nationalgrid

Raquel J. Webster
Senior Counsel

January 16, 2018

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4783 - Proposed FY 2019 Electric Infrastructure, Safety, Reliability Plan
<u>Responses to PUC Data Requests – Set 1</u>

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's responses to the first set of data requests issued by the Rhode Island Public Utilities Commission in the above-referenced docket.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4783 Service List
Greg Booth, Division
Leo Wold, Esq.
Al Contente, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

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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 16, 2018
Date

Docket No. 4783 National Grid's Electric Infrastructure, Safety and Reliability Plan FY 2019 - Service List as of 1/8/17

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PUC 1-1

Request:

Please provide all responses to the three sets of data requests or information requests issued by the Division of Public Utilities and Carriers (Division) prior to the filing of this proposal with the PUC.

Response:

Please see Attachments PUC 1-1-1 through PUC 1-1-4.

nationalgrid

Raquel J. Webster
Senior Counsel

November 8, 2017

BY HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2019 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

I have enclosed National Grid's[1] responses to the Division's first set of data requests in the above-referenced matter. Please be advised that the Company's responses to R-I-14, R-I-25, and R-I-37 are pending.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosure

cc: Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth
Al Contente

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

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R-I-1

Request:

Confirm that the current pilot VVO/CVR benefit is 3.3%.

Response:

The last Measurement and Verification (M&V), which was presented to the Division, covered the 38F3 and the 38F5 feeders out of the Putnam Pike substation. This M&V was performed using day-on, day-off testing from April 2016 to September 2016. The results showed a demand reduction of 3.15% and 3.50%, respectively. The detailed M&V assessments on the remaining Putnam Pike feeder (38F1), and the Tower Hill feeders, is ongoing and the Company will share those results with the Division when they are available. The impact of VVO will vary between feeders due to the mix of load and physical characteristic of the feeder. At this time, for planning purposes, National Grid estimates a 3% improvement for each feeder.

R-I-2

Request:

Confirm that the expected benefit of the VVO/CVR expansion (excluding AMI) is also 3.3%

Response:

National Grid assumes that the expected benefit of the VVO/CVR expansion (including AMI) is 3%.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-3

Request:

Confirm that the expected incremental benefit of adding AMI to the VVO/CVR expansion is 1%, for a total of 4.3%.

Response:

National Grid expects to achieve a 1% incremental benefit with the addition of AMI data, beyond the 3% savings estimated for future VVO/CVR projects, for a total of 4%. Utilidata, the Company's VVO vendor, has observed similar incremental results through lab trials and field deployments with select customers.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-4

Request:

Describe the existing VVO/CVR pilot control system head end, communications systems, and the components in the substations and distribution system.

Response:

The Adaptivolt™ system (i.e., the VVO/CVR control system) monitors and controls regulators/load tap changers at the substation, midline regulators, capacitor banks, and midline/end of the line voltage monitors on the distribution feeders being controlled. The Adaptivolt™ system consists of two closed loop feedback control loops.

The first control loop is the "CVR loop, which uses feeder metering data at the substation along with line voltage monitoring data from points along the feeder to make tap decisions on the regulators.

The second control loop is the "VAR loop", which uses reactive power data obtained from the substation feeder meters to make Trip/Close decisions on the capacitor banks.

To date, the communications systems utilized in the deployments include both private RF mesh network and cellular network technologies, which are described in the Company's response to R-I-8.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-5

Request:

Provide a description of, and vendors for, all services and equipment in use in the existing VVO/CVR pilot.

Response:

The following is a list of vendors (including their services and/or equipment) associated with the existing VVO/CVR pilot:

- Utilidata: Provides line voltage monitors, the Adaptivolt™ system, professional services, and measurement & verification analysis
- Trilliant: Provides the private radio frequency mesh communications network that is deployed for a portion of the Putnam Pike region; professional services; and radio frequency site surveys
- Verizon Wireless: Provides the cellular communications network that is deployed for the Tower Hill region and a portion of the Putnam Pike region. Verizon also provides back office communications service between the Adaptivolt™ Server and Field Devices and managed information system services.
- General Electric: Provides the cellular radios deployed with the field devices (capacitors, line voltage monitors, and voltage regulators)
- Schweitzer Engineering Laboratories: Provides capacitor controls (SEL-734B)
- Beckwith: Provides voltage regulator controls (M2001-D)
- Lindsey: Provides line sensors for monitoring at capacitor locations.
- NovaTech: Provides back office data concentrators
- Securicon: Provides Digital Risk and Security testing services
- CSC: Provides information system services for Trilliant Network management services

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's First Set of Data Requests
Issued October 19, 2017

R-I-6

Request:

Provide detailed cost data breakdown of all installation, and operating and maintenance costs incurred to date for the existing VVO/CVR pilot divided by category including, but not limited to, equipment cost, labor (engineering, design, installation, programming, and program management), operations and maintenance. Provide in native, executable format.

Response:

The VVO/CVR Pilot is categorized into three accounting projects: substation charges, distribution line work, and Information Services. The total spent to date on the Pilot (for the life of the pilot) is captured in the table below.

	Sum of CAPEX - Amount	**Sum of OPEX - Amount**	**Sum of COR - Amount**	**Sum of Amount**
Base Labor	$155,654	$23,301	$3,830	$182,785
Capitalized Interest	$0	$0	$0	$0
Consultants	$702,474	$137,796	$0	$840,270
Contractors	$174,342	$0	$0	$174,342
Employee Expenses	$0	$157	$0	$157
Materials	$92	$0	$0	$92
Other Employee Benefit	$65,757	$10,135	$1,725	$77,618
Other Expenses	$103,777	$0	$0	$103,777
Pension and OPEB	$51,446	$5,755	$1,233	$58,434
Transportation	$16	$0	$0	$16
Volt Var - IT/IS SubTotal	**$1,253,558**	**$177,144**	**$6,788**	**$1,437,490**

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
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	Sum of CAPEX - Amount	Sum of OPEX - Amount	Sum of COR - Amount	Sum of Amount
Base Labor	$938,230	$247,393	$34,736	$1,220,359
Capitalized Interest	$81,195	$0	$0	$81,195
Consultants	$427,583	$1,413	$0	$428,996
Contractors	$540,283	$8,189	$2,571	$551,043
Employee Expenses	$9,430	$402	$0	$9,831
Materials	$556,963	$35,205	$3,306	$595,474
Other Employee Benefit	$369,427	$83,867	$12,850	$466,144
Other Expenses	$526,253	$5,790		$532,042
Overtime	$74,818	$17,054	$9,636	$101,508
Pension and OPEB	$334,276	$78,644	$12,980	$425,899
Transportation	$79,957	$43,652	$9,592	$133,201
Volt Var Dline RI Pilot Project SubTotal	**$3,938,414**	**$521,609**	**$85,670**	**$4,545,692**
Base Labor	$66,599	$867	$0	$67,466
Capitalized Interest	$4,488	$0	$0	$4,488
Consultants	$19,750	$0	$0	$19,750
Contractors	$4,481	$0	$0	$4,481
Employee Expenses		$85	$0	$85
Materials	$47,064	$0	$0	$47,064
Other Employee Benefit	$25,508	$328	$0	$25,835
Other Expenses	$26,838	$190	$0	$27,028
Overtime	$5,330	$0	$0	$5,330
Pension and OPEB	$22,541	$130	$0	$22,672
Transportation	$6,811	$0	$0	$6,811
Volt Var-Substation SubTotal	**$229,409**	**$1,600**	**$0**	**$231,009**
Grand Total	**$5,421,380**	**$700,353**	**$92,458**	**$6,214,191**

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R-I-7

Request:

Describe how the company currently operates the VVO/CVR Control System.

Response:

The Adaptivolt™ system (i.e., the VVO/CVR control system) is integrated with National Grid's Energy Management System (EMS). Control room operators monitor and control the Adaptivolt™ system through EMS. The Adaptivolt™ system uses a "heartbeat" function to monitor communications with the field devices. If a field device loses communications with the Adaptivolt™ system, the field device will go into an "autonomous" mode – using the device's internal settings to operate based on local conditions, similar to what performance would have been before VVO/CVR was deployed. Further, the Adaptivolt™ will disable itself if a critical device to VVO/CVR operations loses communications.

National Grid keeps the Adaptivolt™ system 'active' during normal operating conditions. In abnormal operating conditions, the system is manually shut down and voltage is managed through the autonomous mode.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-8

Request:

Describe the communications systems used in the current VVO/CVR pilot.

Response:

The existing VVO/CVR pilot has a private radio frequency mesh network for most of the Putnam Pike region and a cellular network for the Tower Hill area and a portion of the Putnam Pike area. The private radio frequency mesh network utilizes an unlicensed 5.8GHz radio band spectrum, and supports communications for the remote control of the field devices. The field devices' data is aggregated at the mesh gateway, which provides backhaul connectivity to National Grid's network. A data concentrator on this network requests information every 15 seconds from the field devices.

The cellular network includes cellular modems to communicate with the field devices through the Verizon wireless network. The cellular radios offer device-level security and prevent access to unauthorized local or remote users. Verizon has reserved an exclusive address space for National Grid's cellular devices on its cloud. A secure MultiProtocol Label Switching (MPLS) circuit connects the Verizon wireless cloud to the VVO server. The data concentrator, which is also connected to the MPLS circuit, requests information every five minutes from the field devices through unsolicited messaging and periodic polls. It also connects National Grid's emergency management system to the VVO server to increase the control center operators' visibility into the distribution system.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-9

Request:

Describe the current frequency of control requests and response times from the Utilidata control system to the field devices.

Response:

To optimize voltage, the Adaptivolt™ system does the following:

- requests information from all available field devices every 15 seconds;
- processes this information using proprietary algorithms; and
- sends operational commands to field devices.

It is difficult to quantify the response time of the system because the timing will vary depending on the variability of system conditions. An extreme voltage swing (due to a large load change) would be responded to immediately, while a small voltage swing may not be addressed for minutes.

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's First Set of Data Requests
Issued October 19, 2017

R-I-10

Request:

Explain the evaluation processes, methods, criteria, and results of the substation selection process that lead to the selection of the Washington and Staples substations for the VVO/CVR expansion.

Response:

National Grid has ranked its distribution feeders based on an estimated cost per MWh savings considering:

- Physical characteristics of the feeder (devices, length, voltage class, construction type, etc.)
- Historic and forecasted loading and capacity
- Inspection and maintenance information
- Existing substation automation levels

The Company only considered feeders that were overhead 15kV class. Order of magnitude (OOM) costs are created using typical costs to upgrade the substation and distribution field devices. The field devices attached to the substation are each assigned a cost to upgrade, as is the substation itself, to develop an OOM cost. Substation peak loads and total energy consumption information are used to determine a relative savings value for each substation and its feeders.

National Grid's Distribution Planning group then selects the next feeders to deploy VVO/CVR from the top candidates from the screening described above. For the fiscal year 2019 Electric ISR Plan, the Washington and Staples substations ranked #2 and #4, respectively, in terms of expected cost per MWh. The other highest ranked substations were not selected because of other company upgrade activities.

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The Narragansett Electric Company
d/b/a National Grid
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R-I-11

Request:

What other substations were considered? Explain why they were not selected.

Response:

When selecting substations for VVO/CVR, the Company considers all substations in RI. It uses a ranking method, described in R-I-10, to determine top tier candidates, and then Distribution Planning recommends substations from that list. For 2019, the Company identified the following top five potential locations: were identified were:

• PAWTUCKET 1 107
• WASHINGTON 126
• JEPSON 37
• STAPLES 112
• WOONSOCKET 26

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
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Issued October 19, 2017

R-I-12

Request:

Explain the selection process(es) for the ten feeders.

Response:

National Grid identifies feeders based on the selection of their substation, referenced in R-I-10. Once a substation is selected, all feeders attached to it are included in the program (with the exception of one ~0.5 mile feeder with minimal load out of the Washington substation).

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R-I-13

Request:

What are the circuit and load characteristics used to select the ten feeders, and how did you determine that these provide the highest value?

Response:

Please see the Company's response to Data Request R-I-10, which includes a description of the selection criteria the Company used to select the ten feeders. Please see Attachment R-I-13 for a description of Circuit and Load characteristics.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-15

Request:

Does the expansion propose to use the same components as the existing VVO/CVR pilot? If not, explain the differences and include a description of, and vendors for, any different services and equipment in use.

Response:

The Company plans to use to use the same components as the existing VVO/CVR pilot for the expansion. However, the supporting telecommunications may vary. If the VVO/CVR scheme is a stand-alone project a Verizon cellular network may be used to integrate the field devices with the central controller. If the VVO/CVR project is coupled with AMI, then a private radio frequency (RF) mesh network may be utilized. ITRON will provide the Private RF network.

R-I-16

Request:

From a communications perspective, provide the expected differences in the reliability, latency and redundancy of the mesh FAN compared to the cellular system used previously to control voltage controlling devices under the VVO/CVR pilot.

Response:

Reliability: The mesh FAN reliability is comparable to the reliability of the cellular network. With extensive built-in acknowledgements and retries, the mesh system provides high reliability for data collection and control of field devices; in addition, as described below, it benefits from redundancy.

Latency: The mesh network is a multi-hop network with per hop latencies as low as 0.15 seconds. As a point-to-multipoint network, cellular will provide latency for roundtrip communications of typically less than one second.

Redundancy: The mesh network provides for redundant and self-optimizing paths for each meter/device to route back through the network. This redundancy also applies to the field area routers. If there is a failure or disruption in backhaul communications, the meters/devices will migrate to a neighboring field area router. Cellular networks must be properly planned with adequate tower locations to allow for the neighboring cell towers to "bloom" and cover end points under a failed cell tower.

R-I-17

Request:

Describe the expected control performance difference between the communications now in use to control line devices that are not part of the VVO/CVR pilot and the proposed mesh FAN.

Response:

National Grid, and its affiliate companies, have used both cellular and private wireless (e.g. WiMAX, 900MHZ and 700MHZ licensed spectrum radios) radio frequency (RF) mesh networks to control distribution line devices. Selecting an appropriate communications scheme depends on its intended application. For example, a Fault Location, Isolation, and Service Restoration (FLISR) application that relies on very low latency peer-to-peer communications may not be compatible with all of the options available. Whereas a wider array of telecommunications options may be cost-effective and appropriate for applications such as AMI, VVO/CVR, remote monitoring, and SCADA control. For the AMI and VVO/CVR project proposed, the RF mesh network is expected to provide the necessary bandwidth and latency for both metering and voltage control.

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R-I-18

Request:

Describe the expected impact on total number of operations of voltage controlling devices.

Response:

Based on the measurement and verification (M&V) performed for the 38F3 and 38F5 feeders served by the Putnam Pike substation,[1] the Company does not expect an increase in operations on its voltage regulating equipment as the result of deploying VVO/CVR.

[1] The Company filed the M&V report with the PUC on December 12, 2016 in Docket No. 4592.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-19

Request:

Describe the expected impacts on maintenance costs of voltage controlling devices.

Response:

National Grid has not quantified expected impacts on maintenance costs.

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R-I-20

Request:

Describe all additional services and equipment required to integrate the AMI data to the current Utilidata system to read an additional 16,000 data points. Provide the incremental costs and describe the required upgrades.

Response:

National Grid expects that the following services and equipment are required to integrate AMI data with the current Utilidata system. This table represents capital costs and includes a brief description of those costs.

Investment	**Description**	**Cost**
Meter Costs	Cost of the AMI meter	$1,625k
Field Area Network	Cost of radio equipment	$147k
Professional Services	Vendor Professional Services	$2,064k
Incidental Material and Handling	Material Handling	$200k
Meter Installation	Installation of Meters	$444k
National Grid Project Management Office	PMO to manage Meter installation	$1,500k
Information Services	IS upgrades	$1,087k
Field Area Network Installation	FAN installation	$307k
MPLS	MPLS network costs	$50k
Total CAPEX		**$7,366k**

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R-I-20, page 2

Investment	**Description**	**Cost**
Information Services	IS Upgrades	$305k
Customer Outreach	Customer Outreach	$500k
Field Area Network Installation	FAN installation	$160k
Total OPEX		**$965k**

R-I-21

Request:

Describe all additional services and equipment required to integrate the AMI data to the current Utilidata system to read 10% of the proposed AMI meters, or 1,600 data points. Provide the incremental costs and describe the required upgrades.

Response:

The purpose of the AMI pilot is to test how AMI meters, when deployed at a system level, can best be integrated to enhance VVO/CVR rather than test the opportunity for the incorporation of targeted "bell weather" secondary monitoring points. National Grid has also been advised by its VVO/CVR vendor that 10% of data would not be sufficient to inform the VVO/CVR system controls to achieve the expected improvement in performance. Therefore, National Grid does not have cost estimates for this scenario.

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R-I-22

Request:

Provide the assessment criteria and vendor ranking used when selecting Utilidata

Response:

Utilidata was selected through a competitive solicitation for the VVO/CVR pilot in Rhode Island. Selection criteria included: response to requirements, response to specific questions (e.g., technical, sensing and control), overall scope, and cost. Please see the table below for National Grid's scoring criteria:

Sections used for evaluation:	Percentage used for scoring:
Specific detail	44%
Sensing and control	20%
Technical content of scope	30%
Cost	6%

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R-I-23

Request:

If system-wide AMI is deployed in the future and the vendor in this proposed AMI pilot is not selected, what is the course of action for the AMI meters installed for the pilot?

Response:

National Grid seeks solutions that are standards-based, allow for interoperability (see the Company's response to Data Request R-I-24) and support vendor meter diversity for system-wide investments. Therefore, if system-wide AMI is deployed in the future, and the metering vendor in this proposed AMI pilot is not selected, National Grid presumes that it will still utilize the AMI pilot meters. The Company would perform an assessment of options once specifics regarding a system-wide deployment are known.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-24

Request:

Describe any expectations of how the proposed mesh FAN is compatible with AMI equipment from other vendors.

