuate the Climate Mandates.

IV. <u>Timing of Grid Modernization Investments</u>

Q. Why is now the time for the grid modernization investments proposed in the FY 2024 Electric ISR Plan?

A. They are necessary to improve reliability and enable functionality to better operate a distribution system that already is more complex than anticipated in the original design and will continue to become more so. These investments and the enhanced functionality and operational insight they provide will reduce risks for customers and for the Company as it continues to operate a distribution system that must be equipped to maintain safety and reliability while helping effectuate important public policy objectives such as the Act on Climate, R.I. Gen. Laws § 42-6.2-1 et seq., R.I. Gen. Laws § 39-26.3-4.1(d) related to interconnections of distributed generation ("DG"), and the Renewable Energy Standard ("RES"), R.I. Gen. Laws § 39-26-1 et seq.

The grid modernization investments are appropriate for inclusion in the ISR because they are consistent with the purposes of the Decoupling Act, R.I. Gen. Laws § 39-1-27.7.1., four of which are:

- Increasing efficiency in the operations and management of the electric and gas distribution system;
- Achieving the goals established in the electric distribution company's plan for system reliability and energy efficiency and conservation procurement as required pursuant to § 39-1-27.7(d);
- Reducing risks for both customers and the distribution company including, but not limited to, societal risks, weather risks, and economic risks; and
- Facilitating and encouraging investment in utility infrastructure, safety, and reliability.

Q. Why is it appropriate to include the grid modernization investments in the FY 2024 Electric ISR Plan before the complete GMP has been fully reviewed in a separate docket?

A. The GMP serves as supplemental and additional support for approval of the grid modernization investments that are pending before the PUC as part of the ISR Plan. The GMP only confirms and more precisely quantifies what was already presented to demonstrate that the investments are beneficial to customers and are consistent with the Company's long-term strategy. The Division was fully aware of the Company's approach, had input over several years, and had an understanding of the content that was being proposed in the GMP. The Division also was aware that the ISR Plan would be the instrument the Company would use to seek funding for grid modernization investments.

The grid modernization investments included in the ISR Plan deliver safety and reliability benefits independent of any of the other investments proposed as part of the complete GMP. The Company provided justification and support for these investments as part of the ISR Plan. These investments also are described and additional support is provided for them in the GMP, but the grid modernization investments in the ISR Plan do not rely on the other investments in the GMP to provide value. Rather, they are required for the continued safe and reliable operation of the electric distribution regardless of the ultimate portfolio of future investments. In short, these investments are appropriate for the ISR now because they are the types of investments for which the ISR is intended; they are reasonably needed to maintain safe and reliable distribution service over the short and long term. And, they are reasonably needed now because the Company requires the additional operational insights and functionality they provide to ensure that it can manage the increasing complexity of the electric distribution system and respond more efficiently and effectively to problems that occur on the system to mitigate the impacts to customers.

The Company's viewpoint on this is consistent with the position taken by the Division's consultant historically. For example, the Division's consultant has openly supported advanced field devices in the past to provide Volt Var Optimization ("VVO") and has verbally indicated in meetings that each feeder should have 2 – 3 reclosers and the ties between feeders should include a recloser, which is substantially similar to what the Company is proposing.

Q. Did the Company provide sufficient information to facilitate review and approval of the ISR Plan?

A. Yes. The Company provided voluminous evidence to the Division during the pre-filing consultation period and as part of the record in this docket demonstrating that the proposed investments meet the "reasonably needed" standard in the Decoupling Statute. There were numerous occasions where the Division and the Company discussed the grid modernization needs and solutions during and prior to the 60-day consultation period set by statute, such as the 33 interactions between September 9 and December 31, 2022 that are listed within Mr. Booth's Testimony, Booth Testimony, 9-12 (Exhibit GLB-1). And, in regard to grid modernization, the Company began engaging with the Division under National Grid's ownership years prior to those communications. For example, as shown in the GMP, Figure 1.2: PST AMF/GMP Sub-Committee Meetings Featuring GMP, Bates page 12, the Company began engaging about grid modernization in 2018 as part of the Power Sector Transformation ("PST") Advisory Group with 14 different meetings that were held through the end of 2019. Under PPL leadership, grid modernization dialog continued with PST Advisory Group meetings in July, August, October, November and December of 2022. Through the interactions in the July and August, 2022 meetings, the GMP study scope, forecast analysis, scenarios, solutions, and ISR coordination was reviewed. In October, a demonstration of the model that was used to base the grid modernization investments was provided, followed by a meeting in November where alternatives were discussed and the preliminary findings of the benefit-cost analysis

("BCA") were revealed. The PST Advisory Group met again in December 2022 where updated BCA results were discussed. The Division was often consulted on the scope and approach of the meetings and in all cases the Division was invited and participated in the meetings.

The Company, therefore, met and exceeded its statutory obligation to provide a proposed plan to the Division and consult with the Division in an attempt to reach agreement on a plan to file with the PUC. Even if the Division is of the opinion that it would have liked more time to review and evaluate the proposed plan, that is immaterial. The Company is not obligated to reach agreement with the Division on the plan or to persuade the Division to agree with its investments. The Company has now presented the PUC with its proposed plan and presented substantial evidentiary justification for the investments and spending included in the ISR Plan, and the PUC will determine whether the Company's proposed investments meet the legal standard based on the evidence presented.

Q. Please explain how the $45 million of grid modernization spending that is being proposed in the ISR Plan will achieve reliability enhancements and distributed energy resources ("DER") enablement, independent of AMF becoming fully functional.

A. The grid modernization investments proposed in the ISR Plan do not require AMF to deliver the safety and reliability benefits that justify their inclusion in the ISR Plan. Rhode Island Energy needs the operational functionality of the grid modernization investments proposed in the ISR Plan now to reliably and safely manage the increased complexity of the electric distribution system. The concept that the grid modernization investments are viable independent of AMF is best described through material provided in the GMP filing. The proposed grid modernization solutions are summarized in the GMP, Section 4.1: Solutions Selected for Tier 1 Functionalities, Bates page 70. Each solution individually provides direct impact or contribution to the various functionalities. This coupled with the information shown in the GMP, Figure 6.25: AMF Functionalities & Impact on Rhode Island Energy GMP Functionalities, Bates page 156, shows that AMF further enables (but is not needed) for the following Functionalities: Observability, Power Quality Management, Distribution Grid Control, Grid Optimization, and Reliability Management. This demonstrates that the grid modernization investments as proposed in the ISR are viable, with or without AMF.

The grid modernization investments proposed in the ISR Plan can begin in 2023 because of the Advanced Distribution Management System ("ADMS") availability. Rhode Island Energy's transition to ADMS Basic will start in 2023 and be operational by May 2024, as shown in the first two columns of the ADMS roadmap, GMP, Figure 6.6: ADMS and Operational Functionality Timeline, Bates page 131. The first two columns also describe the ADMS Basic functionality that will be available at that time. Rhode Island Energy SCADA and advanced distribution device cutover will be available and start in 2023. Processes have been defined with supporting operational procedures to map any new automated distribution field devices that are installed by Rhode Island Energy directly into the ADMS starting in 2023.

