nationalgrid

**Andrew S. Marcaccio**
Senior Counsel

January 25, 2022

**VIA ELECTRONIC MAIL**

Luly E. Massaro, Clerk
Rhode Island Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

**RE: Docket 5209 - Proposed FY 2023 Electric Infrastructure, Safety, and Reliability Plan**
**<u>Responses to Data Requests – PUC Set 1 (Complete Set)</u>**

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed please find the electronic version of the Company's complete set of responses to the Public Utilities Commission's First Set of Data Requests in the above-reference matter.[1]

This transmittal contains the Company's response to data request PUC 1-7 and completes the Company's responses in this set.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263.

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Docket 5209 Service List
Jon Hagopian, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division

[1] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

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Certificate of Service

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

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

____________________________________
Joanne M. Scanlon

January 25, 2022
Date

## Docket No. 5209 - National Grid's Electric ISR Plan FY 2023
## Service List as of 01/10/2022

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| **File an original & five (5) copies w/:**<br>Luly E. Massaro, Commission Clerk<br>Cynthia Wilson-Frias, Esq.<br>Public Utilities Commission<br>89 Jefferson Blvd.<br>Warwick, RI 02888 | Luly.massaro@puc.ri.gov;<br>Cynthia.WilsonFrias@puc.ri.gov;<br>Todd.bianco@puc.ri.gov;<br>Alan.nault@puc.ri.gov; | 401-780-2107 |
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| Matt Sullivan, Green Development LLC | ms@green-ri.com; | |

## PUC 1-1

Request:

The Company has detailed reasons for increased spending on Vegetation Management activities in FY 2023 citing, in part, increased costs per foot "primarily due to the shortage in qualified tree workers." (Bates page 98). The total amount number of miles to be trimmed is also higher. (Bates pages 97-98). In light of the shortage of qualified workers, what level of confidence does the Company have that the expanded tree trimming will be completed in FY 2023? Please explain, including any references to contractor responsibilities under various contracts.

Response:

The Company is confident that all planned work will be completed in FY 2023.

When the Company awards work, it considers the geographic areas, total mileage awarded to each vendor and availability of resources to complete the proposed allocation of work. By spreading out the work among several vendors, the Company reduces the risk of any vendor not being able to complete their assigned work. Additionally, each vendor is contractually obligated to complete work during the assigned fiscal year. Any vendor that fails to complete their assigned work could face financial penalties and would likely lose some or all of their market share in future bid events.

Prepared by or under the supervision of: Ryan Moe

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## PUC 1-2

Request:

The Company also proposed the continuation of $200,000 to focus on pockets of poor performance. What areas were included in the FY 2022 spend under this category? How does the Company determine that an area qualifies for such additional pruning (please explain the term "large number of tree-related outages"). (Bates page 102).

Response:

The Company is targeting three areas for pockets of poor performance work in FY 2022. The first is Woodville Road in Hopkinton on the 49_56_85T3, where we are addressing dead trees adjacent to the conductor. The second is Tunk Hill Road in Scituate on the 49_53_15F2, where we are removing overhanging branches and hazard trees. The last are the Camp Westwood and Weeks Hill areas in Coventry on 49_56_54F1, where we removed hazard trees and removed overhanging branches.

The process of determining which areas to target for this work is reviewing the number of outages for each individual fuse across the distribution system. The reliability team then discusses the locations with the largest number outages and the appropriate response for each. Before selecting an area for work, the Company will consider what work has been done there in the past, when it is scheduled for work again, and then do a field review to evaluate what work may be done to improve reliability.

The term, "large number of tree-related outages" is a comparison of tree-related outages at each fuse relative to all other fuses. The Company looks at the fuses with the largest number of tree-related outages first when determining where work is appropriate.

PUC 1-3

Request:

The Company has cited a 51% reduction in tree related events and a 60% reduction in customers interrupted in areas where pockets of poor performance work has been performed.

a. Are the reductions related exclusively to tree work or a combination of factors?
b. If possible, please compare the cost of this work per mile to EHTM and cycle pruning costs.
c. What criteria will the Company use to determine whether the program is worth continuing or expanding?

Response:

a. The statistics in the FY 2023 ISR Plan Section 3 page 82 of 99 pertain to only tree-related interruptions in the areas that have been worked. All other types of interruption are excluded from the analysis.

b. From FY 2019 to FY 2021 the Company averaged $4,641 per mile for pruning and $12,312 per mile for EHTM. In FY 2021, the Company spent $18,893 per mile for pockets of poor performance work.

   Costs for EHTM work were significantly reduced in FY 2020 and FY 2021 from FY 2019 due to the focus on EHTM removals due to the Gypsy Moth infestation. In FY 2019, the Company averaged $34,993 per mile for EHTM, but only $10,330 per mile in FY 2020 and FY 2021. The reduced cost per mile in FY 2020 and FY 2021for Gypsy Moth removals was due to the large number of trees removed in small pockets, and learnings from FY 2019 where we created partnerships with RI DOT and the impacted communities to share costs for clean-up and traffic control.

c. The Company has begun the same cost/benefit analysis for Pockets of Poor Performance (PPP) as it currently does for both its pruning and EHTM programs. That analysis looks at performance for a full year after implementation and the Company is planning to provide the complete PPP results with that period of results in the next ISR pre-filing in August 2022.

Prepared by or under the supervision of: Ryan Moe

## PUC 1-4

Request:

The Commission and Division have received inquiries from local and state officials regarding reliability performance in the Collins Road area of Hopkinton. Based on responses to the officials, the Commission is aware that this area has been identified by National Grid. Please explain the nature of the reliability concerns, how the Company identified the source of the poor performance, and how the Company is addressing the concerns in the area, including a timeline of work completed and any work to be completed.

Response:

The reliability concerns in the Collins Road area of Hopkinton are largely due to tree issues. The Company holds recurring meetings throughout the year to discuss reliability issues and potential poor performing areas. In one of these meetings in 2020, the Company identified a poor performing area in Hopkinton in the vicinity of Maxson Hill, Collins, and Tomaquag Roads. To mitigate the substantial number of tree related events, the Company performed targeted tree removals between January and March 2021. The Company received additional reliability complaints from customers in this same area in October 2021. Engineering reviewed the outage history on the circuit and investigated additional sectionalizing opportunities to decrease the impact of tree related events. Three new fuse locations were identified to better isolate outages and minimize the number of customers interrupted during an outage. These fuses were installed prior to January 3, 2022. This circuit will also be trimmed this year prior to April 1, 2022 as part of the Company's cycle tree trimming process.

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PUC 1-5

Request:

The following relate to the Company's identification and response to pockets of poor performance.

a. Are there objective/measurable criteria the Company uses to identify pockets of poor performance? Please explain.
b. Are there subjective criteria the Company uses to identify pockets of poor performance? Please explain.
c. Is there a minimum threshold criteria the Company uses to determine when a pocket of poor performance requires immediate remedial remedies? Please explain.