Response:

The proposed mesh network is IPv6 standards-based to support interoperability through the Wi-SUN Alliance. Any device compliant with the Wi-SUN Alliance FAN 1.0 interoperability profile can operate on the proposed IPv6 mesh network. Vendors can build products based on the Wi-SUN reference design or integrate their devices with pre-built network interface cards.

R-I-26

Request:

Describe the interval data collected and how it is stored.

Response:

Interval data for energy and voltage is collected in 5, 10, 15, 30, or 60-minute intervals. In addition to the AMI meter retaining the interval data in non-volatile memory, data is stored in the meter data management system and data analytics database.

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R-I-27

Request:

Please describe how frequently the AMI readings will be obtained and their latency

Response:

Data collection frequency is configurable. The Company's affiliates have had experience collecting AMI data, at intervals down to five-minute granularity, from the AMI meters three times a day (midnight, 8 AM, and 4 PM.) or more often, as needed. Read schedules are typically set up to return AMI readings within four-hour read windows, three times a day. These read windows can be adjusted as required based on the use case. The latency depends on the frequency of the remote interrogation, normally between three and four times per day and the time configured to allow the data to be retrieved, which is typically between four and six hours depending on the total number of meters. The assumption is to have the majority of meters follow this remote interrogation schedule to allow for automated contingency reads. Utilidata's VVO solution requires a flat file transfer (in .csv format) of all available AMI data once per day. This file must include hourly reads from all available AMI meters for the past 24 hours.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-28

Request:

Please describe how the backhaul from the mesh FAN will be handled, including a description and cost breakdown for any incremental investment required above existing facilities on the Company's system.

Response:

The Company expects to utilize a public cellular backhaul, which would not require any incremental capital investments. Monthly operation and maintenance costs for the associated data plan with the wireless carrier are included in the project estimate. The proposed field area router offers backhaul options such as Ethernet (RJ45 or fiber SFP), 4G LTE, and WiMAX.

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R-I-29

Request:

How are control commands prioritized versus data observations on the mesh FAN and backhaul?

Response:

Itron's solution prioritizes control commands over data observations. The proposed field area network offers full support for IP routing and enables enterprise-class traffic prioritization and Quality of Service. This approach is used for managing the disparate requirements around bandwidth allocation, prioritization, and system configuration of multiple applications and data on the IPv6 mesh. Traffic is classified and prioritized using industry-standard Internet Engineering Task Force Quality of Service (QoS), which extends from the end points to the head end system.

R-I-30

Request:

What AMI meters are proposed? Please describe the benefits and costs compared to other comparable meters.

Response:

Itron's OpenWay Riva CENTRON meters are proposed. These meters offer:

- a wide-range of measurements for interval data
- two-way, "adaptive" communications (i.e., the ability to dynamically select both the physical media – RF or PLC – and optimal modulation rate for connectivity)
- built-in microprocessors to enable distributed intelligence (e.g., the ability to disaggregate customer loads which could be used to target energy efficiency services, detect electrical faults and safety conditions, validate network connectivity)
- power outage detection and restoration notification
- voltage monitoring
- automatic tamper and theft detection
- remote meter reprogramming
- ability to download new firmware via the network

Although the Company did not perform a full market request for proposal process for the proposed pilot, the costs and features appear to be comparable or better than other vendors' smart meters based on market research.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-31

Request:

How long does the company expect to run the AMI pilot program? When will the initial benefit analysis be available?

Response:

National Grid plans to deploy the VVO/AMI pilot in FY2019. Measurement and Verification (M&V) will run for a minimum of 120 days after the system is deployed. The Company expects that the M&V phase will capture summer peak effects. National Grid will provide the M&V report once it is available.

Prepared by or under the supervision of: Jacquelyn Bean and James Patterson

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R-I-32

Request:

Do you plan to deploy AMI on any feeders currently involved in any VVO/CVR? If not, why?

Response:

Not at this time. The Company proposes this AMI pilot with an assumption that the Company will propose a system-wide deployment of AMI in the near future. The AMI pilot will provide valuable lessons learned regarding the integration of AMI and VVO that can be leveraged in future AMI project. The Company does not expect to deploy AMI meters solely for integration with the VVO/CVR system beyond this pilot. If a system-wide AMI deployment were not planned, the Company would consider other alternatives for granular voltage monitoring that would provide secondary voltage monitoring that may enhance the performance of the VVO/CVR system.

If in the future AMI is deployed system-wide, the VVO/CVR control schemes previously deployed will be integrated with the AMI data on those feeders.

Prepared by or under the supervision of: Jacquelyn Bean and James Patterson

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R-I-33

Request:

How do you propose measuring the incremental benefit of AMI over the VVO benefit?

Response:

The measurement and verification (M&V) process would be accomplished by operating the pilot area in both AMI-Enhanced VVO and non-VVO modes on alternating days. A constant Conservation Voltage Reduction (CVR) factor is assumed over the service voltage range observed during the M&V evaluation period in both the AMI-enhanced VVO and non-VVO operating modes. The CVR factor will be estimated using M&V Protocol #1.
See Attachment R-I-33.

When operating in AMI-enhanced VVO mode, voltage and demand data from each AMI meter is evaluated to determine whether the targeted voltage at the distribution primary level can be reduced from what it would have been if only primary voltage sensing and assumed secondary voltage drops were considered. The incremental benefit of incorporating AMI data will be computed by assessing the difference between what the primary voltage setting would have been when operating VVO without AMI and what the primary voltage setting actually was when operating AMI-enhanced VVO. A calculated demand reduction for operating VVO without AMI will be determined by applying the CVR factor to the difference in primary voltage settings with and without AMI data.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

Automated CVR Protocol No. 1

Primary Sector and End-Use:

Electric utility distribution feeders and substations feeding residential, commercial and industrial customers; large industrial or commercial customers that have the ability to implement automated conservation voltage regulation (CVR) within their facility.

Application Specifications:

This method applies to automatic CVR systems. These automated systems can be turned on and off on a daily basis, have the voltage set-points changed on a daily basis, have the ability to measure and record period average bus and end-of-line voltages, period kWh, period kVARh on a per feeder basis and measure and record period average temperature. The method is applicable where no previous energy usage information is available

The ideal application would be where the automatic CVR control components could also monitor and store the period data.

Method Description:

Primary Method

The primary method of verifying energy savings is to operate the system in such a way as to operate at different voltage levels on alternating days. The initial verification period would last one year. The verification would begin with 90 days or three months of one day at full voltage reduction, one day with voltage set at the controlled nominal midpoint above full reduction and one day of open loop (automated CVR off). During the next 9 months the automated CVR would be on continuously. Three out of these nine months would be selected based on season and other factors such as geographic weather patterns etc., to operate the system so that on alternate days the system is at full voltage reduction, and the next day at the controlled nominal midpoint.

Time series analysis procedures, robust statistical methods, and temperature compensation methods are then used to evaluate the total energy conservation by comparing energy use on similar days at different voltage levels. For instance, winter weekdays would be compared against winter weekdays, summer weekdays against summer weekdays, etc. Conservation voltage regulation factors (CVRf) then computed for each feeder the different seasons for weekdays and for weekends.

CVRfs are used to estimate total ongoing energy conservation. CVRfs are verified during similar periods in following periods by running alternating days with full end of line voltage reduction and 2 volts above full end of line voltage reduction for two to four week periods.

Program Savings

The program savings are estimated by using the following definition:

Esaved = Eused [(CVRf*Vr%/(1-CVRf*Vr%)]

In which:

Esaved = Energy Conserved for period in kWh, MWh or GWh

Eused = Measured Energy used for period in kWh, MWh or GWh

CVRf = Period conservation voltage reduction factor as computed using time series analysis and robust statistical methods with temperature compensation for specific seasons. CVRf will be different for weekday and weekend. (See estimation method below.)

Vr = Average period end of line voltage reduction

Vr% = Average period end of line voltage reduction in percent

Voc = measured average end of line voltage with automated CVR non operational

Vcvr = measured average end of line voltage with automated CVR operational

Vr = Voc – Vcvr

Vr% = Vr/Voc * 100

CVRf Estimation (applies to the performance evaluation period)

Integrated demand profiles, one each for the automated CVR system active and inactive, are estimated on a common ambient temperature basis using the UtiliData CVR Estimation Method ("Estimation of Automated CVR System Performance Using Observed Energy Demand Load Profiles"); the 24-hour sum of the difference between these profiles is the estimated conserved energy for the evaluation. The mean difference of the end of circuit voltages for the automated CVR system active and inactive is estimated. The CVRf is then determined from the ratio of these two quantities, and can be expressed on an absolute or per unit basis (the per unit basis is recommended).

Recognizing (1) the stochastic nature of the energy observations as discussed in the UtiliData CVR Estimation Method, (2) the requirement to evaluate the performance of candidate automated CVR systems using the smallest (least duration) set of energy observations, and (3) that the probability densities of the relevant observations clearly exhibit non-homogeneous variance and are also clearly not Gaussian processes, the required estimations should be carried out using robust statistical procedures. Specifically, the Minimum Covariance Determinant estimators should be applied, because (1) their breakdown point is high and (2) they do not require that the observations exhibit a symmetrical probability density.

Automated CVR Performance Forecasting

The UtiliData CVR Estimation Method referenced above, estimates CVR using the observations of the automated CVR system inactive state as a reference. In principle, forecasting for a given circuit then simply requires a base demand profile, a projected end of circuit voltage reduction, and the estimation results from the evaluation period.

Special Considerations:

Temperature

Correct temperature data is essential to the accurate use of this verification method. It is recommended that the automated CVR system records period temperatures at the substation. Because the substation is usually at the geographic center of the area served this temperature will usually suffice. However, if significant microclimates are known to exist, temperature monitoring and recording may also be required at the feeder end-of-line location, so that an average temperature for the feeder may be obtained.

Metering and Data

Data recording periods should be no greater than one hour, and can be as short as the system allows. Weather data should be collected on the same time period as the load data. Data collected is subject to audit.

Instrumentation

Voltage monitors should have linearity of better than ½% within the expected ranges of voltage and temperature drift should be less than ½% from -40 degrees C to 65 degrees C. Power monitors should be revenue grade accuracy but need not be revenue class.

Shop Calibration and Field Verification

Instruments and meters should be shop calibrated. Field verification and inspections are required to verify correct installation and correct readings.

Baseline

The baseline voltage levels are established by the historical regulator or LTC control settings. One or more years of historical regulator or LTC setting information should be made part of the verification data records.

Re-verification Triggers

Re-verification will be required when there is a +/- 10% shift in temperature adjusted total annual load, a +/-10% shift in temperature adjusted total load during heating regime hours, a +/-10% shift in temperature adjusted total load during cooling regime hours, or a permanent reconfiguring of the distribution system (not including re-conductoring, transformer replacement, capacitor banks, or other distribution system efficiency project).

If re-verification is triggered by a shift in the loads during heating or cooling regimes, the re-verification protocol will consist of one sixty day period during either the heating or cooling period. If re-verification is triggered by a shift in total annual load or a permanent re-configuration the re-verification protocol will consist of two sixty day periods, one in the heating period and one in the cooling period. During the re-verification periods the system will alternate daily, operating one day at full voltage reduction and the next day at the controlled nominal midpoint.

The new CVRfs determined by these re-verifications will be used in lieu of the original CVRfs.

Model

The current model used for the time series analysis includes compensation for temperature. There are a number of additional factors that affect energy use and could be added to the model. Addition of these factors will tend to improve the predictive accuracy and reduce "outlier" data points. Factors that may be considered for inclusion in the model in the future will include daylight and dark hours, solar intensity, day of week, humidity, etc.

Adding any or all of these to the model should not change the basic measurement and verification protocol.

Control Group:

No control group required because with on-off and variable voltage set point capability, the application group can act as its own control group during testing periods.

Recommended Models and Tools:

UtiliData Automated CVR Estimation Method Tools

MatLab® (©1994-2003 by the MathWorks, Inc.) tools are available from PCS UtiliData to use with this protocol.

References:

1. Rousseeuw, P J, Leroy AM, 'Robust Regression and Outlier Detection', Wiley 1987.
2. Rousseeuw, P J, 'Introduction to Positive Breakdown Methods', in Handbook of Statistics, Volume 15: Robust Inference, editors G S Maddala and C R Rao, Elsevier 1997.
3. "Estimation of Automated CVR System Performance using Observed Energy Demand Profiles", David Bell, March 15, 2004. (available at www.pcsutilidata.com)

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's First Set of Data Requests
Issued October 19, 2017

R-I-34

Request:

Please provide a detailed cost estimate for all VVO/CVR expansion program components.

Response:

To inform the expansion program costs, National Grid took the average installation costs, by device for the pilot, and applied them to future expansion activities. The average costs by device type and number of devices included in the fiscal year 2019expansion are shown in the table below:

Category	**Average CAPEX**	**Average OPEX**	**Average COR**	**Qty**
New Capacitors	$15,702	$2,509	$1,476	36
Retrofit Capacitors	$11,416	$7,307	$675	8
Substation Load Tap Changer	$156,200	$36,200	$7,600	3
Line Voltage Monitors	$11,428	$2,758	$874	10
Telecom Integration (per device)	$1,562	$362	$76	57

In addition, the per feeder software license and services under a separate agreement will be allocated to the fiscal year 2019 expansion. This includes a per feeder cost of $57,640 to be applied to the ten feeders. The total project cost, including proposed and prior investments, is $2.3 million.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

R-I-35

Request:

Please explain the considerations that were relied on to decide on the number of meters in the AMI pilot.

Response:

National Grid is proposing to include 100% of customers on the feeders in which VVO/CVR is planned for deployment in fiscal year 2019. The purpose of the AMI pilot is to provide learnings as to how AMI data, when deployed system wide, can be integrated into the VVO/CVR control algorithms to provide additional efficiencies.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's First Set of Data Requests
Issued October 19, 2017

R-I-36

Request:

What are the specific components and costs of the AMI pilot deployment, including meters, mesh FAN, backhaul, and changes to the system to communicate with and control the load tap changers, voltage regulators and capacitor banks? Provide in native, executable format.

Response:

Please see the Company's response to Data Request R-I-20 for all AMI-related costs. For VVO/CVR related costs, please see the Company's response to Data Request R-I-34.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-38

Request:

Have you evaluated cellular communications rather than mesh FAN for AMI? If so, please provide all analysis and work papers, including cost assumptions.

Response:

Yes, the relative merits of cellular versus RF mesh networks have been evaluated by the industry for several years. In economic terms, RF mesh becomes more cost-effective than cellular once the system exceeds an average of 50-75 devices per router. The key parameters considered are:

- Cellular meters will have a price premium over a mesh meter due to the costlier cellular communications modules

- Cellular meters will incur ongoing monthly costs per unit for backhaul links.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-39

Request:

How would additional devices impact the overall cellular cost per device?

Response:

Assuming cellular backhaul for the field area routers, a typical data plan of 1GB per month is adequate for a fully loaded field area router (3,000 meters). The more devices that can utilize a router the lower the average cellular costs are per device. Field area routers can average between 1,500 and 2,000 devices in many deployments, which enables significant device population growth before any additional cellular costs are incurred.

R-I-40

Request:

What is the cost of the FAN compared to previously used cellular communications, and how is the reliability, latency and redundancy compared?

Response:

Please see the Company's response to data request R-I-20 for AMI FAN related costs. National Grid expects that a dedicated FAN will improve the reliability and latency, but the company has not quantified the improvement. National Grid does not anticipate any redundancy benefits.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

nationalgrid

Raquel J. Webster
Senior Counsel

November 14, 2017

BY HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2019 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 1</u>

Dear Ms. Massaro:

I have enclosed National Grid's[1] responses to Data Requests R-I-14, R-I-25, R-I-32, and R-I-37.

Please note that the Company's responses to Data Requests R-I-2 and R-I-6 have been amended, and the amendments have been marked to show changes.

This transmittal completes the Company's responses to the Division's first set of data requests in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Raquel J. Webster

Enclosure

cc: Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth
Al Contente

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

R-I-14

Request:

For the selected feeders, provide the number of customers by customer class, peak load for each customer for the prior three years, circuit length, and existing voltage control equipment specifications including size, type, capability, and location.

Response:

Please see the table below.

Substation Name	Feeder Number	Total Circuit Length (miles)	Customers Served (#)	Peak Load (Amps)			Voltage Control Equipment
				2014	2015	2016	
Staples	112W41	13.93	Resi: 1789 C&I: 136 Total: 1925	207	237	245	115/13.8 kV 24/32/40 MVA TRF LTC[1]; 1 line capacitor (600kVAr fixed)
Staples	112W42	31.59	Resi: 2564 C&I: 279 Total: 2843	403	329	372	115/13.8 kV 24/32/40 MVA TRF LTC; 1 line capacitor (900kVAr fixed)
Staples	112W43	16.27	Resi: 856 C&I: 85 Total: 941	136	138	140	115/13.8 kV 24/32/40 MVA TRF LTC; 4 line capacitors (1 900kVAr switched; 2 1200kVAr switched; 1 600kVAr switched)
Staples	112W44	51.94	Resi: 2191 C&I: 89 Total: 2280	365	323	343	115/13.8 kV 24/32/40 MVA TRF LTC; 2 line capacitors (600kVAr fixed)
Washington	126W40	6.63	Resi: 127 C&I: 19 Total: 146	241	220	227	112/14.4 kV 25/35.3/46.6 MVA TRF LTC - 261 Bank; 4 line capacitors (3 900kVAr switched; 1 1200kVAr switched)
Washington	126W41	37.79	Resi: 2291 C&I: 313 Total: 2604	401	385	387	112/14.4 kV 25/35.3/46.6 MVA TRF LTC - 261 Bank; 6 line capacitors (2 600kVAr fixed; 3 600kVAr switched; 1 1200kVAr switched)
Washington	126W42	12.24	Resi: 293 C&I: 214 Total: 507	377	380	362	112/14.4 kV 25/35.3/46.6 MVA TRF LTC - 261 Bank; 3 line capacitors (1 600kVAr fixed; 1 600kVAr switched; 1 1200kVAr switched)
Washington	126W50	32.72	Resi: 1401 C&I: 133 Total: 1534	490	448	448	112/14.4 kV 28/37/46 MVA TRF LTC - 262 Bank; 2 line capacitors (2 600kVAr switched)
Washington	126W51	32.30	Resi: 2207 C&I: 264 Total: 2471	471	443	403	112/14.4 kV 28/37/46 MVA TRF LTC - 262 Bank; 2 line capacitors (1 600kVAr fixed; 1 1200kVAr switched)
Washington	126W54	19.93	Resi: 659 C&I: 109 Total: 768	407	365	465	112/14.4 kV 28/37/46 MVA TRF LTC - 262 Bank; 4 line capacitors (1 600kVAr fixed; 1 900kVAr switched; 2 1200kVAr switched)

[1] Transformer Load Tap Changer.