Q. Will the communication network necessary for the grid modernization benefits be available in the absence of AMF approval and deployment?

A. Yes. None of the grid modernization investments proposed in the ISR Plan is dependent on the proposed AMF RF mesh communication network. As described in the GMP Filing, Figure 4.2: GMP Functionalities Comprise of Solutions in Five Integrated Facets, Bates page 72, and Figure 6.22: Communication System with Fiber Backhaul, Bates page 151, the grid modernization investments will utilize cellular communications independent from the RF network proposed for AMF. Accordingly, Mr. Booth's testimony that "Both AMF and GMP rely on this fundamental (RF network) communication network and system integration for operations and to achieve expected benefits", Booth Testimony 15:19-21, is inaccurate.

V. Reliability

Q. Why are grid modernization investments necessary to improve reliability if the Company's reliability metrics satisfy PUC guidelines?

A. Reliability at Rhode Island Energy was discussed in the GMP, Bates pages 24- 28. *See* Figure 1.8: Rhode Island Energy Reliability (SAIFI) 2011 – 2021, Figure 1.9: Rhode Island Energy Reliability (SAIDI) 2011 – 2021, Figure 1.10: Rhode Island Energy CEMI Performance VS EEI Survey 2021 and Figure 1.11: Rhode Island Electric Reliability Compared to PPL Electric and Peers. The graphs depicted in these figures reflect trends that are moving in the wrong direction and the performance gap is widening between Rhode Island Energy and its peers due to performance degradation in Rhode Island compared to steady improvement elsewhere. This observation is further reinforced by Customers Experiencing Multiple Interruptions ("CEMI") being in the 3rd quartile and Customer Satisfaction surveys benchmarking in the 4th quartile. Rhode Island Energy and its parent company, PPL Corporation, cannot accept simply maintaining this relatively poor level of performance, which, given the trends, is likely to continue to degrade. The goals that were established and maintained over time are not good enough given the realities of today.

Q. Why do the realities of today dictate a departure from these standards and a change in approach?

A. Historically, there was an approach to infrastructure investments that reflected a fix-on-fail philosophy – *i.e.*, waiting until something on the electric distribution breaks to take action to fix the problems caused by the break. Many other utilities have a long history of utilizing a fix-on-fail investment approach. These experiences have demonstrated that the adoption of targeted investment that includes a strategy of grid modernization to avoid foreseeable problems on the electric distribution system is key to successfully operating the system safely and reliably.

Rhode Island Energy is challenged daily with the lack of visibility in a complex and dynamic operating environment. The operational reality in Rhode Island coupled with the historic consequences for other utilities of doing just-enough and only-when-needed, is driving the urgency for the grid modernization investments. Reclosers that are needed for fault location, isolation and service restoration ("FLISR") functionality are the highest priority investment. FLISR will reduce the number of customers who experience a sustained outage and will shorten the duration of certain sustained outages. FLISR also will provide increased visibility into outage events occurring on the system for engineering and operations personnel, which will inform the Company's operations and future investments in the system.

Q. How would the grid modernization investments alleviate reliability concerns?

A. Rhode Island Energy forecasts that SAIFI will improve by up to 30% because of these grid modernization investments. And, the FLISR capability enabled by the investments also is expected to improve Rhode Island Energy's CEMI performance. Reclosers, when coupled with ADMS and the FLISR application, bring better visibility, control and optimization of the distribution system. It is, therefore, important to move forward with these investments now so the electric distribution system does not further hinder system reliability, customer empowerment or the achievement of the Climate Mandates and does not create higher costs in the long run.

Q. Why is it reasonable that the Company places emphasis on SAIFI, as opposed to SAIDI?

A. PPL and Rhode Island Energy place the greatest emphasis on avoiding the outage, thereby reducing the frequency of them. The Company has drawn a conclusion that improved SAIFI is statistically correlated to improved customer satisfaction. Customers would rather not have an outage than have one. For this reason, SAIFI has been the primary driver, which will be aided by reclosers and FLISR functionality.

Q. Please explain how reliability will be improved with grid modernization investments with or without an increase in vegetation management.

A. The Company agrees with the Division, Booth Testimony at 15:1-6, that reliability programs, such as increased vegetation management, will result in improved reliability. However, the Company disagrees that, with an increase in vegetation management, the reclosers will have minimal impact on reliability. Even with increased spending on vegetation management there will continue to be outages from multiple causes. A recloser reduces customer exposure to outages on the system, and as a result, with more reclosers installed, fewer customers will experience the outages that do occur on the system. Future customer outages (whether the same number or fewer because of other reliability investments), will be reduced because customers are exposed to fewer outages.

Q. Is the Company's Inspection & Maintenance ("I&M") program sufficient to maintain safety and reliability without making additional grid modernization investments?

A. No. The Company needs to make changes to its approach, and as discussed above, the negative reliability trends contradict the notion that the Company is maintaining safety and reliability using the current approach. Mr. Booth's testimony to the contrary demonstrates that he believes a "break-and-fix" or "fix-on-fail" approach is better than the Company's proposal to modernize the grid. This approach to managing aging assets in the Company's I&M program is not a model for utilities to follow. Rather, it is a *de* *minimis* program that fails to leverage new technology or advanced analytics. Further, the relatively low spend allocated to the program, which resulted from downward pressure on earlier program spending proposals, only provides for the wherewithal to address immediate system reliability and safety concerns that are corrective in nature. The industry has learned over time that the short-term approach that limits spending to that which is in immediate need because breakage has occurred or is imminent is more expensive in the long run and results in the degradation of system reliability and customer satisfaction. Furthermore, as that philosophy struggles to maintain what was, it fails to adopt new technologies and practices that increase efficiencies and add value. Accordingly, the fix-on-fail practice is not normal practice in the utility industry today and does not reflect progressive thinking because it shuns the need for programmatic spending to address aging infrastructure and limits the ability to adopt new technology that brings about increased functionality necessary to operate safely and reliably as the system becomes more complex.

Rhode Island Energy's reliability has been declining. Continuing the current I&M philosophy and approach will cause reliability to further erode and will inhibit the ability to operate reliably, safely and most optimally, especially given the emerging operational complexity that is becoming a daily reality.

Q. Could you provide some examples of other utilities that have overcome reliability and operational challenges, in part due to under-investment, and have risen to have notable performance achievements through the use of grid modernization investments?

A. Yes. Examples of other utilities that have overcome reliability and operational challenges in part due to under-investment and have risen to have notable performance achievements with grid modernization investments include Commonwealth Edison Company ("ComEd"), Hydro One Limited ("Hydro One"), and Pacific Gas and Electric Company ("PG&E"). The experiences of those companies are summarized below.

Hydro One – In July 2021, Hydro One in Ontario, Canada announced that it made investments for smart field devices consisting of reclosers and sensors to help reduce the impact of power outages by an average of approximately 40% in areas where they are deployed. This is part of Hydro One's grid modernization program, which leverages digital technology including smart switches and sensors to automate the electric system and improve power reliability.