Response:

a. No, the Company does not currently have formal criteria in place to identify pockets of poor performance. While the Company does perform Engineering Reliability Reviews (ERRs) on an annual basis, circuits are selected to be analyzed by reliability metrics which are not heavily impacted by pockets of a system, with minimal customers, that have experienced poor performance. The Customers Experiencing Multiple Interruptions (CEMI) index identifies those portions of the system that have experienced reliability challenges. The Company has progressed CEMI driven projects in the past but has not recently on a programmatic basis.

b. Yes, the Company does have subjective criteria used to identify pockets of poor performance. The subjective evaluations are based on input from company subject matter experts (operations, forestry, reliability team, etc.) and/or customer complaints. Reliability meetings are generally held monthly where Operations, Forestry, Reliability, and Engineering will discuss recent events and the reliability team provides outage history data. Engineering works with these groups to determine if a circuit's or area's reliability performance is trending poorly. All groups collaborate to determine if further investigation should be taken. Similarly, when a customer complaint is received, Engineering, Operations, Forestry, and the Reliability teams collaborate on the details of the complaint.

c. Currently the Company does not have an active program with minimum threshold criteria for pockets of poor performance. As described in PUC 1-5 a. and b., there is a subjective method in place that uses Operations experience and other information, which can vary from case to case. National Grid has used a CEMI index in the past and plans to refine this method in the near future to enhance the current subjective process and improve Customer Satisfaction.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

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PUC 1-6

Request:

In response to Division 1-13, the Company stated that it has pausing additional VVO activities pending a decision by PPL about the implementation strategy.

a. When does Narragansett expect the closing to happen assuming approval by the Division?
b. When does Narragansett expect PPL to make a decision about the implementation strategy?
c. Please provide any documentation from PPL that Narragansett should suspend VVO activities in the FY 2023 ISR.
d. Why is it relevant to the response that "The Company's plan prior to PPL acquiring The Narragansett Electric Company was ultimately to transition to an advanced distribution management system (ADMS) based solution for a more holistic Grid Modernization Plan approach."?
e. Why should VVO activities be paused pending implementation of an ADMS?

Response:

a. The Company anticipates closing to happen near March 1, 2022 assuming approval by the Division.

b. The Company anticipates PPL will file an updated grid modernization plan shortly after close which will include its VVO implementation strategy.

c. Suspending VVO activities in the FY2023 ISR was not a result of direction provided by PPL to the Company. This was a decision that the Company made based on the evolving nature of the program and that a transition could happen between the two companies in the near term. Regardless of the transition, National Grid was planning for major changes to the VVO program associated with its Grid Mod Plan as submitted in RI PUC Docket 5114. First, the Company was transitioning from the VVO Pilot efforts to a programmatic deployment. Second and concurrently, National Grid was developing its own grid modernization plan which would fundamentally impact deployment. Specifically, a grid modernization plan would move voltage control and capacitor deployment from a VVO-only cost benefit analysis to an overarching grid modernization evaluation to which VVO costs and benefits become a component. Third, National Grid was evaluating a fundamental change to the control method for VVO type projects. As a result of the major VVO changes already under consideration by National Grid, the Company determined that it would be inappropriate to implement these changes considering a pending transition to PPL. Instead of continuing with VVO activities, the Company determined that a brief pause was appropriate.

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d. This is relevant because the current VVO projects use a stand-alone control system that is not integrated with the Company's Energy Management System (EMS) and would not be integrated with a future ADMS. The existing VVO control system uses the sensors installed at the time of the project. Converting to an ADMS-based control would allow VVO algorithms to use all system sensors including voltage sensing at reclosers and customer meter sensing should an Advanced Metering Infrastructure (AMI) effort be pursued. Also, new sensors installed would automatically be incorporated into an ADMS based real-time loadflow algorithm, for continued VVO refinement. The relevance is based on the fact that the Company was already considering a major change to the VVO control system prior to the PPL acquisition. As described in PUC 1-6 c. above, the Company believes it would be inappropriate to implement such a change prior to further grid modernization discussions and to the transition. Furthermore, the Company understands this centralized VVO control system linked to all system sensors is consistent with the method used by PPL for their VVO efforts.

e. The Company recommends pausing VVO activities pending implementation of an ADMS in order to ensure all VVO installations moving forward are economically integrated with ADMS. As described in the Grid Mod Plan in Docket 5114 and the responses to PUC 1-6 c. and d. above, integrating VVO with ADMS is a major control change that is expected to result in both improved performance and reduced costs compared to the stand-alone control system used in the VVO pilot projects today.

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## PUC 1-7

Request:

In Docket No. 4770, the Commission approved funding for System Data Portal, Control Center Enhancements, and Other Grid Modernization Investments (Enterprise Service Bus, Data Lake, PI Historian, Advanced Analytics, Telecommunications, and Cybersecurity). Please provide a one to two sentence of each, a one to two sentence of the investments to date, and status. Will any of these investments be transferred to PPL as part of the sale?

Response:

System Data Portal – The System Data Portal is online and operational. The latest major update was completed in the Summer/Fall 2021 and monthly distribution generation updates continue. The Company has communicated the history of the System Data Portal and its role in external DG communications to PPL. Engineering personnel, who have been instrumental in the development and continued maintenance of the Rhode Island System Data Portal and the underlying analysis models, will be conveying to the PPL organization on Day 1.

Control Center Enhancement – The Control Center Enhancements include GIS Data Enhancements and Advanced Distribution Management System ("ADMS") Core Functionality. GIS data improvements and data hardening are underway, which includes general data cleanup as well as changes to baseline GIS to allow for new asset types, new equipment, expanded attributes, and characteristics. National Grid USA Service Company, Inc.'s ("Service Company") Phase 1 ADMS system design activities are complete, major vendor contracts are in place, and hardware and software have been procured. National Grid USA and Service Company understand that PPL has an existing technology platform that includes an ADMS system, which is already interconnected with PPL's GIS model and that will enable PPL to import Rhode Island data upon transaction close to leverage the systems already in place.[1]

Other Grid Modernization Investments – These investments include Enterprise Service Bus, Data Lake, PI Historian, Advanced Analytics, Telecommunications, and Cybersecurity. The planning and scoping have been completed and architecture and initial equipment for these technologies have been selected. All scoping documents and equipment requirements will be communicated and shared with PPL prior to the transaction closing.

[1] *See* PPL Corporation's and PPL Rhode Island Holdings, LLC's response to Rhode Island Attorney General Record Request #1 filed in Docket No. D-21-09; *see also* PPL Corporation's and PPL Rhode Island Holdings, LLC's response to Division Data Request 7-51 and Division Data Request 7-52 in Docket No. D-21-09 (discussing PPL's plans for how it will utilize existing Service Company investments in grid modernization.).

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PUC 1-8

Request:

The investments identified in PUC 1-7 were represented to be foundational investments needed to advance a modern grid regardless of the grid modernization plan ultimately approved by the Commission. Please explain how customers will benefit from the investments funded in Docket 4770 after the sale to PPL.

