nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

February 21, 2020

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4995 - National Grid's Proposed FY 2021 Electric Infrastructure, Safety, and Reliability Plan
Responses to PUC Data Requests – Set 1

Dear Ms. Massaro:

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

This filing also contains a Motion for Protective Treatment of Confidential Information in accordance with 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(A), -(B). National Grid seeks protection from public disclosure of certain confidential and privileged information in Attachment PUC 1-11-5. In compliance with Rule 1.3(H), National Grid has provided the PUC with one complete, unredacted copy of Attachment PUC 1-11-5.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 4995 Service List
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division
Al Contente, Division

---

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

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

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

February 21, 2020
Date

Docket No. 4995 - National Grid's Electric ISR Plan FY 2021
Service List as of 12/26/2019

Name/Address	E-mail Distribution	Phone
Jennifer Hutchinson, Esq. **National Grid** 280 Melrose St. Providence, RI 02907	jennifer.hutchinson@nationalgrid.com; celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7288
National Grid Melissa Little Patricia Easterly Kathy Castro Susan Toronto Ryan Constable William Richer	Melissa.Little@nationalgrid.com; Patricia.easterly@nationalgrid.com; Kathy.Castro2@nationalgrid.com; Susan.Toronto@nationalgrid.com; Ryan.Constable@nationalgrid.com; William.Richer@nationalgrid.com;	
Division of Public Utilities (Division) Christy Hetherington, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Chetherington@riag.ri.gov ; Dmacrae@riag.ri.gov; MFolcarelli@riag.ri.gov; John.bell@dpuc.ri.gov; Jonathan.Schrag@dpuc.ri.gov; Joseph.shilling@dpuc.ri.gov; Robert.Bailey@dpuc.ri.gov;	
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440

Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616
Office of Energy Resources (OER) Andrew Marcaccio, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Andrew.marcaccio@doa.ri.gov;	401-222-3417
Christopher Kearns, OER Carrie Gill Nick Ucci	Christopher.Kearns@energy.ri.gov; Carrie.Gill@energy.ri.gov; Nicholas.Ucci@energy.ri.gov;	
File an original & ten copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.harrington@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; Margaret.hogan@puc.ri.gov;	401-780-2107

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Fiscal Year 2021 Electric Infrastructure, Safety and Reliability Plan	))))	Docket No. 4995

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) and R.I. Gen. Laws § 38-2-2(4)(A), -(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On February 21, 2020, National Grid submitted its responses to the Public Utilities Commission's (PUC) First Set of Data Requests in the above-captioned docket. Data Request PUC 1-11 requested a copy of the Company's delegation of authority (DOA) governance policy. The Company seeks protective treatment for confidential information related to certain aspects of the Company's delegation of authority governance policy contained in Confidential Attachment PUC 1-11-5. Confidential Attachment PUC 1-11-5 consists of the U.S. Tertiary Delegations Matrix, which includes the figures representing the maximum expenditure a specific executive or board may authorize, and is competitively sensitive and confidential information.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the competitively sensitive and confidential information contained in Attachment PUC 1-11-5. Accordingly, the Company is providing both redacted and un-redacted versions of Attachment PUC 1-11-5.

II. LEGAL STANDARD

Rule 1.3(H) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

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

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive

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

position of the person from whom the information was obtained. *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47. National Grid meets the first and second prongs of this test, which apply here.

III. BASIS FOR CONFIDENTIALITY

The information contained in Attachment PUC 1-11-5 should be protected from public disclosure. The information provided in this attachment contains confidential and competitively sensitive information of the type that National Grid does not ordinarily make public. Attachment PUC 1-11-5 specifies the authority of various executives and boards within the Company to make business decisions, including their authority to enter agreements or contracts on behalf of the Company with third parties. The limits of authority of specific executives and boards should not be disclosed to the public because such disclosure places the Company at a competitive disadvantage and harms the bargaining position of the Company in negotiations with vendors, contractors, opposing litigants and any other party with whom the Company must negotiate. For example, if a third party in negotiations with an executive of the Company knows the extent of the Company executive's authority limit, the third party would have an unfair advantage in the negotiation process and could use that knowledge in a variety of ways to the detriment of the Company and its customers.

For each of the above reasons, the confidential and competitively sensitive information related to the Company's delegation of authority contained in Attachment PUC 1-11-5 should be protected from public disclosure under R.I. Gen. Laws § 38-2-2(4)(B). National Grid is providing Attachment PUC 1-11-5 on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

Jennifer Brooks Hutchinson, Esq. (#6176)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7288
Dated: February 21, 2020

PUC 1-1

Request:

Refencing page 24, please provide an update on National Grid's progress on developing a quantitative methodology to calculate the costs and benefits of traditional utility investments. Please include the Company's expected timeline for the development, including when the Company expects the methodology to be reviewed by stakeholders and the PUC.

Response:

As described in the pre-filed joint testimony of Company Witnesses Patricia C. Easterly and Kathy Castro, Bates Pages 23-28, the Company attempted to apply a quantitative analysis to new or incremental investments in the FY 2021 ISR Plan using the Docket 4600 Framework. The Company progressed development of this analysis by collaborating with its Grid Modernization team to improve on the assessment prepared with the FY2020 ISR Plan. As documented in Section 2, Attachment 5, the analysis incorporates approximately 34 separate cost or benefit categories, many of which were either not applicable or could not be quantified as part of assessing the proposed ISR investments. The quantitative methodology known as the "RI Test", upon which the Docket 4600 Framework is based, does not lend itself to a quantitative assessment of traditional utility infrastructure investments; therefore, to calculate reliability benefits, the Company used the U.S. Department of Energy Interruption Cost Estimate (ICE) Calculator. To calculate CO_2 reduction benefits, the Company relied on Regional Greenhouse Gas Initiative (RGGI) values. Finally, the Company calculated the NOX/SOX benefits using the U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics. While these methodologies may be individually recognized within the industry, the use of these methodologies have not undergone full stakeholder input to be applied to the quantitative assessment of traditional utility investments within the Docket 4600 Framework. The Company's reference to its progress to develop a quantitative methodology in its prefiled joint testimony on Bates Page 24 is in reference to the efforts discussed above. See also Rebuttal Testimony of Company Witness Patricia C. Easterly and Kathy Castro at 11 (discussing the types of projects for which a separate benefit-cost analysis may not be required or appropriate).

The Company included its proposed quantitative and qualitative analysis in the FY 2021 Plan to give transparency to the work done to date, and to facilitate discussion and stakeholder input around a suitable methodology; however, there is still more work to be done to refine the Docket 4600 Framework application to projects and programs in the ISR. The Company submits that such work should be done in consultation with the Division and the PUC.

Prepared by or under the supervision of: Kathy Castro and Patricia C. Easterly

PUC 1-2

Request:

Referencing page 27, please provide the "specific DER interconnections" and related "potential concerns" National Grid is proposing to proactively install Accelerated 3VO, Mobile 3VO, Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors, and Advanced Recloser Controls. Please explain and provide what the proposed customer contribution and all-ratepayer contribution is for these investments.

Response:

The reference to "specific DER interconnections" on page 27 is a typo, this should read due to the aggregation of DER.

The "potential concerns" addressed by 3V0, Mobile 3V0, Advanced Capacitor/Regulator and Feeder Monitor Sensors, and Advanced Recloser Controls vary. The addition of distributed energy resources (DER) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. For certain transmission faults, additional transmission protection, zero sequence overvoltage or "3V0" protection, is required to prevent the DER from contributing to fault overvoltage conditions. As DER penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is a factor, the duration of the 3V0 work can also impact the viability of proposed DER projects. Both the Accelerated 3V0 and Mobile 3V0 investments will address these technical and duration issues.

With the interconnection and increase of DER, and localized unique demand requirements in certain areas of the system comes a change in loading, voltage, and protection profiles. The issues can have location, time, and direction components such that existing infrastructure and control methods are unable to manage loading, voltage, and protection needs. The Advanced Capacitor/Regulator and Feeder Monitor Sensors, and Advanced Recloser Controls programs will proactively upgrade recloser controls, install new reclosers at circuit connection points, upgrade capacitor controls and regulator controls, and install sensing to sufficiently manage load, voltage, and protection needs. projects. These investments are in line with standard actions that the Company currently performs to maintain and address immediate system performance and reliability needs for all customers

National Grid's Distribution Planning and Asset Management engineers analyze the impact of DER on the electrical distribution power system's performance at commencement of discrete System Impact Studies. The analysis conducted identifies potential concerns due to DER interconnections and provide system modifications required to maintain compliance. Studies consider all interconnected and proposed DER within the analysis. System issues are addressed as a combination of system improvements (benefiting and recovered from all customers) and System Modifications (benefiting and recovered from developers). System improvements are those that are required to address conditions of the existing system that are not due to or for the benefit of the DER interconnection while System Modifications are required specifically for the benefit of the DER interconnection. As more DER is proposed to be interconnected, it is expected to become increasingly difficult to assign the cost of the types of upgrades in the Strategic Advancement of DER program to any one project as many projects in a certain area all contribute to the need. Specific DER project upgrades for large projects will still be the responsibility of the DER owner as is the case today, but the investments proposed in the ISR would cover the impact from the growing saturation of many DER projects on the system for which specific assignment is not possible.

PUC 1-3

Request:

Referencing Chart 1 on page 39, is "Annual Planning Review % Complete" (Column 7 of Chart 1) the same as "annual capacity review" as used in the 2021 ISR Proposal?

Response:

Yes "Annual Planning Review % Complete" is the same as "annual capacity review."

Prepared by or under the supervision of: Kathy Castro

PUC 1-4

Request:

Referencing Chart 1 on page 39 and pages 48-9, please confirm that "Northwest RI" (as used in the 2020 ISR Proposal) is now referred to as Blackstone Valley and North Central Rhode Island. Please explain why Northwest RI was split into the two separate areas, and explain why the area around Burrillville is not included in an area study.

Response:

The Northwest RI study encompasses both the Blackstone Valley and North Central RI study areas. In the FY 2021 ISR Plan, the Company represented the areas on separate line items to show that the study covers both areas. Burrillville is not included in the area study because the distribution facilities that serve the town are owned and maintained by Pascoag Utility District.

PUC 1-5

Request:

Referencing Chart 1 on page 39, please provide a copy of Chart 1 using information as of December 2018.

Response:

See Attachment PUC 1-5 with updated Chart 1 with data provided in PUC 1-1 of the FY2020 ISR.

Prepared by or under the supervision of: Kathy Castro

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Planning Review % Complete	Area Planning Study % Complete	Area Planning Study Stage	Estimated Planning Study Complete Date	Expected Commencement of next Area Study
1	Providence	358	19%	95	17	100%	**100%**	**Stage 9**	Complete 2017	2024
2	East Bay	147	8%	22	7	100%	**100%**	**Stage 9**	Complete 2015	2022
3	Central Rhode Island East	204	11%	37	9	100%	**100%**	**Stage 9**	Complete 2017	2024
4	South County East	159	9%	22	9	100%	**100%**	**Stage 9**	Complete 2018	2025
5A	Blackstone Valley North	139	8%	27	6	100%	50%	Stage 5	Dec-2019	2025
5B	North Central Rhode Island	269	15%	35	10	100%	50%	Stage 5	Dec-2019	2025
6	South County West	98	5%	14	5	100%	0%	NA	Mar-2020	2026
7	Central Rhode Island West	167	9%	33	11	100%	0%	NA	Jun-2020	2026
8	Tiverton	28	2%	4	1	100%	0%	NA	Dec-2020	2027
9	Blackstone Valley South	171	9%	54	11	100%	0%	NA	Dec-2020	2027
10	Newport	105	6%	42	12	100%	0%	NA	Jun-2021	2020
	Totals	**1845**	**100%**	**385**	**98**	**100%**	58.5%[1]			

[1] Percent of Total State Load

PUC 1-6

Request:

Referencing pages 45-6, please define the following terms: capacity review, capacity planning process, annual planning, and annual planning review, and area studies. In addition, please answer the following:

a) When the Company uses the term "assessment process" is it referring to capacity review, capacity planning process, or something else?
b) Are "annual planning studies" and "Annual Planning Studies" the same thing? If not, please explain the differences.
c) What process does "this assessment process" refer in this sentence on page 46: "Completion of this assessment process is also known as an annual planning review."

Response:

The capacity review, capacity planning process, annual planning, and annual planning review, all refer to the same system planning process as discussed in Section 2 of the FY 2021 ISR Plan, System Planning, Bates Pages 45-47. The Company recognizes that it has used these terms somewhat interchangeably; therefore, to clarify system planning processes include annual capacity reviews and area planning studies. Annual capacity reviews inform and help to prioritize the area planning studies, sometimes referred to in the Plan as Area Studies. Area planning studies refer to the comprehensive area analysis described on Bates Pages 46-47.

a) The term "assessment process" refers to both capacity review and capacity planning process. As explained above, capacity review, capacity planning process, annual planning, and annual planning review, all refer to the same system planning process discussed above.
b) The Company assumes this question is referring to "area planning studies" and "Area Planning Studies," which both refer to the same process, as discussed above.
c) See response to subpart (a).

Prepared by or under the supervision of: Kathy Castro

PUC 1-7

Request:

Referencing page 47, please answer the following:

a) For Stage 3, who is included in the "larger stakeholder group" and how are they informed?
b) For Stage 5, who proposes alternatives and how are they proposed?
c) How do the 9 Stages relate to the "Area Planning Study % Complete" in Chart 1 on page 39?

Response:

a) The larger stakeholder group consists of representative from internal National Grid Departments that form the study team. These departments include but are not limited to:

    a. Distribution Planning and Asset Management Field Engineers (DPAM)
    b. Substation O&M Services
    c. Transmission Planning and Asset Management
    d. Operation
    e. Transmission and Distribution Regional Control Center
    f. Distribution Line Design
    g. Substation Engineering and Design
    h. Transmission Line Design
    i. Community and Customer Management
    j. Non-wires alternative team

    The study engineer will request study team members, via a Study Engineering Request form and/or email. Once the study team is formed, the study engineer schedules the study kickoff meeting.

b) In Stage 5, the study engineer continues to engage with the stakeholders who comprise the study team. In the initial parts of Stage 5, the study engineer develops alternatives to mitigate issues identified in the prior stages. The study engineer leverages the detailed engineering analysis of Stage 4 to develop comprehensive alternative plans. Throughout this process, the study engineer is in frequent informal communication (e.g., emails, conversations, meetings) with study team members to solicit input on the alternatives being developed or recommendations for new alternatives. The study engineer reviews alternative proposals from the study team to confirm that they address the issues identified by the study. The study engineer then prepares one-line diagrams to document and communicate the alternative plans that will be developed further.

Prepared by or under the supervision of: Kathy Castro

PUC 1-7, page 2

The remainder of Stage 5 consists of a more formal process of study team member engagement, in which the study engineer requests investment grade estimates and feasibility assessments for each alternative from the relevant study team member (e.g., Options Solutions Engineering, Distribution Line Design, Non-Wires Alternative Solutions). The information provided by these team members is used in Stage 6 to review each alternative's relative costs and benefits and identify the recommended plan. While evaluating alternatives, the study engineer consults with study team members to include:

- An economic analysis of the recommended plan
- An environmental and safety review of the recommended plan
- Required system outages for the recommended plan
- Operational flexibility of the recommended plan
- The recommended plan schedule

When the recommended plan is selected, study team members will express their formal support for the recommended plan through a stage gate review process.
While the Company does not have any one specific mechanism for proposing an alternative, an Area Study is a collaborative process lead by the study engineer, who is in frequent communication with all team members. At any time during alternatives development and analysis, a study team member may suggest a new alternative, or a modification to an existing alternative, for evaluation. The alternatives, concerns, and considerations raised by team members are documented by the study engineer in the final Area Study report (Stage 8).

c) The "Area Study % Complete" relates to the % complete of the entire study which consists of the 9 stages defined on Bates Pages 46 – 49 of the plan. The assigned percentage of Study Complete is based on the expected effort required for the remaining stages, which vary in complexity and duration.