Prior to 2018, Hydro One's performance was concerning as evidenced by comments in the 2015 Annual Report:

"Hydro One's mandate is to be a safe, reliable, and cost-effective transmitter and distributor of electricity. Instead, Hydro One's customers have a power system for which reliability appears to be worsening while costs are increasing,"

"Customers are experiencing more frequent power outages, mostly because assets aren't being fully maintained, aging equipment isn't being consistently replaced, and trees near powerlines aren't being trimmed often enough to prevent outages."

Since that report, Hydro One has added thousands of smart devices to its system, with plans to install more in the coming years. Energizing these smart devices in communities across the province has avoided 20 million customer minutes of power interruptions with smart devices that have been deployed in 10% of Hydro One's service territory.[3]

ComEd – After failing to invest in its transmission and distribution infrastructure for decades, major portions of the City of Chicago and many surrounding communities went dark on a hot summer weekend in 1999. Customers, regulators, and politicians had seen and experienced horrible electric reliability for years and had enough (*Mayor Richard Daley today lashed out at…* - Chicago Tribune, Aug. 11, 1999, "The lack of infrastructure in the company for many years – it's coming home to roost," – Mayor

[3] https://www.tdworld.com/overhead-distribution/article/21169596/hydro-one-makes-smart-investments-to-improve-power-reliability-for-customers

Richard Daley). Outage frequency (SAIFI) was 1.25 in 2001, which meant that on average, every customer of ComEd experienced 1.25 outages annually. Following two years of investment at levels never imagined before or seen in the company's history (which included distribution automation, increased infrastructure to build additional capacity, and dedication to pursue proactive and systematic maintenance practices after addressing backlogs), ComEd customers experienced improved system performance that resulted in a SAIFI of 1.09 outages annually in 2003 (*Daley's '99 scolding sparked upgrades* – Chicago Tribune, June 25, 2005). Furthermore, the cost/customer reduced more than 15%, and there were dramatic improvements in customer satisfaction. Since then, electric reliability has further improved as reinvestment occurred to replace aging assets and add modernization that included automation technology, smart devices, advanced digital meters, and maintenance upkeep. As a result, ComEd has transitioned from the highest profile investor-owned utility that had a reputation for under-performance and mis-management to one of the top performers in the country, claiming industry recognition for innovation, performance and customer satisfaction.[4] By 2015, ComEd ranked No. 2 in the country by GridWise Alliance for overall Smart Grid efforts and No. 1 for forward-looking policy support. While no two storms are identical, comparable storms in 2005 and 2015 show that Smart Grid investments are working: a November 2015 windstorm resulted in 44 percent fewer customer interruptions than a

[4] https://www.comed.com/SiteCollectionDocuments/AboutUs/Progress-Report-Final.pdf

comparable 2005 storm. Fast forward to 2022, benchmarking showed that ComEd ranked Number 1 in the U.S. for providing reliable electric service to customers according to 25 peer U.S. energy companies with approximately 1 million customers or more.[5] ComEd continues to affordably provide industry-leading reliability at some of the lowest costs to customers in the nation. Based on data from the U.S. Energy Information Administration, in 2021, the average monthly bill for a ComEd residential customer was lower than the average in 49 out of 50 U.S. states. For example, the performance was achieved while reducing the average monthly residential bill for ComEd customers in 2022 from the prior year.

PG&E – For decades PG&E in California failed to invest in its transmission and distribution infrastructure in terms of replacing aging assets, performing preventative and corrective maintenance, and modernizing with automation technology – resulting in 4th quartile reliability in both outage frequency (SAIFI) and duration (SAIDI). Customers, regulators, and the company recognized this was no longer sustainable and embarked on a reliability improvement program and significant infrastructure reinvestment. PG&E replaced aging assets with a multi-billion-dollar capital reinvestment plan, automating much of their electric system with FLISR and other technologies, and worked off hundreds of thousands corrective maintenance work orders that were backlogged.

[5] https://www.comed.com/News/Pages/NewsReleases/2022-11-14-2.aspx#:~:text=ComEd%20has%20continued%20its%20consistent,smart%20grid%20improvements%20in%202012

PG&E's distribution reliability improved significantly over the next several years to 2nd quartile reliability with a SAIDI of just over 72 minutes in 2015 and a SAIFI of .69 (excluding IEEE major events).[6] Since then, the reliability has regressed somewhat over the last few years due to wildfires and "proactive" power system shutoffs and operating the system through more extreme weather conditions.

In addition to these three utilities, there are many other utilities across the country that now deliver improved reliability performance and added storm resiliency for their customers because of grid modernization investments. *See* GMP at Bates page 23 for PPL Electric Utilities Corporation's reliability improvement due to grid modernization. Additionally, EBP Chattanooga in Tennessee and Florida Power and Light in Florida also have been recognized for tremendous system performance achievements due to their investments in grid modernization. With PPL's support, Rhode Island Energy now intends to align practices and investment strategy with other utilities across the country to adopt technology and revamp its programs to become more efficient and affordable, improve operability and system flexibility, improve reliability, and increase customer satisfaction.

[6] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-divisi on/documents/infrastructure/electric-reliability-reports/2020-pge-2020-annual-electric-reliability-report.pdf

Q. What are the possible consequences if the proposed investments are not made?

A. Without the making the requested investments there is a lack of visibility into conditions on and lack of control of the distribution system. Additionally, degrading asset condition and reliability will occur while DER interconnections are increasing. These eventualities can lead to safety concerns for the public and employees. Degrading asset condition and reliability, and more recently, the proliferation of DER, have produced catastrophic consequences for the both the public and utility company employees. Countless industry events across the US over many decades have resulted in loss of life, injuries, and significant property/equipment damage. The issues associated with both public and employee safety as summarized below:

Lack of visibility and control: without grid operators' understanding of the electric system conditions such as demand, load flows, current, voltage, electrical system configuration, etc., members of the public and employees are at risk for serious potential harm. Overvoltage and undervoltage conditions, fault current, system configuration, and lack of awareness of system conditions can result in wires down, blown transformers, and catastrophic equipment failures at both substations and out on the distribution system, exposing the public to serious potential harm. Further, electricians and field operators/technicians also can be at risk because they are literally performing physical switching and other operations/maintenance on their systems on a daily basis. Without awareness of system conditions, they can be exposed to serious potential harm from electrical flashes and explosive equipment failures.

Degrading asset condition and reliability: waiting to replace assets until they are beyond their useful/expected lives and/or they are in poor condition due to environmental and/or operational issues or poor maintenance can lead to significant potential harm to both the public and employees. When assets are in use beyond their expected lives, or when they are exposed to coastal conditions such as the salt air or excessive heat or wintry conditions, or when they are not maintained in accordance with manufacturer's guidance or industry best practices, equipment failures can result. These can range from wires down and underground cable faults to catastrophic equipment failure at substations, in underground vaults under city streets and sidewalks, and out on the distribution system on pole-mounted structures. Also, poor electric reliability and/or reliability that is trending negatively, e.g., either increased outage frequency and/or duration, is indicative of a failure to replace aging assets, modernize through automation and technology, and/or failure to perform the required preventative and corrective maintenance of equipment. Customers feel this impact over time and eventually, major power outages and/or extended power outages occur that cannot be remedied in short order. Under these conditions, both public and employee safety are impacted as physical security is diminished in terms of securing facilities and homes, lack of security lighting and public streetlights, life-saving equipment that is offline, and civil unrest and disturbances.