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R-I-14, page 2

Please note that, at this time, more granular customer data is not readily accessible. All voltage control is performed by transformer load tap changers at the substation.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-25

Request:

Did this program consider similar pilot programs? If so, what were they?

Response:

Regarding VVO/CVR, National Grid considered additional technologies (e.g., smaller, secondary capacitors; strategically-placed secondary voltage regulators) in support of the VVO/CVR pilot and expansion proposals. Based on the experience to date, the Company decided that integrating interval AMI voltage data into the expansion of the existing VVO/CVR system was the incremental next step necessary to improve the benefit of the VVO/CVR system.

The Company is leveraging lessons learned, including technology selection and process improvements, from AMI pilot programs in Massachusetts and New York. In Rhode Island, the Company hopes to expand on what it has learned from its existing pilots and to enhance the benefit of VVO technology through the proposed small-scale deployment of 16,000 AMI meters. This deployment will offer additional insight into conceptual benefits that have not yet been tested in any jurisdiction, identify conditions that are unique to Rhode Island that can impact widespread deployment, and help the local workforce better understand the technology and implementation requirements. Areas of learning include:

- **Volt-VAR Optimization:** The primary focus of this deployment is to integrate interval voltage data from AMI meters into optimization algorithms to improve system efficiency.

- **New Meter and Communications Technology:** This deployment will use the latest generation meter technology that will include new features such as load disaggregation and locational awareness.

- **Installation and Integration:** National Grid will have the opportunity to work with the Rhode Island jurisdiction to deploy AMI technology on a small scale and incorporate lessons learned in any future deployment.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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R-I-32

Request:

Do you plan to deploy AMI on any feeders currently involved in any VVO/CVR? If not, why?

Response:

Not initially. The AMI/VVO pilot will provide valuable lessons learned regarding the integration of AMI and VVO/CVR that can be leveraged in the future. The Company is considering proposing, as part of the Power Sector Transformation for Rhode Island, a business case for laying out a path for a state-wide AMI deployment. If AMI is deployed state-wide, the Company will undertake the process of integrating the previously deployed VVO/CVR control schemes with the AMI data now available on those feeders.

Prepared by or under the supervision of: Jacquelyn Bean and James Patterson

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R-I-37

Request:

Describe the rationale used in selection of the VVO/CVR expansion components, including AMI meters, over other similar systems.

Response:

National Grid chose the components, meters, and systems that align with its long-term grid modernization strategy.

Recent efforts in Rhode Island have shown that a volt var optimization (VVO)/conservation voltage reduction (CVR) control scheme reduces demand and energy consumption in a cost-effective manner. The efficiency of the VVO/CVR system can be further enhanced if the primary voltage monitoring is augmented with actual secondary voltage performance data supplied by an interval AMI meter. This pilot is designed to test how secondary voltage from all AMI meters can be utilized, and it was not intended to test a system of targeted, or "bell weather" sensors

National Grid believes that the combined project, as proposed, maintains a positive benefit/cost ratio. For the AMI pilot, National Grid has made a conscious decision to limit the scale to only the integration of AMI with VVO/CVR technology because National Grid has gathered enough insights into the time-variable rate (TVR) benefits enabled by AMI in other jurisdictions. An additional qualitative benefit of deploying AMI initially at small-scale is learning valuable operational lessons (specific to Rhode Island) that the Company will leverage for any larger AMI deployment. This could include: training of the workforce, customer reaction to the new meter, and management of the interval data.

National Grid and its affiliates have worked with the VVO/CVR and metering vendors on various projects in the past, and have evaluated their products and services in previous competitive solicitations.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

Redlined Version
Amended Response to R-I-2

Request:

Confirm that the expected benefit of the VVO/CVR expansion (excluding AMI) is also 3.3%

Response:

National Grid assumes that the expected benefit of the VVO/CVR expansion (~~including~~ excluding AMI) is 3%.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

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Clean Version
Amended Response to R-I-2

Request:

Confirm that the expected benefit of the VVO/CVR expansion (excluding AMI) is also 3.3%

Response:

National Grid assumes that the expected benefit of the VVO/CVR expansion (excluding AMI) is 3%.

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

Redlined Version
Amended Response to R-I-6

Request:

Provide detailed cost data breakdown of all installation, and operating and maintenance costs incurred to date for the existing VVO/CVR pilot divided by category including, but not limited to, equipment cost, labor (engineering, design, installation, programming, and program management), operations and maintenance. Provide in native, executable format.

Response:

The VVO/CVR Pilot is categorized into three accounting projects: substation charges, distribution line work, and Information Services. The total spent to date on the Pilot (for the life of the pilot) is captured in the table below.

	Sum of CAPEX - Amount	Sum of OPEX - Amount	Sum of COR - Amount	Sum of Amount
Base Labor	$ 162,078 ~~$155,654~~	$ 23,301 ~~$23,301~~	$ 3,830 ~~$3,830~~	$ 189,208 ~~$182,785~~
Capitalized Interest	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 0 ~~$0~~
Consultants	$ 742,452 ~~$702,474~~	$137,796 ~~$137,796~~	$ 0 ~~$0~~	$ 880,249 ~~$840,270~~
Contractors	$ 174,342 ~~$174,342~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 174,342 ~~$174,342~~
Employee Expenses	$ 0 ~~$0~~	$ 157 ~~$157~~	$ 0 ~~$0~~	$ 157 ~~$157~~
Materials	$ 92 ~~$92~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 92 ~~$92~~
Other Employee Benefit	$ 68,337 ~~$65,757~~	$ 10,135 ~~$10,135~~	$ 1,725 ~~$1,725~~	$ 80,197 ~~$77,618~~
Other Expenses	$ 110,015 ~~$103,777~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 110,015 ~~$103,777~~
Pension and OPEB	$ 52,924 ~~$51,446~~	$ 5,755 ~~$5,755~~	$ 1,233 ~~$1,233~~	$ 59,912 ~~$58,434~~
Transportation	$ 16 ~~$16~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 16 ~~$16~~
Volt Var - IT/IS SubTotal	**$1,310,255 ~~$1,253,558~~**	**$177,144 ~~$177,144~~**	**$ 6,788 ~~$6,788~~**	**$1,494,188 ~~$1,437,490~~**

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
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In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
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Redlined Version
Amended Response to R-I-6, page 2

	Sum of CAPEX - Amount	Sum of OPEX - Amount	Sum of COR - Amount	Sum of Amount
Base Labor	$1,138,422 ~~$938,230~~	$270,436 ~~$247,393~~	$ 47,210 ~~$34,736~~	$1,456,068 ~~$1,220,359~~
Capitalized Interest	$ 81,022 ~~$81,195~~	$ 0 ~~$0~~	$ 758 ~~$0~~	$ 81,780 ~~$81,195~~
Consultants	$ 455,609 ~~$427,583~~	$ 1,413 ~~$1,413~~	$ 13,869 ~~$0~~	$ 470,891 ~~$428,996~~
Contractors	$ 587,095 ~~$540,283~~	$ 17,174 ~~$8,189~~	$ 4,761 ~~$2,571~~	$ 609,030 ~~$551,043~~
Employee Expenses	$ 14,861 ~~$9,430~~	$ 1,068 ~~$402~~	$ 0 ~~$0~~	$ 15,930 ~~$9,831~~
Materials	$ 630,134 ~~$556,963~~	$ 44,307 ~~$35,205~~	$ 3,328 ~~$3,306~~	$ 677,770 ~~$595,474~~
Other Employee Benefit	$ 449,026 ~~$369,427~~	$ 89,964 ~~$83,867~~	$ 18,249 ~~$12,850~~	$ 557,238 ~~$466,144~~
Other Expenses	$ 514,087 ~~$526,253~~	$ 76,204 ~~$5,790~~	$ 3,206	$ 593,497 ~~$532,042~~
Overtime	$ 110,444 ~~$74,818~~	$ 17,015 ~~$17,054~~	$ 11,886 ~~$9,636~~	$ 139,346 ~~$101,508~~
Pension and OPEB	$ 390,163 ~~$334,276~~	$ 85,146 ~~$78,644~~	$ 15,880 ~~$12,980~~	$ 491,189 ~~$425,899~~
Transportation	$ 108,390 ~~$79,957~~	$ 47,624 ~~$43,652~~	$ 15,343 ~~$9,592~~	$ 171,358 ~~$133,201~~
Volt Var Dline RI Pilot Project SubTotal	**$4,479,254** ~~**$3,938,414**~~	**$650,352** ~~**$521,609**~~	**$134,490** ~~**$85,670**~~	**$5,264,097** ~~**$4,545,692**~~
Base Labor	$ 67,792 ~~$66,599~~	$ 4,747 ~~$867~~	$ 0 ~~$0~~	$ 72,538 ~~$67,466~~
Capitalized Interest	$ 4,640 ~~$4,488~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 4,640 ~~$4,488~~
Consultants	$ 19,750 ~~$19,750~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 19,750 ~~$19,750~~
Contractors	$ 4,481 ~~$4,481~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 4,481 ~~$4,481~~

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
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Redlined Version
Amended Response to R-I-6, page 3

Employee Expenses	$ 0	$ 85 ~~$85~~	$ 0 ~~$0~~	$ 85 ~~$85~~
Materials	$ 47,064 ~~$47,064~~	$ (578)~~$0~~	$ 0 ~~$0~~	$ 46,486 ~~$47,064~~
Other Employee Benefit	$ 25,898 ~~$25,508~~	$ 1,957 ~~$328~~	$ 0 ~~$0~~	$ 27,855 ~~$25,835~~
Other Expenses	$ 26,997 ~~$26,838~~	$ 190 ~~$190~~	$ 0 ~~$0~~	$ 27,187 ~~$27,028~~
Overtime	$ 5,330 ~~$5,330~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 5,330 ~~$5,330~~
Pension and OPEB	$ 22,880 ~~$22,541~~	$ 1,024 ~~$130~~	$ 0 ~~$0~~	$ 23,904 ~~$22,672~~
Transportation	$ 6,966 ~~$6,811~~	$ 0 ~~$0~~	$ 0 ~~$0~~	$ 6,966 ~~$6,811~~
Volt Var-Substation SubTotal	**$ 231,797 ~~$229,409~~**	**$ 7,425 ~~$1,600~~**	**$ 0 ~~$0~~**	**$ 239,222 ~~$231,009~~**
Grand Total	**$6,021,306 ~~$5,421,380~~**	**$834,921 ~~$700,353~~**	**$141,279 ~~$92,458~~**	**$6,997,506 ~~$6,214,191~~**

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

Clean Version
Amended Response to R-I-6

Request:

Provide detailed cost data breakdown of all installation, and operating and maintenance costs incurred to date for the existing VVO/CVR pilot divided by category including, but not limited to, equipment cost, labor (engineering, design, installation, programming, and program management), operations and maintenance. Provide in native, executable format.

Response:

The VVO/CVR Pilot is categorized into three accounting projects: substation charges, distribution line work, and Information Services. The total spent to date on the Pilot (for the life of the pilot) is captured in the table below.

	Sum of CAPEX - Amount	**Sum of OPEX - Amount**	**Sum of COR - Amount**	**Sum of Amount**
Base Labor	$162,078	$23,301	$3,830	$189,208
Capitalized Interest	$0	$0	$0	$0
Consultants	$742,452	$137,796	$0	$880,249
Contractors	$174,342	$0	$0	$174,342
Employee Expenses	$0	$157	$0	$157
Materials	$92	$0	$0	$92
Other Employee Benefit	$68,337	$10,135	$1,725	$80,197
Other Expenses	$110,015	$0	$0	$110,015
Pension and OPEB	$52,924	$5,755	$1,233	$59,912
Transportation	$16	$0	$0	$16
Volt Var - IT/IS SubTotal	**$1,310,255**	**$177,144**	**$6,788**	**$1,494,188**

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's First Set of Data Requests
Issued October 19, 2017

Clean Version
Amended Response to R-I-6, page 2

	Sum of CAPEX - Amount	**Sum of OPEX - Amount**	**Sum of COR - Amount**	**Sum of Amount**
Base Labor	$1,138,422	$270,436	$47,210	$1,456,068
Capitalized Interest	$81,022	$0	$758	$81,780
Consultants	$455,609	$1,413	$13,869	$470,891
Contractors	$587,095	$17,174	$4,761	$609,030
Employee Expenses	$14,861	$1,068	$0	$15,930
Materials	$630,134	$44,307	$3,328	$677,770
Other Employee Benefit	$449,026	$89,964	$18,249	$557,238
Other Expenses	$514,087	$76,204	$3,206	$593,497
Overtime	$110,444	$17,015	$11,886	$139,346
Pension and OPEB	$390,163	$85,146	$15,880	$491,189
Transportation	$108,390	$47,624	$15,343	$171,358
Volt Var Dline RI Pilot Project SubTotal	**$4,479,254**	**$650,352**	**$134,490**	**$5,264,097**
Base Labor	$67,792	$4,747	$0	$72,538
Capitalized Interest	$4,640	$0	$0	$4,640
Consultants	$19,750	$0	$0	$19,750
Contractors	$4,481	$0	$0	$4,481

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's First Set of Data Requests
Issued October 19, 2017

Clean Version
Amended Response to R-I-6, page 3

Employee Expenses	$0	$85	$0	$85
Materials	$47,064	$ (578)	$0	$46,486
Other Employee Benefit	$25,898	$1,957	$0	$27,855
Other Expenses	$26,997	$190	$0	$27,187
Overtime	$5,330	$0	$0	$5,330
Pension and OPEB	$22,880	$1,024	$0	$23,904
Transportation	$6,966	$0	$0	$6,966
Volt Var-Substation SubTotal	**$231,797**	**$7,425**	**$0**	**$239,222**
Grand Total	**$6,021,306**	**$834,921**	**$141,279**	**$6,997,506**

Prepared by or under the supervision of: Jacquelyn Bean and James Perkinson

nationalgrid

Raquel J. Webster
Senior Counsel

November 15, 2017

BY HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2019 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

I have enclosed National Grid's[1] responses to Division's second set of data requests in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosure

cc: Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth
Al Contente

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Division 2-1

Request:

Referring to Section 4, Page 5, Chart 2, please explain why the Company believes that the AMI capital costs, AMI operating expenses, and VVO/VCR [sic] operating expenses are eligible for recovery through the ISR revenue requirement.

Response:

Pursuant to Section 39-1-27.7.1(c) and (d) of the Decoupling Act[1] and the Company's Electric Infrastructure, Safety, and Reliability (ISR) Provision RIPUC No. 2118, the Company files an annual Electric ISR Plan, which includes an annual spending plan by fiscal year for the anticipated capital investments and other spending relating to maintaining safety and reliability of the Company's electric distribution system. The Company's Electric ISR Plans have always included meters, voltage regulating equipment, and the field-based telecommunications to integrate these field devices for safe, reliable, and efficient grid operations.

The AMI pilot proposed in the Company's fiscal year 2019 Electric ISR Plan is limited in scope to: the installation of advanced meters and the supporting telecommunications; gathering the interval metering data; and integrating the voltage monitored by these meters at the grid edge with the volt var optimization (VVO)/conservation voltage reduction (CVR) application, which controls traditional grid devices such as capacitors and voltage regulators.

The proposed VVO/CVR project includes the installation of the distribution power monitors, telecommunications equipment, and controls technology to ensure that the voltage is maintained within required service quality levels and optimized for efficiency.

These two projects combined are intended to ensure that distribution system is operated reliably, within voltage standards and as efficiently as possible and, therefore, meet the purposes of the Decoupling Act with respect to the Electric ISR Plan.

[1] R.I. Gen. Laws § 39-1-27.7.1 (the Decoupling Act).

Division 2-2

Request:

What amount of AMI capital costs is included in the FY 2019 plant in service in Chart 8 in Section 2, Page 11?

Response:

The Company did not include AMI capital costs in Chart 8 for fiscal year (FY)_2019 plant-in-service. When the Company filed the proposed FY 2019 Electric ISR Plan with the Division, the timing of all aspects of the implementation of the AMI pilot program had not been finalized, so the Company could not forecast the appropriate plant-in-service for the FY 2019 Electric ISR Plan.

At this time, the Company forecasts that capital cost for the plant-in-service on Chart 8 would now include an incremental total of $7,367,000 in the System Capacity and Performance Category. This would represent an incremental total of $417,412 for the FY 2019 Electric ISR Revenue Requirement. This, in turn, would result in a monthly bill increase from $0.50 to $0.54, and from $105.27 to $105.81 for a typical residential electric customer utilizing 500 kWh per month.