Prepared by or under the supervision of: Kathy Castro

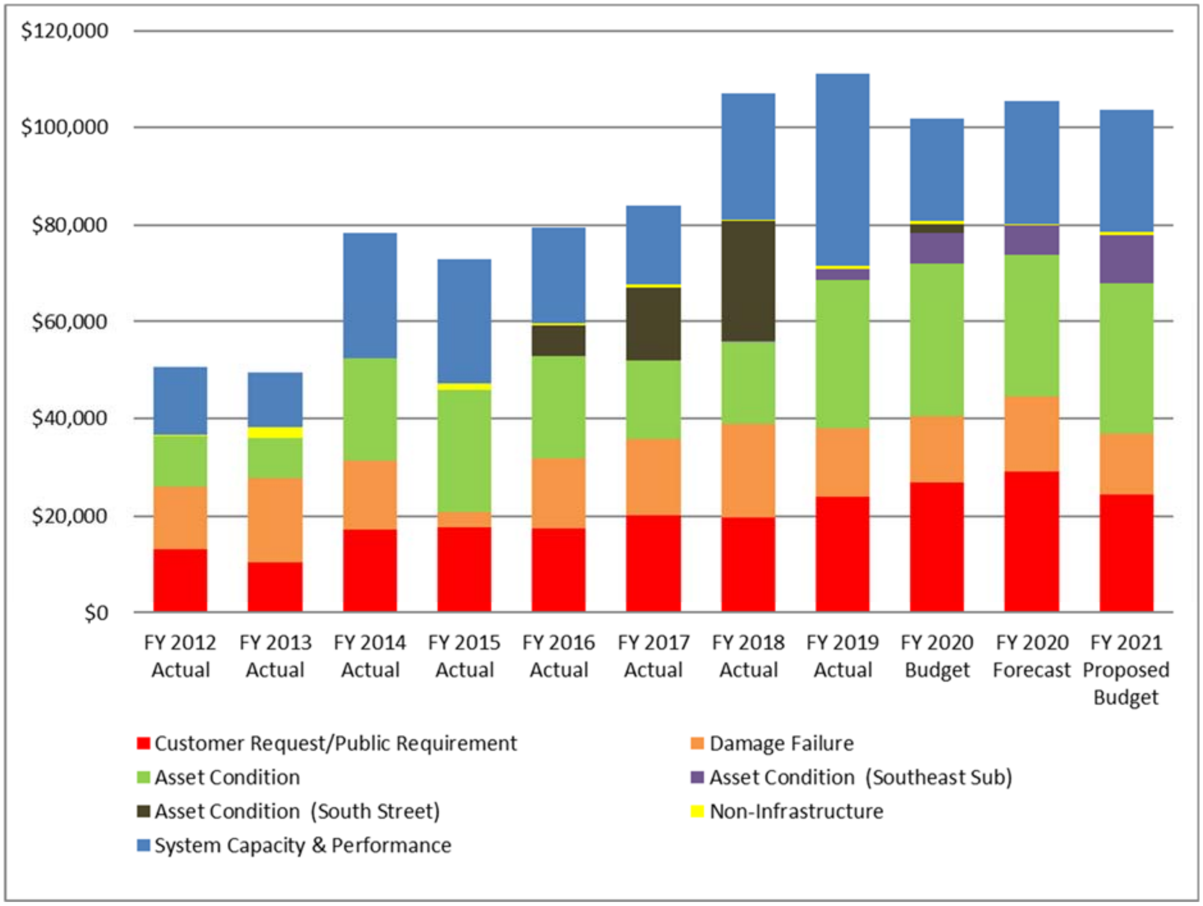
PUC 1-8

Request:

Referencing page 51, please redo Chart 5 to include labels for all values (it appears that System Capacity & Performance is not in the key). In addition, please select colors that more easily show the distinction between spending categories (do not use more than one shade of any color).

Response:

Please see updated Chart 5 below.



Prepared by or under the supervision of: Patricia C. Easterly

---

PUC 1-9

Request:

Referencing page 54, please provide the total "Customer Request/Public Requirement" including all costs such as contributions in aid of construction (CIAC).

Response:

While the Company does not budget specifically by cost elements such as contributions in aid of construction (CIAC), the Company examined the blanket projects trending and estimate approximately $2.5 million in CIAC's for the upcoming fiscal year.

Non-Blanket projects and reserves within the Customer Request/Public Requirement category are estimated at net spending and CIACs are not specifically budgeted for these items.

See response to PUC 1-34 for additional information.

PUC 1-10

Request:

Referencing page 58, please detail and describe how the Company calculates the "project risk score" and provide an algorithm, associated inputs, and scaling factors if any exist.

Response:

Refer to Attachment PUC 1-10 for process to calculate risk score.

Prepared by or under the supervision of: Patricia C. Easterly

Investment Planning Review

Risk Scoring Guide

Final V1.0 January 2008

Risk scoring methodology

Contents

Risk scoring methodology – What is it and why do we need it?

Purpose

- Create a **single risk score** which can be used to compare the safety, reliability and environmental risks addressed in the capital plan for each of our businesses

How will it be used

- Provide **transparency** within the Lines of Business and to the Executive on the amount of risk being mitigated in each business relative to the capital plan
- **Link the return** on investment to the risk eliminated by investing into the business

Relevance

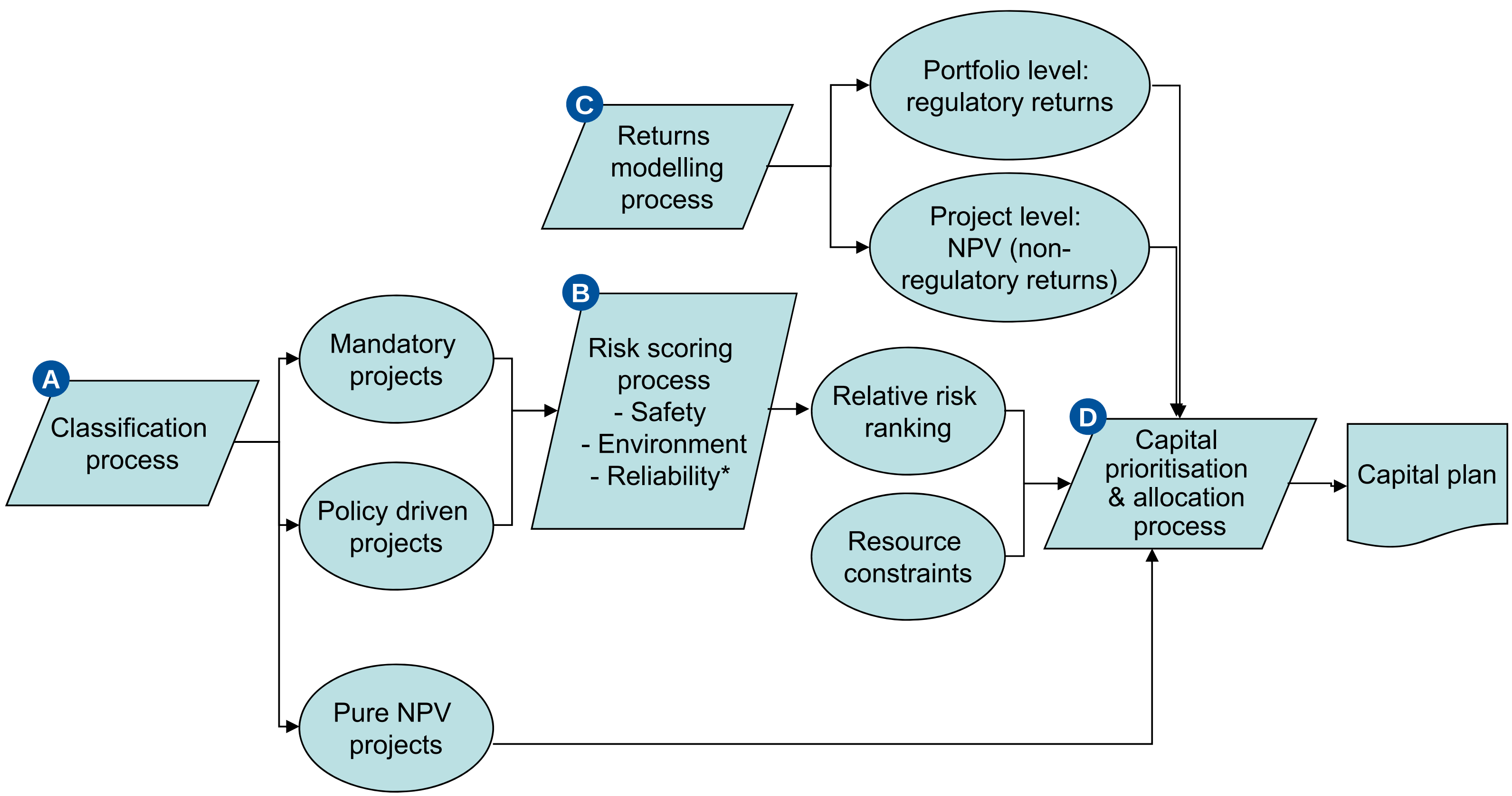
- Previously **no common method** to assess risk across the business
- Opportunity for you to **shape**, going forward, the standardised way this should be done
- Opportunity to **inform regulatory dialogue** and debate

What this concept is not

- Is not a technical measure of **residual** system risk, i.e. the risk remaining to be mitigated once the proposed projects have been completed

LOX-NGT011-20071101-MHJP

Risk scoring and capital prioritisation process (1/2)



Final V1.0 January 2008

nationalgrid

* Includes avoided penalties and incentives relating to reliability

Risk scoring and capital prioritisation process (2/2)

A Classification process

- Categorise projects into
  - Mandatory
  - Policy driven
  - Pure NPV
- Where necessary, bundle projects into programmes, for ease of risk scoring and sanctioning

B Risk scoring process

Mandatory
- Default to highest risk score

Policy driven
- Compute risk score on following criteria
  - Safety
  - Environment
  - Reliability (including avoided penalties)

C Returns modelling process

Mandatory and Policy driven
- Calculate portfolio returns
- Calculate incremental returns for projects with opex savings

Pure NPV
- Compute NPV

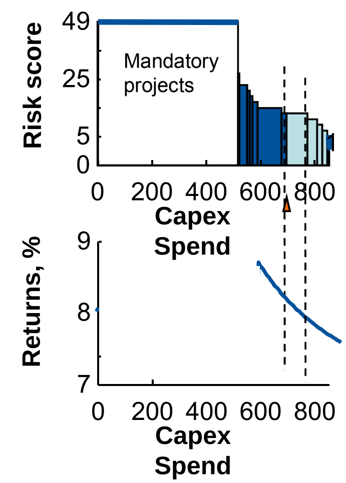
D Capital prioritisation & allocation process

Prioritisation

- Unconstrained prioritisation based on:
  - Risk score
- Constrained prioritisation based on
  - Operational and timing constraints
  - Incremental financial benefits
- Strong governance for projects the LOB wants to justify on:
  - Incremental financial benefits
  - 'Strategic' rationale

Risk-return trade-off

Mandatory and policy driven



- Trade-off level of investment in terms of risk and return

Pure NPV
- Do all positive NPV projects

nationalgrid

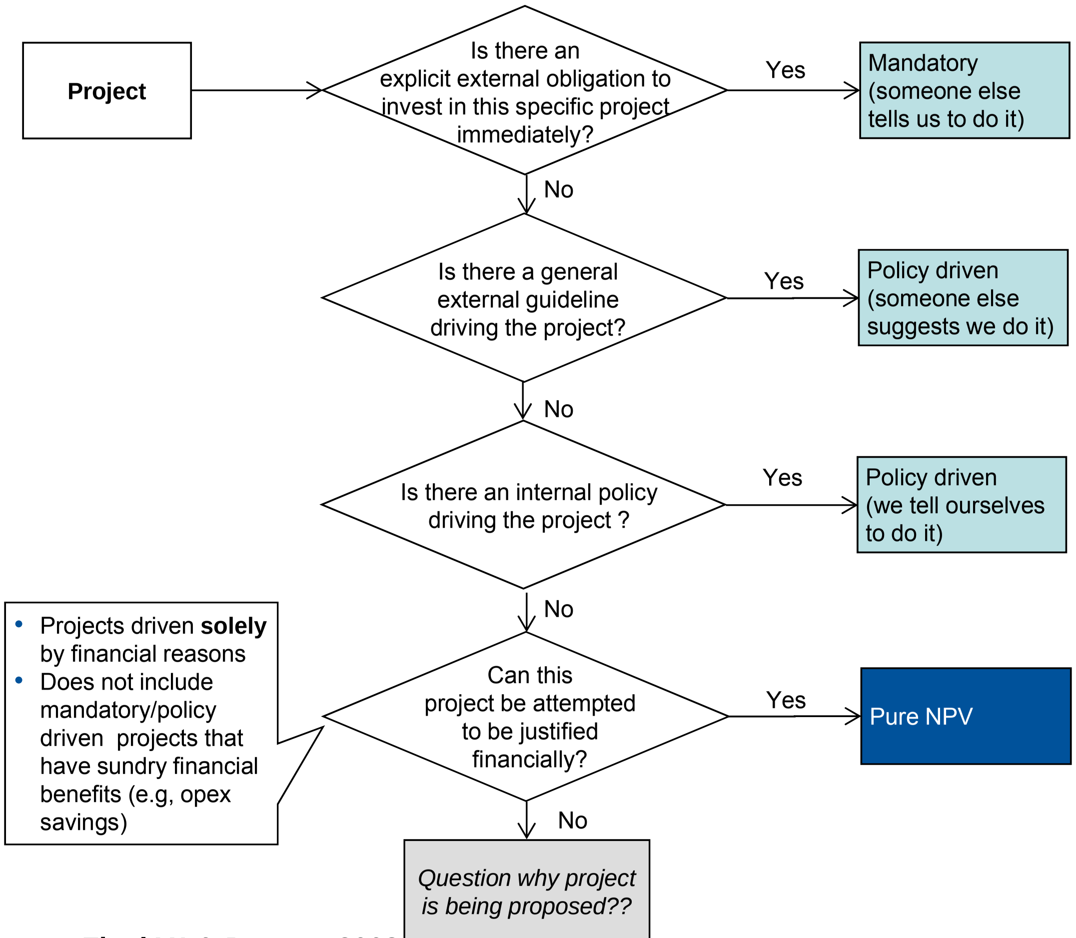
Risk scoring methodology

Contents

- What is the end-to-end risk scoring process and why do we need it?
- Risk scoring methodology process steps
  - **How does Project Classification work?**
  - How does Risk Scoring work?
  - How does Prioritisation work?