Growth of DER: the proliferation of DER has altered power flows and created more dynamic electric system conditions that are unlike the last 100 years that power systems have been in operation. Without specific knowledge of where those resources are, what their current state is, and the resulting system conditions, both the public and employees can be exposed to increased safety risks. As the electric distribution system becomes more saturated with DER, electrical load flows can be bi-directional and change at any time. This can produce unstable system conditions making it increasingly difficult for system operators to balance demand and production, a fundamental principle of the electric delivery system. Consequently, equipment can trip off line, equipment failures such as wires down and blown transformers can occur, and damage to customer equipment can result, including damage to their generating resource, internal house wiring, and associated appliances and property. As system operators monitor and operate the grid on a continuous basis and without specific knowledge of the current state of DER and locational information, they may unknowingly perform operations and switch into unknown loads and equipment resulting in equipment failure and potential harm to customers and the public. Likewise, field technicians may be operating the system, and, if unaware of system conditions including the state of DER, they could be exposed to those same safety risks and serious potential harm.

VI. Reclosers & Protective Device Coordination Study

Q. Please describe the role that protection coordination studies should have in planning for the investment in and deployment of advanced reclosers?

A. Protection studies are used to develop settings for protective equipment, such as advanced reclosers that contain micro-processor relays. As shown in Exhibit Joint Rebuttal-2, the rule for sectionalizing is the Fundamental Law of Sectionalization which states that "[t]he number of CUSTOMER FAULTS SAVED by any protective device is the product of the customers protected upstream times the line mileage downstream." This rule focuses on the number of customer interruptions saved, not on the coordination of such devices. Specifically, on page 5 of 18 under Rules for Sectionalization, the report provides that completing a full circuit study or coordination on a sectionalized circuit is not required.

Q. Do you believe a systemwide fault current availability protective device coordination study is required to approve the advanced reclosers that are proposed in the ISR Plan?

A. No. I agree with the Company. A systemwide fault current availability protective device coordination study, demonstrating the need, the location, and/or the way reclosers will be coordinated, is not necessary before progressing major recloser additions. This is contrary to the position taken by Mr. Booth in his testimony and recommendations. My position is based upon experience supporting PPL Electric and following utility best practice.

The common utility practice is to pursue advanced recloser approval to improve the protection architecture with increased customer segmentation, improve system visibility and ready the distribution system for increased DER. With increased customer segmentation, reliability does improve in terms of frequency of outages and the duration of them because fewer customers are exposed to any particular outage, and, when one does occur, the dispatching can be more targeted for a faster response. The Company is proposing initial investments in the ISR to improve reliability, safety, and add increased system visibility and system control.

After the decision is made to advance reclosers, more specific plans to locate the advanced field devices will be made, and protection coordination studies will be performed, as needed, to define the settings prior to installation. The close timing proximity to the installation is necessary because the changing nature of the distribution system impacts the settings (new DER, changing load, changing configuration). Performing protection studies prematurely is subject to change and rework, therefore is not a prudent use of engineering resources.

Accordingly, a protection study (systemwide or otherwise) is not a prerequisite to determining that it is appropriate to invest in advanced reclosers. Nor is it necessary to identify locations at which to install the reclosers. Rather, protection coordination studies are necessary and appropriate when preparing to install the reclosers to determine the appropriate settings.

Q. Mr. Booth cites to a Form 3A recloser study that was completed by National Grid in 2016 suggesting that National Grid conducted a systemwide fault current availability protective device coordination study. What is your opinion on that 2016 study?

A. The study example that Mr. Booth referenced for Rhode Island Energy that was completed by National Grid to assess the future for Form 3A reclosers, Booth Testimony 19:12-14, did not include a systemwide protection coordination study or a commitment to perform one. Rather, its purpose was to provide the basis for a decision to eliminate old equipment exhibiting a variety of service and operational problems. As a result of the study, the Company committed to review field conditions and feeder configurations to determine the best location of future switching devices. The approach defined by the Company is aligned with the factors that Rhode Island Energy is using to identify recloser locations, starting with the first 100 mainline reclosers, and will continue as the advanced field reclosers are located based upon feeder length, number of customers, type of customers and feeder reliability values to preclude mainline fault impacts.

Q. What experience to do you have with utilities adopting advanced reclosers in the industry and how do they typically handle distribution coordination studies?

A. I have held senior leadership positions in two large investor-owned utilities having responsibility for automation, engineering, asset management and grid modernization to name a few. In both cases, we were able to select, engineer and deploy advanced field switching devices to provide increased segmentation, FLISR functionality and additional visibility with added system sensing. In both of these cases, thousands of devices were installed, resulting in significant system operational improvements for safety and reliability. In neither case were protection studies required for approval of the advanced reclosers or to initiate the orders.

In addition, for more than a decade, I was the Vice President of Power Systems Services for a major manufacturer of medium voltage switchgear and protection equipment that included advanced recloser capability where my division offered engineering, procuring, construction, commissioning and field services to utilities and major industrial companies. During this time, I was involved in the sales and service of advanced field devices to provide engineering, installation, and commissioning support across the globe. The projects that my team and I supported ranged from boutique recloser projects and microgrid installations to installations that consisted of thousands of units at large investor-owned utilities deployed over multiple years. To my knowledge, none of these cases included a comprehensive systemwide protection coordination study prior to the procurement process. Rather, the service organization that I was responsible for would occasionally assist customers with protection strategy, which set the stage for the application of protection devices before placing the orders. Protection coordination studies typically occurred much later in the process for the aspect of the system that was changing, well after the equipment was procured and often performed just-in-time to support the construction schedule to load the settings in a timely manner. As field conditions and protection philosophies change, fortunately the electronic controls in advanced reclosers today are flexible, easily customizable and programmable, and have advanced protection capability. They also provide the flexibility to make modifications in the future remotely over-the-air to accommodate system changes.

Q. Why are reclosers needed in the ISR Plan now?

A. The Rhode Island Energy system currently experiences regular lock-outs. Advanced reclosers will limit the customer exposure to outages, so few customers will be affected. Adding reclosers into the circuit can reduce the number of customers that are exposed to any particular outage, improve switching capability and thereby reduce the likelihood that customers experience an outage. If they do experience an outage, restoration can occur faster due to automation and targeted dispatching.

Further, the distribution systems are radial in nature and over-current based protection schemes are set for unidirectional flow of fault currents. Penetration of DER usually causes meshed configuration (multi-directional power flow) of distribution systems where fault current can flow in both directions. The protection schemes, which are designed for unidirectional flow of fault currents, fail to provide the adequate protection coordination when DER power is injected in the distribution system. The impact of DER on protection depends upon number, size, type and location of DER. Increasing DER and associated bi-directional fault current causes a requirement of additional directional over-current relays, and potentially modified settings of over current relays. The Company's proposal is to increase the application of reclosers to increase switching and protection architecture to limit customer exposure to outages and to protect the system and workers from bi-directional fault current. With new advanced recloser technology, updates to settings can be done remotely, and in the future perhaps dynamically, as the system changes.

Q. Are there other reasons beyond reliability why reclosers are a priority in the GMP and being included in the ISR Plan?