Division 2-3

Request:

Referring to Section 5, Page 9, if the Company is currently estimating that in FY 2017, FY 2018 and FY 2019 there will be taxable income, why is there no reflection of utilization of previously accumulated NOLs in the calculation of the FY 2019 revenue requirement?

Response:

The Narragansett Electric Company (Narragansett) files its tax return as part of National Grid's consolidated federal income tax return. Narragansett's separate company taxable income is offset by taxable losses of other companies in the consolidated group. Narragansett's net operating loss (NOL) would not start to be utilized until the consolidated group was in a taxable income position on its federal income tax return. For ratemaking purposes, the generation or utilization of an NOL is based on cash. Narragansett will not be paid for any portion of its NOL until the entire consolidated group starts using NOL carry forwards. This is forecasted to be in year 2020.

Prepared by or under the supervision of: William R. Richer

Division 2-4

Request:

Referring to Section 5, Page 10, please provide a sample calculation of how the benefit of utilization of currently accumulated NOLs will be flowed through to customers in future tax years.

Response:

The benefit of the utilization of currently accumulated Net Operating Losses (NOLs) flowed through to customers is illustrated on Attachment Division 2-4 by the following consolidated tax group scenarios:

Consolidated Tax Group Year 1 – In this illustration on Page 1 of Attachment Division 2-4, the consolidated tax group is in a taxable income situation with illustrative Narragansett-generated taxable losses due to accelerated tax deductions related to bonus depreciation and capital repairs tax deductions, as shown on Line 2, fully offset by taxable income of other consolidated tax group participating companies (Line 4). As shown in that example, the calculated tax liability of the other consolidated tax group participating companies, Line 4, Column (b), is funded by those companies. Narragansett is reimbursed for 100% of its taxable losses (Line 7). Consequently, Narragansett does not record any NOL tax asset because its cash tax position was fully reconciled within the consolidated group (Line 8, Column (d)).

Consolidated Tax Group Year 2 – In this illustration, the consolidated group is in a taxable loss situation with the same illustrative Narragansett-generated taxable losses, as in the previous scenario; however, in this example, those losses are only partially offset by taxable income of other consolidated tax group participating companies. As shown in that example, the tax liability of the other tax group participating companies, shown on Line 16 is funded by those companies and paid to Narragansett for its generated tax losses. However, Narragansett is reimbursed for only a portion of its taxable losses and, therefore, a NOL tax asset is recorded by Narragansett and equal to the difference in Narragansett's total tax receivable, Line 15, Column (b) versus the amount of cash received by Narragansett from the other tax group participating companies, as shown on Line 19, Column (b).

Consolidated Tax Group Year 3 – The consolidated group is in a Taxable Loss situation but in this example, Narragansett is producing a taxable income that is fully offset by taxable losses generated by other tax group participating companies. In this scenario, Narragansett fully funds its tax liability, Line 27. By definition, if Narragansett generates taxable income, no NOL is generated. In this instance, the tax liability funded by Narragansett is used to partially fund the tax losses produced by other tax group participating companies, as shown on Line 28. Although not depicted in the example, because the other tax group participating companies were only

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Division 2-4, page 2

partially funded for their tax losses, an NOL tax asset would be recorded on the balance sheets of those companies. This scenario is the one that most aligns with the tax assumptions used for the fiscal year (FY) 2019 Electric Infrastructure, Safety, and Reliability (ISR) Plan in which Narragansett is projected to generate taxable income in FY 2019, but none of its previously generated NOLs were able to be utilized because the consolidated tax group is projected to produce a taxable loss for the year.

Consolidated Tax Group Year 4 – Alternative A

In Year 2 and Year 3, the consolidated tax group reported a Net Taxable Loss. In Year 4, the consolidated tax group is in a Taxable Income situation (Line 5) before Net Operating Loss Carryforward utilization (Line 6). After Net Operating Loss Carryforward utilization, the consolidated tax group reports zero taxable income. In this scenario, Narragansett is producing taxable income (Line 3) and calculating a Tax liability before Net Operating Loss Carryforward utilization (Line 8). In this scenario, the consolidated group is utilizing Net Operating Loss Carryforward to offset the current year taxable income, and Narragansett is reimbursed for Net Operating Loss Carryforward utilized (Line 9). The reduction of the NOL tax asset is reflected in Column (d).

Consolidated Tax Group Year 4 – Alternative B

In Year 2 and Year 3, the consolidated tax group reported a Net Taxable Loss. In Year 4, the consolidated tax group is in a Taxable Income situation (Line 18) before Net Operating Loss Carryforward utilization (Line 19). After Net Operating Loss Carryforward utilization, the consolidated tax group is in a net taxable income position (Line 20). In this scenario, Narragansett is in a taxable loss position (Line 16) and calculating a Tax benefit before Net Operating Loss Carryforward utilization (Line 22). In this scenario, the consolidated group is utilizing Net Operating Loss Carryforward to offset the current year taxable income, and Narragansett is reimbursed for Net Operating Loss Carryforward utilized (Line 23). The reduction of the NOL tax asset is reflected in Column (d).

Prepared by or under the supervision of: William R. Richer

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Illustrative Examples of Consolidated Tax Group Taxable Income Scenarios and associated Net Operating Loss Impacts

Consolidated Tax Group Year 1 - Consolidated Taxable Income
Narragansett Taxable Loss/Fully Offsetting Participating Company Tax Income
YEAR 1

		(a) Amount	(b) Income tax 35.00%	(c) Deferred Tax Provision Def Tax Liability (Reduces RB)	(d) Non-utilized NOL NOL Tax Asset (Increases RB)		(e)
1	Narragansett Electric Taxable Income Before Bonus Depreciation and Capital Repairs accelerated tax deduction	$20,000,000	$7,000,000				
2	Bonus Depreciation and Capital Repairs Tax Deductions	($30,000,000)	($10,500,000)	$10,500,000			
3	Total Narragansett Taxable Income/Calculated Tax liability (Receivable)	($10,000,000)	($3,500,000)				
4	Taxable Income/Tax Liability of other Consolidated Tax Participants	$25,000,000	$8,750,000				
5	Total Taxable Income/Tax Liability (Not Less Than Zero)	$15,000,000	$5,250,000				
6	Narragansett Calculated Tax Liability - Cash		$0				
7	Cash received from other Consolidated tax participants		$3,500,000				
8	Net Cash Received (Paid) by Narragansett		$3,500,000	+	$0	=	$3,500,000
9	Net Payment to the IRS		$5,250,000				
10	Narragansett Net Operating Loss Generated	($10,000,000)					
11	Narragansett Net Operating Loss Utilized by the Consolidated Group	($10,000,000)					
12	***Narragansett Net Operating Loss Available for Carryforward by the Consolidated Group***	$0					

Consolidated Tax Group Year 2 - Consolidated Taxable Loss
Narragansett Taxable Loss/Partially Offsetting Participating Company Tax Income
YEAR 2

		(a)	(b)	(c)	(d)		(e)
13	Narragansett Electric Taxable Income Before Bonus Depreciation and Capital Repairs accelerated tax deduction	$20,000,000	$7,000,000				
14	Bonus Depreciation and Capital Repairs Tax Deductions	($30,000,000)	($10,500,000)	$10,500,000			
15	Total Narragansett Taxable Income/Calculated Tax liability (Receivable)	($10,000,000)	($3,500,000)				
16	Taxable Income/Tax Liability of other Consolidated Tax Participants	$7,500,000	$2,625,000				
17	Total Taxable Income/Tax Liability (Not Less Than Zero)	($2,500,000)	$0				
18	Narragansett Calculated Tax Liability - Cash		$0				
19	Cash received from other Consolidated tax participants		$2,625,000				
20	Net Cash tax liability/NOL Tax Asset		$2,625,000	+	$875,000	=	$3,500,000
21	Net Payment to the IRS		$0				
22	Narragansett Net Operating Loss Generated	($10,000,000)					
23	Narragansett Net Operating Loss Utilized by the Consolidated Group	($7,500,000)					
24	***Narragansett Net Operating Loss Available for Carryforward by the Consolidated Group***	($2,500,000)	($875,000)				

Consolidated Tax Group Year 3 - Consolidated Taxable Loss
Narragansett Taxable Income/Participating Company Tax Loss
YEAR 3

		(a)	(b)	(c)	(d)		(e)
25	Narragansett Electric Taxable Income Before Bonus Depreciation and Capital Repairs accelerated tax deduction	$35,000,000	$12,250,000				
26	Bonus Depreciation and Capital Repairs Tax Deductions	($30,000,000)	($10,500,000)	$10,500,000			
27	Total Narragansett Taxable Income/Calculated Tax liability (Receivable)	$5,000,000	$1,750,000				
28	Taxable Income/Tax Liability of other Consolidated Tax Participants	($9,500,000)	($3,325,000)				
29	Total Taxable Income/Tax Liability (Not Less Than Zero)	($4,500,000)	$0				
30	Narragansett Calculated Tax Liability - Cash		($1,750,000)				
31	Cash received from other Consolidated tax participants		$0				
32	Net Cash tax liability/NOL Tax Asset		($1,750,000)	+	$0	=	($1,750,000)
33	Net Payment to the IRS		$0				
34	Narragansett Net Operating Loss Generated	$0					
35	Narragansett Net Operating Loss Utilized by the Consolidated Group	$0					
36	***Narragansett Net Operating Loss Available for Carryforward by the Consolidated Group***						
37	Other Consolidated Tax Participants Net Operating Loss Generated	($9,500,000)					
38	Other Consolidated Tax Participants Net Operating Loss Utilized by the Group	($5,000,000)					
39	***Other Consolidated tax participants Net Operating Loss Carryforward***	($4,500,000)					

The Narragansett Electric Company
d/b/a National Grid
Division 2-4
Electric Infrastructure, Safety, and Reliability Plan FY 2019
Attachment Division 2-4
Page 2 of 2

	Consolidated Tax Group Year 4 - Consolidated Taxable Income **Narragansett Taxable Income/Participating Company Taxable Income** **Net Operating Loss Carryforward Utilization** **YEAR 4 ALTERNATIVE A**	**(a)** **Amount**	**(b)** **Income tax** **35.00%**	**(c)** **Deferred Tax Provision** **Def Tax Liability (Reduces RB)**		**(d)** **Non-utilized NOL** **NOL Tax Asset (Increases RB)**		**(e)**
1	Narragansett Electric Taxable Income Before Bonus Depreciation and Capital Repairs accelerated tax deduction	$31,000,000	$10,850,000					
2	Bonus Depreciation and Capital Repairs Tax Deductions	($30,000,000)	($10,500,000)	$10,500,000				
3	Total Narragansett Taxable Income/Calculated Tax liability (Receivable)	$1,000,000	$350,000					
4	Taxable Income/Tax Liability of other Consolidated Tax Participants	$2,000,000	$700,000					
5	Taxable Income before Net Operating Loss Carryforward	$3,000,000	$1,050,000					
6	Consolidated Group Net Operating Loss Carryforward (see Note A)	($3,000,000)	($1,050,000)					
7	Taxable Income after Net Operating Loss Carryforward	$0	$0					
8	Narragansett Calculated Year 4 Tax Liability before NOL Carryforward		($350,000)					
9	Cash received from other Consolidated tax participants for NOL carryforward utilization		$875,000					
10	Net Cash tax liability/NOL Tax Asset		$525,000		+	($875,000)	=	($350,000)
11	Net Payment to the IRS		$0					
	NOTE A							
12	Narragansett Net Operating Loss Carryforward from Year 2	($2,500,000)						
13	Other Consolidated Tax Participants Net Operating Loss Carryforward from Year 3	($500,000)						
		($3,000,000)						

	Consolidated Tax Group Year 4 - Consolidated Taxable Income **Narragansett Tax Loss/Participating Company Taxable Income** **Net Operating Loss Carryforward Utilization** **YEAR 4 ALTERNATIVE B**	(a)	(b)	(c)		(d)		(e)
14	Narragansett Electric Taxable Income Before Bonus Depreciation and Capital Repairs accelerated tax deduction	$28,000,000	$9,800,000					
15	Bonus Depreciation and Capital Repairs Tax Deductions	($30,000,000)	($10,500,000)	$10,500,000				
16	Total Narragansett Taxable Income/Calculated Tax liability (Receivable)	($2,000,000)	($700,000)					
17	Taxable Income/Tax Liability of other Consolidated Tax Participants	$10,000,000	$3,500,000					
18	Taxable Income before Net Operating Loss Carryforward	$8,000,000	$2,800,000					
19	Consolidated Group Net Operating Loss Carryforward (Note B below)	($7,000,000)	($2,450,000)					
20	Taxable Income after Net Operating Loss Carryforward	$1,000,000	$350,000					
21	Narragansett Calculated Year 4 Tax Liability - Cash (before NOL Carryforward)		$0					
22	Cash received from other Consolidated tax participants for Year 4 Loss		$700,000					
23	Cash received from other Consolidated tax participants for Net Operating Loss Carryforward		$875,000					
24	Total Cash Received (Paid) by Narragansett		$1,575,000		+	($875,000)	=	$700,000
25	Net Payment to the IRS		$350,000					
	NOTE B							
26	Narragansett Net Operating Loss Carryforward from Year 2	($2,500,000)						
27	Other Consolidated Tax Participants Net Operating Loss Carryforward from Year 3	($4,500,000)						
28	Consolidated Net Operating Loss Carryforward	($7,000,000)						

nationalgrid

Raquel J. Webster
Senior Counsel

December 1, 2017

BY HAND DELIVERY AND ELECTRONIC MAIL

Rhode Island Division of Public Utilities and Carriers
c/o Luly Massaro
89 Jefferson Boulevard
Warwick, RI 02888

RE: National Grid's Proposed FY 2019 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 3

Dear Ms. Massaro:

I have enclosed National Grid's[1] responses to Division's third set of data requests in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosure

cc: Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth
Al Contente

1 The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2121 ■ raquel.webster@nationalgrid.com ■ www.nationalgrid.com

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's Third Set of Data Requests
Issued November 16, 2017

R-III-1

Request:

Regarding the FY2019 ISR Section 2, page 17:

a. Please provide all project closure papers prepared in FY2016 and FY2017.
b. Provide the Company's rationale for instituting an Investment level estimate grade accuracy of +200/-50%. Specifically, explain if a +200/-50% budget variance is an acceptable tolerance level for the Company's activities that are not related to the ISR.
c. The Company states that it strives "to have Project grade estimates for many, if not all, of the projects that require construction in the upcoming fiscal year." Applying the Company's four levels of estimate grade accuracy (footnote of page 17), provide the construction timeline for both East Providence and Warren Substations and describe when the Company anticipates reaching each estimate grade accuracy level leading to the ultimate Project level (+10/-10%).

Response:

a. Please see Attachment R-III-1for the closure papers from April 1, 2015 through March 31, 2017. This period covers fiscal years (FY) 2016 and 2017.

b. The Company's rationale for instituting an Investment level estimate grade accuracy of +200%/-50% is aligned with the guidelines and definitions established by the Associate for the Advancement of Cost Engineering (ACCE International). The Investment level is used as an order of magnitude amount for enabling project approval and initiating e the project's start and design.

   Whether a project is included in the ISR is not a key driver for the Company's determination of an acceptable tolerance level for a budget variance. Rather, through the Company's sanctioning process, the dollars approved are determined at the +/- 10% level. As the project is better defined or developed, the level of accuracy will be updated to reflect this new information.

c. The East Providence and Warren Substation projects were inadvertently reported at an Investment grade level estimate, and are at a Conceptual grade level estimate (+50%/-25%). The Company expects that a Planning Grade Estimate for these projects will be available in the third quarter of FY 2019. A project level estimate for the East Providence and Warren Substations will be available in FY 2020.

Prepared by or under the supervision of: Ryan Constable and Prabhjot Anand

Attachment R-III-1

Attachment R-III-1 is a very large electronic file and is being provided on CD-ROM

Prepared by or under the supervision of: Ryan Constable and Prabhjot Anand

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's Third Set of Data Requests
Issued November 16, 2017

R-III-2

Request:

Provide a detailed explanation of the Quonset Substation projected $1.1 million variance in FY2018, including components that contributed to a higher cost estimate for the project than planned (see p. 5 of FY2018 Q1 report). Was there a scope change?

Response:

The Quonset Substation line item in the fiscal year 2018 Quarter 1 report was based on a Planning Grade estimate. The Project Grade estimate reflected that an increase of approximately $1 million in additional labor was needed for the project in the following areas: civil, protection and telecommunication, electrical substation, and underground. There were no scope changes for the project contributing to this variance.

Prepared by or under the supervision of: Ryan Constable and Prabhjot Anand

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R-III-3

Request:

For the Volt/Var Expansion program, explain the process and criteria for determining target circuits. What circuits have been identified (noting study area, substation, and load)? How does the Company propose to coordinate efforts with major work being planned in those areas?

Response:

National Grid has ranked its distribution feeders based on an estimated cost per MWh savings considering:

- Physical characteristics of the feeder (devices, length, voltage class, construction type, etc.);
- Historic and forecasted loading and capacity;
- Inspection and maintenance information; and
- Existing substation automation levels,

The Company only considered feeders that were overhead 15kV class. Order of magnitude (OOM) costs are created using typical costs to upgrade the substation and distribution field devices. To develop and OOM cost, the substation and the field devices attached to the substation are each assigned a cost to upgrade. Substation peak loads and total energy consumption information are used to determine a relative savings value for each substation and its feeders. National Grid's Distribution Planning group then selects the next feeders to deploy VVO/CVR from the top candidates from the screening described above. For the fiscal year 2019 Electric ISR Plan, the Washington and Staples substations ranked #2 and #4, respectively, in terms of expected cost per MWh. The other highest ranked substations were not selected because of other Company upgrade activities. Once a substation is selected, all feeders attached to it are included in the program (with the exception of one ~0.5 mile feeder with minimal load out of the Washington substation).