LOX-NGT011-20071101-MHJP

A Projects will be classified as mandatory, policy driven and pure NPV, using the following decision tree



Definitions

- Projects done to fulfil an explicit, deterministic statutory/regulatory obligation, where there is absolutely no discretion on timing or options and there is an immediate and palpable risk of regulatory or legal breach
- Projects undertaken to fulfil a statutory/regulatory obligation, where there is some discretion* on timing or options
- Projects necessary to meet internal policies**
- Projects undertaken to deliver financial benefits at complete discretion of NG, not driven by external or internal policies
- Residual projects that should be questioned/ policies to be reviewed

Final V1.0 January 2008

* Decision on project elements (i.e., timing, which option, etc.) reflect corporate risk appetite

** Internal policies reflect corporate risk appetite

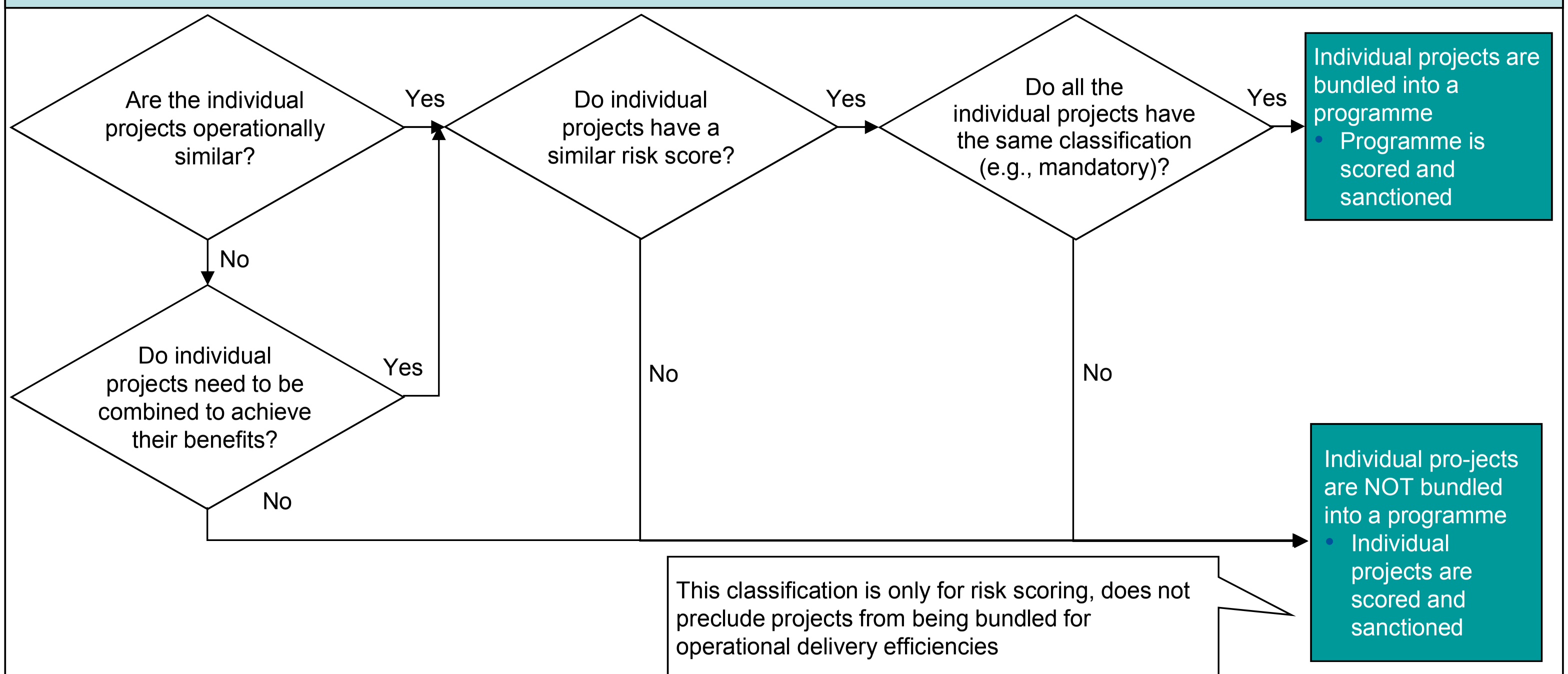
LOX-NGT011-20071101-MHJP

A A portfolio of projects will be bundled into a programme for risk scoring and sanctioning

Definition of programme

- A portfolio of individual projects, that are can be scored and sanctioned together, which are:
  - Either operationally similar or required to be combined in order to achieve benefits
  - Have similar risk scores and same classification (mandatory, policy driven, etc.)

Decision tree for bundling individual projects into a programme



Final V1.0 January 2008

nationalgrid

A How project classification will be done in practice

Goals

- To ensure consistent classification by all LOBs into mandatory, policy-driven, pure NPV
- To provide guidance on interpretation of above definitions
- To ensure sufficient transparency on bundling of projects into programmes
- To update definitions and checklists if required

	How will governance work?	What will this entail?
Guidance notes	• Customised checklist will be provided to LOBs to assist them in classifying projects into mandatory, policy-driven, etc. as well as to bundle projects into programmes	• A checklist will be developed (in conjunction with LOBs) to classify projects
Guidance meetings	• Investment Planning project team/Investment Decision Support* (IDS) team member to interact periodically with LOB investment planners on risk scoring	• Project team/IDS member to review classification of projects to ensure consistency and provide guidance

nationalgrid

* IDS = Investment Decision Support: explained in detail later in document

Risk scoring methodology

Contents

- What is the end-to-end risk scoring process and why do we need it?
- Risk scoring methodology process steps
  - How does Project Classification work?
  - **How does Risk Scoring work?**
  - How does Prioritisation work?

B Risk scoring process will use following principles

1 Determine Impact and likelihood levels

Step 1 – Score project on **impact** in each of the following criteria

Impact	Safety	Reliability	Environment
Very low	1	1	1
Low	2	2	2
Moderately low	3	3	
Moderate	4	4	
Moderately high	5	5	
High	6	6	
Very high	7	7	

Any impact of penalties for reliability/ health and environment to be considered when scoring project on impact

Step 2 – Score project on **likelihood** of occurrence in each of the following criteria

Likelihood	Safety	Reliability	Environment
Very low	1	1	1
Low	2	2	2
Moderately low	3	3	3
Moderate	4	4	4
Moderately high	5	5	5
High	6	6	6
Very high	7	7	7

Final V1.0 January 2008

2 Obtain blended risk score* for each criterion

Safety score

Impact							
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13
Likelihood	1	2	3	4	5	6	7

Reliability score*

Impact							
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13
Likelihood	1	2	3	4	5	6	7

Scores are ranked based on the expected monetary value of each outcome

Environmental score*

Impact							
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13
Likelihood	1	2	3	4	5	6	7

3 Obtain overall risk score

- Overall score is maximum of
  - Safety (7)
  - Environment (11)
  - Reliability (28)
- Maximum score method was selected because:
  - Impact levels are assessed on an exponential scale, hence the highest score outweighs other lower scores (e.g.,Level 7 has a monetary impact > £20Mn and Level 1 has a a monetary impact of <£5k)
  - Aggregating different scores into a simple score is mathematically inaccurate
  - Maximum score ensures that projects with a high score on a single criteria are not ignored
  - Most projects are expected to have a single driver that dominates

* Scores are grouped and colour coded for ease of viewing (40 and above - red, 16-39 - yellow and 15 and below - green)

B1 Impact Matrix – Safety & Environment (1/3)

Score	Financial Impact	Health and Safety	Environment
1	• < £5K • < $10K	• Minor injury requiring First Aid with a quick and complete recovery (£100-200/$200-400) • Minor illness with up to one –week absence. No permanent health consequences (£500/$1000)	• Non-significant Environmental Incident without agency oversight (e.g., minor spillage (e.g., < 5 litres) that does not enter drain or water course, small quantities of hazardous waste left on site, temporary impact to the environment) (£1K- 2K/$2K-4K) or a minor regulatory compliance issue.
2	• £5K-50K • $10K-100K	• Illness with over one week absence but no permanent health consequences (£5K/$10K)	• Significant Environmental Incident usually without agency oversight (e.g., spillage that does not enter drain or water course, fly tipping on National Grid land or site, a release of methane gas under 200 tonnes) (£5K-50K/$10K-100K) or regulatory non-compliance issues that may result in minimal fines.
3	• £50K-250K • $100K-500K	• Injury to member of public requiring medical treatment but no permanent consequences (£50K/$100K)	• Significant Environmental Incident with agency oversight (e.g., minor silt run off to reservoir, discolouration noted around edges, mitigation measures required and some clean up required, a release of more than 200kg of sulphur hexafluoride gas) (£50K-250K/$100K-500K) or a non-compliance issue that results in significant fines and/or actions taken by regulatory authorities (e.g. permit limits for air emissions exceeded).
4	• £250K-1Mn • $500K-2Mn	• Permanently incapacitating injury or illness to employees (Moderate to severe pain for 1 – 4 weeks with possible recurrence of pain for certain activities and some permanent restrictions to leisure or work) (£500K/$1000K) • Injury to member of public requiring extended medical treatment but no permanent consequences	• Significant Environmental Incident with agency oversight (e.g., uncontained release of liquid (e.g silty water or bentonite drilling fluid, petroleum) to a drain or water course that has the potential for enforcement action and which may cause fish or aquatic plants to die) (£250K-1Mn/$500K-2Mn) non-compliance issue that results in significant fines and/or actions taken by regulatory authorities (e.g. permit limits for air emissions exceeded, noise abatement order issued).
5	• £1Mn-5Mn • $2Mn-10Mn	• Permanently incapacitating injury to a member of public or fatality to employee (£4.5Mn/$9Mn)	• Significant Environmental Incident (e.g., several full drums of oil spill contents on to ground and significant quantity enters high quality water course leading to >500 fish killed and damage to river bed requiring remediation and leading to prosecution, damage to environmentally sensitive sites, listed buildings, or damage to a Site of Special Scientific Interest) (£1Mn-5Mn/$2Mn-10Mn) or non-compliance issue results in significant fines and actions taken by regulatory authorities.
6	• £5Mn-20Mn • $10Mn-40Mn	• Fatality to a single member of public/ Multiple fatalities to employees (<4 people) (£20Mn/$40Mn)	• Catastrophic Environmental incident (e.g., contamination of a ground water source leading to prosecution, enforced clean up, and provision of alternative water supply) (£5Mn-20Mn/$10Mn–40Mn) or a non-compliance issue that results in fines and actions taken by regulatory authorities and presents a risk of affecting future business operations.
7	• £20Mn + • $40Mn +	• Multiple public fatalities or Multiple fatality of 5 or more employees (£50 Mn/$100Mn)	

B1 Impact Matrix – Reliability (2/3)

Score	Financial Impact	Reliability – EDx	Reliability – EDx
1	• < £5K • < $10K		
2	• £5K-50K • $10K-100K	• Loss to less than 500 customers • Less than <50K CMI • Loss of 0.5 (13KV) feeder • Loading: 95-100%	• Voltage (P.U.): 0.93-0.95 • MWh:<= 4 • Pocket Frequency:3
3	• £50K-250K • $100K-500K	• Loss to 500-5,000 customers • 50K to 500K CMI • Loss of 0.5-1 (13KV) feeder • Loading: 100-105%	• Voltage (P.U.): 0.92-0.93 • MWh:>4<=8 • Pocket Frequency:4-5
4	• £250K-1Mn • $500K-2Mn	• Loss to 5,000-10,000 customers • 500K to 1M CMI • Loss of 1-3 (13 KV) feeder • Loading: 105-110%	• Voltage (P.U.): 0.90-0.92 • MWh:>8<=16 • Pocket Frequency:6-10
5	• £1Mn-5Mn • $2Mn-10Mn	• Loss to 10,000-25,000 customers • 1M to 5M CMI • Loss of 3-6 (13KV) feeder • Loading: 110-115%	• Voltage (P.U.): 0.87-0.90 • MWh:>16<=40 • Pocket Frequency:10-15
6	• £5Mn-20Mn • $10Mn-40Mn	• Loss to 25,000-50,000 customers • 5M to 20M CMI • Loss of 6-10 (13KV) feeder • Loading: 115-120%	• Voltage (P.U.): 0.85-0.87 • MWh:>40<=80 • Pocket Frequency:16-20
7	• £20Mn + • $40Mn +	• Loss to 50,000 customers • More than 20M CMI • Loss of more than 10 (13KV) feeders • Loading: 120%	• Voltage (P.U.): less than 0.85 • MWh:>80 • Pocket Frequency:>20

Assumed exchange rate: £1=$2

B1 Impact Matrix – Reliability (3/3)

Score	Financial Impact	Reliability – Global IS and shared services	Reliability – LNG
1	• < £5K • < $10k	• -	• -
2	• £5K-50K • $10K-100K	• Local failure of infrastructure or business systems affecting <100 employees for a day	• Loss of liquefaction capability for up to 3 days
3	• £50K-250K • $100K-500K	• Local failure of infrastructure or business system affecting <100 employees for <1 week	• Loss of liquefaction capability for between 4 and 14 days
4	• £250K-1Mn • $500K-2Mn	• Failure of infrastructure or business system at a major business location (>300 employees) for a day. Potential impact into more critical IS systems	• Loss of liquefaction capability for between 15 and 50 days • Loss of site export capability for up to 1 day at time of winter peak
5	• £1Mn-5Mn • $2Mn-10Mn	• Enterprise wide or multiple major location failure of infrastructure or business systems for <24 hours. More critical IS systems impacted	• Loss of liquefaction capability for between 51 and 150 days • Loss of site export capability for between 1 and 5 days at time of winter peak
6	• £5Mn-20Mn • $10Mn-40Mn	• Enterprise wide or multiple major location of infrastructure or business systems for >24 hours. More critical IS systems seriously impacted	• -
7	• £20Mn + • $40Mn +	• Extended enterprise failure or infrastructure or business systems that impact national Grid's ability to function as a commercial business. More critical IS systems highly impacted	• -

Assumed exchange rate: £1=$2

B1 Likelihood Matrix 1 of 5 – Guide to use the likelihood tables

• **Safety projects caused by a single event (e.g., installation of handrails)**	3 of 5	

Asset failure	No coincident event needed for impact	Coincident event needed for impact
• Time to failure known and earliest asset of failure has not been reached	2 of 5	4 of 5
• Time to failure known and earliest asset of failure has already been reached	3 of 5	5 of 5
• Time to failure not known, but history of similar failures is available	3 of 5	5 of 5

B1 Likelihood Matrix (2 of 5) – Using a *time to failure* approach

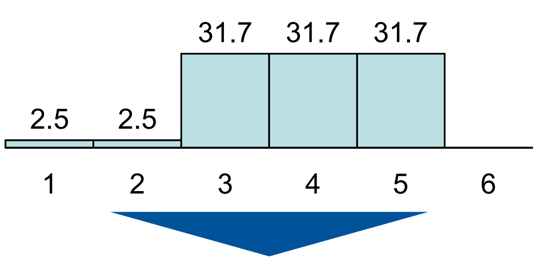
Resulting likelihood scores after considering time to failure

Time to failure (in years)	Likelihood level
<1 years	7
1 to 3 years	6
3 to 5 years	5
5 to 10 years	4
10 to 20 years	3
20 to 100 years	2
>100 years	1

Example

An asset is not expected to fail in the next 2 years, but it is expected to fail in 3 to 5 years

Probability of failure, %



Likelihood score – 5

Guidance to use this table

- Step 1 – Establish the earliest and latest time to failure for an asset
- Step 2 – Derive the resulting likelihood score by scrolling across the table – e.g., if an asset is not expected to fail in the next 3 years, but it is expected to fail in 3 to 5 years, the likelihood score is 5

B1 Likelihood Matrix (3 of 5) – Using *time to certain event* or *probability* approach

Resulting likelihood scores after considering the time to a certain impact or the probability of an impact happening next year (assuming a uniform distribution)

Years to certain impact	Likelihood level	Probability of certain impact happening next year
1	7	100%
2	7	50%
3	6	33%
5	6	20%
6	5	17%
10	5	10%
20	4	5%
100	4	1%
200	3	0.5%
500	2	0.2%
1000	2	0.1%
2000	1	0.05%

Example

An event will happen in the next 5 years (on the probability of the event happening next year is 20%)

Probability of an event occurring, %

20 20 20 20 20

1 2 3 4 5 6

Likelihood score – 6

Guidance to use this table

- Step 1 – Establish the time to a certain impact or the probability of a certain impact happening next year
- Step 2 – Derive the resulting likelihood score from the central column by scrolling across the table above – e.g., if an event will happen in the next 5 years (or the probability of the event happening next year is 20%), the likelihood score is 6

B1 Likelihood Matrix (4 of 5) – Using a *time to failure* approach and *coincident event*

Resulting likelihood scores after considering time to asset failure and coincident event required for the impact

		Time to coincident event									
		1	2	3	4	5	10	20	33	100	1000
Time to failure	>1 years	7	7	6	6	6	5	4	4	4	2
	1 to 3 years	6	6	6	6	5	5	4	4	4	2
	3 to 5 years	5	5	5	5	5	4	4	4	3	1
	5 to 10 years	4	4	4	4	3	3	2	2	1	1
	10 to 20 years	3	3	3	3	3	2	2	1	1	1
	20 to 100 years	2	2	2	2	2	2	1	1	1	1
	>100 years	1	1	1	1	1	1	1	1	1	1
		100%	50%	33%	25%	20%	10%	5%	3%	1%	0.1%
		Likelihood of coincident event									

Guidance to use this table

- Step 1 – Establish the earliest and latest time to failure for an asset
- Step 2 – Establish the likelihood of co-incident event required to result in the impact (say failure of another asset required to result in the impact of loss of supply). If no coincident event is required, assume 100%
- Step 3 – Derive resulting likelihood score by scrolling across the table – e.g., 3–5 years to failure and coincident event likelihood of 25% (will happen in the next years) results in a likelihood score of 5

B1 Likelihood Matrix (5 of 5) – Using a *probability of impact in the next year* approach and *coincident event*