A. In addition to offering up to a 30% reduction in outages when used in conjunction with ADMS-Basic FLISR, advanced reclosers also support or enhance improved system visibility, flexibility for system configuration, enhanced protection capability, voltage data to improve volt/VAR optimization analysis, and operational efficiencies. The associated electronic controls are more flexible, more easily customized and programmed, offer over-the-air update capability – and many have advanced protection, metering, and automation functionality that is not currently available.

Q. How have the benefits from reclosers been quantified?

A. The enhanced flexibility and visibility offered by advanced reclosers and other advanced field devices, especially when implemented in conjunction with ADMS, are critical functionalities to operate safely and reliably as the system becomes more dynamic and complex. However, these attributes are difficult to quantify. In addition to improved reliability, the advanced reclosers have been quantified in the GMP BCA through OPEX Labor Efficiency, Avoided D-System Infrastructure Cost, and Reduced DER Curtailment due to the ability of the system operator to optimize power output from renewable DER by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance.

Q. How should the benefits of advanced reclosers be considered relative to all benefits from investments proposed in the GMP?

A. While the advanced reclosers are the largest line item in the ISR Plan and most urgently needed, the other investments also are important. By focusing solely on any one component, such as advanced reclosers and making choices about certain elements of the portfolio to approve and delay, it will likely result in a piecemeal deployment that will provide value, however it will be sub-optimized. Analyzing the value of each grid modernization element individually will achieve value; however it will not result in the same level as the multiple benefits that can be achieved when analyzing a completely integrated grid modernization portfolio. Value assessment of the integrated portfolio is the sound engineering approach.

VII. Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes.

WANDA REDER

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PROFILE

Entrepreneurial and proven senior executive who is globally recognized with prestigious achievements, including National Academy of Engineering and IEEE Fellow. A transformative leader with significant achievements in utilities and related technical professional associations, service providers, suppliers and regulatory groups. Track record of providing strategic direction and successfully executing large-scale change initiatives, resulting in turnarounds and sustainable growth. Expertise in leading large domestic and international organizations, start-up ventures and mergers & acquisitions, and implementing leading-edge solutions. A creative thinker and influential collaborator with proven skills for leading, networking, fundraising, building partnerships, investing capital and delivering multimillion-dollar, bottom-line growth. A committed philanthropist and trusted advisor to Boards of Directors, C-Suites, professional associations and utility industry stakeholders.

- **Visionary Industry Leader:** Valued for forecasting and delivering unprecedented transformation and innovation to the utility industry. Highly sought-after senior executive, thought leader, speaker and advisor (see www.gridxpartners.com for list of articles and presentations).
- **Strategic Planning and Financial Acumen:** History developing comprehensive strategic plans based on a global industry perspective, inclusive of mission and vision, growth projections, business risk assessments, market insights, investment requirements, manufacturing needs and human capital requirements. Outcomes are typically Board-endorsed and foundational for investment plans, rebranding, restructuring, developing road maps and acquisitions.
- **Operational Excellence and Human Capital Performance:** Team-oriented and impact-driven. Proven effective in bringing together a wide variety of different stakeholders and their perspectives to align with a common vision. Extensive experience leading large organizations (1,000-plus employees), overseeing sizeable budgets, developing personnel, remapping processes, reorganizing (impacting 7,000-plus employees) and executing strategies to achieve business results.
- **Entrepreneurial:** With an MBA in New Ventures, has repeatedly identified emerging market needs and seized the opportunity; a demonstrated early mover who has built high-performing teams that have successfully embraced new technologies and initiatives, many in the Smart Grid domain, having a positive and long-lasting impact on the industry.

PROFESSIONAL EXPERIENCE

Grid-X Partners, LLC, Chicago, IL, **2018 – Present**

Woman-owned provider of strategic management consulting services for utility clients around the world, providing business and technology expertise to support operations, projects and future grid goals. Women Business Enterprise certification pending.

President and CEO

Global business owner, consultant and trusted advisor. Creating strategic direction, facilitating public/private partnerships, executing large-scale change initiatives, building collaborative networks and contributing thought leadership to Boards and their Committees through membership. Engagement examples:

- **Utility Grid Modernization Consultation:** Provide strategic consultation, acquisition alignment, regulatory support and technical expertise for grid modernization and automated meter reading filings in the Northeast.
- **Utility Public/Private Partnership**: Led the business planning for one of the top five U.S. utilities and cities that are working together to build a Smart City business model that can apply to other states and regions nationally or globally.
- **Illinois Next Grid:** Thought leader and participant for a consumer-focused study to address critical issues facing Illinois' electric utility industry, examining new technologies and their potential to improve the electric grid.
- **Singapore National Research Foundation:** Chair of the Energy Grid 2.0 Advisory Board for the Prime Minister's Office, funding R&D to transform Singapore into a vibrant smart-nation that is a magnet for excellence in science and innovation.
- **U.S. Department of Energy (DOE):** Chair of the Electricity Advisory Committee for DOE, providing advice and direction to modernize the national electric delivery infrastructure to be more flexible, resilient, secure, cost-effective and reliable. Past-Chair of the Smart Grid Sub-Committee, oversaw $9 billion of American Reinvestment Recovery Act investment to accelerate technology adoption and increase Smart Grid penetration. Appointed by U.S. Secretary of Energy.
- Ongoing affiliations/continued work with professional associations having significant accomplishment:
    - **National Academy of Engineering (NAE), 2016 – Present**
      Private, independent, non-profit institution that marshals the expertise of the world's most accomplished engineers to provide independent advice and solutions to the U.S. government on matters involving engineering and technology.
        - 2016 inducted as Member with the citation "for leadership in electric power delivery and workforce development."

- **Edison Electric Institute (EEI), 1987 – Present**
  Represents all U.S. investor-owned electric companies operating in 50 states and the District of Columbia, providing public policy leadership, strategic business intelligence and conferences.
    - Served on the Transmission and Distribution Leadership and Asset Management (Chair) Committees.
    - Advised on utility workforce shortages, which inspired the Center for Energy Workforce Development.
    - Participate in various sub-committee activity i.e. positioning for FERC Order 2222
- **Institute of Electrical and Electronic Engineers (IEEE), 1998 – Present**
  Leading professional association for the advancement of technology, with more than 400,000 members worldwide.
    - 2012 IEEE Fellow receiving the citation "For leadership in power engineering implementation and workforce development."
    - President-Elect candidate, 2016; Board Member, 2014-2015.
    - Chair and Founder of IEEE Smart Grid, 2009 - 2013. With nearly 150,000 followers, positioned IEEE as a global thought leader for Smart Grid and related standards.
- **IEEE Power & Energy Society (PES), 1998 – Present**
  Leading provider of scientific and engineering information on electric power and energy for the betterment of society, and the preferred professional development source for its more than 38,000 members and the electric utility industry.
    - President, 2008 – 2009, first female to hold the position in 125-year history; led strategy to re-engineer PES, which included a historic name-change in 2008, in anticipation of significant industry transformation.
    - Increased awareness of PES activities while visibly embracing broader concept of energy.
    - Introduced new publications, global conferences and educational venues to address emerging areas.
    - Changes led to significant PES financial and membership growth in the last 10 years.
    - Board Member 2002- 2011, 2013-2015 globally recognized distinguished Lecturer and Keynote Speaker.
- **IEEE Foundation, 2014 – Present**
  The philanthropic partner of IEEE; inspires donors and is responsible for about $40 million Enables IEEE programs that improve access to technology, enhance technological literacy and support technical education and the IEEE professional community.
    - Chair and Founder of IEEE PES Scholarship Plus, 2011 – 2014.
        - ✓ Led the philanthropic campaign, achieving $6 million on a $10 million goal to date.
        - ✓ Provided 835 power engineering students from the U.S., Canada and Puerto Rico with 1,135 scholarships.
        - ✓ Credited for doubling the rate of undergraduate engineers pursuing power in the U.S. and Canada since 2006.
    - Board Member serving on Development, Audit, Signature Program Review and Nomination & Governance Committees.