The Company coordinates VVO/CVR work efforts with other major work, as described in the selection process above. In general, VVO/CVR work is planned after major system rearrangements.

R-III-4

Request:

Provide the most current system flood mitigation studies.

Response:

Please see Attachment R-III-4 for a copy of the Company's flood mitigation study update.

Prepared by or under the supervision of: Ryan Constable

National Grid Substation Flood Hardening Program - Rhode Island

1. Introduction

1.1 Purpose

Climate change and climate resiliency have become an important focus for National Grid. Among the greatest evolving threats to our infrastructure are natural hazards, and the costliest hazard in terms of loss of life and physical damage is flooding. Recent events, including the Rhode Island flooding in 2010 and Superstorm Sandy in 2012 brought flooding of substations to the forefront.

In 2010, the Warwick area was soaked by roughly 20 inches of rain over the course of just 38 days. The record rainfall resulted in extreme river flooding on the order of a 500-year (0.2% annual chance) event, causing the Pawtuxet River to crest at 11 feet (3.4 m) above flood stage. Significant damage was caused to area substations (ref. **Figure 1**). Two years later, Superstorm Sandy, a category 3 hurricane at its peak, made landfall in New Jersey as a post-tropical cyclone with hurricane-force winds. Sandy brought a storm surge with subsequent flooding to the northeastern seaboard with a ferocity never seen before. Rhode Island was spared the coastal devastation that was experienced between New Jersey and Connecticut, thanks mainly to the timing of low tide as the fast-moving surge passed Rhode Island. In response, National Grid, along with many other utilities, took a proactive approach to find ways to minimize the impacts related to flooding events.

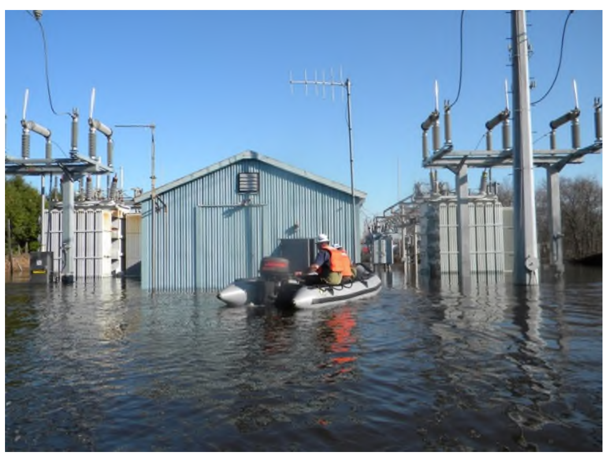

Figure 1 - 2010 Flooding of RI Substation (Sockanosset 24)

1.2 Problem

An inventory was made of all National Grid substations that were located within the Special Flood Hazard Area, or floodplain, as defined the 100-year (1% Annual Chance Event) Flood established by the latest Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRMs). The program identified 14 National Grid substations in Rhode Island.

A risk management register was then created that would identify and prioritize the risk of a flood impacting any particular station along with the anticipated severity of damage (See Prioritization section below). **Table 1** lists the 14 Rhode Island substations, ranked in order of highest priority.

Table 1
Rhode Island Substations Located within the 100-Year Floodplain

Substation	City
Warren 5	Warren
Sockanosset 24	Warwick
Westerly 16	Westerly
West Howard 154	Newport
Hunt River 40	Warwick
Pawtucket 1 107 Sub	Pawtucket
Pawtuxet 31	Warwick
Riverside 8	Woonsocket
Warwick Mall 28	Warwick
Gate II 38	Newport
Pontiac 27	Cranston
South Aquidneck 122	Middletown
Hope Valley 41	Hopkinton
Hope 15	Scituate

2. Background

Flood hardening, as generally defined by the Department of Energy (DOE), is a physical alteration (referred herein as civil alternatives) to the substation to reduce susceptibility of contact between floodwaters and vulnerable components (i.e., equipment, controls, energized conductors, switches, etc.) In simplest terms, hardening involves either physically raising the vulnerable components or controlling the floodwater with physical barrier and pump systems. Flood hardening is similar to, but distinct from, flood proofing as defined by the Federal Emergency Management Agency (FEMA), and flood resistance as defined by ASCE 24. Flood hardening is a key component of flood resiliency, which is defined herein, as interpreted from the definition by DOE, as eliminating or reducing the number and duration of customer service interruptions from flooding impacts. Other components to flood resiliency include preparedness and programmatic changes such as network re-routing / subnetworking, utilizing mobile substations, and expediting restoration (referred herein as non-civil alternatives).

It was determined early in the process that stakeholder input would be a significant component to the alternatives analysis. Program effectiveness and efficiency requires that both hardening and resiliency approaches be continually considered throughout the evaluation process. As new flood hardening products continually enter the market, the program needs to continually consider all practical and feasible alternatives, with attention paid to minimizing interruptions and effectively integrating with substation planning. Further, the program needs to effectively addresses the full spectrum of challenges and objectives from the big picture of managing risk and integrating with short- and long-term planning, down to the details of integration with other capital projects and minimizing interruption to daily facility operations and maintenance (O&M).

3. Objectives

3.1 Immediate, Short-Term, and Long-Term Objectives

The time scale component of flood hardening was found to be a key planning concept. Generally speaking, and as reasonably anticipated, a direct relationship was found to exist between the overall effectiveness - technically and operationally – of a flood hardening solution and the time to place that flood hardening solution into service, as well as the service life of that solution. In the interim, lesser technically and operationally effective flood hardening alternatives requiring less, or no, initial construction and with inherently shorter service lives, were pursued in order to satisfy both immediate and short-term flood hardening needs. In some cases, the interim (immediate or short-term) alternatives were found to be sufficient or even appropriate for substations of lesser criticality, and/or shorter remaining substation service lives.

3.2 Prioritization

Substation criticality was also considered when prioritizing the utility's substations located within the floodplain for flood hardening. FEMA's continual updating of FIRMs, especially for many coastal communities, means that during the course of the program additional substations may need to be added to the program. A substation prioritization ranking, comprised of flood risk and damage potential, was created to focus the flood hardening efforts toward resources in order of highest to lowest importance. Flood risk considered the anticipated frequency of surrounding flood waters rising to a height of impacting various low-lying substation features such as the yard level, control building floor, control panels, vulnerable components of pad-mounted equipment, etc. Damage potential considered such factors as asset value and service criticality. Several variables were considered including the substation's role in New England Independent System Operator's reliability analysis of the bulk grid, the number and primary voltages of transformers, the customer count, and the potential for customers to be served by re-routing alternatives, and the substation's remaining service life.

3.3 Implementation

The ultimate objective of the flood hardening program is to address long-term flood resilience. In most cases, the long-term hardening solution requires significant capital expense and several years to implement. For that reason, the short-term hardening solutions are the current focus of the Rhode Island substations. In some instances, the criticality of the substation is such that an immediate flood hardening response action has been developed that has no initial construction, rather consists of only a storm response action to protect critical substation items to the extent feasible.

The long-term, short-term, and in some cases the immediate hardening solution, requires multiple components to arrive at a technically feasible and cost-effective solution. Components include an alternatives analysis, planning, permitting, design, procurement, construction, training, operations and maintenance, followed by forecasting and storm response. For brevity, these components are not described herein; however, can be further explained under separate cover.

4. Program Status

Table 2 lists the 14 Rhode Island substations and their current status in the flood hardening program with respect to short-term flood hardening solutions. **Table 2** also provides approximate construction costs spent to date and concept-level future construction cost estimates to complete the short-term hardening solution. Partial long-term hardening solutions via raising of vulnerable equipment and controls have been implemented at Riverside 8 and Pontiac 27, and is proposed at Hope 15.

Table 2
Status of Short-Term Flood Hardening of Rhode Island Substations

Substation	Status of Short-Term Flood Hardening	Cost to Date [1, 2] ($,000)	FY18 [1] ($,000)	FY19 [1] ($,000)
Stations in Design – Flood Hardening to be Installed in FY19				
Warren 5	Barrier System Planned for Construction 2018. Interim Response Plan Established and Tested. Risk Level Reduced.	$60	$340	$205
Sockanosset 24	Barrier System in Design.	$31	$25	$410
Westerly 16	Barrier System in Design.	$7	$30	$410
Flood Hardening Installed				
West Howard 154	Barrier System Completed. Risk Level Reduced.	$138	$5	$0
Stations Reviewed – Determined no Flood Hardening Required				
Hunt River 40	Planned for Decommissioning, No Hardening Proposed	$2	$0	$0
Pawtucket 1 107 Sub	Planned for Re-build. No Hardening Proposed	$25	$0	$0
Pawtuxet 31	Planned for Decommissioning, No Hardening Proposed	$0	$0	$0
Riverside 8	Equipment Raised. Risk Level Reduced.	$4	$0[3]	$0
Warwick Mall 28	Planned for Re-build. No Hardening Proposed	$4	$0	$0
Gate II 38	Low risk of flooding. No Hardening Proposed.	$7	$0	$0
Pontiac 27	Equipment Raised. Risk Level Reduced.	$2	$0[3]	$0
South Aquidneck 122	Planned for Decommissioning, No Hardening Proposed	$3	$0	$0
Hope Valley 41	Planned for Decommissioning, No Hardening Proposed	$5	$0	$0
Hope 15	Equipment planned to be raised 2018. No Interim Hardening Proposed	$13	$0[3]	$0
Estimated Civil Construction Costs for Short-Term Flood Hardening		**$645**	**$400**	**$1,025**

1. Above construction costs exclude permitting, land acquisition, maintenance, and decommissioning costs associated with the hardening method.
2. Engineering costs to date include prior years and FY18. Costs are associated with obtaining field data, risk and alternatives analysis, planning, design, and construction support.
3. Re-build and/or raising equipment is incorporated into a substation upgrade. The construction cost specific to the flood hardening component is not included herein.
4. Sockanosset Station, will eventually be retired. Interim measures are being installed to facility protection of the facilities prior to retiring. The plan for the project and facility protection is currently in design.
5. Westerly Station, will eventually be rebuilt. Interim measures are being installed to facility protection of the facilities prior to rebuilding. The plan for the project and facility protection is currently in design.

Table 4
Status of Construction & Design

Substation	Barrier System	Design Complete	Construction Start	Construction Complete
Warren 5	Flood Stops	Sept-2016	April-2018	June-2018
Sockanosset 24	Flood Stops	Feb-2018	June-2018	Aug-2018
Westerly 16	Flood Stops	Mar-2018	Sept-2018	Dec-2018
West Howard 154	Flood Stops	Feb-2015	Mar-2016	April-2016

R-III-5

Request:

For Other Flood Work, provide a list of the targeted 12 substations. Include for each, the detailed scope, budget and timing of planned work.

Response:

Please see Tables 2 and 4 below, which are copied from the updated flood mitigation study in Attachment R-III-4. These two tables outline the list of the original 12 targeted substations in addition to two substations that were added upon further review. Included in the two tables are scopes of work, budgets, and timing of planned work for the substations moving forward.

Of the 14 substations included in these tables, only three have planned work for fiscal year 2019. The fourth substation, West Howard, has already been completed.

Table 2
Status of Short-Term Flood Hardening of Rhode Island Substations

Substation	Status of Short-Term Flood Hardening	Cost to Date [1,2] ($,000)	FY18 [1] ($,000)	FY19 [1] ($,000)
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Pontiac 27	Equipment Raised. Risk Level Reduced.	$2	$0[3]	$0
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Hope Valley 41	Planned for Decommissioning, No Hardening Proposed	$5	$0	$0
Hope 15	Equipment planned to be raised 2018. No Interim Hardening Proposed	$13	$0[3]	$0
Estimated Civil Construction Costs for Short-Term Flood Hardening		**$645**	**$400**	**$1,025**

Table 4
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Warren 5	Flood Stops	Sept-2016	April-2018	June-2018
Sockanosset 24	Flood Stops	Feb-2018	June-2018	Aug-2018
Westerly 16	Flood Stops	Mar-2018	Sept-2018	Dec-2018
West Howard 154	Flood Stops	Feb-2015	Mar-2016	April-2016

R-III-6

Request:

For the Recloser Replacement Program, provide the work orders and actual cost for any work performed in FY 2017. Provide a list of targeted reclosers and circuits, identifying the substation and study area.

Response:

Please see Attachment R-III-6, which describes the reclosers replaced in FY 2017, including work orders and actual cost. Attachment R-III-6 also shows the reclosers that are planned for the future, including substation and study area.

Prepared by or under the supervision of: Ryan Constable

Attachment R-III-6

District Description	City/Town	Completion Date	Work Order Number	Feeder	Substation	Study Area	Work Request Description	Charged Cost
Capital, RI	SMITHFIELD	10/31/2016	22919861	53-23F1	Farnum Pike 23	North Central RI	Removed recloser, P29 Esmond St., replaced with Load Break Switch	$ 3,328.05
Coastal, RI	TIVERTON	1/31/2017	21100070	56-33F2	Tiverton 33	Tiverton	Replaced existing recloser at pole 119 Main St with new recloser	$ 52,934.49
Capital, RI	SCITUATE	2/3/2017	22923589	53-34F1	Chopmist 34	North Central RI	Replaced existing recloser on P204-1 Danielson Pike with new recloser	$ 52,011.20
Capital, RI	SCITUATE	2/17/2017	22923543	53-34F1	Chopmist 34	North Central RI	Replaced existing recloser on P97 Chopmist Hill Rd with new recloser	$ 70,548.95
Capital, RI	PROVIDENCE	8/25/2017	22934197	53-79F2	Lippitt Hill 79	Providence	Replaced existing recloser on P13 Doyle Ave, Providence with new recloser	$ 71,891.44
Capital, RI	BARRINGTON	Planned Work	23220931	53-5F1	Warren 5	East Bay	Planned to replace existing recloser on P6 New Meadow Rd with new recloser	TBD
Capital, RI	PROVIDENCE	Planned Work	22934175	53-79F2	Lippitt Hill 79	Providence	Planned to replace existing recloser on P27 Camp St. Providence with a new recloser	TBD
Coastal, RI	COVENTRY	Planned Work	24162389	56-54F1	Coventry 54	Central RI West	Planned to replace existing recloser on P143 Harkney Hill Rd with new recloser	TBD
Capital, RI	CRANSTON	Planned Work	24532414	56-72F3	Lincoln Avenue 72	Central RI East	Planned to replace existing recloser with new recloser	TBD
Capital, RI	EAST PROVIDENCE	Planned Work	24962121	53-48F5	Wampanoag 48	East Bay	Planned to replace existing recloser on P39 with new recloser	TBD
Capital, RI	EAST PROVIDENCE	Planned Work	24962134	53-48F6	Wampanoag 48	East Bay	Planned to replace existing recloser on P21 Sutton with new recloser	TBD
Capital, RI	PROVIDENCE	Planned Work	23988996	53-13F3	Clarkson Street 13	Providence	Planned to replace existing recloser with new recloser	TBD
Capital, RI	BRISTOL	Planned Work	23220996	53-51F2	Bristol 51	East Bay	Planned to replace existing recloser on P32 Franklin St with new recloser	TBD
Coastal, RI	TIVERTON	Planned Work	23132551	56-33F3	Tiverton 33	Tiverton	Planned to replace existing recloser on P240 Nannaquaket Rd with new recloser	TBD
Capital, RI	EAST PROVIDENCE	Planned Work	25183873	53-78F3	Waterman Ave 78	East Bay	Planned to replace existing recloser on P27 Woodward with new recloser	TBD
Coastal, RI	NARRAGANSETT	Planned Work	25046367	56-17F2	Wakefield 17	South County East	Planned to replace existing recloser with new recloser	TBD
Coastal, RI	TIVERTON	Planned Work	25004724	56-33F2	Tiverton 33	Tiverton	Planned to replace existing recloser on P114 Main Rd with new recloser	TBD
Coastal, RI	WEST GREENWICH	Planned Work	25054558	56-63F2	Hopkins Hill 63	Central RI West	Planned to replace existing recloser on P219 New London Turnpike with new recloser	TBD

R-III-7

Request:

Please explain the significant SCP reserves included in years FY2021 through FY2023.

Response:

These system capacity performance reserves are placeholders for future work that originates from completed area studies, programmatic efforts such as the Energy Management System (EMS) expansion, and other reliability reasons. For budgetary and strategic planning purposes, the amount is generally determined by a rolling trend.

Prepared by or under the supervision of: Ryan Constable

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's Third Set of Data Requests
Issued November 16, 2017

R-III-8

Request:

Provide a Metalclad Switchgear Replacement Program update.

Response:

There is no Metalclad Switchgear Replacement Program updates because, as noted in the Company's Electric Infrastructure, Safety, and Reliability Plan FY 2019 Proposal Pre-filing Planning Information – August 11, 2017 (Recommendation 12 Page 64 of 66), there are no new metal-clad replacement projects in the five-year spending plan.

Prepared by or under the supervision of: Ryan Constable

R-III-9

Request:

Provide a detailed scope of metalclad replacement work being performed in FY2018. Does the FY2019/FY2020 proposed work include removal of all substation equipment, including metalclad switchgear, at Lee Street, Cottage Street and Front Street?

Response:

In fiscal year (FY) 2018, three metal clad stations were retired. These included Southeast, Daggett, and Hyde. All substation and distribution line work was completed, and all substation equipment has been removed from site, which includes the metal clad switchgears.