Resulting likelihood scores after considering likelihood of primary and coincident event required for the impact

Years to certain impact (assuming uniform likelihood)	Time to coincident event: 1	2	3	4	5	10	20	33	100	1000	Probability of certain impact happening in the next year
1	7	7	6	6	6	5	4	4	4	2	100%
2	7	6	6	6	6	5	4	4	4	2	50%
3	6	6	6	6	5	5	4	4	4	2	33%
4	6	6	6	6	5	5	4	4	4	2	25%
5	6	6	5	5	5	5	4	4	3	2	20%
6	5	5	5	5	5	4	4	4	3	1	17%
7	5	5	5	5	5	4	4	4	3	1	14%
8	5	5	5	5	5	4	4	4	3	1	13%
9	5	5	5	5	5	4	4	4	3	1	11%
10	5	5	5	5	5	4	4	4	3	1	10%
20	4	4	4	4	4	4	4	3	2	1	5%
50	4	4	4	4	4	3	3	2	2	1	2%
100	4	4	4	4	3	3	2	2	1	1	1%
200	3	3	3	3	3	2	2	1	1	1	0.5%
500	2	2	2	2	2	2	1	1	1	1	0.2%
1,000	2	2	2	2	2	1	1	1	1	1	0.1%
2,000	1	1	1	1	1	1	1	1	1	1	0.05%
Likelihood of coincident event	100%	50%	33%	25%	20%	10%	5%	3%	1%	0.1%	

Guidance to use this table

- Step 1 – Establish the likelihood (or time to event) of the primary event
- Step 2 – Establish the likelihood (on time to event) of co-incident event required to result in the impact
- Step 3: Derive resulting likelihood score by scrolling across the table – e.g., Probability of primary event happening next year is 50% (or a max of 2 years to a certain event) and coincident event likelihood of 25% (or max of 4 years to a coincident event) results in a likelihood score of 6

Final V1.0 January 2008

nationalgrid

B2 The blended score for each outcome is derived from ranking the product of impact (£/$) and likelihood (%)

Blended Impact and Likelihood scores*

Impact \ Likelihood	1	2	3	4	5	6	7
7	25	32	38	43	47	48	49
6	20	29	33	40	44	45	46
5	15	22	26	35	39	41	42
4	9	17	19	28	34	36	37
3	5	10	14	21	27	30	31
2	3	6	8	16	18	23	24
1	1	2	4	7	11	12	13

- Blended scores are derived by ranking expected monetary values of each possible outcome
- Expected monetary value (EMV) for a given outcome is the product of the average monetary impact and the average probability. For example:
  - Impact of 6 and likelihood of 2 gives an expected monetary value of £75,000, derived as product of:
    - Level 6 impact of £12.5 M (average of £5M and £20M)
    - Level 2 average cumulative probability of 0.60% (between 0.2% and 1%)
- All the expected monetary values are ranked from 1 to 49 to give blended scores. For example:
  - The highest EMV of £33.25M is assigned a score of 49 (highest possible score)
  - Likewise, the EMV of £75,000 is assigned a score of 29

Expected monetary value, £

Impact	Average monetary impact, £	1	2	3	4	5	6	7
7	*35,000,000*	35,000	210,000	612,500	3,937,500	13,125,000	25,375,000	33,250,000
6	*12,500,000*	12,500	75,000	218,750	1,406,250	4,687,500	9,062,500	11,875,000
5	*3,000,000*	3,000	18,000	52,500	337,500	1,125,000	2,175,000	2,850,000
4	*625,000*	625	3,750	10,938	70,313	234,375	453,125	593,750
3	*150,000*	150	900	2,625	16,875	56,250	108,750	142,500
2	*27,500*	28	165	481	3,094	10,313	19,938	26,125
1	*2,500*	3	15	44	281	938	1,813	2,375
	Average likelihood	*0.10%*	*0.60%*	*1.8%*	*11%*	*38%*	*73%*	*95%*

Likelihood

Final V1.0 January 2008

* Scores are grouped and colour coded for ease of viewing (40 and above - red, 16-39 - yellow and 15 and below - green)

nationalgrid

How to . . .

Classify
Score as 50

1. Diagnostic studies
2. Projects to comply with targets set by the regulator
3. Blankets

Risk score

4. Projects whose impact requires a coincident event
5. Asset failure projects for assets that have reached the earliest onset of failure
6. Projects with mitigation alternatives
7. Programs that are bundles of similar projects
8. Projects on interdependent assets

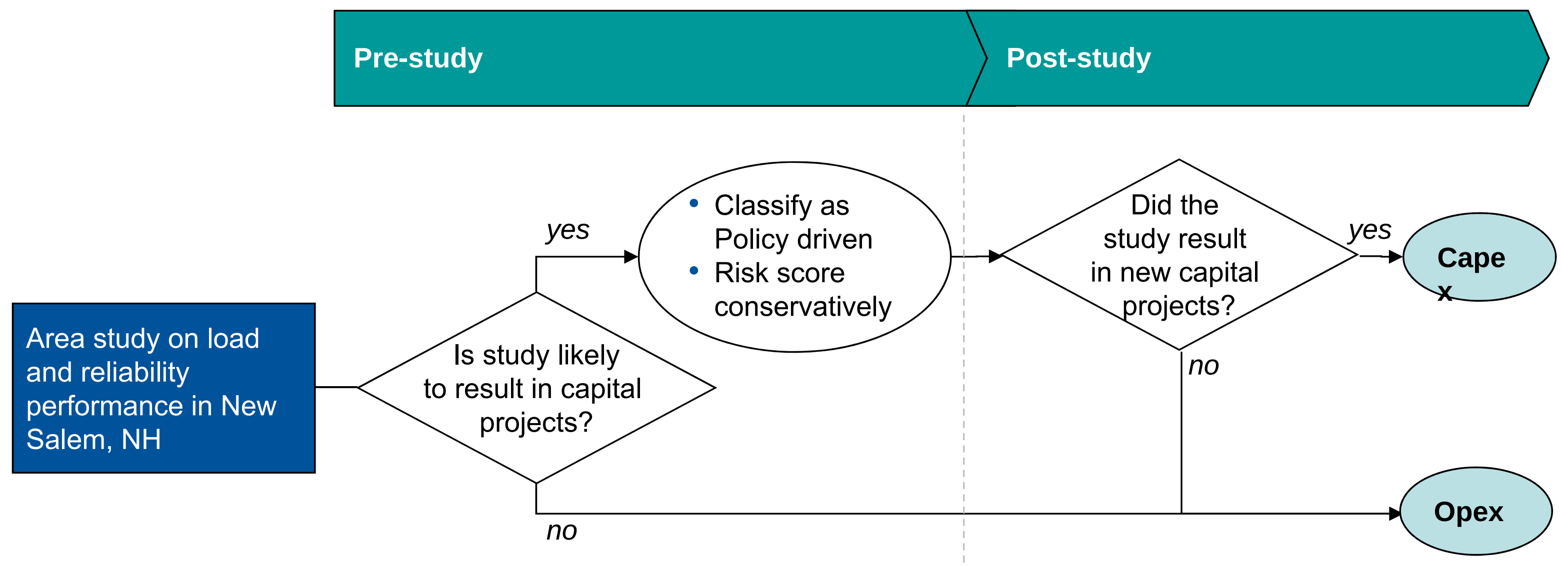
Final V1.0 January 2008

Source: Team analysis

1 How to classify diagnostic studies

- A study should be considered **opex** unless it is likely to result in a capital project
- Capex studies should be classified as **policy driven and scored conservatively** (i.e., worst possible consequence that the study may uncover)
- Studies that were considered capex and do not result in capital investments should be expensed and written off the capital plan

Example



Final V1.0 January 2008

Source: Risk scoring pilots; team analysis

2 How to classify projects to comply with targets set by the regulator

- **Policy driven** if the targets are on reliability, safety or environmental parameters, as there is **discretion on projects needed** to achieve these targets
- **Mandatory** if the targets are on capex (or capex equivalent) spent on **specific project/programmes immediately**

Examples

Project	Classification	Rationale
1 Transformer replacement to maintain reliability targets/ standards	• Policy driven	• Discretion on specific projects needed to achieve targets
2 Replacement of specified length of gas mains (e.g. KED LI regulatory target – 60 mile **per year**)	• Policy driven	• Obligation to achieve target immediately, but there is discretion on which mains to replace, and the mix will affect the capex required
3 Replacement of specific length of miles of gas mains (regulatory target – 300 miles in **5 years**)	• Policy driven	• Capex-equivalent target on specific program, but there is discretion on timing of the replacement

Source: Risk scoring pilots; team analysis

3 How to classify blankets

- Blankets (or provisions) are capital allocations for unspecified expenditures during capital plan period – e.g., new connections, load relief
- Blankets should be classified in the same way as one of its expenditures (i.e. mandatory or policy driven)
- If policy driven, they should be scored according to the risk/likelihood of a single expenditure

Examples

Project	Classification	Rationale
1 **New connections** blanket providing capital for expected new connections	• Mandatory	• New connections will be required by regulator immediately
2 Blanket for **load relief** work	• Policy driven	• Load relief projects occur at the discretion of an LOB
3 Damage and failure	• Mandatory	• Repairs will be required by regulator immediately

Final V1.0 January 2008

Source: Risk scoring pilots; team analysis

4 How to risk score projects whose impact requires a coincident event

- Estimate the time to failure for the asset or the probability of the asset failing. This is the **primary event**
- Estimate the probability of the **coincident event**, making sure that you **correct for exposure**
- Look up the likelihood score in pages 4/5 or 5/5

Example

Replacement of a circuit breaker. There is a risk of catastrophic failure and subsequent injury to an employee. The breaker is expected to fail in 5–10 years

Primary event	Coincident event	Likelihood score
Time to failure: 5–10 years	An employee spends 8 hours a day on site Monday–Friday and is near the breaker for 50% of the time he spends on site	• Time to failure: 5–10 years • Probability of coincident event: 12% • Likelihood page 4/5

% of time spent on site: $\frac{8\text{ h} \times 5}{24\text{ h} \times 7} = 24\%$

×

% of time near breaker: 50%

=

Probability of coincident event: **12%**

Likelihood score is 3

Final V1.0 January 2008

Source: Risk scoring pilots; team analysis

nationalgrid

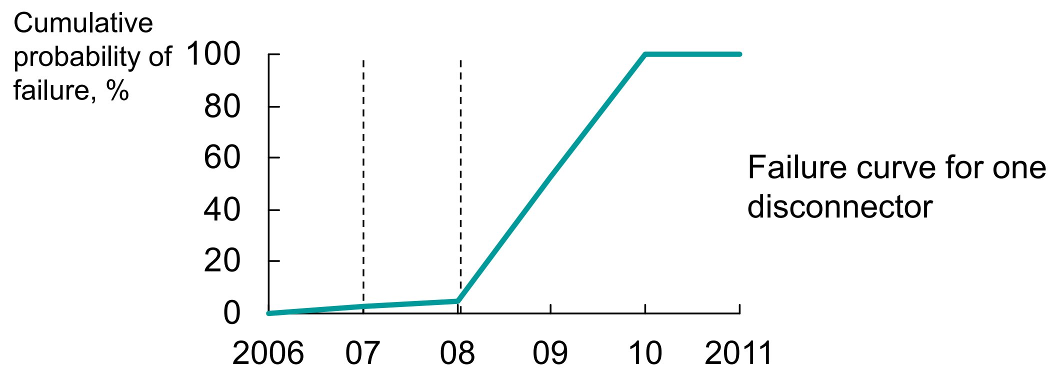
LOX-NGT011-20071101-MHJP

5 How to risk score asset failure projects for assets that have reached their earliest onset of failure

- Estimate the time to failure in years and use likelihood page 3/5 if asset has reached its earliest onset of failure

Example

Replacement of a disconnector



Impact may be caused by disconnector failure. What is the likelihood score?

	Likelihood page	Years to failure	Likelihood score
Before earliest onset of failure (2007)	2/5	• 1–3 (earliest asset in 2008 and failure expected by 2010)	6
After earliest onset of failure (2008)	3/5	• 2 (failure expected anytime before 2010)	7

uary 2008

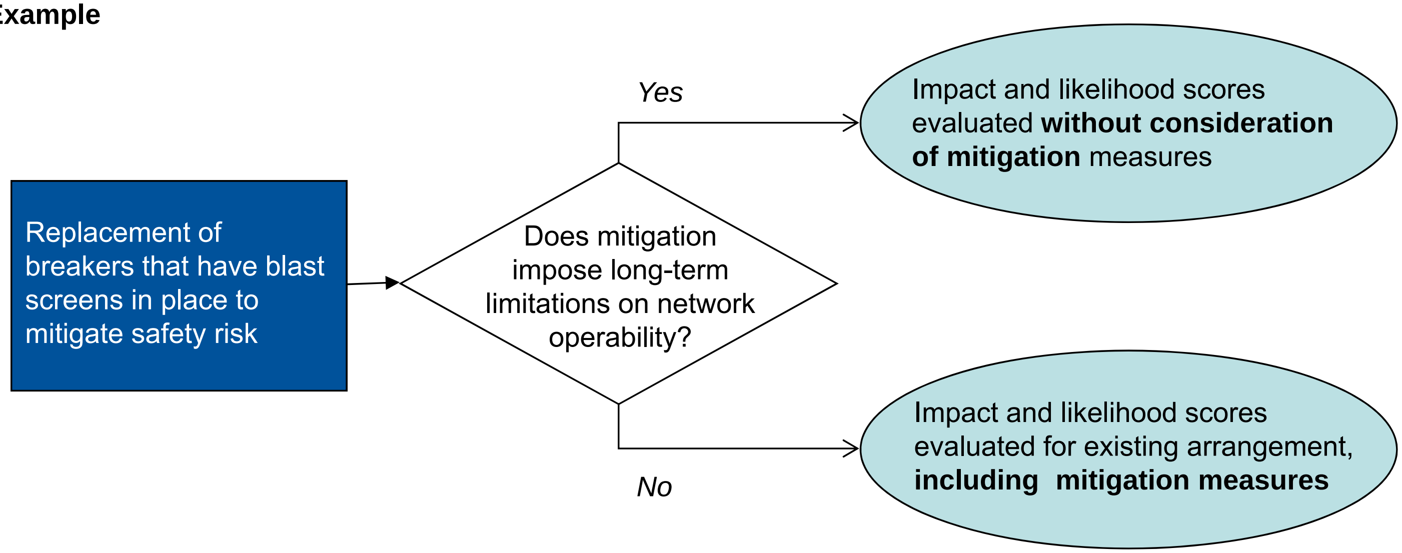
nationalgrid

Source: Risk scoring pilots; team analysis

6 How to risk score projects with mitigation alternatives

- Risk mitigation measures are sometimes available as alternatives to asset replacement or permanent repair
- In cases where alternative mitigation measures may be undertaken, the scoring approach is driven by the long-term liability of the mitigation:
  - If mitigation can remain **stable** with little/no impact on network operability in the long term, projects should be considered **post-mitigation**
  - If mitigations are **temporary** in nature or impose limitations on network operability (unacceptable long-term), risk scores should be evaluated **pre-mitigation**

Example



Final V1.0 January 2008

nationalgrid

Source: Risk scoring pilots; team analysis

7 How to risk score programmes made up of several similar projects

- Similar projects bundled into a single programme of work should be scored according to the risk/likelihood appropriate for **one** such project.
- If bundled projects vary in impact and/or likelihood (i.e., equipment of varying ages or with different levels of connectivity), programme should be disaggregated and risk scores evaluated for each component project

Example Programme 1

A replacement programme to upgrade 60 governor stations with similar risk profiles:

Project	Impact	Likelihood	Risk score
Each of the 60 governor stations	5	6	41
Total programme	**5**	**6**	**41**

Project scored to evaluate impact / likelihood of a single failure, not the combined total impact

Fin

Example Programme 2

A replacement programme to upgrade 60 governor stations with different risk profiles:

Project	Impact	Likelihood	Risk score
15 governor stations	5	5	39
45 governor stations	5	6	41

This program should be disaggregated to appropriately reflect the different risk profiles

nationalgrid

Source: Risk scoring pilots; team analysis

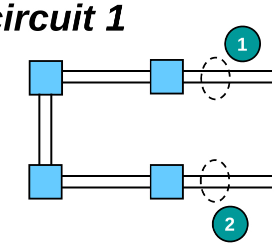
8 How to risk score projects on interdependent assets

- Risk score the project considering the failure of the individual asset
- Risk score the project considering coincident failures (e.g., within the same electrical zone) of the **interdependent assets within the network**
- **The higher of the two scores is used for prioritisation**

Example

Electricity transmission – overhead line work

The project is to refurbish double-circuit 1



Double-circuit (DC) 1 is expected to fail within 5 years

	Impact	Likelihood	Risk
Individual failure	• **2** Disruption and mainte-nance costs	• **6** Expected to fail within 5 years	• **23**
Coincident failure	• **6** Loss of both lines would cause supply loss between 250–1,000 MW	• **3** Probability of coincident failure of DC 2 is 1%	• **33**

Risk of the project is 33

Source: Risk scoring pilots; team analysis

PUC 1-11

Request:

Referencing page 59, please provide a copy of the Company's DOA governance policy. Please identify the parts of the policy where the percentages referenced in Footnote 8 are found and where the affect of the Company's "aiming" for certain estimates is implied.