S&C Electric Company, Chicago, IL, **2004 – 2018**
An employee-owned S Corporation that is a global provider of premier equipment and services for electric power systems. Founded in 1911, the company is a specialist in switching, protection and control solutions for electric power transmission and distribution applications.

Chief Strategy Officer *(2015 – 2018)*
Reporting to the CEO, responsible for developing, engaging and aligning the Board of Directors and senior management on S&C's future strategic direction to fulfills its mission and growth objectives. Also responsible for M&A, liaising with regulatory and industry associations, and providing industry thought leadership.

- Developed inclusive strategic planning processes, resulting in alignment and support of the senior leadership team and the Board of Directors. Facilitated new strategic initiatives through inception phase.
- Identified emerging trends to develop strategies and identify business opportunities for sustainable growth. Created a scenario planning framework that provided context for investment and market repositioning.
- Championed an analysis to define the growth required to provide industry-leading retirement benefits for team members.
- Established a Board-approved five-year growth plan that was used to reorganize the company. Identified growth by product and geographic application; supporting elements included business risk assessment, global channels, shifts in manufacturing strategy, enhanced research investment, strategic partners, acquisition targets, product line divestitures and resource reallocation. 2017 financial performance and stock price increase were historically exceptional and record setting.
- Led negotiations and acquired IPERC as a wholly owned subsidiary of S&C in seven months; sponsored integration efforts and chaired the board. IPERC is a North American leader in cybersecurity and microgrid controls.
- Sponsored a five-year hiring plan defining competencies changes and "hard-to-hire" positions to deliver the growth plan.
- Developed External Engagement Plan, including S&C roles and responsibilities for community participation and government involvement.

Vice President, Power Systems Solutions (PSS) *(2004 – 2014)*
Recruited to develop and lead a new service business with full P&L responsibilities; reported to the CEO.

- Achieved significant business growth (from $13 million to $75 million) by building consulting, engineering, field services and project management capability.
- Led S&C's transformation from equipment sales to solution-based offerings.
- Developed a team to address U.S. and global service needs in Canada, Mexico, Brazil, China, the UK and Australia that included a successful turn-key project capability and commissioned more than 7 GW of wind-power projects and more than 70 MW of solar projects.
- Developed organizational capability to become the leading battery storage integrator in the U.S. Successfully interconnected more than 150 MWh of storage and first to couple it with wind in the U.S.
- Implemented most extensive self-healing distribution automation systems in the world, which have improved reliability across the entire electric utility sector.
- Developed a 24/7 remote monitoring global call center that improved field response and customer service.

Exelon Corporation, Oakbrook Terrace, IL, **2001 – 2004**
More than 5 million energy services customers in Illinois and Pennsylvania; a $15-plus billion in annual sales. Energy Delivery has $10-plus billion in annual revenue and more than 94,000 electric circuit miles.

Vice President, Asset Management, Exelon Energy Delivery *(2003 – 2004)*
Vice President, Engineering & System Planning, Exelon Energy Delivery *(2001 – 2003)*
Reported to the President of Exelon Energy Delivery; directly responsible for leading more than 1,000 employees. Led an asset management organization consisting of asset investment strategy (work plan of more than $1.2 billion), electric transmission, substation and distribution standards; system capacity planning; reliability and maintenance programs; new business engineering (more than 85,000 new connections per year); delivery engineering; facility records; and work management.

- Led the integration of two major investor-owned utilities' transmission and distribution organizations post-merger, which included organization redesign to reduce layers and spans, impacting more than 7,000 employees.
- Created single investment asset strategy and associated processes that optimized infrastructure investment decisions. Reduced system outage frequency from 1.25 in 2001 to 1.09 in 2003 while reducing cost per customer more than 15% and increasing customer satisfaction.
- Sponsored many business process redesigns: prioritizing and approving work; advancing the timing of capacity planning; improving construction lead-time; automating mapping, engineering and balanced scorecards by utilizing web-based tools; and automating joint work agreements.

Davies Consulting, Inc., Chevy Chase, MD, **2000 – 2001, 2004**
A strategic management-consulting firm establishing sustainable competitive advantages in the energy and pharmaceutical sectors.

Vice President, Energy Sector
Launched and led the energy-consulting practice specializing in asset management, reliability, resiliency and best practices. Developed a $3 million pipeline in the first year, leading to year-over-year growth and an eventual acquisition.

- Provided C-Suite consulting to investor-owned utilities, which resulted in a successful electric utility acquisition.
- Consulted for broadband start-up venture offering high-speed services to REITS across the U.S.
- Assessed Florida utility infrastructure and developed new hardening standards and emergency preparedness plans leading to exceptional performance for storm restoration that is second-to-none and widely recognized.

Ultra Power Technologies, Inc., Brooklyn Park, MN, **1997 – 2000**
An unregulated subsidiary of Northern States Power established to perform diagnostic testing on underground distribution cable for electric infrastructure owners in the U.S. and Canada.

President & Chief Executive
Secured exclusive rights to state-of-the art technology and formed an unregulated subsidiary for Northern States Power Company (NSP) to perform leading-edge cable testing in the U.S. and Canada. Full P&L responsibility. Tested more than 2,000 miles of cable and generated $3.6 million of revenue in the first two years of operation. Successfully led the divestiture of the company; today it is very viable, global and has significant sales revenue.

Northern States Power Company (NSP), Minneapolis, MN, **1987 – 1997**
A combination electric and gas utility serving more than 1.2 million customers in Michigan, Minnesota, North Dakota, South Dakota and Wisconsin; merged in 2000 and is now a component of Xcel Energy.

***Director, Automated Energy Services** (1996 – 1997)*
Created the strategy and business plan to automate electric and gas meters (AMI) in Minneapolis and St. Paul service area. First AMI of this scale in the country. Negotiated long-term communication contract, addressed union issues, managed IT efforts and oversaw three work groups to exchange meters while maintaining contiguous billing operations. Directed installation of more than 100,000 meters, leading to converting more than 1 million meters. Also implemented Distribution Management System to support Operations with schematics, communications and control of automated distribution devices.

***Team Leader, Delivery System Planning** (1993 – 1996)*
Created a 15-year, long-range transmission and distribution system capacity plan incorporating distribution automation capabilities. Led a team that defined planning criteria, forecasted growth rates, determined transmission and distribution constraints, selected alternatives, performed related economic comparisons and recommended investments. Responsible for communicating plans and getting project approvals, often requiring action from the Board of Directors.