The proposed FY 2019 and FY 2020 Metal Clad Replacement work at Lee Street, Cottage Street, and Front Street includes the removal of all substation equipment, including metalclad switchgear. Additional information is provided below:

- Cottage Street – Please see the "Electric Infrastructure, Safety, and Reliability Plan FY 2019 Proposal Pre-filing Planning Information" (FY 2019 ISR Proposal) provided to the Division on August 11, 2017 at Page 33. The recommended plan to address the concerns at Cottage Street is to retire the substation. The substation load will be supplied from the existing area 13.8 kV distribution system through conversions and pole mounted step-down transformers. This project removes all substation equipment from Cottage Street, including equipment foundations and substation yard fence. The site will be converted into a green field.

- Lee Street – Please see the FY 2019 ISR Proposal at Page 35. The recommended plan to address the concerns at Lee Street is to retire the substation. The substation load will be supplied from the existing area 13.8 kV distribution system through conversions and pole mounted step-down transformers. This project removes all substation equipment from Lee Street including foundations and substation yard fence. The site will be converted into a greenfield.

- Front Street – The recommended plan to address the concerns at Front Street is to retire the substation. The substation load will be supplied from the existing area 13.8 kV distribution system.

Prepared by or under the supervision of: Ryan Constable

R-III-10

Request:

Provide a detailed scope of transformer replacement work being performed in FY2018. Provide an updated Transformer Loading Table for the system, and a transformer criticality ranking report.

Response:

Two stations had transformer replacement work performed in FY2018: Lafayette #30 and West Cranston #21.

Lafayette #30
Scope of Work:

- Replace existing 5 MVA T1 transformer, its foundation, and containment with a new 9.375 MVA unit, new foundation, and containment.
- Replace existing disconnect switches 301, 301, 1TR, and the fused disconnects ahead of T1 and T2.
- Add one new gang operated disconnect switch between the 34kV bus structures.
- Replace the wood pole 12.47kV structure, bus, and all disconnects for the 30F1 feeder with new standard aluminum box structure, new strain bus, and disconnects.
- Upgrade Remote Terminal Unit and regulator controllers.

Work done during FY2018: The project was progressed through design and materials were purchased. The first outage is planned for April 2018.

West Cranston #21
Scope of Work:

- Replace the existing No. 2 transformer with a 40 MVA LTC transformer.
  Two 15 kV circuit breakers will also be replaced.
- Make foundation and structural changes to the project.
- Upgrade the existing electro-mechanical transformer protection for both transformers to processor-based protection.
- Add new alarms points to the existing Remote Terminal Unit (RTU) via fiber-optic cable for remote status, control, and monitoring of the switching devices and transformers.

Work done during FY2018: The project was progressed through design, and a payment was made for a transformer. The Company anticipates that the transformer will be delivered in July 2018.

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R-III-10, page 2

A Transformer Loading Table is included as Attachment R-III-10 and matches the table provided in the FY 2019 Electric ISR Proposal. See Recommendation 10, Attachment Rec 10-1, Pages 10-14.

Currently, National Grid has no transformer criticality ranking report. The current transformer replacement work is determined through a watchlist based on routine maintenance by the Company’s Substation Operations and Maintenance Department and specific asset condition reviews included in area studies.

Prepared by or under the supervision of: Ryan Constable

Study Area	Substation	Transformer ID	System Voltage (kV)		Rating (MVA)		2017 MVA	2017 %SN	2018 MVA	2018 %SN	2019 MVA	2019 %SN
			From	To	SN	SE						
Blackstone Valley North	Highland Park #200	T1	115	13.8	73.00	82.00	6.7	9%	15.1	21%	15.0	21%
Blackstone Valley North	Highland Park #200	T2	115	13.8	70.00	79.00	5.3	8%	15.0	21%	14.9	21%
Blackstone Valley North	Farnum #105	T1	115	23	37.30	37.30	1.8	5%	1.7	5%	1.7	5%
Blackstone Valley North	Nasonville #127	T271	115	13.8	47.80	47.80	29.4	62%	29.5	62%	29.7	62%
Blackstone Valley North	Riverside #108	T81	115	13.8	41.83	45.23	26.6	64%	17.9	43%	17.8	43%
Blackstone Valley North	Riverside #108	T82	115	13.8	49.62	58.74	31.6	64%	23.8	48%	23.7	48%
Blackstone Valley North	Staples #112	T124	115	13.8	47.80	47.80	28.9	60%	26.6	56%	26.5	55%
Blackstone Valley North	Woonsocket	T1	115	13.8	47.80	50.00	26.5	55%	26.3	55%	26.2	55%
Blackstone Valley South	Valley #102	T23	115	24	42.01	51.51	5.5	13%	5.5	13%	5.5	13%
Blackstone Valley South	Pawtucket No.1 #107	T71	115	13.8	47.80	47.80	34.1	71%	35.3	74%	38.2	80%
Blackstone Valley South	Pawtucket No.1 #107	T73A	115	13.8	47.80	47.80	45.6	95%	45.3	95%	45.7	96%
Blackstone Valley South	Pawtucket No.1 #107	T74	115	13.8	47.80	47.80	35.6	74%	35.3	74%	35.2	74%
Blackstone Valley South	Valley #102	T21	115	13.8	38.36	45.95	17.8	46%	17.7	46%	14.0	37%
Blackstone Valley South	Valley #102	T22	115	13.8	31.60	40.29	20.0	63%	19.9	63%	19.8	63%
Blackstone Valley South	Washington #126	T261	115	13.8	47.80	47.80	25.6	54%	25.5	53%	25.4	53%
Blackstone Valley South	Washington #126	T262	115	13.8	59.27	59.27	35.3	60%	35.0	59%	34.9	59%
Blackstone Valley South	Central Falls #104	South Bank	13.8	4.16	3.12	3.12	1.8	57%	1.8	57%	1.8	57%
Blackstone Valley South	Central Falls #104	North Bank	13.8	4.16	3.00	3.00	1.2	39%	1.2	39%	1.2	39%
Blackstone Valley South	Pawtucket No.2 #148	T1	13.8	4.16	7.60	9.36	1.8	24%	1.8	24%	1.8	24%
Blackstone Valley South	Pawtucket No.2 #148	T2	13.8	4.16	7.60	9.36	2.4	32%	2.4	32%	2.4	32%
Central RI East	APPONAUG 3	3	23	12.47	15.50	19.60	7.8	50%	8.4	54%	8.4	54%
Central RI East	APPONAUG 3	4	23	12.47	11.90	12.60	6.6	55%	6.6	55%	6.6	55%
Central RI East	KILVERT STREET 87	1	115	12.47	72.00	82.00	23.6	33%	23.5	33%	23.5	33%
Central RI East	KILVERT STREET 87	2	115	12.47	70.00	78.00	18.5	26%	18.4	26%	18.4	26%
Central RI East	LINCOLN AVENUE 72	1	115	12.47	52.07	54.92	26.3	50%	26.2	50%	26.2	50%
Central RI East	LINCOLN AVENUE 72	2	115	12.47	52.07	54.92	29.3	56%	29.2	56%	29.2	56%
Central RI East	PONTIAC 27	1	115	12.47	50.67	53.32	22.3	44%	22.2	44%	22.3	44%
Central RI East	PONTIAC 27	2	115	12.47	46.49	51.88	23.7	51%	23.6	51%	23.6	51%
Central RI East	WARWICK 52	1	23	12.47	11.60	12.70	8.3	71%	8.2	71%	8.2	71%
Central RI East	WARWICK 52	4	23	12.47	12.00	12.00	9.8	82%	9.8	82%	9.8	82%
Central RI East	AUBURN 73	1	23	4.16	10.56	11.81	5.2	50%	5.2	50%	5.1	49%
Central RI East	AUBURN 73	2	23	4.16	9.66	10.64	3.5	37%	3.5	37%	2.3	23%
Central RI East	LAKEWOOD 57	1	23	4.16	10.09	10.63	4.8	48%	4.8	47%	4.8	47%
Central RI East	LAKEWOOD 57	2	23	4.16	10.15	11.46	2.8	28%	2.8	28%	2.8	28%
Central RI East	DRUMROCK 14	3	115	23/12.47	53.00	76.04	27.4	52%	27.3	51%	27.3	52%
Central RI East	DRUMROCK 14	4	115	23	89.00	107.40	37.1	42%	37.0	42%	37.0	42%
Central RI East	DRUMROCK 14	5	115	23/12.47	107.00	107.00	50.3	47%	50.2	47%	50.2	47%
Central RI East	SOCKANOSSET 24	1	115	23	50.29	56.81	19.3	38%	19.3	38%	19.3	38%
Central RI East	SOCKANOSSET 24	2	115	23	50.37	57.03	23.0	46%	22.9	45%	22.9	45%
Central RI West	ANTHONY	1	23	12.47	7.80	8.10	6.0	77%	6.0	77%	6.0	77%

Central RI West	ANTHONY	2	23	12.47	7.80	8.10	7.7	98%	7.7	98%	4.2	54%
Central RI West	COVENTRY	1	23	12.47	11.40	13.50	10.2	89%	10.2	89%	10.2	89%
Central RI West	DIVISION ST	1	34.5	12.47	23.70	27.60	14.8	62%	14.7	62%	14.7	62%
Central RI West	DIVISION ST	2	34.5	12.47	23.70	27.60	14.9	63%	14.9	63%	12.0	51%
Central RI West	HOPE	1	23	12.47	7.53	8.51	7.5	99%	7.4	99%	4.7	63%
Central RI West	HOPE	2	23	12.47	13.65	16.46	10.1	74%	10.0	74%	8.4	62%
Central RI West	HOPKINS HILL	1	34.5	12.47	48.80	51.00	22.4	46%	22.3	46%	20.7	42%
Central RI West	HOPKINS HILL	2	34.5	12.47	49.20	52.00	23.9	49%	23.8	48%	22.9	47%
Central RI West	KENT COUNTY	1	115	34.5	57.25	67.64	31.0	54%	30.9	54%	30.9	54%
Central RI West	KENT COUNTY	2	115	34.5	66.33	69.90	35.0	53%	34.9	53%	35.0	53%
Central RI West	KENT COUNTY	6	115	12.47	50.69	58.89	17.1	34%	17.0	34%	14.3	28%
Central RI West	KENT COUNTY	7	115	34.5	57.25	68.78	34.3	60%	34.2	60%	34.2	60%
Central RI West	KENT COUNTY	5	115	12.47	50.00	58.00	25.3	51%	25.2	50%	25.3	51%
Central RI West	NATICK	1	23	12.47	13.20	14.30	8.4	64%	8.4	63%	6.5	50%
Central RI West	NATICK	2	23	12.47	13.50	14.50	5.9	44%	5.9	44%	5.9	44%
Central RI West	WARWICK MALL	1	23	12.47	8.80	8.90	3.1	35%	3.1	35%	3.1	35%
Central RI West	WARWICK MALL	2	23	12.47	8.70	9.10	2.0	23%	2.0	23%	2.0	23%
Central RI West	ARCTIC	1	23	4.16	5.00	5.00	3.5	70%	3.5	69%	0.0	0%
Central RI West	ARCTIC	2	23	4.16	6.70	7.40	3.8	56%	3.7	56%	0.0	0%
Central RI West	TIOGUE AVE	1	34.5	12.47	13.00	14.00	10.6	82%	10.6	81%	10.6	81%
Central RI West	NEW LONDON AVE	1	115	12.47	55.00	60.00	0.0	0%	0.0	0%	30.7	56%
East Bay	BARRINGTON 4	1	23	12.47	35.19	35.19	20.4	58%	20.3	58%	20.2	57%
East Bay	BRISTOL 51	1	115	12.47	56.90	63.40	19.4	34%	19.3	34%	19.2	34%
East Bay	BRISTOL 51	2	23	12.47	25.10	29.80	11.1	44%	11.0	44%	11.0	44%
East Bay	PHILLIPSDALE 20	T1	115	23	56.00	56.00	19.3	35%	19.2	34%	19.1	34%
East Bay	PHILLIPSDALE 20	T2	115	23	45.32	56.75	9.8	22%	9.7	21%	9.7	21%
East Bay	PHILLIPSDALE 20	T3	23	12.47	25.16	28.87	14.3	57%	14.2	56%	14.1	56%
East Bay	WAMPANOAG 48	T1	115	12.47	42.83	52.72	31.4	73%	31.2	73%	31.1	73%
East Bay	WAMPANOAG 48	T2	115	12.47	52.36	55.33	30.8	59%	30.6	58%	30.5	58%
East Bay	WARREN 5	T1	115	12.47	48.28	53.43	17.4	36%	17.3	36%	17.2	36%
East Bay	WARREN 5	T2	115	12.47	50.62	59.57	18.1	36%	18.0	36%	17.9	35%
East Bay	WARREN 5	5	115	23	60.96	65.05	11.2	18%	11.1	18%	11.1	18%
East Bay	WARREN 5	6	115	23	59.60	64.17	26.1	44%	25.9	44%	25.8	43%
East Bay	WATERMAN AVENUE 78	T1	23	12.47	16.36	18.26	6.3	38%	6.2	38%	6.2	38%
East Bay	WATERMAN AVENUE 78	T2	23	12.47	16.36	18.26	5.8	36%	5.8	35%	5.7	35%
East Bay	KENT CORNERS 47	T1	23	4.16	7.14	7.53	2.6	37%	2.6	37%	2.6	36%
East Bay	KENT CORNERS 47	T2	23	4.16	6.82	8.07	4.5	66%	4.5	66%	4.5	66%
Newport	Bailey Brook	191	23	4.16	8.32	8.68	1.7	21%	1.7	21%	0.0	0%
Newport	Bailey Brook	192	23	4.16	8.57	10.43	1.8	21%	1.8	21%	0.0	0%
Newport	Clarke St	651	23	4.16	4.06	4.34	3.0	73%	2.9	72%	2.9	72%
Newport	Clarke St	652	23	4.16	6.00	7.00	2.6	44%	2.6	44%	2.6	43%
Newport	Dexter	361	115	69	121.00	130.00	64.6	53%	63.9	53%	0.0	0%
Newport	Dexter	362	115	69	61.00	65.00	27.7	45%	27.4	45%	0.0	0%

Newport	Dexter	363	115	69	61.00	65.00	27.7	45%	27.4	45%	0.0	0%
Newport	Dexter	364	115	13.8	44.64	47.44	24.6	55%	24.3	54%	24.2	54%
Newport	Eldred	T1	23	4.16	6.54	7.40	4.0	61%	3.9	60%	3.9	60%
Newport	Gate 2	381	69	23	54.24	63.70	21.1	39%	20.8	38%	15.4	28%
Newport	Gate 2	T2	69	13.8	11.00	12.00	5.8	52%	5.7	52%	5.7	52%
Newport	Gate 2	731	23	4.16	8.11	8.70	3.0	37%	3.0	37%	0.0	0%
Newport	Harrison	321	23	4.16	8.33	9.73	3.6	44%	3.6	43%	3.6	43%
Newport	Harrison	322	23	4.16	8.07	10.12	5.2	65%	5.2	64%	5.2	64%
Newport	Hospital	461	23	4.16	4.06	4.34	2.0	50%	2.0	50%	2.0	50%
Newport	Hospital	462	23	4.16	4.06	4.34	2.4	58%	2.3	58%	2.3	57%
Newport	Jepson	371	69	23	16.52	18.47	2.0	12%	2.0	12%	0.0	0%
Newport	Jepson	372	69	23	23.20	24.80	9.9	42%	9.8	42%	0.0	0%
Newport	Jepson	373	69	23	48.88	57.87	29.9	61%	29.6	61%	0.0	0%
Newport	Jepson	374	69	13.8	42.86	48.58	28.1	65%	27.8	65%	16.5	39%
Newport	Jepson	341	23	4.16	9.74	10.42	2.1	22%	2.1	21%	0.0	0%
Newport	Jepson	376	69	23	15.44	16.35	6.0	39%	6.0	39%	0.0	0%
Newport	Kingston	311	23	4.16	7.90	9.56	5.6	71%	5.5	70%	4.6	58%
Newport	Kingston	312	23	4.16	7.90	9.56	4.3	55%	4.3	54%	4.3	54%
Newport	Merton	511	23	4.16	2.24	2.40	1.5	65%	1.4	64%	0.4	17%
Newport	Merton	512	23	4.16	8.38	10.00	4.4	52%	4.3	52%	3.2	39%
Newport	No. Aquidneck	211	23	4.16	7.98	10.20	4.7	59%	4.7	59%	0.0	0%
Newport	So. Aquidneck	221	23	4.16	7.90	9.56	4.8	61%	4.8	60%	0.0	0%
Newport	Vernon Ave	231	23	4.16	3.63	3.88	3.2	87%	3.1	86%	0.0	0%
Newport	Vernon Ave	232	23	4.16	3.63	3.88	1.1	32%	1.1	31%	0.0	0%
Newport	West Howard	541	23	4.16	12.57	14.76	6.8	54%	6.8	54%	5.7	45%
Newport	West Howard	542	23	4.16	13.09	13.58	4.5	35%	4.5	34%	4.5	34%
Newport	Newport Sub	T1	69	13.8	0.00	0.00	0.0	0%	0.0	0%	19.8	36%
Newport	Jepson	T2	69	13.8	0.00	0.00	0.0	0%	0.0	0%	18.3	33%
Newport	Eldred	T2	23	4.16	6.49	7.35	2.0	31%	2.0	30%	2.0	30%
North Central RI	Johnston #18	T1	115	23	63.40	77.00	30.9	49%	30.7	48%	30.5	48%
North Central RI	Johnston #18	T2	115	23	80.00	90.00	27.5	34%	27.3	34%	27.2	34%
North Central RI	Wolf Hill #19	T1	115	23	65.01	69.83	29.3	45%	29.1	45%	29.0	45%
North Central RI	Centerdale #50	T3	23	12.47	7.93	8.34	7.1	89%	7.0	89%	7.0	88%
North Central RI	Chopmist #34	T1	23	12.47	15.96	16.42	11.0	69%	10.9	69%	10.9	68%
North Central RI	Chopmist #34	T2	23	12.47	13.84	13.57	7.9	57%	7.8	56%	7.8	56%
North Central RI	Chopmist #34	T3	23	12.47	12.81	13.94	4.7	36%	4.6	36%	4.6	36%
North Central RI	Farnum Pike #23 (New)	T1	115	12.47	77.00	86.00	20.2	26%	20.0	26%	19.9	26%
North Central RI	Farnum Pike #23 (New)	T2	115	12.47	77.00	86.00	23.6	31%	23.4	30%	23.3	30%
North Central RI	Johnston #18	T1	115	12.47	25.00	35.00	0.0	0%	0.0	0%	0.0	0%
North Central RI	Johnston #18	T3	115	12.47	80.00	94.00	43.5	54%	43.2	54%	43.0	54%
North Central RI	Johnston #18	T4	115	12.47	68.60	74.00	32.6	47%	31.6	46%	31.5	46%
North Central RI	Manton #69	T2	23	12.47	25.46	26.66	21.5	85%	21.4	84%	21.3	84%
North Central RI	Putnam Pike #38	T1	115	12.47	64.94	68.79	29.1	45%	22.7	35%	22.6	35%