Response:

The investments in Docket 4770 included area specific scoping that will benefit RI customers. For example, GIS investments consider the electrical configuration in RI for scoping necessary equipment counts and data base and modeling sizes. Data refinement efforts will contribute to any grid modernization system. Additionally, many of the Docket 4770 investments, such as the System Data Portal include a database of the RI electric system model that will transfer directly to PPL. These system databases, including connectivity and equipment attributes, can be imported into any PPL system.

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PUC 1-9

Request:

Are there any investments in the FY 2023 ISR budget that are critically linked to the investments described in PUC 1-7? If so, please explain.

Response:

No, there are no investments in the FY2023 ISR budget that are critically linked to the investments described in PUC 1-7.

PUC 1-10

Request:

In Division 1-14, the Company provided a table showing the 3V0 investments from 2019-2023 (projected).

a. Please provide a list of all substations and identify whether they are equipped with 3V0 or not. For those that do not have 3V0 installed, please indicate when they are scheduled for installation.
b. Please provide an update on the mobile 3V0 equipment and how it is being used.

Response:

a. See Attachment PUC 1-10 for a list of all substations with corresponding 3V0 information. It is important to note that not all substations will require 3V0 protection. The need for 3V0 protection is dependent upon numerous factors including transformer winding configuration, the existence of high-speed protection, minimum load values and amount of distributed generation interconnected to the transformer. Therefore, stations with specific winding configurations and existing high-speed protection are identified as no 3V0 installed with a note stating 3V0 is not required. Additionally, some stations are listed with a need for 3V0 protection To Be Determined (TBD). A note of TBD includes stations where there is no current need for 3V0 based on existing levels of interconnected DG. It is possible these stations may need 3V0 in the future if the amount of DG increases.

b. The Company recently purchased four mobile 3V0 units. All four are distribution voltage units and were received in July 2021. Three units are 34.5kV/23kV and one unit is 13.2/12.47kV. The Company staged one 34.5kV/23kV unit on standby for the recent customer work served from the Lafayette substation. There are two pending customer related interconnections at the Peacedale and Langworthy Corner substations. Determination on the use of mobile 3V0 units will not be finalized until just prior to construction. Massachusetts owned transmission voltage level mobile 3V0 units have been used at two substations in the past – Johnston (2 units) and Dexter substations (1 unit).

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| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| Admiral Street #9 | T1 | 23 | 11/4.16 | NO | NO - To be retired in FY23/New station will have 3V0 protection |
| Admiral Street #9 | T2 | 23 | 11/4.16 | NO | NO - To be retired in FY23/New station will have 3V0 protection |
| Admiral Street #9 | T3 | 115 | 23 | NO | NO - To be retired in FY23/New station will have 3V0 protection |
| Admiral Street #9 | T4 | 115 | 23 | NO | NO - To be retired in FY23/New station will have 3V0 protection |
| Admiral Street #9 | T5 | 23 | 4.16 | NO | NO - To be retired in FY23/New station will have 3V0 protection |
| ANTHONY | T1 | 23 | 12.47 | NO | YES - Central RI West Area Study includes plans to install 3V0 protection |
| ANTHONY | T2 | 23 | 12.47 | NO | YES - Central RI West Area Study includes plans to install 3V0 protection |
| APPONAUG 3 | T3 | 23 | 12.47 | NO | YES - Station is planned for major re-build starting in FY24 which will include 3V0 protection |
| APPONAUG 3 | T4 | 23 | 12.47 | NO | YES - Station is planned for major re-build starting in FY24 which will include 3V0 protection |
| AUBURN 73 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| AUBURN 73 | T2 | 23 | 4.16 | NO | NO - Planned for retirement |
| AUBURN 73 | T1 | 115 | 12.47 | YES | N/A |
| AUBURN 73 | T2 | 115 | 12.47 | YES | N/A |
| BARRINGTON 4 | T1 | 23 | 12.47 | NO | NO - Planned for retirement |
| BIPCO | T1 | 34.5 | 2.4 | NO | TBD |
| BONNET 42 | T2 | 34.5 | 12.47 | NO | TBD |
| BRISTOL 51 | T2 | 23 | 12.47 | NO | TBD |
| BRISTOL 51 | T1 | 115 | 12.47 | YES | N/A |
| Centerdale #50 | T3 | 23 | 12.47 | NO | TBD |
| Centerdale #50 | T1 | 23 | 4.16 | NO | NO - Planned for retirement per Northwest RI Study |
| Central Falls #104 | TSOU | 13.8 | 4.16 | NO | NO - Planned for retirement per Blackstone Valley South Study |
| Central Falls #104 | TNOR | 13.8 | 4.16 | NO | NO - Planned for retirement per Blackstone Valley South Study |
| Centre Street #106 | blank | 13.8 | 4.16 | NO | NO - Planned for retirement per Blackstone Valley South Study |
| CHASE HILL | T1 | 115 | 12.47 | YES | N/A |
| CHASE HILL | T2 | 115 | 12.47 | YES | N/A |
| Chopmist #34 | T1 | 23 | 12.47 | YES | N/A |
| Chopmist #34 | T2 | 23 | 12.47 | YES | N/A |
| Chopmist #34 | T3 | 23 | 12.47 | YES | N/A |
| Clarke St | T651 | 23 | 4.16 | NO | TBD |
| Clarke St | T652 | 23 | 4.16 | NO | TBD |
| Clarkson Street #13 | T1 | 115 | 12.47 | NO | YES - Planned for FY23 |
| Clarkson Street #13 | T2 | 115 | 12.47 | NO | YES - Planned for FY23 |
| COVENTRY | T1 | 23 | 12.47 | YES | N/A |

| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| Crossman St #111 | blank | 13.8 | 4.16 | NO | NO - Planned for retirement per Blackstone Valley South Study |
| DAVISVILLE 84 | T1 | 115 | 34.5 | YES | N/A |
| DAVISVILLE 84 | T2A | 115 | 34.5 | YES | N/A |
| Dexter | T364 | 115 | 13.8 | YES | N/A |
| DIVISION ST | T1 | 34.5 | 12.47 | NO | YES - Central RI West Area Study includes plans to install 3V0 protection |
| DIVISION ST | T2 | 34.5 | 12.47 | NO | YES - Central RI West Area Study includes plans to install 3V0 protection |
| DRUMROCK 14 | T3 | 115 | 23/12.47 | NO | NO - Not required |
| DRUMROCK 14 | T4 | 115 | 23 | NO | NO - Not required |
| DRUMROCK 14 | T5 | 115 | 23/12.47 | NO | NO - Not required |
| Dunnell Park #1201 | T1 | 115 | 13.8 | YES | N/A |
| Dunnell Park #1201 | T2 | 115 | 13.8 | YES | N/A |
| Dyer St #2 | T1 | 11.5 | 4.16 | NO | NO - Not required |
| Dyer St #2 | T2 | 11.5 | 4.16 | NO | NO - Not required |
| East George St. #77 | T1 | 23 | 4.16 | NO | TBD |
| East George St. #77 | T2 | 23 | 4.16 | NO | TBD |
| EAST PROVIDENCE SUB | T1 | 115 | 12.47 | NO | YES - This is a new substation that will be equipped with 3V0 protection |
| Eldred | T1 | 23 | 4.16 | YES | N/A |
| Eldred | T2 | 23 | 4.16 | YES | N/A |
| Elmwood #7 (12.47 kV) | T2 | 23 | 12.47 | NO | NO -Planned for retirement |
| Farnum #105 | T1 | 115 | 23 | NO | NO -Planned for retirement |
| Farnum Pike #23 (New) | T1 | 115 | 12.47 | YES | N/A |
| Farnum Pike #23 (New) | T2 | 115 | 12.47 | YES | N/A |
| Franklin Square #11 | T3320 | 115 | 34.5 | NO | TBD |
| Franklin Square #11 | T3324 | 115 | 34.5 | NO | TBD |
| Franklin Square #11 | T2207 | 115 | 23 | NO | TBD |
| Franklin Square #11 | T2210 | 115 | 23 | NO | TBD |
| Franklin Square #11 | T2220 | 115 | 23 | NO | TBD |
| Franklin Square #11 | T1 | 115 | 11.5 | NO | TBD |
| Franklin Square #11 | T2 | 115 | 11.5 | NO | TBD |
| Franklin Square #11 | T3 | 115 | 11.5 | NO | TBD |
| Gate 2 | T381 | 69 | 23 | NO | NO - Not required |
| Geneva #71 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| Geneva #71 | T2 | 23 | 4.16 | NO | NO - Planned for retirement |

| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| Harris Avenue #12 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| Harris Avenue #12 | T2 | 23 | 4.16 | NO | NO - Planned for retirement |
| Harrison | T321 | 23 | 4.16 | NO | TBD |
| Harrison | T322 | 23 | 4.16 | NO | TBD |
| Highland Park #200 | T1 | 115 | 13.8 | NO | TBD |
| Highland Park #200 | T2 | 115 | 13.8 | NO | TBD |
| HOPE | T1 | 23 | 12.47 | NO | YES - Central RI West Area Study includes plans to install 3V0 protection |
| HOPE | T2 | 23 | 12.47 | NO | TBD |
| HOPKINS HILL | T1 | 34.5 | 12.47 | YES | N/A |
| HOPKINS HILL | T2 | 34.5 | 12.47 | YES | N/A |
| Hospital | T461 | 23 | 4.16 | NO | TBD |
| Hospital | T462 | 23 | 4.16 | NO | TBD |
| Huntington Park #67 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| Jepson | T371 | 69 | 23 | YES | N/A |
| Jepson | T372 | 69 | 23 | YES | N/A |
| Jepson | T373 | 69 | 23 | YES | N/A |
| Jepson | T374 | 69 | 13.8 | YES | N/A |
| Jepson | T341 | 23 | 4.16 | YES | N/A |
| Jepson | T376 | 69 | 23 | YES | N/A |
| Jepson | T2 | 69 | 13.8 | YES | N/A |
| Johnston #18 | T1 | 115 | 23 | NO | NO - Not required |
| Johnston #18 | T2 | 115 | 23 | NO | NO - Not required |
| Johnston #18 | T3 | 115 | 12.47 | YES | N/A |
| Johnston #18 | T4 | 115 | 12.47 | YES | N/A |
| KENT CORNERS 47 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| KENT CORNERS 47 | T2 | 23 | 4.16 | NO | NO - Planned for retirement |
| KENT COUNTY | T1 | 115 | 34.5 | NO | NO - not required |
| KENT COUNTY | T2 | 115 | 34.5 | NO | NO - not required |
| KENT COUNTY | T6 | 115 | 12.47 | NO | NO - not required |
| KENT COUNTY | T7 | 115 | 34.5 | NO | NO - not required |
| KENT COUNTY | T5 | 115 | 12.47 | NO | NO - not required |
| KENYON 68 | T1 | 115 | 12.47 | YES | N/A |
| KENYON 68 | T2 | 115 | 12.47 | YES | N/A |

| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| KILVERT STREET 87 | T1 | 115 | 12.47 | YES | N/A |
| KILVERT STREET 87 | T2 | 115 | 12.47 | YES | N/A |
| Kingston | T311 | 23 | 4.16 | NO | YES - Newport area study project will include 3V0 protection |
| Kingston | T312 | 23 | 4.16 | NO | YES - Newport area study project will include 3V0 protection |
| Knightsville #66 | T1 | 22.9 | 4.16 | NO | NO - Planned for retirement |
| Knightsville #66 | T2 | 22.9 | 4.16 | NO | NO - Planned for retirement |
| LAFAYETTE 30 | T1 | 34.5 | 12.47 | YES | N/A |
| LAFAYETTE 30 | T2 | 34.5 | 12.47 | YES | N/A |
| LAKEWOOD 57 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| LAKEWOOD 57 | T2 | 23 | 4.16 | NO | NO - Planned for retirement |
| LANGWORTHY 86 | T1 | 34.5 | 12.47 | NO | YES - 3V0 Program FY22-FY23 |
| LINCOLN AVENUE 72 | T1 | 115 | 12.47 | NO | TBD |
| LINCOLN AVENUE 72 | T2 | 115 | 12.47 | NO | TBD |
| Lippitt Hill #79 | T1 | 22.9 | 12.47 | NO | TBD |
| Lippitt Hill #79 | T2 | 22.9 | 12.47 | NO | TBD |
| Manton #69 | T2 | 23 | 12.47 | NO | TBD |
| Merton | T511 | 23 | 4.16 | NO | YES - Newport area study project will include 3V0 protection |
| Merton | T512 | 23 | 4.16 | NO | YES - Newport area study project will include 3V0 protection |
| Nasonville #127 | T271 | 115 | 13.8 | YES | N/A |
| NATICK | T1 | 23 | 12.47 | NO | TBD |
| NATICK | T2 | 23 | 12.47 | NO | TBD |
| NEW LONDON AVE | T1 | 115 | 12.47 | YES | N/A |
| Newport Sub | T1 | 69 | 13.8 | YES | N/A |
| OLD BAPTIST ROAD 46 | T1 | 115 | 12.47 | YES | N/A |
| OLD BAPTIST ROAD 46 | T2 | 115 | 12.47 | YES | N/A |
| Olneyville #6 | T1 | 11.5 | 4.16 | NO | NO - Planned for retirement |
| Olneyville #6 | T3 | 11.5 | 4.16 | NO | NO - Planned for retirement |
| Pawtucket No.1 #107 | T71 | 115 | 13.8 | NO | NO - Planned for retirement |
| Pawtucket No.1 #107 | T73A | 115 | 13.8 | NO | NO - Not required |
| Pawtucket No.1 #107 | T74 | 115 | 13.8 | NO | NO - Not required |
| Pawtucket No.2 #148 | T1 | 13.8 | 4.16 | NO | NO - Planned for retirement |
| Pawtucket No.2 #148 | T2 | 13.8 | 4.16 | NO | NO - Planned for retirement |
| PEACEDALE 59 | T1 | 34.5 | 12.47 | NO | YES - 3V0 Program FY22-FY23 |

| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| PEACEDALE 59 | T2 | 34.5 | 12.47 | NO | YES - 3V0 Program FY22-FY23 |
| PHILLIPSDALE 20 | T1 | 115 | 23 | NO | NO - not required |
| PHILLIPSDALE 20 | T2 | 115 | 23 | NO | NO - not required |
| PHILLIPSDALE 20 | T3 | 23 | 12.47 | NO | NO - Planned for retirement |
| PHILLIPSDALE 20 | T4 | 115 | 12.47 | NO | YES - new transformer will include 3V0 protection |
| Point Street #76 | T1 | 115 | 12.47 | YES | N/A |
| Point Street #76 | T2 | 115 | 12.47 | YES | N/A |
| PONTIAC 27 | T1 | 115 | 12.47 | YES | N/A |
| PONTIAC 27 | T2 | 115 | 12.47 | YES | N/A |
| Putnam Pike #38 | T1 | 115 | 12.47 | YES | N/A |
| Putnam Pike #38 | T2 | 115 | 12.47 | YES | N/A |
| QUONSET 83 | T1 | 34.5 | 12.47 | YES | N/A |
| QUONSET 83 | T2 | 34.5 | 12.47 | YES | N/A |
| Riverside #108 | T81 | 115 | 13.8 | YES | N/A |
| Riverside #108 | T82 | 115 | 13.8 | YES | N/A |
| Rochambeau Ave #37 | T1 | 22.9 | 4.16 | NO | NO - Planned for retirement |
| Rochambeau Ave #37 | T2 | 11.45 | 4.16 | NO | NO - Planned for retirement |
| Shun Pike #128 | T1 | 115 | 13.2 | NO | TBD |
| SOCKANOSSET 24 | T1 | 115 | 23 | NO | NO - Planned for retirement |
| SOCKANOSSET 24 | T2 | 115 | 23 | NO | NO - Planned for retirement |
| South Street #1 | T2201 | 11.5 | 23 | NO | NO - not required |
| South Street #1 | T2216 | 11.5 | 23 | NO | NO - not required |
| South Street #1 | T2248 | 11.5 | 23 | NO | NO - not required |
| South Street #1 | T24 | 11.5 | 23 | NO | NO - not required |
| South Street #1 | T1 | 115 | 11.5 | NO | NO - not required |
| South Street #1 | T2 | 115 | 11.5 | NO | NO - not required |
| South Street #1 | T3 | 115 | 11.5 | NO | NO - not required |
| Sprague St. #36 | T1 | 23 | 4.16 | NO | NO - Planned for retirement |
| Sprague St. #36 | T2 | 23 | 4.16 | NO | NO - Planned for retirement |
| Staples #112 | T124 | 115 | 13.8 | YES | N/A |
| TIOGUE AVE | T1 | 34.5 | 12.47 | NO | TBD |
| TIVERTON | T1 | 115 | 12.47 | YES | N/A |
| TIVERTON | T2 | 115 | 12.47 | YES | N/A |

| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| TOWER HILL 88 | T1 | 115 | 12.47 | YES | N/A |
| Valley #102 | T23 | 115 | 24 | NO | NO - Not required |
| Valley #102 | T21 | 115 | 13.8 | NO | NO - Not required |
| Valley #102 | T22 | 115 | 13.8 | NO | NO - Not required |
| WAKEFIELD 17 | T3 | 34.5 | 12.47 | NO | TBD |
| WAKEFIELD 17 | T4 | 34.5 | 12.47 | NO | TBD |
| WAKEFIELD 17 | T5 | 34.5 | 12.47 | NO | TBD |
| WAMPANOAG 48 | T1 | 115 | 12.47 | NO | YES - Planned for FY23 |
| WAMPANOAG 48 | T2 | 115 | 12.47 | NO | YES - Planned for FY23 |
| WARREN 5 | T5 | 115 | 23 | NO | NO - not required |
| WARREN 5 | T6 | 115 | 23 | NO | NO - not required |
| WARREN 5 | T1 | 115 | 12.47 | YES | N/A |
| WARREN 5 | T2 | 115 | 12.47 | YES | N/A |
| WARWICK 52 | T1 | 23 | 12.47 | NO | TBD |
| WARWICK 52 | T4 | 23 | 12.47 | NO | TBD |
| WARWICK MALL | T1 | 23 | 12.47 | NO | YES - Central RI West project will include 3V0 protection |
| WARWICK MALL | T2 | 23 | 12.47 | NO | TBD |
| Washington #126 | T261 | 115 | 13.8 | YES | N/A |
| Washington #126 | T262 | 115 | 13.8 | YES | N/A |
| WATERMAN AVENUE 78 | T1 | 23 | 12.47 | NO | NO - Planned for retirement |
| WATERMAN AVENUE 78 | T2 | 23 | 12.47 | NO | NO - Planned for retirement |
| West Cranston #21 | T1 | 115 | 12.47 | YES | N/A |
| West Cranston #21 | T2 | 115 | 12.47 | YES | N/A |
| West Greenville # 45 | T3 | 23 | 12.47 | NO | TBD |
| West Howard | T541 | 23 | 4.16 | NO | TBD |
| West Howard | T542 | 23 | 4.16 | NO | TBD |
| WEST KINGSTON 62 | T1 | 115 | 34.5 | NO | NO - Not required |
| WEST KINGSTON 62 | T2 | 115 | 34.5 | NO | NO - Not required |
| WESTERLY 16 | T2 | 34.5 | 12.47 | NO | TBD |
| WESTERLY 16 | T4 | 34.5 | 12.47 | NO | TBD |
| Wolf Hill #19 | T1 | 115 | 23 | YES | N/A |
| WOOD RIVER 85 | T10 | 115 | 34.5 | YES | N/A |
| WOOD RIVER 85 | T20 | 115 | 34.5 | YES | N/A |

| Substation | XFMR # | XFMR Voltage (kV) - From | XFMR Voltage (kV) - To | 3V0 in Service? | 3V0 Planned? |
|---|---|---|---|---|---|
| Woonsocket | T1 | 115 | 13.8 | YES | N/A |

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## PUC 1-11

Request:

As part of the FY 2022 ISR budget, the Commission approved $650,000 for strategic DER for work at Chopmist and Hopkins Hill substations.

a. Please provide an update on the $670,000 being spent in FY 2022 for this work.
b. Is there no need for such strategic DER spending (e.g., feeder monitors, advanced devices engineering) in FY 2023?

Response:

a. The FY22 ISR budget of $650,000 included the following:

   - $150,000 capex for Feeder Monitors on Chopmist substation feeders
   - $450,000 capex for Feeder monitors on Hopkins Hill substation feeders
   - $50,000 for engineering and design of full implementation of advanced devices at Chopmist substation.