Response:

Footnote 8 states: "Associated with the new complex capital delivery process, the Company is aiming for complex projects to come out of an Area Study with an estimate of +50%/-25% and will go through a stage-gate process that will develop a risk-assessed estimate. The DOA for projects will be done at +/- 10%."

The cost estimation tolerances that the complex capital delivery team is aiming to achieve is not part of the Delegation of Authority (DOA) governance policy but rather business process aspirations.

Capital project governance follows the U.S. Capital Sanctioning Process. Please see the following attachments for capital projects sanctioning processes, procedures, and DOA policies. Attachment PUC 1-11-1, Section 18.0 Definitions defines DOA Tolerance and Accuracy on page 20 of 22.

Attachment PUC 1-11-1: National Grid U.S. Sanctioning Committee Procedure applicable to all utilities

Attachment PUC 1-11-2: Sanction Procedure for Projects < $1M applicable to all utilities

Attachment PUC 1-11-3: National Grid USA U.S. Sanctioning Committee Terms of Reference applicable to all utilities

Attachment PUC 1-11-4: National Grid USA Senior Executive Sanctioning Committee Terms of Reference applicable to all utilities

Attachment PUC 1-11-5: **CONFIDENTIAL** DOA – U.S. Tertiary Delegations Matrix applicable to all utilities

Prepared by or under the supervision of: Patricia C. Easterly

nationalgrid

National Grid US Sanctioning Committee Procedure

Authorized by

Date: 14 August 19

Kathleen Geraghty, Vice President
National Grid USA

National Grid USA
40 Sylvan Road
Waltham, MA 02451-1120

TABLE OF CONTENTS

1.0 Change Control

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	March 7, 2012	Implementation of new procedures for all US utility services.	M. Carlino	Approved by Mary Fuller
Issue 2	May 8, 2013	Revision to incorporate changes to procedure	R. Morey	Mary Fuller
Issue 3	January 7, 2015	Annual Review	M. Carlino & M. Roby	Mary Fuller
Issue 4	March 25, 2016	Annual Review	M. Carlino	Mary Fuller
Issue 5	May 08, 2017	Annual Review	D. Monteiro	Mary Fuller
Issue 6	May 30, 2018	Annual Review	MJ Barry	Sue Martuscello
Issue 7	July 29, 2019	Annual Review	MJ Barry	Sue Martuscello

2.0 Introduction

2.1 This procedure is intended to provide guidance for sanctioning and re-sanctioning capital investments greater than or equal to $1 million.

2.2 The purpose of this document is to establish a formal review and approval process for all National Grid utility services.

2.3 All investments must receive proper Delegation of Authority ("DoA") prior to that expenditure being committed, except in emergency situations as outlined in Section 11.5. Approval will be based on maximum risk-range (tolerance) cost including capital, Operations and Maintenance ("O&M"), removal, and salvage costs.

2.4 This document shall be reviewed annually and amended as needed.

2.5 The sanction process utilizes several key digital templates:

2.5.1 Sanction Templates will be used for partial sanctions, full sanctions, re-sanctions and project development.

2.5.2 The Closure Template is used to close out the funding project after all the work has been completed. The Spending Review Template is used for annual Blankets/Programs and Project Development at fiscal year-end.

3.0 Applicability

3.1 This procedure is applicable to the following Utility Services:

- Power Plant Operations
- Property
- Gas
- LNG
- Electricity Transmission and Distribution
- Fleet
- Information Technology

3.2 Site Investigation and Remediation (SIR) will be subject to the US Environmental Oversight Committee's Terms of Reference

3.3 The Executive Sanctioning Committees may require any other Utility Services to occur before it is permitted for approval.

4.0 Exceptions

4.1 This procedure does not apply to:

- Energy Procurement
- Regulatory DoA

5.0 References

5.1 Supporting policies and procedures are available on the Infonet and reviewed on an annual basis. Terms of Reference link is set to the main page where both documents can be located.

5.1.1 National Grid USA Delegations of Authority (DoA) Site
5.1.2 Terms of Reference (US Sanctioning Committee and Senior Executive Sanctioning Committee)
5.1.3 Cost Overrun Procedure (Under Development)

6.0 Sanction Paper – General:

6.1 Investment proposals may progress as a partial sanction paper or full sanction paper.

6.2 A sanction paper shall be used to approve any expenditure as required in the Executive Sanctioning Committee's Terms of Reference and provides the financial DoA to deliver the funding project as detailed within the proposal.

6.2.1 The funding project amount to be sanctioned and for which DoA is requested shall be the gross expected expenditure. Any CIAC or other contributions are not to be used to reduce the gross amount. For example, if a $5.0M funding project is initiated and a $1.0M customer contribution is expected, DoA shall be requested for $5.0M. It would not amount to $4.0M.

6.3 Sanction paper numbers are obtained from the USSC Technical Secretary prior to submitting the paper as an agenda item for the Sanctioning Committee meetings.

6.4 Land purchases must have their own funding project number.

6.5 A partial sanction paper shall be submitted to advance a funding project when a request for full authorization cannot be submitted due to the lack of a complete scope and final cost (except as noted in section 8.0). The author should ask for enough DoA in their first partial sanction paper to get them through all the activities prior to construction, when possible. DoA under a partial sanction provides authority for items such as, but not limited to:

- Engineering and design
- Land purchase
- Services procurement from consultants, attorneys, etc. to obtain permitting and licensing ahead of construction
- Long lead-time material procurement
- In emergencies, when approval is required immediately
- Preliminary field work
- Other steps necessary to move a funding project towards execution
- An increase in scope, schedule or cost from a previously approved partial sanction

6.6 Generally, only one operating company is to be included in a sanction paper. Exceptions to this include sanctions initiated by

6.6.1 Papers involving New England Power and another New England distribution or transmission companies where multiple funding projects may be included in the same paper.

6.7 Committee Approval is determined by the potential investment at the time the paper is presented for approval.

6.7.1 For example, if a Partial Sanction was approved at the Senior Executive Sanctioning Committee (SESC) due to the potential investment being greater than $25M (including tolerance). If the full sanction potential investment becomes less than $25M (including tolerance), then United States Sanctioning Committee (USSC) shall approve the paper.

6.7.2 Determination of Committee Approval between Weekly Tuesday Committee and USSC does not includes tolerance.

6.7.3 The final spend for Closures and Spending Reviews shall determine which sanctioning committee it is presented to for approval.

6.8 Related funding projects can cross lines of business (e.g. Transmission and Distribution Electric, Gas, Property, IS, SIR or Generation investments) and companies. These related funding projects should be identified in a Sanction Paper with a <u>very brief</u> scope and total cost by line of business and company

7.0 Sanction Paper: Specific Projects, Blankets, and Programs greater than or equal to $1M

7.1 **Gas and Electric** DoA requests for investments greater than or equal to $1M and less than $8M, whether high, medium or low complexity, to use the short form digital template.

7.1.1 These papers will be approved and signed by the USSC Chair and placed on the USSC agenda on a quarterly basis for noting.

7.2 **Gas and Electric** DoA requests for high or medium complexity funding projects with total costs of $8M or greater to use the USSC sanction digital template which will be presented to the USSC for approval.

7.3 **Gas and Electric** DoA requests for low complexity funding projects with total costs of $8M or greater to use the short form digital template which will be presented to the USSC for approval

7.3.1 In the event a Gas or Electric funding project is estimated to be below $8M but the tolerance raises the DoA above $8M, a short form digital template can be used and signed by the USSC chair, however:

- If the forecast is expected to reach or exceed $8M and is above the allowable tolerance; the paper must be re-sanctioned and submitted to the USSC on the appropriate form as described above.
- The paper must clearly explain that the original sanction was for under $8M.

7.4 **SIR** contracts with total costs that are:

- Between $1M and $5M with a low complexity may be completed using SIR DoA procedure with appropriate documentation.
- Between $1M and $5M with a medium or high complexity will be completed using the USSC sanction digital template and will be presented to the Environmental Oversight Committee for approval.
- Greater than $5M with a medium or high complexity will use the USSC sanction digital template and will be presented to the Environmental Oversight Committee for approval.
- Greater than $5M with a low complexity will use the short form digital template and will be presented to the Environmental Oversight Committee for approval.

7.5 **LNG** projects with total costs that are:

- Equal to or greater than $8M with a low complexity will use the short form digital template.
- Equal to or greater than $8M with a medium or high complexity will use the standard sanction digital template which will be presented to USSC for approval.

7.6 **IT** funding projects that are:

- Greater than or equal to $1M and less than $5M with a low complexity, will use the short form digital template.
- Greater than or equal to $1M and less than $5M with a medium or high complexity, will use the USSC sanction digital template.
- Greater than $5M with a low complexity will use the short form digital template and will be presented to the USSC for approval
- Greater than $5M with a medium or high complexity will use the USSC sanction digital template and will be presented to the USSC for approval

7.7 **Property** funding projects that are:

- Greater than or equal to $1M and less than $3M with a low complexity, will use the short form digital template.

- Greater than or equal to $1M and less than $3M with a medium or high complexity, will use the USSC sanction digital template.
- Greater than $3M with a low complexity will use the short form digital template and will be presented to the USSC for approval.
- Greater than $3M with a medium or high complexity will use the USSC sanction digital template and will be presented to the USSC for approval.

7.8 **Power Plant Operations** (Generation) funding projects that are:

- Greater than $1M with a low complexity will use the short form digital template and will be presented to the USSC for approval.
- Greater than $1M with a medium or high complexity will use the USSC sanction digital template and will be presented to the USSC for approval.

7.9 All Utility Services

- DoA requests for all utility services funding projects with total costs greater than $25M to use the USSC sanction digital template which will be presented and noted for recommendation by the USSC, to move forward to the SESC for approval. If a project is less than $25M but the tolerance puts the project greater than $25M, then the project will go to the USSC for noting and to the SESC for approval. An overview presentation is also required for SESC.

7.10 Blanket Funding Projects

- Each fiscal year the blanket funding projects are presented to the Sanctioning Committees for approval using the short form digital template.
- Blanket funding projects have a complexity score of 15
- An overview presentation of the blanket funding paper is required when presented at the Senior Executive Sanctioning Committee. (For USSC, a one-page slide highlighting total blanket spend when multiple operating companies are involved).
- Blanket funding projects may not be segmented into smaller pieces to sanction the spending at a lower level of authority than would otherwise be required.
- A spending review document is presented at the end of each fiscal year no later than the July sanction approval.
- Senior Executive Sanctioning Committee (SESC) has authorization to approve Blanket funding projects exceeding the SESC approval limit.

7.11 Programs

- Each fiscal year the program(s) is/are presented to the Sanctioning Committees for approval using the short form digital template.
- Program complexity scores should reflect an average of the program.
- An overview presentation of the program is required when presented at the Senior Executive Sanctioning Committee. (For USSC, a one-page slide highlighting total program spend when multiple operating companies are involved).
- Program funding projects may not be segmented into smaller pieces to sanction the spending at a lower level of authority than would otherwise be required.

- A spending review document is presented at the end of each fiscal year no later than the July sanction approval.
- Senior Executive Sanctioning Committee (SESC) has authorization to approve Program funding project(s) exceeding the SESC approval limit.

7.12 Project Development

- Each fiscal year specific capital project development costs are aggregated in a single sanction paper for each Operating Company ("OpCo").
- The utilization of the single paper approval for portfolio project development costs supports the new capital delivery process.
- Project Development Funding Papers will be presented to the Sanctioning committee.
- An overview presentation of the Project Development is required when presented at the SESC.
- A spending review document is presented at the end of each fiscal year no later than the July sanction approval.

8.0 Sanction Paper: Engineering / Design

8.1 If a project is requesting funds for engineering/design only, it may be done using the short form template or by using the appropriate personal DoA in PowerPlant to approve a Project Funding number.

8.1.1 All sanctions following the engineering/design partial sanction will abide by the requirements listed above.

9.0 Re-Sanctioning:

9.1 All specific, blanket and program funding projects, for all Utility Services (excluding electric blankets) must be re-sanctioned within 60 calendar days of notification that the cost is outside of the tolerance approved in the sanction template.

- Partial sanctions are not re-sanctioned using the re-sanction template. In the event the funding project scope or cost has changed since a partial sanction paper was approved, another partial sanction would be presented using the appropriate template until the investment has been sanctioned at the full sanction at +/-10%.

9.2 Funding project schedule and scope variances are not governed by this process. Variances are documented and approved in accordance with the applicable Utility Services procedures.

9.3 If DoA was obtained for a funding project originally estimated to be below $1M, but the forecasted total cost or the actual spend subsequently equals or exceeds $1M, then the funding project must be re-sanctioned by the Program Manager and presented to the appropriate committee.

- The paper must clearly explain that the original sanction was for under $1M and explain what drove the variance.

9.4 A cost is incurred at the moment the payment obligation is incurred. Non-payment of valid invoices is not an acceptable method of remaining within DoA.

9.5 If there are any outstanding contractual claims in an investment (contractor, land owner, etc.) that may push costs over the upper sanction range, the Sanctioning Committees and responsible executive sponsor shall be notified with an explanation of the issue along with a description of potential outcomes. The investment should be re-sanctioned for cost when the value of the claim is known.

9.6 An investment must also be re-sanctioned if the project scope fundamentally changes, there is a material increase or decrease in project scope, or changes occur in the actual work even though the operational outcome remains the same. The decision as to whether changes in a project are "material" rests with the Sponsor.

9.7 Summary of Re-sanction thresholds:

Re-sanction for:	Re-sanction Threshold
Cost	Once forecasted to be above the DoA authorized in the Sanction Paper **it must be re-sanctioned** (requested amount plus tolerance)
Scope	Fundamental or material increase or decrease in scope – determined by Sponsor

9.8 Re-sanction papers should not re-state the original need case. Rather the paper must include a detailed explanation of the new sanction requirements and why they have changed from that which was originally approved. In addition, the re-sanction paper should include details of lessons learned including an explanation of any significant variances in cost. If they are not fully known at the time, they must be included in the closure or spending review paper.

9.9 If the original investment drivers change during the course of a funding project, but the investment costs and scope remain as sanctioned, the funding project must be re-sanctioned.

9.10 Re-sanction papers must be presented through the full DoA chain until it reaches the authority that can approve the revised total amount.

9.11 In the event there is a personnel change to the project or program manager following approval of a sanction paper, the funding project does not have to be re-sanctioned.

Closure Paper:

9.12 Funding project closure papers shall be required for all funding projects $1M or greater. All annual Program and Blanket closure papers shall use the Spending Review template and be presented at the appropriate sanction committee by July of the next fiscal year.

9.13 Specific funding project closure papers shall be submitted to the Sanctioning Committee's Secretary as soon as possible after all work orders and projects are closed.

9.14 Investment Management will circulate the Closure report quarterly for any updates to the project closure dates. The project sponsor/owner will have 10 business days to respond back with any changes to project closure dates.

9.15 Re-sanction for under spend may be combined with the closure paper if the under spend is not forecasted until late in the construction phase.

10.0 Fast-Track Approval Process

10.1 Where the needs of the business demand it, papers may be approved via a fast-track process administered by the Technical Secretary.