***Manager, Automation Planning and Development** (1991 – 1993)*
Provided strategic planning for distribution automation. Initiated and managed automation projects, including communications, software and field trials for capacitor banks, switches, gas regulator points, meters and large customer loads. Performed budgeting, interfaced with vendors and supervised staff. Integrated substation feeder breakers and more than 600 points of feeder mainline telemetry to notify dispatchers of alarm conditions.

***Engineer I, II, Marketing Engineer, Product Development and Analysis** (1987 – 1991)*
Responsible for developing conservation and demand-side management programs. Conducted economic analysis and prepared filings for the state Commerce Commission. Conceptualized and led the first large-scale water heater and air-condition load control program in the U.S. using VHF-radio technology to reduce demand. Directed all aspects – statistical analysis for impact, customer focus groups, rate-making design, field pilot, radio design and deployment, database creation, promotion, recruiting and installation activities, resulting in more than 200 MW of diversified demand relief.

CURRENT BOARD MEMBERSHIPS

- **Singapore Energy Grid 2.0 Advisory Board,** 2018 – Present
- **U.S. Department of Energy Electricity Advisory Committee,** 2011– 2017 and 2018 - Present
- **IEEE:**
  - **New Initiatives Committee,** 2017 – Present
  - **Future Directions Committee,** 2009 – 2015, 2018
  - **Employee Benefits & Compensation Committee,** 2017 – Present
- **IEEE Foundation Board**, 2014 – Present
- **South Dakota State University Council of Trustees,** 2017 – Present
- **Illinois Institute of Technology Engineering Advisory Board,** 2014 – Present
- **South Dakota State University Dean's Advisory Committee,** 2011 – Present

PAST BOARD MEMBERSHIPS

- **IPERC,** Member and Chair of the Board, 2016 – 2018
- **IEEE:**
  - President-Elect Candidate, 2017
  - **Governing Board,** 2014 – 2015
  - **IEEE Smart Grid,** Chair from 2009 – 2013
  - **Public Visibility Committee,** 2014-2015
  - **IT Ad Hoc Committee,** 2014
  - **Industry Ad Hoc Committee,** 2014 (Chair) – 2015
  - **IEEE PES Scholarship Plus,** Chair from 2011 – 2014
  - **IEEE Power & Energy Society (PES),**
    - **Governing Board** Member, 2002 – 2011, 2013 – 2015
    - President, 2008 – 2009
    - **Fellows Selection Committee,** 2018
    - **Long-Range Planning Committee,** 2006 - 2011

EDUCATION

University of St. Thomas, St. Paul, MN; MBA, New Ventures, 1990
South Dakota State University, Brookings, SD; BS, Engineering, 1986

ACHIEVEMENTS AND RECOGNITIONS

- **National Women's Business Enterprise Certification,** awarded to Grid-X Partners, LLC, 2018
- **U.S. Government Secret Clearance**, 2017
- **National Academy of Engineering,** 2016
- **IEEE Richard M. Emberson Award**, 2014
- **EEE PES Wanda Reder Pioneer in Power Award,** 2014 – Present (endowed award to recognize a deserving female annually and promote diversity)
- **IEEE TAB Hall of Honor Award**, 2013
- **Electrical and Computer Engineering Department Heads Association (ECEDHA) Industry Award,** 2013
- **IEEE PES Meritorious Service Award,** 2013
- **IEEE Fellow,** Class of 2012
- **IEEE PES Leadership Award,** 2012
- **Wayne E. Knabach Excellence In Power Award,** 2012
- **South Dakota State University Distinguished Engineer Award,** 2007

PUBLICATIONS, ARTICLES and INDUSTRY PRESENTATIONS
Resume Addendum

Title	Event
"Selecting and implementing a Pilot Communication System Supporting Distribution Automation at Northern States Power Company"	• 1992 Dist. Automation/Demand Side Management Conference • 1992 Minnesota System Power Conference; St. Paul • 1992 American Power Conference; Chicago, Illinios • 1993 Automation/Management of Electrical Distribution; Paris, France • 1993 Automated Meter Reading Association • 1993 Distribution Automation/Demand Side Management Conference
"Distribution Automation; Yesterday, Today and Tomorrow..."	• 1996 SINAD; Rio De Janeiro, Brazil
"Applying 15 Year Delivery System Plan to Business Decisions"	• 1996 American Power Conference; Chicago, IL
"Power Quality and Rate Structures"	• 1996 IEEE Winter Meeting; Baltimore, Maryland • 1996 IEEE meeting; California • 1996 IEEE meeting; Key West, FL
"Re-think Distribution"	• 1997 Keynote for EEI Distribution Committee Meeting; Baltimore, MD
"Cable Management and Non-destructive PD Cable Testing"	• 1998 WEPI; Boise, Montana • 1999 WEPI; Las Vegas Nevada (part II)
"Accessory Partial Discharge: 60 Hz Field Testing Lessons"	• 1999 IEEE Insulated Conductor Committee; Charlotte, NC
"Addressing Distribution Challenges Using Predictive Diagnosis"	• 1999 AEIC; Duluth, Minnesota
"Partial Discharge Cable Testing Experiences and Lessons Learned"	• 1999 IEEE T&D/PES; New Orleans, Louisiana • 1999 Jicable, Paris, France
"Cable Modeling for Predicting Underground Failure"	• 2000 Infocast, Improving Distribution Reliability; Washington, DC
"Reliability Centered Maintenance for Underground Distribution Systems: Using Predictive Diagnostics"	• July 2000: IEEE Summer Meeting
"Reliability – the Moving Target"	• Fall 2000 EEI Distribution Committee Meeting; Burlington, Vermont
"Reliability in the New Millennium"	• 2001 EEI Customer Operation Management Workshop,

	New Orleans
"Managing Aging Distribution Assets is Different Today! Engineering and Planning for Aging T&D Infrastructure"	• Feb 2001 EEI T&D Conference, Denver, CO
"Managing Distribution Assets in the New Millennium"	• 2001 EUCI Power T&D Asset Management Conference; Atlanta, GA
"Recent Events and the Impact on Technology"	• 2003 Keynote for Distributech; Las Vegas, Nevada
"Our Energy Situation: The Impact of Technology and Leadership Development"	• 2003 Keynote for Electricity Engineers' Association; Christchurch, New Zealand
"Managing the Aging Workforce"	• 2004 EEI T&D Advisory Group, Minneapolis, MN
"Managing the Aging Workforce with Technology and Process Improvement"	• 2004 EEI Substation Committee, Minneapolis, MN
"IEEE PES Board Orientation"	• Jan 2005: IEEE PES Board Meeting, Los Vegas, Nevada
"Stewardship: Who is in Charge Now?"	• April 2005: MEAG Electric Cities of Georgia. Savannah, GA
"Aging Intellectual Talent is Creating a Technical Talent Challenge	• June 2005: Plenary Speaker IEEE PES General Meeting San Francisco, CA
"Managing the Power Delivery Maturing Workforce"	• Nov 2005: Minnesota System Power Conference; St. Paul, MN
"Managing the Talent Challenge"	• Oct 2005: EUCI, St. Louis MO • Oct 2005: UPMG
"Our Maturing Workforce is Creating a Technical Talent Challenge"	• Nov 2005: International Power Engineering Conference, Singapore
"The Technical Talent Challenge"	• Jan / Feb 2006: Power & Energy Magazine
"Managing the Technical Talent Challenge" (and related titles)	• Feb 2006: IEEE PES at Chapter, Fort Worth, TX • April 2006: EEI, Houston • June 2006: NATD Montreal, Canada • March 2006: CAEL Users Group, Denver • May 2006: IEEE NY WIE and the NY PES Chapter, New York, NY • May 2006: PSERC, Madison, WI • May 2006: USMA, Houston, TX • June 2006: PES General Meeting, Montreal Canada • August 2006: French PES Chapter, Paris, France • October 2006: South Dakota Regional Power Conference