   The Feeder monitors on Chopmist and Hopkins Hill feeders are all design complete and are in varying stages of construction. The Company anticipates completion of all this work by the end of the fiscal year.

   The design of full implementation of advanced devices at Chopmist substation is approximately 65% complete. The Company decided to pause design on these devices when the Company made the decision to not include Strategic DER investments in the FY23 ISR plan. The Company expects to complete the design and implementation in alignment with a Grid Modernization Plan.

b. The Company is not recommending proactive Strategic DER investments in the FY23 ISR plan to enable alignment of investments with a Grid Modernization Plan.

PUC 1-12

Request:

Referencing Bates page 47, Chart 8 shows an increase in asset condition spending in FY 2023. Given the fact that the Electric ISR construct has been in place since FY 2012, why has asset condition spending appeared to increase rather than decrease over time? Does the Company think the design of the reconciliation of the discretionary budget have anything to do with it?

Response:

Asset Condition projects and programs have been identified to reduce the risk and consequences of unplanned asset failures and are identified as part of the System Planning process. The focus is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the potential for reliability issues. Moreover, the large number of aged assets in the Company's service area requires the Company to develop strategies to replace assets if their condition impairs reliable and safe service to customers. Experience with assets that have poor operating characteristics in the field has led the Company to develop strategies to remove such equipment. The investments made in these assets are prioritized based on their likelihood of failure along with consequences of such an event.

The Asset Condition portfolio consists of Large Projects, Programs and other smaller projects as summarized in the table below with Large Projects and Programs being the largest components. In more recent years as the Company completes Area Studies, large projects will enter into the ISR Plan, which explains the increase in Large Project amounts since earlier years in the ISR. Programs are developed to avoid the possibility that a large number of similar assets fail at the same time or within a short window of time. The aging nature of the Company's Underground Cable has been driving increased levels of Programs spending in recent years as compared to earlier years.

| Asset Condition $'000s | FY 2012 Actuals | FY 2013 Actuals | FY 2014 Actuals | FY 2015 Actuals | FY 2016 Actuals | FY 2017 Actuals | FY 2018 Actuals | FY 2019 Actuals | FY 2020 Actuals | FY 2021 Actuals | FY 2022 Forecast | FY 2023 Budget |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Large Projects | 4,870 | 420 | 2,719 | 2,369 | 6,400 | 15,217 | 25,210 | 8,827 | 8,098 | 19,027 | 18,280 | 23,310 |
| Programs | 1,445 | 3,483 | 12,531 | 18,160 | 16,462 | 12,594 | 11,365 | 18,673 | 19,001 | 14,927 | 14,570 | 16,935 |
| Other | 4,006 | 4,166 | 5,655 | 4,611 | 4,317 | 3,463 | 5,406 | 5,397 | 5,778 | 7,862 | 5,837 | 8,044 |
| Total | $10,320 | $8,070 | $20,905 | $25,140 | $27,179 | $31,274 | $41,980 | $32,897 | $32,877 | $41,816 | $38,687 | $48,289 |

No, the design of the reconciliation of the discretionary budget does not influence the Company's system planning and investment processes.

Prepared by or under the supervision of: Patricia Easterly

PUC 1-13

Request:

Referencing Chart 14 on Bates page 58, the Company included $1,000,000 of the budget associated with Distributed Generation. The explanation of the chart on Bates pages 57-58 states that "[s]ince the Company is reimbursed for a portion of this spending, the budget represents the capital the Company expects to spend net of contributions in aid of construction and other reimbursements." Attachment 1 on Bates page 77 shows a forecasted spend of 5,406,000 for FY 2022.

a. Please describe the Distributed Generation Capital Spending for which the Company is not reimbursed.
b. Please provide an accounting of such expense for FY 2022.

Response:

As mentioned in its response to PUC 1-34 in Docket 4995, the Company implemented a new process that offsets distributed generation (DG) capital project costs with related contributions in aid of construction (CIAC) received in the month of the capital expenditure at the work order level. This differs from the previous process when the CIAC was recognized as a credit to the project capital spending when received. Under the new process, CIAC's are credited to Miscellaneous Current and Accrued Liabilities FERC Account 242, and a semi-automatic process occurs to transfer credits from Account 242 to Capital Work in Progress (CWIP) FERC Account 107 for related CIAC monthly to offset the capital expenditures of that month. The Company expects that there will be some lag between actual spend and transfer activity since the process is not completely automated.

**Accounting with new process**

***Customer CIAC:*** The Company typically offers a two payment plan as the default for any CIAC over $25,000. Occasionally if the CIAC is very large, then a three or four payment plan is allowed to align the receipt of these payments to the Company's milestone engineering and construction plans. Regardless of the number of payments required, the CIAC is billed before all or most of the capital work is performed. CIACs are based on initial estimates and the customer CIAC could be deposited in several work orders, depending on the nature of the project.

***Construction Expenditure & netting process:*** The interconnection construction activities, including the cost of labor and materials, are initially recorded as capital in FERC account 107 CWIP by work order. As construction progresses, the respective CIAC amounts recorded are transferred from the Miscellaneous Current Liability account. CIAC billed to customers will net to zero when spending equals the estimate. For a DG project, there could be work on a customer's property, work on the Company's distribution line or work on the Company's substation. The Company creates several work orders to perform different types of work, and based on asset type, there could be multiple funding projects created. In theory, as mentioned above, after monthly transfer, work order should net to zero. However, since there could be several work orders and funding projects, there could be situations where portion of the CIAC may still be in one of the work order/funding project than where the construction work is actually performed. This could result into positive balance on one work order/funding project and related CIAC still sitting in deferred account.

***Reconciliation process & project overruns:*** The Company is required to reconcile all DG projects where construction is performed as per Interconnection Tariff RIPUC 2244 (Interconnection Tariff). Typically, the company must wait until all work orders are closed in its work management system to start the reconciliation process. This typically takes 1-3 months after construction is complete. This allows any contractor invoices to be applied and any as-built work to be completed. Once work orders are closed, the Company has 120 business days to complete reconciliation. As per the Interconnection Tariff, customers are required to pay any overruns as a result of reconciliation. Once reconciliation is complete, if a balance exists, a final CIAC bill is generated in accordance with the Interconnection Tariff, or refunds are made to customers for spending under the CIAC received. The reconciliation process could typically take 6-9 months from the completion of the construction. Therefore, t funding projects could reflect capital expenditures in excess of CIACs until all reconciliations are complete.

a. Please describe the Distributed Generation Capital Spending for which the Company is not reimbursed.

   In the event that a project runs over budget, the additional costs incurred are capitalized, representing additional costs of constructing the Company-owned system modifications. In the event of an overrun and the company is not reimbursed, the asset value is adjusted to its net value (difference between total spend and customer payments). To the extent that the Company invoices the customer for the overage, the additional cash collected is netted against the cost basis of the asset, resulting in an additional reduction to the net book value of the specific related plant, as it is paid for by the DG customer.

b. Please provide an accounting of such expense for FY 2022.