10.2 Under this process, papers must be submitted to the Business Director and Sponsor for an abbreviated review and support cycle prior to being circulated to the Committee members as appropriate.

10.3 Fast-track process approval for any paper shall be in written form (which may include, without limitation, electronic form) and will require approval of at least three Committee members.

10.4 Papers approved by the fast-track process will be presented for noting by the full Committee at its earliest convenience or at the next Committee meeting.

10.5 This fast-track process should only be used in exceptional circumstances, e.g., where a delay will impair safety, reputation and/or incur financial losses. The reason for the fast-track approval request must be clearly stated. The Investment Planning Director may use this process at his/her discretion as deemed necessary.

11.0 Delegations of Authority

11.1 In the event that an individual's DoA is used in-lieu of the sanctioning process; the Manual DoA form must be submitted to the Investment Strategy Director for auditing purposes. Electric

Investment Management will retain all Executive Sanctioning Committee's documentation. This individual DoA must be followed up with a sanction paper. Approvals must align to the DoA Tertiary Matrix and a sanction must be written for the full project expenditure.

11.2 The Sanctioning Committee's DoA will be authorized in PowerPlan by a proxy in Investment Management.

- The proxy will verify that the Sanctioning Committees approved amount for each funding project matches the DoA requested in PowerPlan prior to authorizing it.

11.3 Funding projects may not be segmented into smaller pieces to sanction the spending at a lower level of authority than otherwise would be required. Related funding projects shall be included in one investment document. A funding project is related to another funding project if it cannot fully accomplish its intended purpose unless the other funding project is also carried out.

11.4 DoA cannot be given to contract personnel.

11.5 In certain circumstances, it may not be practical to seek a proper delegated authority approval prior to entering a commitment. This is acceptable if the spend is nondiscretionary and following the delegated authority approval process would hinder operations in an emergency (e.g., response to storms, damage failures).

- DoA for full project expenditures must be obtained within 7 business days.

12.0 Special Meeting for Specific Projects ≥ 100M

12.1 Managing a complex project presents a series of challenges of greater magnitude, as a result an expanded reviewers and supporters meeting will prioritize the focus, drive continuous engagement while ensuring content and accuracy of the sanction request prior to presentation to USSC.

12.2 Include Project Sponsor, Vice Presidents of Asset Management, Business Development, Gas Resource Planning, Investment Strategy, and Project Management, as applicable.

13.0 NY Distributed Generation (DG) Sanction Process

13.1 This process shall only be used to expedite the funding project creation / approval for NY Distributed Generation (DG) projects $1M or greater.

13.2 Initially, the abbreviated NY DG digital form will be utilized to achieve the authorization to advance the project. If at any point, additional funds are needed, a re-sanction digital form shall be submitted while adhering to the sanction guidelines / process in place.

13.3 Signatory shall be the Vice President of Electric Asset Management and Planning.

14.0 Cost Overrun Report (Detailed Procedure Under Development)

On a monthly basis, each Utility Service shall prepare and distribute the Cost Overrun Report to responsible business stakeholders for action.

14.1 The Cost Overrun report identifies capital funding projects that have exceeded the sanctioned / authorized amount.

14.2 All Utility Services (Electric, Gas, Generation, Property and IT) shall provide Investment Management with comprehensive / high level data utilized to compile the 30 Day DoA Awareness Scorecard.

14.3 Within 10 business days from notification date, the responsible person must provide a driver for overrun in addition to a written plan to bring the affected funding project back into DoA compliance.

14.3.1 The actions may be a transfer of some of the costs to a different work order, re-sanctioning the sanctioned amount i.e. writing a paper or submitting a "Change in DoA Request Form".

14.3.2 Each Utility Service responsible person will follow up within their respective Utility Service if no action plan is received within 10 business days:

14.3.3 If no action plan is received – Projects that are at risk of becoming a 60 day overrun will be escalated to the Director of Investment Planning and VP of Investment Strategy and Regulatory Compliance at the 45 calendar day mark.

15.0 Responsibilities

15.1 *Director* - The *Director of Electric Investment Strategy* is the owner of the sanctioning process. The Director is responsible for developing, revising and maintaining the sanction templates, processes, procedures and ensuring that all changes are communicated to the corporation.

15.2 *Investment Management* – Revising and maintaining sanction templates, training, oversight of the Business Review Process within PowerPlan and sanction approval committees. Maintains approved sanction papers to PowerPlan and the USSC library while retaining approved sanction papers, and monitoring compliance with DoA.

15.3 *Investment Planning* – Ensures the funding projects described in the sanction papers are included, where applicable, in the budget and forecast. Facilitates annual sanctions for Blankets and Programs

15.4 *Program / Project Manager* – An individual responsible for implementing all aspects of a funding project including, planning, coordinating, and controlling a funding project. The Program / Project Manager, who is supported by a cross-functional project team, is accountable for delivering the funding project in accordance with the approved scope, cost, schedule and quality parameters.

15.5 *Reviewer* – A reviewer is an individual that reviews a proposal for content, language and recommends edits as necessary. A reviewer may or may not be a project team member but typically has expertise in one or several areas of a proposal. A reviewer's approval is required to advance a proposal.

15.6 *Sponsor* – The sponsor must be a vice-president or above and is ultimately responsible for assuring that a project delivers its proposed scope, cost, schedule and benefits. The sponsor works in conjunction with the project manager getting commitment from and managing cross-functional support and resource needs and clarifies business priorities and strategy. Also, the sponsor provides a route to escalate any issues and acts as a decision maker for issues beyond the project team's scope of authority. The sponsor (or designee) attends team meetings, as required, and regularly reviews project timelines, key milestones and outstanding issues. The sponsor is responsible for the quality and content of the sanction papers presented to the USSC or other governance committees.

15.7 *Supporter* – A supporter is typically a manager, director or vice-president. The supporter endorses a project or proposal when he or she is in agreement with the overall scope, cost, schedule and methodology incorporated in the proposal as it relates to his or her area of responsibility. The supporter also agrees that they have aligned, or will align, their part of the business to support the project. If a supporter does not endorse a project, then the project sponsor and the supporter must resolve any issues before the project can move forward.

15.8 *USSC – United States Sanctioning Committee* - Approves, endorses or notes investment papers for DOA within its authority. The USSC Terms of Reference (TOR) is posted on the Investment Planning Infonet site.

15.9 *SESC – Senior Executive Sanctioning Committee* - Approves, endorses or notes investment papers for DOA within its authority. The SESC Terms of Reference (TOR) is posted on the Investment Planning Infonet site.

15.10 *Sanction Committee Secretary* – Coordinates the investment proposals to be presented at the sanction committee meetings. Issues action items for US Sanctioning Committee and Senior Executive Sanctioning Committee meetings. Prepares and circulates the minutes associated with Committee meetings. Manages the Fast Track Sanction process, and progresses papers to the NGUSA Board for approval, as required.

16.0 Considerations in Preparation of Investment Papers

16.1 Authors are responsible to post papers to the USSC Sanction SharePoint site that are complete and ready for presentation to the Committees *per the due dates posted on SharePoint*.

- Any paper that has not been properly reviewed will be sent back to the author and rescheduled.
- Papers received after this deadline will not be accepted on the current month's USSC, and SESC agendas or weekly sanction review agenda.

16.2 Authors shall allow adequate time to incorporate reviewer and supporter comments prior to submittal to the USSC SharePoint site. Papers shall be sent to all supporters and reviewers listed on the paper allowing at least 5 business days for review.

- The reviewer and supporter list is posted on the US Sanctioning Committee's (USSC) SharePoint site.

16.3 If the investment paper includes Critical Energy Infrastructure Information (CEII) it should not be viewed by anyone not trained on procedures regarding CEII. Training is provided and tracked in MyHub prior to posting papers, the approved (signed) paper is sent to the Transmission Planning Department to determine if the paper contains CEII. If it does, the paper is processed accordingly before posting. The distribution of papers within and outside of National Grid shall follow CEII procedures.

17.0 Retention and Notification of Approval of Investment Papers

17.1 Final investment papers shall be posted by the author to the USSC SharePoint site as major version 3 with all edits requested by the Approving committee incorporated. The Investment Management Department will circulate sanction papers for signature approval. Investment Management will retain all Executive Sanctioning Committee's approved sanction papers and alternate forms requesting DoA (i.e. Manual DoA form, etc.)

17.2 All Executive Sanctioning Committee's approved sanction papers will be saved electronically to the USSC SharePoint library and as a hardcopy by Investment Management.

18.0 Definitions

Term / Acronym	Definition
Approved Amount	The approved amount represents the estimated project cost requested for approval. The authorizing individual or committee must have DoA equal to or greater than the dollars being requested. The estimated project cost plus the tolerance would be the DoA amount.
Blanket Funding project	Blanket funding projects consist of many work orders that are typically standard construction and are of short duration. Both, Gas and Electric blanket funding projects are work that are typically externally driven (reactive in nature). Blankets are intended to have a duration of a single year and must be re-authorized each fiscal year. Examples of blanket funding projects may be New Business, Damage/Failure, etc. Electric blanket funding project work order gross expenditures shall not exceed $100,000. Multiple blanket funding projects may be sanctioned together on a single sanction paper. Close-out papers are written for each blanket funding project on an annual basis, either individually or as a group, similar to how the blankets were originally sanctioned.
Blanket Funding Project Work Order:	Work orders initiated and linked to Blanket Funding Projects
Closure Paper	A closure paper is a paper prepared for noting to the Executive Sanctioning Committees at the completion of a funding project that details the financial and objective outcomes of the funding project. A closure paper shall be prepared using the Closure Paper template. A closure paper must be prepared for all funding projects approved by the Sanctioning Committees, including canceled funding projects.
Conflict of Interest	Federal law prohibits the disclosure of non-public transmission function information or non-public information acquired from unaffiliated transmission customers to employees in our Marketing function.

Noting	Noting consists of items that, because of their nature, can be decided by the USSC based on written reviews and analyses previously made available to the committee and do not require discussion. Any item under the Noting section requiring discussion may be resolved via email or added to the following month's sanction meeting agenda.
Critical Energy Infrastructure Information (CEII)	Critical Energy Infrastructure Information (CEII) is defined as "specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure" that: • Relates details about the production, generation, transportation, transmission, or distribution of energy; • Could be useful to a person in planning an attack on critical infrastructure; • Is exempt from mandatory disclosure under the Freedom of Information Act; and • Does not simply give the general location of the critical infrastructure.
Deferred Work	A funding project that was originally scheduled to begin within the fiscal year, but it did not start, and it was not canceled.
Delegations of Authority (DoA)	A hierarchy of authorization that empowers individual(s) to enter into contracts, other external commitments or take (or not take) other actions which might result in an obligation by National Grid. DoA is obtained at the funding project level.
Emergent Work	Unidentified work that arises within a fiscal year (or after the business plan has been sent to Resource Planning).
Executive Sanctioning Committees	The Executive Sanctioning Committees consists of the US Sanctioning Committee (USSC) and/or the Senior Executive Sanctioning Committee (SESC). See definitions below for each committee. • Weekly Sanction Review Meeting
Fast Track Approval Process (as related to Executive Sanctioning Committee's sanctioning)	Where the needs of the business demand it, papers may be approved via a fast track process administered by the Executive Sanctioning Committee's Technical Secretary. Under this process, papers must be submitted to the Director for an abbreviated review and support cycle prior to being circulated to the Committee members. Three members of the Executive Sanctioning Committees must approve the paper and the paper must be presented to the full Committee where the full committee will endorse the action.

Funding Project	A funding project is a method of tracking work charges in the PowerPlan system and is assigned an alpha numeric value. Work orders are generated in the appropriate work management system and linked to the funding project. A funding project may have one or more work orders linked to it. A separate funding project is generally assigned for different types of work or for work in different major locations. Several different funding projects may be included in a single project. For example, a $10M project to build a new substation may have three funding projects under it, one funding project for Transmission Line, one for Substation, and one for Distribution Line.
In-Service Date	This is the date when the facility is placed in operation or is ready for service. The cost of the facility becomes part of the Company's asset base and is no longer eligible for AFUDC. The date is tracked in PowerPlan and P6 where applicable.
Mandatory	There is an explicit external obligation to do this specific project immediately. There is no discretion on the spend, such as with statutory regulatory or damage failure type work (referred to as non-discretionary).
Partial Sanction	A Partial Sanction paper may be submitted when full authorization cannot be submitted due to the lack of a full scope or final cost, but approval must be obtained to progress the funding project. For examples, refer to section 6.5
Policy-driven	The driver for these will be either a general external guideline, including statutory and regulatory obligations, or an internal policy. Either way, the company will usually have choices as to how and when it makes such investments, i.e. there is some discretion about scope and timing such as with system capacity and performance, asset condition and non-infrastructure type work.
Program Funding Project	A program is generally proactive work that is done on the assets such as breakers, main replacement, etc. There is a start and end date. Programs are re-authorized each fiscal year.
Program Funding Project Work Order	Work orders initiated and linked to Program Funding Projects.

Project	Project can be either complex and non-complex (see distinction below) Complex Project – Major modifications, large, complex projects (or multiple related projects) generally with a high dollar value, typically spanning multiple fiscal years, involve complex permitting and extensive stakeholder interactions and are critical to the business are designated "Complex". The full Network Delivery Process (formally known as the Complex Capital Delivery Process) shall be applied. Non-Complex Project – Small configuration changes, low risk and low dollar values are designated Non-Complex with fewer project management process steps applied. The processes and steps for these projects are described in the Project Management Playbook Level 3.
Project Development	Ensure complex electric and gas capital projects are fully scoped, budgeted and scheduled in a timely manner to meet to customer, operational, safety and regulatory requirements.
Project Schedule and Scope Changes	Project schedule and scope variances are not governed by this process. Variances are documented and approved in accordance with the applicable Utility Services procedures.
Property	Property is defined as Facilities and/or Real Estate.
Re-sanction	The process of receiving authorization to revise the existing approved cost, for specific funding projects, gas blankets and all programs. Re-sanction is required for all complexity levels and all estimated costs. Re-sanction will include resubmittal of the paper and presentation at the committee meeting (e.g. USSC, SESC, PLC, etc.).
Reviewer	A Reviewer is an individual that reviews a proposal for content and language and recommends edits as necessary. A Reviewer may or may not be a project team member but typically has expertise in one or several areas of a proposal. Refer to section 13.5 for additional details.
Ready for Load / Ready for Use	The date when a facility's construction is complete and is ready for electricity/gas service.

Sanction (as in Sanction paper)	A Sanction Paper is the document submitted to the appropriate Sanctioning Committee for project approval. A Sanction, as opposed to a partial sanction, is generally prepared for the full scope and cost of the funding project. Generally, the costs are expected to have a tolerance of +/-10%. This is considered the final approval to undertake the funding project.
Spending Review paper	A spending review paper is a paper prepared for presentation to the appropriate Sanctioning Committees at the completion of a program or blanket that details the financial and objective outcomes of the program or blanket. A spending review paper shall be prepared using the Spending Review template. A Spending review paper must be prepared for all programs, blankets and project development approved by the appropriate Sanctioning Committees, including canceled programs and blankets.
Sponsor	The Sponsor must be a vice-president or above and is ultimately responsible for assuring that a funding project delivers its proposed scope, cost, schedule, and benefits. Refer to section 13.6 for additional details.
Supporter	A Supporter is an individual, typically a manager, director, or vice-president, that represents an area of the business that is affected by the proposed project. Refer to section 13.7 for additional details.
Tolerance and Accuracy	The permissible upper and lower limit of variation in expected funding project spending is expressed in percent (e.g. +/- 10%). Do not confuse accuracy with tolerance. The more accurate the estimate the less of a contingency should be built in. • The tolerance for the request for money should always be (+/- 10%), unless it can be justified otherwise by the author. (E.g. Bids not in, Permitting, etc.). • The accuracy for the total funding project cost on a partial sanction should be in line with the Capital Delivery process, unless otherwise justified by the author. • Full Sanction tolerances should always be at the project grade estimate (+/-10%), unless it can be justified otherwise by the author.