	• Jan 2007: EUCI Solutions to an Aging Workforce Conference – moderator, Los Vegas, Nevada • Mar 2007: TechAdvantage, Los Vegas, Nevada • May 2007: Marcus Evans - 4th Annual Transmission & Distribution Asset Management, Overcoming Manpower Attrition Using Creative Succession Planning – panel participant, San Diego, CA • June 2007: North Central Electric Association Leadership Conference, Stone Harbor Resort, Door County, WI • June 2007: Southeast Electric Exchange Executive Committee, Miami Fl • June 2007: IEEE PES General Meeting, Tampa, Fl • Sept 2007: Minnesota Rural Electric Association Engineering and Operations Conference • Oct 2006: Power System Conference and Exposition, Atlanta, GA • Nov 2007: Workshop on Energy Workforce, Iowa State, Ames, IA • Nov 2007: National Science Foundation Workshop • on the Future Power Engineering Workforce – moderator, Arlington, VA • April 2008: IEEE PES Transmission and Distribution Conference and Exposition – Workforce Super Session, Chicago, Illinois • Feb 2009: 2009 DOE-NARUC National Electricity Delivery Forum Panel Discussion moderator, Washington, DC
"Employee Lifecycle: From Cradle to …"	• June 2006: live broadcast CTN, Dallas TX
"Power Sector Must Court Students; Industry Must Combat Image Problems" Article	• June 2006: Energy Central Magazine
"Look at the Numbers"	• August 2006: Transmission &Distribution World Magazine
"Power & Energy Industry Developments: IEEE PES Update" (and related titles)	• Aug 2007: IEEE PES Nuclear Committee, Monterey, CA • Oct 2007: IEEE PES Transformer Committee, Minneapolis, MN • April 2008: IEEE PES Transmission and Distribution Conference and Exposition – keynote, Chicago, IL • July 2008: IEEE PES General Meeting – keynote, Pittsburgh, PA • Aug 2008: IEEE PES Latin America T&D – keynote, Bogota, Columbia • Sept 2008; IEEE PES Power System Relay Committee, Vancouver, BC • Oct 2008: IEEE PES PowerCon, New Delhi, India • Oct 2008: Annual Frontier Power Conference – keynote, Stillwater, Oklahoma

	• Mar. 2009: Power Systems Conference and Exposition - keynote, Seattle, WA • Mar 2009: 2009 Asia-Pacific Power And Energy Engineering Conference – keynote: Wuhan, China • Jun 2009: PowerTech – keynote: Bucharest, Romania • July 2009: IEEE PES General Meeting – keynote, Calgary, Canada • Jan 2010: Innovative Smart Grid Technologies conference – keynote, Gaithersburg, MD
"Preparing Skilled Engineering Workforce for the Smart Grid	• Sept 2009: GridWeek 2009 Workforce Development: The Human Side of the Smart Grid – panel participant, Washington, DC • Feb 2010: Us-Canada Clean Energy Dialogue Forum, Toronto, Canada
"Climbing the Co-op Ladder"	• Aug 2008: Feature article written by Beth Baker on Women in co-ops and electric utility careers
"Power Society Changes Name to Reflect New Direction"	• July 2008: article written and published in "The Institute"
"Electric Utility Jobs, Talent and Attrition"	• Sept 2008: Ken Belson featured W. Reder's work in New York Times article
"Increasing Society Membership through Chapter Engagement"	• Sept 2008: IEEE Sections Congress, Quebec City
"The Wind Market and Practical Lessons Learned"	• Sept 2008: Distinguished Lecturer, Boston, MA • Feb 2009: Distinguished Lecturer, San Juan, Puerto Rico • Mar 2009: Distinguished Lecturer, Detroit, MI • Sept 2009: Renewable Energy Conference – keynote, Valencia, Spain • Oct. 2009: Distinguished Lecturer, Abu Dhabi, UAE • Nov. 2009: Distinguished Lecturer, Hampton Roads, VA
"Distribution Grid of the Future"	• Nov 2008: Minnesota Power Systems Conference, St. Paul, MN
"Smart Grid of the Future"	• Nov 2008: Distinguished Lecturer, Lafayette, LA • May 2009: California Energy Commission, Sacramento, CA • Feb 2010: 2010 Power and Energy Conference • Feb 2010: Illinois Technologies for Future Energy Systems, University of Illinois, Champaign-Urbana, IL • May 2010: Science Congress of Japan – keynote, Tokyo, Japan • May 2010: Distinguished Lecturer at Keio University, Yokohama Japan
"Lighting the Path"	• Winter 2008: Women in Engineering Magazine, IEEE
"Setting the Stage for Smart Grid"	• Jan 2010: IEEE PES Innovative Smart Grid Technologies Conference. Presentation and keynote

	facilitator, Gaithersburg MD
"Building the Power Workforce of Tomorrow"	• Feb 2010: Canada – U.S. Clean Energy Dialog Forum, Toronto, Canada
"Smart Grid: An Aging Workforce GAME-CHANGER!"	• March 2010: Energy Assoc. Electricity Operations Committee, Harrisburg PA • March 2010: Doble Client Conference Keynote presenter, Boston, MA • Nov 2010: Electrical and Computer Engineering Department Heads – NSF Workshop on Energy and Power, Arlington, VA
"Smart Grid, My Journey and Future Leadership"	• April 2010: Chicago IEEE Women In Engineering presentation, Chicago, IL
"Transforming the Workforce"	• April 2010: GridWise Global Forum, Washington DC
"IEEE Smart Grid and Advancements in the US"	• May 2010: Tokyo Electric Power Company, Tokyo, Japan
"United States Renewable Trends and Grid Integration"	• Sept 2010: IEEE Distinguished Lecturer, Phoenix AZ
"IEEE Smart Grid and A Vision for Technical Advancements"	• Oct 2010: 2010 Nebraska Research and Innovation Conference, Lincoln Nebraska
"Experiences from deploying real smart grid projects"	• Oct 2010: Presentation and Panel Session Moderator, IEEE Innovative Smart Grid Technologies Conference, Gothenburg, Sweden
"Advancing Smart Grid Innovation"	• Jan 2011: AGC Chicago Smart Grid Program, Chicago, IL • Jan 2011: IEEE Innovative Smart Grid Technologies Conference, Building Controls Paper Session Chair, Anaheim, CA