   The $5.4 million forecasted spend above relates to amounts that have not yet been transferred from Account 242, or either payments to be received from a payment plan or payments that Company may also receive from DG customers as a result of reconciliation.

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PUC 1-14

Request:

Referencing Attachment 1 on Bates page 77, please explain why the third-party attachment expense was almost 4 times the budgeted expense. Please also explain why FY 2021 actual was a credit.

Response:

Attachment 1 on Bates page 77 shows proposed Third Party Attachment capital spending for FY 2023 of $260,000. Forecasted capital spending for FY 2022 is shown as $1,051,000 and actual capital spending for FY 2021 was ($629,000). In recent years, capital spending in the Third-Party Attachment area primarily represents work performed on the Company's poles to accommodate pole-top wireless service equipment. The Company estimates and bills customers for work in advance of performing the work. Certain work performed in FY 2022 was billed in FY 2021 resulting in the credit to capital spending and a larger than usual spending amount in FY 2022.

The Company does not anticipate a similar timing difference in FY 2023; therefore, the proposed capital spending has returned to a more typical level.

PUC 1-15

Request:

Chart 15 on Bates page 60 includes $1,750,000 in spending in the damage/failure category related to storms and weather events.

a. Referencing Attachment 1 on Bates page 77, why was FY 2015 a credit?
b. Does Attachment 1 on Bates page 77 represent the actual storm related damage/failure expense or is it net of other reimbursement? Please explain.
c. If Attachment 1 on Bates page 77 does not represent the actual total storm related damage/failure expense for each year, please provide the actual total storm related damage/failure expense by year for each of the last 5 years.

Response:

a. Capital spending in FY 2015 appears as a credit because of adjustments to FY 2015 capital spending associated with the Company's storm reconciliation filing and credits associated with an insurance claim. As noted in the Company's FY 2015 Reconciliation Filing (RIPUC Docket No. 4473, FY 2015 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing, Attachment JHP-1 Page 6 of 18), "During the third quarter of FY 2015, an adjustment associated with the Company's storm reconciliation filing, which was made to true-up storm-related capital costs to actual installed units, reclassified $6.2 million from Capital to O&M expense. In addition, the Company received a $2.6 million credit that was associated with an insurance claim for a 2012 Rhode Island Flood."[1] These true up entries were recorded in anticipation of filing the "Final Storm Accounting for 2012 Through March 2013 Storm Events" in accordance with the Rhode Island Public Utilities Commission's (the PUC) Report and Order No. 15360 (August 19, 1997) in Docket No. 2509 and paragraph 4(c) of the Joint Proposal and Settlement in Lieu of Comments (the Settlement) approved by the PUC in that docket.

b. The amounts included on the Major Storms line of Attachment 1 on Bates page 77 represent storm-related capital spending, net of true up adjustments and insurance claims.

c. The amounts included on the Major Storms line of Attachment 1 on Bates page 77 represent storm-related capital spending, net of true up adjustments and insurance claims. It does not include cost of removal or operations and maintenance expenses for storms recovered under the Company's base rate, pension adjustment factor and storm recovery mechanisms. The Company has not received any insurance proceeds for storm costs in the last 5 years.

[1] The date of the Warwick Mall Flood was March 2010. Proceeds from an insurance claim were received in December 2014. The 2015 Reconciliation Filing identified the flood as having taken place in 2012 in error.

Prepared by or under the supervision of: Patricia Easterly

PUC 1-16

Request:

Referencing Attachment 4, Chart 7, please explain why the average number of Customers Interrupted by Cause – Intentional has increased for the period FY 2016 as compared to the period FY 2008 through FY 2015. Why are the number of customers interrupted intentionally in FY 2021 50% higher than FY 2008?

Response:

The Cause – Intentional group includes interruptions coded with a purpose of: System Load Shedding, Emergency Repair, Voltage Conversion or New Construction, Fire, Police Request or 911, Maintenance, or Replace OFC - Employee Safety. The increase for period FY2016 compared to period FY2008 through FY2015 is mainly due to Emergency Repair. Emergency Repair includes those outages where power had to be intentionally cut to make repairs to the system, but power had not been lost beforehand. For example, a motor vehicle accident breaks a pole, but does not cause an outage. In order to safely remove the vehicle, the line is de-energized so no further issues can occur.

The number of customers interrupted intentionally in FY2021 is 50% higher than FY 2008 is also due to the increase in Emergency Repair. There has been a steady increase in both Tree causes and Vehicle causes in interruptions coded as Emergency Repair over the period FY08 to FY21. The Company has increased worker safety procedures in the recent years greatly reducing live line work under damaged system conditions. To keep crews working safely, the Company will take an intentional outage, limiting the impacted customers to the furthest extent possible, to fix the problem.

Prepared by or under the supervision of: Bertram H. Stewart III

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PUC 1-17

Request:

Referencing Attachment 4, Chart 7, the deteriorated equipment cause was higher than any other year since FY 2012. To what does the Company attribute this experience? Given that the ISR construct has been in place since FY 2012, why is deteriorated equipment still consistently a top cause of customer interruptions?

Response:

FY 2021 experienced an increase in customers interrupted under the Deteriorated equipment category because of three instances of splice failures while the system was reconfigured for construction. The three instances were in the Portsmouth, Cumberland/Woonsocket, and North Providence areas. The system reconfiguration resulted in higher than usual customer counts for these outages. These three events accounted for 15% of Customer Interrupted due to Deteriorated equipment in FY2021.

Prepared by or under the supervision of:
Bertram H. Stewart III, Caitlin Broderick, and Ryan Constable

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PUC 1-18

Request:

Is the Company still considering an electrification solution for Aquidneck Island reliability? If so, how has this solution informed the design of the new substation?

Response:

No. The Company is not still considering an electrification solution for Aquidneck Island reliability.

As noted in its October 1, 2021 monthly report to the RI Energy Facilities Siting Board, the Company has progressed its analysis of the preferred long-term solution and has identified the seasonal and temporary operation of LNG at Old Mill Lane as a recommended solution for addressing the capacity constraint and capacity vulnerability needs on Aquidneck Island. The Company carefully examined several other alternatives, but its current assessment is that the alternatives are substantially more expensive, may require significant infrastructure investments, and do not offer the operational advantages provided by Old Mill Lane. The Company will provide the EFSB and the parties with a full analysis of its selection in the supplemental application to be submitted no later than April 4.

Prepared by or under the supervision of: Nathan Kocon and Amy Smith

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PUC 1-19

Request:

As more distributed generation is interconnected to the electric systems, with some causing the need for significant investment, how has the Company incorporated its knowledge of the potential existence of these investments into its overall system planning process?

How have the Company's planning processes changed, if at all, since Mr. Constable's presentation in February 2016 in Docket No. 4592.

Response:

Any investments in the distribution system, whether originally driven by generation or load, are immediately incorporated into system models. The capability of these investments, excluding the commitments made to the originating generation or load customer, are used for system purposes within planning studies. However, it is often the case that generation investments may add load serving capacity, but in areas with limited foreseeable load growth. While the capacity of distributed generation investments is incorporated into system models and can be used for planning purposes, in cases where the additional capacity is in areas with limited load growth, it provides little immediate benefit to system planning.