Technical Secretary (as relates to Executive Sanctioning Committees)	The Executive Sanctioning Committee's Technical Secretary provides all materials to the members, produces the agenda, and keeps track of all action items. Refer to section 13.10 for additional details.
Executive Sanctioning Committee's Secretary	The Executive Sanctioning Committee's Secretary is responsible for preparing and circulating minutes of the meetings.
US Sanctioning Committee (USSC)	The purpose of the Committee is to provide executive management review of proposed major capital funding projects and other proposed commitments deemed appropriate candidates for such review, and to administer a consistent and comprehensive sanctioning process for such funding projects and commitments across the organization. See USSC Terms of Reference for details.
Senior Executive Sanctioning Committee (SESC)	The purpose of the Committee is to provide executive management review of proposed major capital funding projects and other proposed commitments deemed appropriate candidates for such review, and to administer a consistent and comprehensive sanctioning process for such funding projects and commitments across the organization. See SESC Terms of Reference for details.
Template (as in Sanction Template, Closure Paper and Spending Review Template)	A template is an outline for a paper to be presented to the US Sanction Committees. The digital template shall be used for all partial sanctions, sanctions, project development and re-sanctions. The Closure digital Template shall be used for all specific project closure papers. The Spending Review digital Template shall be used for all program and blanket closure papers.

Utility Service	A Utility Service is one of the main operational/functional areas of the company. There are seven Utility Services: • Electricity T&D • Gas • LNG • Power Plant Operations • Property • Environmental • IT
Utility Service Technical Secretary	The Utility Service liaison is an individual designated to assist the Executive Sanctioning Committee's Technical Secretary in coordinating with the related activities for a particular Utility Service Area.
Weekly Sanction Review Meeting	Approves sanction papers with a potential investment below a specific dollar value as outlined in the USSC Terms of reference e.g. Electric sanction papers less than $8M can be approved at the weekly sanction review meeting. See Section 5 - USSC Terms of Reference for dollar value cut off by Utility Service.

nationalgrid

Sanction Procedure for Projects < $1M

Authorized by

Date: 14 August 2019.

Kathleen Geraghty, Vice President
National Grid USA

National Grid USA
40 Sylvan Road
Waltham, MA 02451-1120

TABLE OF CONTENTS

1.0 VERSION HISTORY

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	May 16, 2013	Implementation of new procedures	R.Morey	Approved by Mary Fuller
Issue 2	January 7, 2015	Annual Review	M. Carlino & M. Roby	Mary Fuller
Issue 3	March 25, 2016	Annual Review	M. Carlino	Mary Fuller
Issue 4	May 8, 2017	Annual Review	D. Monteiro	Mary Fuller
Issue 5	June 7, 2018	Annual Review	D. Monteiro	Suzan Martuscello
Issue 6	July 29, 2019	Annual Review	D. Monteiro	Suzan Martuscello

2.0 INTRODUCTION

2.1 This procedure applies to capital specific projects, programs and blankets less than $1 million regardless of complexity levels for all US Utility Services.

2.2 The purpose of this document is to provide:

2.2.1 Guidance in obtaining Sanctioning and Delegations of Authority ("DoA") for applicable blanket funding projects, program funding projects, and specific funding projects;

2.2.2 Guidance in obtaining re-sanctioning when applicable specific, programs, and gas blankets funding projects over-run their approved DoA or have the potential to do so, and;

2.2.3 PowerPlant Operations is excluded from this procedure since the utility service does not use PowerPlan.

3.0 REFERENCES

3.1 Supporting policies and procedures are available on the Infonet and reviewed on an annual basis. Note: The links below may bring the reader to where the document is located.

3.1.1 National Grid Statement of Delegations of Authority (DoA)

3.1.2 National Grid US Sanctioning Committee Procedure

3.1.3 Business Review Process Job Aide

3.1.4 US Tertiary Delegation Matrix (DoA Limits)

3.1.5 Cost Overrun Procedure (Under Development)

4.0 SANCTION (DoA)

4.1 DoA is obtained at the funding project level not at the work order level.

4.2 Funding project sanctioning is obtained electronically in PowerPlan for specific projects, programs and blankets that are less than $1M.

4.3 The funding project DoA to be requested shall be the gross expected expenditure. Any CIAC or other contributions shall not reduce the gross amount. For example, if a $500K funding project is initiated and a $100K customer contribution is expected, DoA shall be requested for $500K not $400K.

4.4 The funding project will remain in "initiated" status and unable to accept charges until the initiator routes it for, and receives, DoA approval.

4.5 Once the funding project DoA is approved, it moves to an "open" status and charges will be accepted from work orders generated under the funding project.

4.6 The initiator shall include the following class codes / justification within PowerPlan for reporting and controls purposes.

4.6.1 Responsible person shall proactively maintain / update the class codes to ensure relevant information including alignment with P6 dates (if applicable).

Key Fields: PowerPlan Reporting Purposes		
Class Code Tab		**Justification Tab**
Budget Classification	USSC Fiscal Yr Sanction	Project Risk Score
Capex Program Name	USSC Utility Service	Project Complexity Score
DoA Type	CAPEX Category	Project Scope
Funding Type	Investment Number (IT)	Risk Identification
Department	Authorization Workflow Type	
Region	Gas Capital by Category (Gas)	
Resource Planning Region	Program Code (Gas)	
Responsible Director	Estimated Close Date	
Responsible Person	In-Service Date	
Spending Rationale		

5.0 SPECIFICS, BLANKET AND PROGRAMS

5.1 Specifics

5.1.1 Specific Funding Projects shall be sanctioned as necessary based on the estimated costs to bring it to completion and shall be routed for DoA approval.

5.1.2 Specific Funding Projects are assigned a complexity score reflective of the project.

5.2 Blanket

5.2.1 Blanket Funding Projects are assigned a default complexity score of 15.

5.2.2 Blanket Funding projects shall be sanctioned at the start of each fiscal year to reflect the upcoming budget and routed for DoA Approval.

5.2.3 (This section applies to Electric Only) Gross expenditures against an Electric blanket funding project work order are not to exceed $100,000. If a work order is estimated to exceed those amounts, then a specific funding project must be created and all charges accumulated under the work order shall be transferred to the new funding project or the appropriate steps are taken to ensure the DoA is reconciled.

5.3 Programs

5.3.1 Program funding projects shall be sanctioned at the start of each fiscal year to reflect the upcoming budget and shall be routed for DoA Approval.

5.3.2 Gas Programs are considered "low complexity" and should default to 15 similar to Blankets.

5.3.3 Electric Programs are an average of the program projects and are scored accordingly.

6.0 RE-SANCTIONING

Re-sanctioning is the process for obtaining additional DoA Approval if the project is, or forecasted to exceed the originally sanctioned amount.

It is the responsibility and accountability of the person managing the project(s) to proactively avoid any cost overruns above the sanctioned amount.

6.1 Re-Sanctioning Requirements

6.1.1 Specific funding projects must be re-sanctioned as soon as the actual spend is greater than or equal to $100,000 or is forecasted to be, above the authorized expenditure (sanctioned amount +/- 10%) or $25,000 whichever is greater. For example, if the Sanctioning is for $500K, the project can spend $550k. Additionally, a $100K project can spend $125K.

6.1.2 In the event a funding project is originally estimated to be under $1M but the forecasted or actual costs exceed $1M, the funding project must be re-sanctioned per the National Grid US Sanctioning Committee Procedure.

6.1.3 If a funding project is sanctioned for less than $100,000 the funding project does not require re-sanctioning until the spending is greater than $100,000

6.2 Electric and Gas Blankets < $1M

(1) Electric Blankets less than $1M, the responsible person is required to submit the "Change in DoA < $1M" form no later than 60 calendar days after the end of the fiscal year.

(2) Gas Blankets require re-authorization if DoA is exceeded within 60 calendar days from notification.

6.3 Electric and Gas Programs < $1M and other Utility Services as applicable.

6.3.1 If the total spend of the program at the end of the year is less than $100,000, a "Change in DoA <$1M" form does not need to be submitted for approval.

6.3.2 If the total spend of the program, or a suite of related programs within a jurisdiction, exceeds $1M in the fiscal year, the program must be re-sanctioned per the National Grid US Sanctioning Committee Procedure.

6.4 Project schedule and scope changes:

6.4.1 Project schedule and scope variances are not governed by this process. Variances are documented and approved in accordance with the applicable Utility Services procedures.

7.0 RE-SANCTIONING PROCESS

7.1 Electric and Gas utilize the "Change in DoA <$1M Form". All Other Utility Services shall input respective Change in DoA directly into PowerPlan under the Justification & Scope tab "Additional Notes".

7.1.1 The funding project re-sanction request shall take into consideration the funding project's total estimated costs including capital, cost of removal and O&M which shall support and justify the prudent increase.

7.1.2 The justification must be clear, concise and accurate. It should contain enough information to allow a full understanding of the reasons for the increase.

7.2 For all Utility Services the revised funding project estimate will be routed through the business (via PowerPlan Business Review Process) and DoA review cycle for approval. Once approval is obtained, the funding project DoA in PowerPlan will be updated.

8.0 COST OVERRUN REPORT (Detailed Procedure Under Development)

On a monthly basis, each Utility Service shall prepare and distribute the Cost Overrun Report to responsible business stakeholders for action.

8.1 The Cost Overrun report identifies capital funding projects that have exceeded the sanctioned / authorized amount.

8.2 All Utility Services (Electric, Gas, Generation, Property, and IT) shall provide Investment Management with comprehensive / high level data utilized to compile the 30 Day DoA Awareness Scorecard

8.3 Within 10 business days from notification date, the responsible person must provide a driver for overrun in addition to a written plan to bring the affected funding project back into DoA compliance.

8.3.1 The actions may be a transfer of some of the costs to a different work order, re-sanctioning the sanctioned amount i.e. writing a paper or submitting a "Change in DoA Request Form".

8.3.2 Each Utility Service responsible person will follow up within their respective Utility Service if no action plan is received within 10 business days:

8.3.3 If no action plan is received – Projects that are at risk of becoming a 60 day overrun will be escalated to the Director of Investment Strategy and VP of Investment Strategy and Resource Planning at the 45 calendar day mark.

8.4 Responsible individual must seek management re-sanction of all funding projects that exceed the authorized spending limit on a timely basis but in no case later than 60 calendar days after notification.

8.4.1 Within 60 calendar days from notification date, the responsible person(s) must ensure stated action is completed, this includes all aspects of the process.

8.4.2 If the re-sanction cannot be attained in 60 calendar days from notification of date, the Vice President of Investment Strategy and Resource Planning must be notified and must approve the exception. The re-sanction will be noted as an exception on the cost overrun report.

8.4.3 The person requesting the exception must provide a plan to obtain compliance.

9.0 GOVERANCE

Governance refers to the activities that ensure Policies and Procedures are being executed according to how they have been designed. The governance structure also defines accountability and responsibility for ownership of the processes stated in this document.

9.1 The activities to ensure the Re-sanctioning process is operating effectively are listed below.

Governance Activities			
Activities	**Description**	**Accountable**	**Responsible**
Documentation Retention	Each Utility Service will keep all the responses for the respective department within the Cost Overrun file and stored in a deemed designated area by Utility Services.	Each Utility Service	Manager of respective Utility Service
Monthly presentation of overrun report at USSC meeting	At each USSC monthly meeting, the Vice President of Investment Strategy & Resource Planning will present the 30 Day DoA Awareness Scorecard, which highlights projects that have not been re-sanctioned timely for each Utility Service.	Investment Strategy & Resource Planning VP	Investment Strategy & Resource Planning VP
Monthly presentation of overrun report at SESC meeting	At each SESC monthly meeting, the Vice President of Investment Strategy & Regulatory Compliance will present the 60 Day DoA Awareness Scorecard, which highlights projects that have not been re-sanctioned timely for all Utility Services	Investment Strategy & Resource Planning VP	Investment Strategy & Resource Planning VP

10.0 DEFINITIONS

Term / Acronym	Definition
Authorized Expenditure	The authorized expenditure (sanctioned amount) represents the amount approved by an authorized individual(s) to spend on a funding project(s).
Blanket Funding Project	Blanket funding projects consist of many work orders that are typically standard construction and of short duration. Both Gas and Electric blanket work orders are typically externally–driven, i.e., reactive in nature. Blankets are intended to have duration of a single year and must be re-authorized each fiscal year. Examples of blanket funding projects may be New Business, Damage/Failure, etc. Gross expenditures under an electric blanket funding project work order shall not exceed $100,000.
Blanket Funding Project Work Order	Work orders initiated and linked to Blanket Funding Projects.
Class Code	A field in PowerPlan that identifies a particular attribute about the funding project. Class codes are usually selected during the funding project initiation. Most class codes are available in PowerPlan via a drop-down although a class code field may be freeform. Examples include budget class, funding type, and responsible person.
Delegations of Authority (DOA)	A hierarchy of authorization that empowers individual(s) to enter into contracts, other external commitments or take (or not take) other actions which might result in an obligation by National Grid. DOA is obtained at the funding project level.
Funding Project	A funding project is a method of tracking work charges in the PowerPlan system and is assigned an alpha numeric value. Work orders are generated in the appropriate work management system and linked to the funding project. A funding project may have one or more work orders linked to it. A separate funding project is generally assigned for different types of work or for work in different major locations.
In-Service Date	This is the date when the facility is placed in operation or is ready for service. The cost of the facility becomes part of the Company's asset base and is no longer eligible for AFUDC. The date is tracked in PowerPlan and P6 where applicable.
Program Funding Project	A program is generally a group of similar proactive work that is done on the assets such as breakers, main replacement, etc. There is a start and end date. Programs are re-authorized each fiscal year.

Program Funding Project Work Order	Work orders initiated and linked to Program Funding Projects.
Project	A funding project is a method of tracking work-related charges in the PowerPlan system. Funding Projects are assigned a 7-digit, alpha-numeric value (e.g. C000001). Funding projects must have at least one work order assigned to them for cost
Re-sanction	The process of receiving authorization to revise the existing approved cost for funding projects. Re-sanction could include re-authorization in PowerPlan i.e. a change in DOA request form.
Specific Funding Project	A specific project is defined as an undertaking representing an investment in time and resources with a specified plan and budget, generally in a specific location, over a discrete period of time, intended to achieve a long-term outcome for assets.
Specific Funding Project Work Order	Work orders initiated and linked to specific funding projects.

NATIONAL GRID USA

US SANCTIONING COMMITTEE

TERMS OF REFERENCE

(Revised effective: September 20, 2019)

1. Definitions

Reference to the "Company" shall mean National Grid USA.

Reference to the "Board" shall mean the Board of Directors of the Company or its Standby Committee or other committee, if any, where the Board is acting through this Standby Committee or other committee.

Reference to the "Committee" shall mean the US Sanctioning Committee.

Reference to the "SESC" shall mean the Senior Executive Sanctioning Committee

2. Membership

The Committee members shall consist of the individuals holding, from time to time, the positions listed below[1]; the individuals currently holding or named to these positions are also listed below for convenience:

Voting Members

US Chief Gas Engineer	Ross Turrini
Vice President, Electric Asset Management and Planning	Carol Sedewitz
Vice President, Gas Capital Delivery	Walter Fromm
Vice President, Service Company Finance Business Partner (Chair)	Christine McClure
Vice President, FERC & Wholesale Regulation	James Holodak

[1] A person appointed in a temporary, acting or interim capacity to perform the function or role represented by any listed position shall be a member of the Committee representing such function or role during the term of such person's temporary, acting or interim appointment, even if such person's title differs from the position title listed above. Variations in the actual title for any listed position shall not invalidate the Committee membership of the person holding such listed position: all such variations in title shall be deemed to represent the same originally listed position so long as the applicable functions or roles performed by the title holder remain substantially the same as those represented by the originally listed position.

Vice President, Transmission Asset Management & Planning and Capital Delivery Electric	Brian Gemmell
Vice President, Head of Information Technology Business Partner	Premjith Lakshman Singh

Non-voting Members

Director, Electric Investment Planning	Suzan Martuscello
Secretary and Technical Secretary	Mary Jane Barry
Vice President, Investment Strategy and Resource Planning	Kass Geraghty
Vice President, Electric Business Process and Performance	David Smith
Vice President, Gas Business Planning and Performance	Pam Viapiano
Vice President, Business Planning Development and Process	James Cross

The Chair shall be the individual holding, from time to time, the title of Vice President, Service Company Finance Business Partner. If the Chair will be absent from a meeting, the Chair may appoint an alternate chair ("Alternate Chair") to serve as chair for the meeting. An Alternate Chair appointed by the Chair is not required to be a member of the Committee. In the event that an Alternate Chair is not named by the Chair, the remaining members present at the meeting shall elect one of the members of the Committee to serve as the Alternate Chair. The Chair may confirm or certify any actions taken by the Committee, including, without limitation, approval of sanction papers.