North Central RI	Putnam Pike #38	T2	115	12.47	64.94	68.79	17.8	27%	18.9	29%	18.8	29%
North Central RI	West Cranston #21	T1	115	12.47	27.78	29.91	10.8	39%	10.7	39%	10.7	38%
North Central RI	West Cranston #21	T2	115	12.47	27.76	29.86	18.8	68%	18.6	67%	18.6	67%
North Central RI	West Greenville # 45	T3	23	12.47	11.91	13.56	2.2	18%	7.9	66%	7.9	66%
North Central RI	Centerdale #50	T1	23	4.16	7.10	7.54	2.7	37%	2.6	37%	2.6	37%
North Central RI	Shun Pike #128	T1	115	13.2	26.00	30.00	14.7	57%	14.6	56%	14.6	56%
Providence	Admiral Street #9	T1	23	11/4.16	15.00	15.00	10.7	72%	10.7	71%	10.7	71%
Providence	Admiral Street #9	T2	23	11/4.16	15.00	15.00	0.0	0%	0.0	0%	0.0	0%
Providence	Franklin Square #11	3320	11.5	34.5	25.87	29.66	5.7	22%	5.7	22%	5.6	22%
Providence	Franklin Square #11	3324	11.5	34.5	25.75	29.50	5.7	22%	5.7	22%	5.6	22%
Providence	Admiral Street #9	T3	115	23	62.10	63.70	26.9	43%	26.8	43%	26.7	43%
Providence	Admiral Street #9	T4	115	23	63.00	64.90	26.3	42%	26.1	41%	26.1	41%
Providence	Franklin Square #11	2207	11.5	23	16.06	18.75	1.5	10%	1.5	10%	1.5	9%
Providence	Franklin Square #11	2210	11.5	23	17.14	15.85	6.7	39%	6.6	39%	6.6	39%
Providence	Franklin Square #11	2220	11.5	23	17.70	19.30	8.8	50%	8.7	49%	8.7	49%
Providence	South Street #1	2201	11.5	23	7.50	7.50	3.2	42%	3.1	42%	3.1	42%
Providence	South Street #1	2216	11.5	23	10.00	10.00	3.4	34%	3.4	34%	3.4	34%
Providence	South Street #1	2248	11.5	23	12.81	14.33	7.9	62%	7.9	61%	7.8	61%
Providence	South Street #1	24	11.5	23	9.10	10.23	4.5	49%	4.5	49%	4.5	49%
Providence	Clarkson Street #13	T1	115	12.47	65.46	81.01	42.6	65%	42.6	65%	42.5	65%
Providence	Clarkson Street #13	T2	115	12.47	65.16	80.24	35.3	54%	35.1	54%	35.0	54%
Providence	Elmwood #7 (12.47 kV)	T2	23	12.47	40.58	45.78	24.7	61%	24.5	60%	24.5	60%
Providence	Lippitt Hill #79	T1	22.9	12.47	25.11	27.54	9.0	36%	8.9	35%	8.9	35%
Providence	Lippitt Hill #79	T2	22.9	12.47	25.11	27.54	9.1	36%	9.1	36%	9.1	36%
Providence	Point Street #76	T1	115	12.47	77.00	89.80	34.7	45%	34.5	45%	34.4	45%
Providence	Point Street #76	T2	115	12.47	76.70	86.50	39.1	51%	38.9	51%	38.8	51%
Providence	Franklin Square #11	T1	115	11.5	50.65	61.04	24.0	47%	23.8	47%	23.8	47%
Providence	Franklin Square #11	T2	115	11.5	51.24	56.69	25.3	49%	25.2	49%	25.1	49%
Providence	Franklin Square #11	T3	115	11.5	51.24	56.69	28.3	55%	28.2	55%	28.1	55%
Providence	South Street #1	T1	115	11.5	66.34	78.75	26.0	39%	25.9	39%	25.9	39%
Providence	South Street #1	T2	115	11.5	66.78	77.14	26.8	40%	26.6	40%	26.6	40%
Providence	South Street #1	T3	115	11.5	72.69	91.22	23.1	32%	23.0	32%	23.0	32%
Providence	Admiral Street #9	T5	23	4.16	15.13	15.36	6.0	40%	6.0	40%	6.0	40%
Providence	Dyer St #2	T1	11.5	4.16	18.27	19.78	5.9	32%	5.9	32%	5.9	32%
Providence	Dyer St #2	T2	11.5	4.16	18.25	19.74	5.9	32%	5.9	32%	5.9	32%
Providence	East George St. #77	T1	23	4.16	12.59	15.27	4.3	34%	4.3	34%	4.3	34%
Providence	East George St. #77	T2	23	4.16	12.59	15.27	4.5	36%	4.5	36%	4.5	35%
Providence	Geneva #71	T1	23	4.16	11.54	14.19	4.1	36%	4.1	36%	4.1	36%
Providence	Geneva #71	T2	23	4.16	7.00	8.00	4.1	59%	4.1	59%	4.1	59%
Providence	Harris Avenue #12	T1	23	4.16	11.48	12.72	4.8	42%	4.8	42%	4.8	41%
Providence	Harris Avenue #12	T2	23	4.16	9.06	11.52	1.5	17%	1.5	17%	1.5	17%
Providence	Huntington Park #67	T1	23	4.16	3.00	3.00	1.8	61%	1.8	61%	1.8	61%
Providence	Knightsville #66	T1	22.9	4.16	10.48	11.02	5.4	51%	5.4	51%	4.7	45%

Providence	Knightsville #66	T2	22.9	4.16	10.48	11.02	5.4	51%	5.4	51%	4.7	45%
Providence	Olneyville #6	T1	11.5	4.16	11.80	13.02	3.7	31%	3.7	31%	3.6	31%
Providence	Olneyville #6	T3	11.5	4.16	11.80	13.02	3.7	31%	3.7	31%	3.6	31%
Providence	Rochambeau Ave #37	T1	22.9	4.16	11.96	13.12	3.6	30%	3.5	30%	3.5	30%
Providence	Rochambeau Ave #37	T2	11.45	4.16	11.02	13.04	5.7	52%	5.7	51%	5.7	51%
Providence	Sprague St. #36	T1	23	4.16	10.58	11.85	2.8	26%	2.8	26%	2.8	26%
Providence	Sprague St. #36	T2	23	4.16	10.79	12.00	3.5	33%	3.5	33%	3.5	33%
South County East	BONNET 42	2	34.5	12.47	11.30	12.20	11.2	99%	11.1	98%	11.1	99%
South County East	DAVISVILLE 84	1	115	34.5	45.30	52.10	19.4	43%	14.8	33%	18.7	41%
South County East	DAVISVILLE 84	2A	115	34.5	45.10	51.80	24.5	54%	21.1	47%	21.0	47%
South County East	LAFAYETTE 30	1	34.5	12.47	7.60	8.60	5.7	74%	5.6	74%	5.6	74%
South County East	LAFAYETTE 30	2	34.5	12.47	12.30	13.20	9.9	81%	9.9	80%	9.9	80%
South County East	OLD BAPTIST ROAD 46	1	115	12.47	48.70	54.40	17.0	35%	16.9	35%	16.9	35%
South County East	OLD BAPTIST ROAD 46	2	115	12.47	48.90	51.90	19.5	40%	18.4	38%	18.4	38%
South County East	PEACEDALE 59	1	34.5	12.47	24.20	27.20	13.9	58%	13.9	57%	13.9	57%
South County East	PEACEDALE 59	2	34.5	12.47	24.20	27.20	11.2	46%	11.2	46%	11.2	46%
South County East	QUONSET 83	1	34.5	12.47	25.60	26.70	17.3	67%	9.6	37%	10.8	42%
South County East	WAKEFIELD 17	3	34.5	12.47	12.90	13.50	10.2	79%	10.2	79%	10.2	79%
South County East	WAKEFIELD 17	4	34.5	12.47	12.90	13.50	11.0	85%	11.0	85%	11.0	85%
South County East	WAKEFIELD 17	5	34.5	12.47	12.90	13.50	10.6	82%	10.5	82%	10.5	82%
South County East	WEST KINGSTON 62	1	115	34.5	43.90	55.70	28.5	65%	28.4	65%	28.4	65%
South County East	WEST KINGSTON 62	2	115	34.5	75.80	93.50	45.7	60%	45.6	60%	45.6	60%
South County East	TOWER HILL 88	1	115	12.47	51.00	60.00	35.5	70%	35.4	69%	35.5	70%
South County East	QUONSET 83	2	34.5	12.47	50.00	50.00	0.0	0%	8.7	17%	8.7	17%
South County East	BIPCO	1	34.5	2.4	10.00	11.50	4.8	48%	4.8	48%	4.8	48%
South County West	ASHAWAY 43	1	34.5	12.47	8.39	9.13	6.5	77%	0.0	0%	0.0	0%
South County West	HOPE VALLEY 41	1	34.5	12.47	7.25	9.29	7.1	98%	0.0	0%	0.0	0%
South County West	KENYON 68	1	115	12.47	49.68	53.71	18.5	37%	17.0	34%	17.0	34%
South County West	KENYON 68	2	115	12.47	49.69	53.74	16.5	33%	16.4	33%	16.4	33%
South County West	LANGWORTHY 86	1	34.5	12.47	13.00	14.00	12.5	96%	11.5	88%	11.5	88%
South County West	WESTERLY 16	2	34.5	12.47	25.60	26.65	20.2	79%	18.1	71%	18.1	71%
South County West	WESTERLY 16	4	34.5	12.47	25.60	26.65	16.6	65%	14.3	56%	14.3	56%
South County West	WOOD RIVER 85	10	115	34.5	48.18	52.44	49.7	103%	36.8	76%	36.8	76%
South County West	WOOD RIVER 85	20	115	34.5	91.24	106.56	26.7	29%	18.1	20%	18.1	20%
South County West	CHASE HILL	2	115	12.47	54.30	63.50	1.6	3%	26.1	48%	26.1	48%
TIVERTON	TIVERTON	1	115	12.47	33.39	33.39	17.5	52%	17.4	52%	17.3	52%
TIVERTON	TIVERTON	2	115	12.47	49.35	53.71	18.4	37%	18.3	37%	18.3	37%

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's Third Set of Data Requests
Issued November 16, 2017

R-III-11

Request:

Provide an explanation for the $1.4 million dollar projected overspend in the Asset Condition Blanket Projects category for FY2018.

Response:

The forecasted overspend in the Asset Condition Blanket Projects category is based on the actual year-to-date run rate in the fiscal year.

Prepared by or under the supervision of: Prabhjot Anand

R-III-12

Request:

Please explain the significant AR reserves included in years FY2021 through FY2023.

Response:

The asset replacement reserves for fiscal year (FY) 2021 through FY 2023 are placeholders for future work that originates from completed area studies and programmatic efforts such as the Underground Cable and Underground Residential Development Cable replacement programs. The amount is generally determined by a rolling trend for budgetary and strategic planning purposes.

Prepared by or under the supervision of: Ryan Constable

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's Third Set of Data Requests
Issued November 16, 2017

R-III-13

Request:

Referencing the Company's Providence Area Study Implementation Plan 2016-2030: Confirm if the cost estimates in Section 9.14 include Capex, Opex, and removals. If not, please provide updated cost estimates for each proposed project to include all three cost components.

Response:

Please see Attachment R-III-13, which shows the Providence Area Study Implementation Plan 2016-2030 cost estimates including capital expense, operational expense, and cost of removal.

Prepared by or under the supervision of: Ryan Constable

Distribution and Substation Spending Plan ($000) - Capex, Opex and Removal

Project	Spending Type	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Clarkson Street 13F10-Hawkins Street	CapEx	$ 140	$ 210	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 20	$ 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 44	$ 66	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Olneyville-transfer customer from 6J5 to 6J6	CapEx	$ 150	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral St - convert 4.16 kV to 12.47 kV	CapEx	$ 916	$ 1,832	$ 1,832	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 92	$ 184	$ 184	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 278	$ 556	$ 556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral St - convert 11 kV to 12.47 kV (Phase 1)	CapEx	$ 294	$ 588	$ 588	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 10	$ 20	$ 20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 62	$ 124	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral St - convert 11 kV to 12.47 kV (Phase 2)	CapEx	$ 86	$ 172	$ 172	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 6	$ 12	$ 12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clarkson Street (assoc. with Admiral Street)	CapEx	$ 276	$ 552	$ 552	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 9	$ 18	$ 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 33	$ 66	$ 66	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lippitt Hill (assoc. with Admiral Street)	CapEx	$ 30	$ 60	$ 60	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 1	$ 2	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 2	$ 4	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral Street-Install breaker in 23kV bay	CapEx	$ 125	$ 250	$ 750	$ 125	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 1	$ 1	$ 3	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 10	$ 20	$ 60	$ 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral Street-Install 23/11 kV transformer	CapEx	$ 125	$ 250	$ 750	$ 125	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ 1	$ 1	$ 3	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ 2	$ 4	$ 12	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oneyville - Convert 4.16 kV to 12.47 kV (Phase 1)	CapEx	$ -	$ 592	$ 1,184	$ 1,184	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ 36	$ 72	$ 72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ 180	$ 360	$ 360	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral Street - Install manhole & duct system	CapEx	$ -	$ 886	$ 1,772	$ 1,772	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ 1	$ 2	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admiral Street - Install new 115/12.47 kV substation	CapEx	$ -	$ -	$ 680	$ 1,360	$ 4,080	$ 680	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ 70	$ 140	$ 420	$ 70	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ 15	$ 30	$ 90	$ 15	$ -	$ -	$ -	$ -	$ -	$ -
Admiral Street - 12.47 kV getaways	CapEx	$ -	$ -	$ 654	$ 1,308	$ 1,308	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Knightsville-Install modular 23/12.47 kV feeder	CapEx	$ -	$ -	$ 130	$ 260	$ 780	$ 130	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ 30	$ 60	$ 180	$ 30	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ 20	$ 40	$ 120	$ 20	$ -	$ -	$ -	$ -	$ -	$ -

Project	Spending Type	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
	CapEx	$ -	$ -	$ 1,276	$ 2,552	$ 2,552	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Knightsville-convert 4.16 kV to 12.47kV	OpEx	$ -	$ -	$ 106	$ 212	$ 212	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ 220	$ 440	$ 440	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ 26	$ 53	$ 53	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Johnston 18F7 (assoc. with Knightsville)	OpEx	$ -	$ -	$ 1	$ 2	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ 10	$ 20	$ 20	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ 1,049	$ 2,098	$ 2,098	$ -	$ -	$ -	$ -	$ -	$ -
Harris Avenue-convert 4.16 kV to 12.47 kV	OpEx	$ -	$ -	$ -	$ 53	$ 105	$ 105	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ 191	$ 382	$ 382	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ 400	$ 799	$ 799	$ -	$ -	$ -	$ -	$ -	$ -
Harris Avenue-convert 11 kV to 12.47 kV (Phase 1)	OpEx	$ -	$ -	$ -	$ 23	$ 45	$ 45	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ 69	$ 138	$ 138	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ 20	$ 39	$ 39	$ -	$ -	$ -	$ -	$ -	$ -
Johnston 18F5 (assoc. with Harris Avenue)	OpEx	$ -	$ -	$ -	$ 1	$ 2	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ 1	$ 2	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 690	$ 1,380	$ 1,380	$ -	$ -	$ -	$ -	$ -
Olneyville - Convert 4.16 kV to 12.47 kV (Phase 2)	OpEx	$ -	$ -	$ -	$ -	$ 68	$ 136	$ 136	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 244	$ 488	$ 488	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 198	$ 396	$ 396	$ -	$ -	$ -	$ -	$ -
Dyer Street-Convert 2J8 partial (assoc. with Olneyville)	OpEx	$ -	$ -	$ -	$ -	$ 2	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 30	$ 60	$ 60	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 483	$ 966	$ 966	$ -	$ -	$ -	$ -	$ -
Harris Avenue-convert 11 kV to 12.47 kV (Phase 2)	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 18	$ 36	$ 36	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 1,031	$ 2,062	$ 2,062	$ -	$ -	$ -	$ -	$ -
Geneva - convert 4.16 kV to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ 76	$ 152	$ 152	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 315	$ 630	$ 630	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 14	$ 28	$ 28	$ -	$ -	$ -	$ -	$ -
Clarkson Street rebuilds (associated with Geneva)	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 1,060	$ 2,120	$ 2,120	$ -	$ -	$ -	$ -	$ -
Auburn - convert 4.16 kV to 12.47 kV (common items)	OpEx	$ -	$ -	$ -	$ -	$ 95	$ 190	$ 190	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 332	$ 663	$ 663	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 677	$ 1,355	$ 1,355	$ -	$ -	$ -	$ -	$ -
Auburn - convert 4.16 kV to 12.47 kV (non common items-Plan 1)	OpEx	$ -	$ -	$ -	$ -	$ 32	$ 64	$ 64	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 157	$ 315	$ 315	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 152	$ 304	$ 304	$ -	$ -	$ -	$ -	$ -
Elmwood rebuilds (associated with Auburn)	OpEx	$ -	$ -	$ -	$ -	$ 3	$ 7	$ 7	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 57	$ 114	$ 114	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 136	$ 272	$ 272	$ -	$ -	$ -	$ -	$ -
Poniac rebuilds (associated with Auburn)	OpEx	$ -	$ -	$ -	$ -	$ 3	$ 6	$ 6	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 16	$ 32	$ 32	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 4	$ 8	$ 8	$ -	$ -	$ -	$ -	$ -
Lincoln Avenue rebuilds (associated with Auburn)	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 1	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -

Project	Spending Type	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
	CapEx	$ -	$ -	$ -	$ -	$ 1,121	$ 2,241	$ 2,241	$ -	$ -	$ -	$ -	$ -
Rochambeau Ave - convert 4.16 kV to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ 91	$ 182	$ 182	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ 301	$ 602	$ 602	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ 8	$ 15	$ 15	$ -	$ -	$ -	$ -	$ -
Lippitt Hill rebuilds (associated with Rochambeau Avenue)	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 832	$ 1,663	$ 4,989	$ 832	$ -	$ -
Auburn-Install new 115/12.47 kV substation	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 70	$ 140	$ 420	$ 70	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 35	$ 70	$ 210	$ 35	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 265	$ 530	$ 530	$ -	$ -	$ -
Auburn-Install 12.47 kV getaways	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ 3	$ 3	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ 17	$ 17	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 102	$ 204	$ 204	$ -	$ -	$ -
23 kV circuits (2213 & 2235) - convert to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ 4	$ 4	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 35	$ 70	$ 70	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 806	$ 1,612	$ 1,612	$ -	$ -	$ -
Sprague Street - convert 4.16 kV to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 53	$ 106	$ 106	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 187	$ 374	$ 374	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 80	$ 159	$ 159	$ -	$ -	$ -
Point Street rebuilds (associated with Sprague Street)	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 4	$ 8	$ 8	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 17	$ 35	$ 35	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 50	$ 100	$ 100	$ -	$ -	$ -
Dyer Street-Convert 2J3 partial (assoc. with Sprague St)	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 32	$ 32	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 194	$ 387	$ 387	$ -	$ -	$ -
Huntington Park - convert 4.16 kV to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 32	$ 32	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 49	$ 98	$ 98	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 819	$ 1,638	$ 1,638	$ -	$ -	$ -
Lakewood-Convert 4.16 kV to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 42	$ 83	$ 83	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ 240	$ 480	$ 480	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 135	$ 270	$ 810
Knightsville-Install second modular 23/12.47 kV feeder	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ 50	$ 150
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 340	$ 680	$ 2,040
Geneva-Install 23/12.47 kV modular feeder	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5	$ 10	$ 30
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90	$ 180	$ 180
Install getaways at Geneva, Knightsville and Lippitt Hill subs	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 12	$ 12
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46	$ 368
Lippitt Hill-Install 3rd 12.47 kV feeder and tie breaker	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 170	$ 340	$ 340
East George-Convert 77J2 feeder (partial) to 12.47 kV	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17	$ 34	$ 34
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48	$ 96	$ 96
	CapEx	$ 2,142	$ 5,392	$ 10,426	$ 10,208	$ 17,283	$ 14,893	$ 14,295	$ 6,293	$ 9,619	$ 1,567	$ 1,516	$ 3,738
Totals	OpEx	$ 134	$ 292	$ 509	$ 565	$ 1,336	$ 994	$ 931	$ 376	$ 656	$ 123	$ 106	$ 236
	Removal	$ 457	$ 1,033	$ 1,461	$ 1,165	$ 2,663	$ 3,500	$ 3,530	$ 1,176	$ 1,316	$ 83	$ 96	$ 96

Transmission Spending Plan ($000) - Capex, Opex and Removal

Project	Spending Type	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Admiral Street - Install 115 kV circuit switchers	CapEx	$ -	$ -	$ 50	$ 100	$ 300	$ 50	$ -	$ -	$ -	$ -	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extend the I-187 and J-188 circuits from Sockanosset to Auburn	CapEx	$ -	$ -	$ -	$ -	$ -	$ 150	$ 450	$ 2,850	$ 2,550	$ -	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 12	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154	$ 154	$ -	$ -	$ -
Auburn - Install 115 kV circuit switchers	CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ 50	$ 100	$ 300	$ 50	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	CapEx	$ -	$ -	$ 50	$ 100	$ 300	$ 200	$ 500	$ 2,950	$ 2,850	$ 50	$ -	$ -
	OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 12	$ -	$ -	$ -
	Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 154	$ 154	$ -	$ -	$ -

The Narragansett Electric Company
d/b/a National Grid
In Re: Division's Review of FY 2019 Proposed Electric ISR Plan
Responses to Division's Third Set of Data Requests
Issued November 16, 2017

R-III-14

Request:

Referencing the Company's East Bay Area Study, Table 7.0 - Recommended Capital Spend by Fiscal Year: Please provide an updated table to include Capex, Opex and removals for each project.

Response:

Please see Attachment R-III-14, which shows the East Bay Area Study cost estimates, including capital expense, operational expense, and cost of removal.

Prepared by or under the supervision of: Ryan Constable

R-III-14, Attachment 1

Projectected Spend by FY ($M)

Capex

Description	FP	TOTAL	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27
East Providence Sub (T-Line)	C049819	$0.40	0.00	0.02	0.08	0.12	0.12	0.06				
East Providence Sub (T-Sub)	C049820	$0.30	0.00	0.02	0.06	0.09	0.09	0.04				
East Providence Sub (D-Sub)	C046726	$6.00	0.06	0.30	1.20	1.80	1.80	0.84				
East Providence Sub (D-Line)	C046727	$7.40	0.07	0.37	1.48	2.22	2.22	1.04				
Warren Sub Expansion (D-Sub)	C065166	$3.50	0.04	0.18	0.70	1.05	1.05	0.49				
Warren Sub Expansion (D-Line)	C065187	$3.70	0.04	0.19	0.74	1.11	1.11	0.52				
Barrington Sub Retirement (D-Sub)	C065293	$0.00										
Kent Corners Retirement (D-Sub)	C065295	$0.00										
Mink Street 23kV Retirement (D-Sub)	C065806	$0.00										
Waterman Ave Retirement (D-Sub)	C065297	$0.00										
Phillipsdale Sub (T-Line)		$0.40				0.00	0.02	0.08	0.12	0.12	0.06	
Phillipsdale Sub (T-Sub)		$0.30				0.00	0.02	0.06	0.09	0.09	0.04	
Phillipsdale Sub (D-Sub)		$6.00				0.06	0.30	1.20	1.80	1.80	0.84	
Phillipsdale Sub (D-Line)		$3.72				0.04	0.19	0.74	1.11	1.11	0.52	
Common Items		$1.21							0.11	0.20	0.50	0.40
T-Spend		$1.40	$0.01	$0.04	$0.14	$0.22	$0.25	$0.24	$0.21	$0.21	$0.10	$0.00
D-Spend		$31.53	$0.21	$1.03	$4.12	$6.28	$6.67	$4.83	$3.02	$3.11	$1.86	$0.40

Opex

Description	FP	TOTAL	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27
East Providence Sub (T-Line)	C049819	$0.00	0.00	0.00	0.00	0.00	0.00	0.00				
East Providence Sub (T-Sub)	C049820	$0.00	0.00	0.00	0.00	0.00	0.00	0.00				
East Providence Sub (D-Sub)	C046726	$0.60	0.01	0.03	0.12	0.18	0.18	0.08				
East Providence Sub (D-Line)	C046727	$0.40	0.00	0.02	0.08	0.12	0.12	0.06				
Warren Sub Expansion (D-Sub)	C065166	$0.30	0.00	0.02	0.06	0.09	0.09	0.05				
Warren Sub Expansion (D-Line)	C065187	$0.10	0.00	0.01	0.02	0.03	0.03	0.01				
Barrington Sub Retirement (D-Sub)	C065293	$0.03					0.01	0.02				
Kent Corners Retirement (D-Sub)	C065295	$0.03					0.01	0.02				
Mink Street 23kV Retirement (D-Sub)	C065806	$0.03					0.01	0.02				
Waterman Ave Retirement (D-Sub)	C065297	$0.03					0.01	0.02				
Phillipsdale Sub (T-Line)		$0.02				0.00	0.00	0.00	0.01	0.01	0.00	
Phillipsdale Sub (T-Sub)		$0.00				0.00	0.00	0.00	0.00	0.00	0.00	
Phillipsdale Sub (D-Sub)		$0.60				0.01	0.03	0.12	0.18	0.18	0.08	
Phillipsdale Sub (D-Line)		$0.10				0.00	0.01	0.02	0.03	0.03	0.01	
Common Items		$0.12							0.01	0.01	0.05	0.05
T-Spend		$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00
D-Spend		$2.34	$0.01	$0.07	$0.28	$0.43	$0.50	$0.42	$0.22	$0.47	$0.17	$0.05

Removal

Description	FP	TOTAL	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27
East Providence Sub (T-Line)	C049819	$0.00	0.00	0.00	0.00	0.00	0.00	0.00				
East Providence Sub (T-Sub)	C049820	$0.00	0.00	0.00	0.00	0.00	0.00	0.00				
East Providence Sub (D-Sub)	C046726	$0.10	0.00	0.01	0.02	0.03	0.03	0.01				
East Providence Sub (D-Line)	C046727	$1.50	0.02	0.08	0.30	0.45	0.45	0.21				
Warren Sub Expansion (D-Sub)	C065166	$0.20	0.00	0.01	0.04	0.06	0.06	0.03				
Warren Sub Expansion (D-Line)	C065187	$0.40	0.00	0.02	0.08	0.12	0.12	0.06				
Barrington Sub Retirement (D-Sub)	C065293	$0.34		0.01	0.01	0.01	0.01	0.30				
Kent Corners Retirement (D-Sub)	C065295	$0.34		0.01	0.01	0.01	0.01	0.30				
Mink Street 23kV Retirement (D-Sub)	C065806	$0.24		0.01	0.01	0.01	0.01	0.20				
Waterman Ave Retirement (D-Sub)	C065297	$0.34		0.01	0.01	0.01	0.01	0.30				
Phillipsdale Sub (T-Line)		$0.01				0.00	0.00	0.00	0.01	0.01	0.00	
Phillipsdale Sub (T-Sub)		$0.00				0.00	0.00	0.00	0.00	0.00	0.00	
Phillipsdale Sub (D-Sub)		$0.40				0.00	0.02	0.08	0.12	0.12	0.06	
Phillipsdale Sub (D-Line)		$0.30				0.00	0.02	0.06	0.09	0.09	0.04	
Common Items		$0.16							0.01	0.01	0.07	0.07
T-Spend		$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00
D-Spend		$4.32	$0.02	$0.15	$0.48	$0.71	$0.74	$1.26	$0.23	$0.23	$0.47	$0.07

PUC 1-2

Request:

The Order in Docket No. 4682 required National Grid to provide several reports and analyses to the Division no later than August 31, 2016. Please provide copies of what was provided to the Division pursuant to the Order (please exclude any Critical Infrastructure Information at this time, noting generally what was excluded).

Response:

Please see Attachments PUC 1-2-1 through PUC 1-2-10. Nothing was excluded as these attachments do not include any Critical Infrastructure Information.

Prepared by or under the supervision of: Prabhjot S. Anand

Attachments PUC 1-2-1 through PUC 1-2-10

Due to the voluminous nature of the-above-referenced attachments, the Company is providing these documents on a USB Flash Drive.

Prepared by or under the supervision of: Prabhjot S. Anand

PUC 1-3

Request:

The Order in Docket No. 4682 the PUC adopted Mr. Booth's recommendation that National Grid should propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum:

a. The traditional elements included in the Company's current studies;
b. The purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline;
c. Discussion on the impact to related Company initiatives, PUC programs;
d. 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;
e. 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;
f. A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.

Please reference where in the proposed FY 2019 Electric ISR plan this was provided. If not provided in the proposed FY 2019 Electric ISR plan or in prior data responses, please provide.

Response:

National Grid's proposed changes in study documentation methodology were not specifically provided in the FY 2019 Electric ISR Plan. Rather, the Company specifically addressed each of Mr. Booth's recommendation in its FY 2019 Pre-Filing Plan Documents submitted to the Rhode Island Division of Public Utilities & Carriers (Division) and had follow-up discussions with the Division on those documents in August of 2017. Please see the Company's Response to PUC 1-2 for the Pre-Planning Documents that were the basis of the discussions for all of Mr. Booth's recommendations, in particular Attachment PUC 1-2-1, Recommendation 2.

Prepared by or under the supervision of: Ryan Constable

PUC 1-4

Request:

In the Order in Docket No. 4682, the PUC adopted Mr. Booth's recommendation that National Grid should develop a proposal on the methodology to assign Contact Voltage program costs for the testing and remediation of elevated voltage to municipal streetlight owners. Please explain the Company's proposal or otherwise reference where in the proposed FY 2019 Electric ISR Plan, or other filing pending before the PUC where this is explained.

Response:

The Company's proposal for Contact Voltage Program costs for the testing and remediation of elevated voltage to municipal streetlight owners was provided to the Rhode Island Public Utilities Commission (PUC) on July 28, 2017 in Section 9, Company Recommendation, of Docket 4237 - National Grid 2017 Contact Voltage Annual Report. In addition, the Company provided a copy of this proposal to the Rhode Island Division of Public Utilities and Carriers (Division) on August 11 2017 in Pre-Filing documents, Recommendation 3. (Please see Attachment PUC 1-2-4).

Under its proposal, National Grid will continue to perform and incur expenses for mobile Contact Voltage testing. As part of that testing, National Grid proposes that in each Designated Contact Voltage Risk Areas (DCVRA) where municipalities own the streetlights, that the municipality have their own contractor crews shadow National Grid crews as elevated voltage testing is performed. If, during the mobile testing, it is determined that remediation of a streetlight is required, then the contractor crews will complete remediation work at that time and direct bill the applicable municipality the costs of remediation.

Currently, the City of Providence has agreed to this proposal. In addition, National Grid is in the process of securing a contact for the City of Westerly to discuss this proposal. Other Municipal streetlight sales have not yet been finalized in the cities of Newport, Pawtucket, and Woonsocket. In these cases, implementation of the Company's proposal is contingent upon finalization of their municipal streetlight sales and approval of National Grid's remediation proposal.

Prepared by or under the supervision of: Bartholemew Cass

PUC 1-5

Request:

Referencing Chart 1a on page 27, despite the claim made on page 25 that the Company is showing an improving downward trend over the past several years, has this trend reversed since 2014? If so, to what does the Company attribute this reversal?

Response:

The Company's SAIFI and SAIDI are showing an improving downward trend over the past several years. This is due to the decrease in outages caused by lightning and deteriorated equipment caused outages.

In calendar year (CY) 2015, TR3/TR4 lockout in Drumrock Substation accounts for 40% of the total customer interrupted by substation. In CY 2016, one outage on 1870 line accounts for 70% of the total customer interrupted by Transmission. The root cause is a shorted DC panel within the West Kingston substation that tripped the 1870 line. The two events caused the trend to reverse.

Prepared by or under the supervision of: Prabhjot S. Anand

PUC 1-6

Request:

Referencing Chart 3 on page 30, in Calendar Year 2016, Transmission accounted for customer interruptions three times more than the prior eight years. Please explain the primary cause of the increase, if known.

Response:

In Calendar Year 2016, one outage on 1870 line accounts for 70% of the total customer interrupted by Transmission. The root cause is a shorted DC panel within the West Kingston substation that tripped the 1870 line.

Prepared by or under the supervision of: Prabhjot S. Anand

PUC 1-7

Request:

Please explain whether the Admiral Street Project referenced on page 48 was included in the five-year projections in Docket No. 4682, providing a page reference, or otherwise indicate where the Company has included the Admiral Street Project in quarterly filings. Please provide an itemization of the $1.1 million in past study costs and continued engineering costs.

Response:

The Admiral Street Project was not included in the five-year projections in Docket No. 4682. This project is a recommendation of the Providence Area Study. Previous ISR Plans did include placeholder Providence LT (long-term) Study projects in the five-year projections (example: FY16 ISR Plan, Docket 4539, Attachment 5). During discussions and consultations regarding long range planning studies, National Grid agreed that it would no longer include large infrastructure projects unless justified under a long range study. In accordance with this agreement, the Providence LT Study placeholder was zeroed out (FY17 ISR Plan, Docket 4592, Attachment 4). Once the study was completed, the Company began the process to provide visibility of the recommendations and costs starting in January 2017 and continued in July 2017.

The following table provides and itemization of the $1.1 million in past study costs:

Description	Hours	Cost w/Overheads
Internal Labor		
Distribution Design / Estimating	1160	$125,200
Distribution Engineering	1182	$87,800
Distribution Planning	3608	$300,100
Estimating	34	$3,400
Miscellaneous	100	$10,300
Operations	17	$1,700
Protection Engineering	70	$6,500
Substation Engineering	289	$27,800
Substation O&M Services	4	$400
Transmission Engineering	64	$6,000
Transmission Planning	258	$23,600
Internal Labor Total		$592,800
Consultants/Contractors		$530,600
Fleet		$400
Travel & Expense		$1,200
Miscellaneous		$5,600
TOTAL		$1,130,600

Prepared by or under the supervision of: Ryan Constable