The planning process has had little change since 2016 except with the forecast inputs. The Company's annual forecasts include Distributed Energy Resources including Energy efficiency (EE), solar photovoltaic (PV), electric vehicles (EV), demand response (DR), and electric heat pumps (EH). Each technology considers a variety of inputs including active application queues, current programs, and state policy documents. The information used to create each technology forecast has improved and continues to improve each year since 2016. Aside from forecasts, the planning process has not changed since 2016 as the Company is limited by the DG Interconnection and load interconnection tariffs. The tariffs do not allow the Company to make proactive investments to facilitate DG interconnections. However, due to the saturation of DG on the system, the Company has taken initial steps to improve its planning tools to better analyze DG and DER impacts on the system. Further advancements in planning tools and processes are expected to require grid modernization sensing and data capabilities.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

## PUC 1-20

Request:

Referencing the Company's response to Division 1-3, asking about Chart 3, the Load Forecasting Process, specifically related to electric vehicles and heat pumps, what is the relevance/significance to the forecasting process of the portion of the Company's response, "EV load is considered beneficial electrification"? Is this type of load considered differently in the forecasting process? Does it have a different impact on the forecast and/or the process?

Response:

The Company considers distributed energy resources (DER) technologies including energy efficiency, solar photovoltaic, electric vehicles, electric heat pumps, energy storage, and demand response in its load forecasting process. Comparing to some other DER items such as energy efficiency, solar photovoltaic, energy storage, and demand response that help reduce load and/or shift peak load, electric vehicle adds load. It is termed "beneficial electrification" because fossil fuel use is replaced with electricity and it is assumed that over time renewables and other climate friendly sources of generation will serve this added load.

As discussed in the Company's response in Docket 5209, Division 1-3, estimated EV load is an addition to the forecasted load.

Prepared by or under the supervision of: Jingrui Xie and Joseph Gredder

PUC 1-21

Request:

Has the Company engaged with policy makers, public transit authority decision makers, or other large users of transportation to discuss how/where electric vehicle charging infrastructure could be deployed in a manner that reduces the related infrastructure investment costs? If so, please explain. If not, why not?

Response:

Yes, the Company has and continues to engage with stakeholders both large and small to site and install electric vehicle supply equipment (EVSEs) in a way that reduces infrastructure investment costs for our customers. In cases where large customers are interested in an EV project, the Company works closely with them to understand their needs, use case, and potential power requirements to support their desired outcomes at the least cost possible to serve the site(s).

For example, the Company holds bi-weekly calls with RIPTA to jointly coordinate the implementation of the necessary infrastructure to electrify their transit buses. The Company and RIPTA have worked closely together since the agency received its first grants to lease electric buses in 2018. Team members include RIPTA consultants, planning, and finance officials, as well as National Grid program managers, engineers, and members from distribution planning and asset management.

The team works closely together to understand customer's needs from both transportation route and energy use perspectives and helps to evaluate sites where there is adequate system capacity to supply those needs. Future sites are being evaluated based on service route needs and existing infrastructure to minimize project costs. In addition, the team ensures that appropriate metering requirements are met so that qualifying customers may participate in the demand credit program as described in the current EV policies.

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PUC 1-22

Request:

During the hearing regarding the FY 2022 ISR, Mr. Booth suggested that the Company should be advising the Division of its visibility into potential opportunities to plan such customer projects with its overall planning once known. He gave an example of a situation where it may make sense to evaluate the risk of delay of a Company-initiated infrastructure project if a customer-initiated project may provide an opportunity to address the same issues. (Docket No. 5098 Hr'g. Tr. at 315-19). How has the Company implemented this suggestion over the past nine months?

Response:

The Company believes it has always considered the impacts and/or benefits of customer related work on system work and vice versa. However, the consideration of such inter-dependencies does not always result in the delay of system work and in some cases requires acceleration of system work. In 2012, the Company delayed upgrades to resolve a transformer contingency issue in the Woonsocket-Cumberland area when a large customer request provided an opportunity to solve the contingency issue with the customer interconnection. Conversely circa 2014, system related work was accelerated when a customer request resulted in major work in the Quonset Point area.

Over the past nine months, National Grid has considered pending 34.5kV assets related to customer interconnections for subsequent customer requests and system needs and has reviewed this information with the RI Division of Public Utilities and Carriers (Division) associated with the review of completed Area Studies and associated recommendations.
In those cases, substantial distribution line infrastructure would need to be added to the pending assets to reach the new interconnection points or system need location. These additional line extensions resulted in higher costs versus other alternatives, and so were not recommended as part of the Area Study solutions. Also, the Company has identified an opportunity to coordinate infrastructure upgrades for system needs with a pending DER interconnection in the Tiverton area. The Company is aligning the timing of the system related work with the DER interconnection work to maximize efficiencies and expects to provide updates on these synergies as we continue our regular discussions with the Division

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PUC 1-23

Request:

During the hearing regarding the FY 2022 ISR, the Company witnesses testified that an investment in the system made pursuant to a customer request cannot be relied upon until it is in service. Is there a point of no return prior to that period (last payment ignored) when the investment is substantially complete? Please explain.

Response:

The Company has stated that it cannot rely upon a customer request until the Company is "fully assured the customer-driven project will be constructed and placed in service." as per response to PUC 1-20 in the FY 2022 ISR Plan in Docket No. 5098. Customers can withdraw their application at any point in time, even after an executed Interconnection Service Agreement (ISA) has been signed. However, once construction is in progress, it can be considered substantially complete just prior to commissioning. Commissioning is the last phase of any construction project before placed in service that tests the functionality of all equipment such as protection controls and communications.

PUC 1-24

Request:

Has the Company ever undertaken a study in Rhode Island, or considered undertaking a study in Rhode Island, to study the impact of interconnecting various levels of hypothetical distributed energy resources to the distribution system under different locational scenarios, for example, the type of studies completed by ISO-NE pursuant to Section 4.1(b) of Attachment K of the OATT? If so, please provide the results. If not, why not? If not, how would the Company develop such a study and what might it cost?

Response:

Yes, the Company considered various levels of distributed energy resources and their impacts or benefits to the distribution system with the Company's Grid Modernization Plan (GMP) filed January 2021 as RI PUC Docket 5114, which was stayed by the PUC on June 29, 2021.

The analysis in the GMP is not pursuant to Section 4.1(b) of Attachment K of the OATT because the distribution system does not have a market-based system. However, the fundamental purpose of finding the least cost, highest benefit solution is aligned between the GMP and Section 4.1(b) of Attachment K of the OATT. Additionally, RI PUC Docket 4600 analysis includes similar economic factors to the ISO-NE studies. The Company's forecast is revised each year including various distributed energy resource scenarios (low, base, and high cases) which provides a suitable basis for future GMP revisions.

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