If a regular member is unable to act due to absence, illness or any other cause, the Chair (or Alternate Chair in absence of the Chair) may appoint another person to serve as an alternate member. If any of the positions listed above becomes vacant or is eliminated, the Chair (or Alternate Chair in absence of the Chair), may appoint another person to serve as an alternate member pending appointment of a replacement member by the Board. Any appointments of an alternate member for a period longer than 3 months in duration must be approved by the Board. No person may serve as an alternate member for more than one voting member of the Committee at the same meeting.

3. Secretary and Technical Secretary

The Chair shall appoint a Secretary and a Technical Secretary. The Secretary and Technical Secretary shall be non-voting members of the Committee.

The Technical Secretary shall make all materials available to the membership, as appropriate, in advance of the meeting to provide a timely review. The Technical Secretary shall receive notices of absence and is also responsible for producing the agenda and keeping track of action items.

The Secretary shall be responsible for preparing and circulating minutes of the Committee meetings.

The positions of Secretary and Technical Secretary may be held by the same person.

4. Quorum

A majority of the voting Committee members, which must include the Chair (or Alternate Chair in absence of the Chair), shall be the quorum necessary for the transaction of business. A duly convened meeting of the Committee at which a quorum is present shall be competent to exercise all or any of the authorities, powers and discretions vested in or exercisable by the Committee.

The Committee may also transact business by written resolution (in either written or electronic form) which shall be approved by all of its voting members.

5. Frequency of Meetings

The Committee will meet as necessary. It is anticipated that the Committee will meet once a month.

6. Notice of Meetings

Meetings of the Committee shall be convened by the Technical Secretary of the Committee at the request of the Chair of the Committee or any other member of the Committee.

When possible, unless otherwise agreed, notice of each meeting confirming the venue, time and date, together with the agenda of the items to be discussed, shall be circulated to each member of the Committee, and any other person required or invited to attend, prior to the date of the meeting.

The Committee shall determine the format of meetings, including the procedures for bringing projects for approval. Unless otherwise agreed, papers will be sent to the Technical Secretary in advance of the meeting for circulation and inclusion in the agenda.

7. Conflict of Interest

The presiding Chair (or Alternate Chair) should ascertain, at the beginning of each meeting, the existence of any conflicts of interest and minute them accordingly. If any conflicts of interest exist with a particular member of the Committee on any particular issue, then such member of the Committee shall not participate or vote on the issue that gave rise to such conflict of interest.

8. Minutes

The Secretary shall minute the proceedings and resolutions of all meetings of the Committee, including recording the names of those present and in attendance. The Technical Secretary shall maintain and circulate an action item list annotated with progress milestones or completion date.

The Secretary should minute at the beginning of the meeting the existence of any conflicts of interest that have been disclosed or that have otherwise come to the attention of the Committee, as referred to in 7 above.

Minutes of the Committee meeting shall be circulated promptly to all members of the Committee following that meeting.

9. Reports

The Committee will report to the SESC, at its request, and at least annually. The Committee will report to the Board by request of the Board.

10. Purpose / Objectives / Duties

a. The purpose of the Committee is to provide executive management review and decision for proposed major capital projects and other proposed commitments having contemplated expenditures not exceeding $25 million on an individual basis that are deemed appropriate candidates for such review and decision, and to administer a consistent and comprehensive sanctioning process for such projects and commitments. Major capital projects and other proposed commitments having contemplated expenditures of more than $25 million will be referred to the SESC. Projects having an original budgeted spend of less than $25 million, but that are forecasted to exceed this $25 million threshold cumulatively across multiple years, must be referred to and approved by the SESC prior to spending any amount in excess of such threshold. If an estimation tolerance is referenced for a project or other proposed commitment, the contemplated expenditures for such project or other proposed commitment shall be calculated using the upper bound of the estimation tolerance for purposes of determining whether the above $25 million threshold is exceeded.

b. The Board may delegate some or all of its authority for approval of projects or other expenditures to the Committee to the extent permitted under the Statement of Delegations of Authority. This delegation, if made, may be revoked by the Board at any time.

c. To the extent of its delegated authority from the Board, the Committee will review and approve projects and other commitments to carry out the projects.

d. If authority is delegated to the Committee, all members of the Committee must understand where the authority has come from and how it has been delegated.

e. Projects to be approved by the Committee are defined as projects that fall within the budget guidelines and/or other guidelines established by the appropriate Jurisdictional President. Each Jurisdictional President will be notified of actions of the Committee and will have the authority to cancel any project or request modifications to projects within such President's Jurisdiction.

f. Projects and other commitments that may be approved by the Committee are further defined as projects and commitments that fall within the authority delegated by the Board to approve expenditures having a total cost not exceeding $25 million on an individual basis ("Committee DOA Limit"), including, but not limited to, capital and opex projects and programs ("Projects"). It is anticipated that the Committee will approve all of the following Projects, provided, in each case, that the proposed expenditures for the individual Project do not exceed the Committee DOA Limit:

- IS Projects above $5 million

- Property Projects above $3 million
- Power Plant Operations Projects above $1 million.
- Gas Transmission and Distribution Projects above $8 million
- Electricity Transmission and Distribution Projects above $8 million
- LNG Projects above $8 million
- And any other Projects at its discretion (including, without limitation, Site Investigation and Remediation Projects that may be referred to it by the US Environmental Oversight Committee).

In addition, the Committee may adopt, from time to time, various project complexity criteria ("Complexity Criteria") to assist it in assessing whether a proposed project or other commitment should be considered by the Committee. Additional Complexity Criteria may be established for other projects or commitments. Complexity Criteria and related project limits, if established by the Committee, may be changed by the Committee at its discretion, subject to compliance with the Committee DOA Limit.

At its discretion, the Committee may choose to see any Projects that are deemed to be of a highly complex nature and additional projects and matters as appropriate for proper control on either a functional or Jurisdictional level, subject to compliance with the Committee DOA Limit.

g. If the total proposed expenditure for a Project exceeds the authority delegated to the Committee, the Project would need to be referred to the SESC and/or other appropriate authority for approval. The Committee shall review and recommend for advancement to the SESC all Projects having a total cost exceeding $25 million on an individual basis (including projects spanning multiple years). Prior to making any such referral, the Committee must review the Project and determine whether to recommend its approval by the SESC or such other authority. If the Project recommended for approval is a non-discretionary Project, including, but not limited to any Site Investigation and Remediation Projects, the Committee shall also request that the approving authority provide or arrange for any notifications that may be required by the Statement of Delegations of Authority.

h. A project/expenditure may not be divided into smaller transactions to bypass the need for Committee, SESC or Board approval.

i. Individual contracts necessary to carry out the approved capital project/expenditure are also separately subject to the delegations of authority, but may be approved by the Committee as well to the extent of its delegated authority from the Board. These commitments can be approved at the time of project/expenditure approval, if the Committee so chooses.

j. The Committee will determine the procedures and forms to be used to submit projects/expenditures for review.

k. The Technical Secretary will prepare a quarterly summary of all on-going projects having a total cost exceeding $25 million on an individual basis previously reviewed and recommended for advancement to the SESC. The Committee will coordinate as needed to assist the SESC and the US Executive team with any quarterly or other reviews of such projects conducted by the SESC and/or the US Executive team.

11. Interface with other Committees

The Committee shall interface with the SESC and other committees and/or areas of the business as appropriate.

12. Authority

Subject to any restrictions imposed by law, the Committee is authorized to seek any information it requires from any employee of the Company or its direct or indirect subsidiaries in order to perform its duties.

The Committee is authorized to call any employee to be present at a meeting of the Committee as and when required.

Subject to the Delegations of Authority, the Committee is authorized to obtain, as is reasonable, at the Company's expense, outside legal, financial or other professional advice on any matters within its Terms of Reference.

The Committee is authorized to delegate any of its powers to a sub-Committee, to another body or to an individual member if it considers this appropriate. In exercising its authority hereunder the Committee shall clearly set out the powers and authorities it is delegating.

The Committee shall review these Terms of Reference and consider its own effectiveness at least annually.

The provisions of these Terms of Reference may not vary any licenses or legal obligations that the business or the Company (including its direct or indirect subsidiaries) may have.

13. Fast Track Approval Process

Where the needs of the business demand it, papers may be approved via a fast track process administered by the Technical Secretary. Under this process, papers will pass through an abbreviated review and support cycle prior to being circulated to the Committee members, as appropriate. Fast track process approval for any paper shall be in written form (which may include, without limitation, electronic form) and approval shall be given by at least three Committee members. Papers approved by fast track process will be presented for ratification by the full Committee at its earliest convenience or at the next Committee meeting.

This fast track process must only be used in exceptional circumstances where a delay will impair safety, reputation and/or incur financial losses. The reason for the fast track submission should be clearly stated at the time of submission.

NATIONAL GRID USA

SENIOR EXECUTIVE SANCTIONING COMMITTEE

TERMS OF REFERENCE

(Revised effective: June 11, 2019)

1. Definitions

Reference to the "Company" shall mean National Grid USA.

Reference to the "Board" shall mean the Board of Directors of the Company or its Standby Committee or other committee, if any, where the Board is acting through this Standby Committee or other committee.

Reference to the "Committee" shall mean the Senior Executive Sanctioning Committee.

"Jurisdictional President" shall mean any of the President, New York, the President, Rhode Island, the President, Massachusetts, or the Chief Operating Officer, Transmission, Generation & Energy Procurement.

Reference to the "USSC" shall mean the US Sanctioning Committee

2. Membership

The Committee members shall consist of the individuals holding, from time to time, the positions listed below[1]; the individuals currently holding or named to these positions are also listed below for convenience:

Voting Members

US Chief Financial Officer (Chair)	Margaret Smyth
Chief Operating Officer, Electric	Chris Kelly *(US Chief Electric Engineer, acting in interim capacity)*
Chief Operating Officer, Gas	Cordi O'Hara
Chief Operating Officer, Transmission, Generation & Energy Procurement	Rudolph Wynter

[1] A person appointed in a temporary, acting or interim capacity to perform the function or role represented by any listed position shall be a member of the Committee representing such function or role during the term of such person's temporary, acting or interim appointment, even if such person's title differs from the position title listed above. Variations in the actual title for any listed position shall not invalidate the Committee membership of the person holding such position: all such variations in title shall be deemed to represent the same originally listed position so long as the applicable functions or roles performed by the title holder remain substantially the same as those represented by the originally listed position.

President, Massachusetts & Executive Vice President Policy & Social Impact	Marcy Reed
President, New York	John Bruckner
President, Rhode Island	Terence Sobolewski
Senior Vice President, Strategy & Regulation	Mike Calviou

Non-voting Members

Director, Electric Investment Planning	Suzan Martuscello
Secretary and Technical Secretary	Mary Jane Barry

The Chair shall be the individual holding, from time to time, the title of US Chief Financial Officer. If the Chair will be absent from a meeting, the Chair may appoint an alternate chair ("Alternate Chair") to serve as chair for the meeting. An Alternate Chair appointed by the Chair is not required to be a member of the Committee. In the event that an Alternate Chair is not named by the Chair, the remaining members present at the meeting shall elect one of the members of the Committee to serve as the Alternate Chair.

If a regular member is unable to act due to absence, illness or any other cause, the Chair (or Alternate Chair in absence of the Chair) may appoint another person to serve as an alternate member. If any of the positions listed above becomes vacant or is eliminated, the Chair (or Alternate Chair in absence of the Chair), may appoint another person to serve as an alternate member pending appointment of a replacement member by the Board. Any appointments of an alternate member for a period longer than 3 months in duration must be approved by the Board. No person may serve as an alternate member for more than one voting member of the Committee at the same meeting.

3. Secretary and Technical Secretary

The Chair shall appoint a Secretary and a Technical Secretary, both of whom shall be non-voting members of the Committee.

The Technical Secretary shall make all materials available to the membership, as appropriate, in advance of the meeting to provide a timely review. The Technical Secretary shall receive notices of absence and is also responsible for producing the agenda and keeping track of action items.

The Secretary shall be responsible for preparing and circulating minutes of the Committee meetings.

4. Quorum

Three voting Committee members, which must include (a) the US Chief Financial Officer (or his/her designated alternate member), (b) either the Chief Operating Officer, Electric (or his/her designated alternate member) or the Chief Operating Officer, Gas (or his/her designated alternate member) and (c) any Jurisdictional President (or his/her designated alternate member), shall be the quorum necessary for the transaction of business. A duly convened meeting of the Committee at which a quorum is present shall be competent to exercise all or any of the authorities, powers and discretions vested in or exercisable by the Committee.

The Committee may also transact business by written resolution (in either written or electronic form) which shall be approved by at least three of its voting members, which must include (a) the US Chief Financial Officer, (b) either the Chief Operating Officer, Electric or the Chief Operating Officer, Gas, and (c) any Jurisdictional President.

In the event that voting on any motion before the Committee results in a tie, the Chair (or Alternate Chair in absence of the Chair) shall break the tie.

5. Frequency of Meetings

The Committee will meet as necessary.

6. Notice of Meetings

Meetings of the Committee shall be convened by the Technical Secretary of the Committee at the request of the Chair of the Committee or any other member of the Committee.

When possible, unless otherwise agreed, notice of each meeting confirming the venue, time and date, together with the agenda of the items to be discussed, shall be circulated to each member of the Committee, and any other person required or invited to attend, prior to the date of the meeting.

The Committee shall determine the format of meetings, including the procedures for bringing projects for approval. Unless otherwise agreed, papers will be sent to the Technical Secretary in advance of the meeting for circulation and inclusion in the agenda.

7. Conflict of Interest

The presiding Chair (or Alternate Chair) should ascertain, at the beginning of each meeting, the existence of any conflicts of interest and minute them accordingly. If any conflicts of interest exist with a particular member of the Committee on any particular issue, then such member of the Committee shall not participate or vote on the issue that gave rise to such conflict of interest.

8. Minutes

The Secretary shall minute the proceedings and resolutions of all meetings of the Committee, including recording the names of those present and in attendance. The Technical Secretary shall maintain and circulate an action item list annotated with progress milestones or completion date.

The Secretary should minute at the beginning of the meeting the existence of any conflicts of interest that have been disclosed or that have otherwise come to the attention of the Committee, as referred to in 7 above.

Minutes of the Committee meeting shall be circulated promptly to all members of the Committee following that meeting.

9. Reports

The Committee will report to the Board by request of the Board.

10. Purpose / Objectives / Duties

a. The principal purpose of the Committee is to provide executive management review and decision for proposed major capital projects and other proposed commitments having contemplated expenditures exceeding $25 million up to $203 million (the "Committee DOA Limit") on an individual basis that are deemed appropriate candidates for such review and decision, and to administer a consistent and comprehensive sanctioning process for such projects and commitments. Subject to the Committee's authority to consider projects for approval at its discretion as referred to below, major capital projects and other proposed commitments having contemplated expenditures of $25 million or less will normally be referred to the USSC. Projects having an original budgeted spend of less than $25 million, but that are forecasted to exceed this $25 million threshold cumulatively across multiple years, will also be referred to the Committee prior to spending any amount in excess of such threshold.

b. The Board may delegate some or all of its authority for approval of projects or other expenditures to the Committee to the extent permitted under the Statement of Delegations of Authority. This delegation, if made, may be revoked by the Board at any time.

c. To the extent of its delegated authority from the Board, the Committee will review and approve projects and other commitments to carry out the projects.

d. If authority is delegated to the Committee, all members of the Committee must understand where the authority has come from and how it has been delegated.

e. Projects to be approved by the Committee are defined as projects that fall within the budget guidelines and/or other guidelines established by the appropriate Jurisdictional President.

f. Projects and other commitments that may be approved by the Committee are further defined as projects and commitments that fall within the authority delegated by the Board, including, but not limited to, capital and opex projects and programs ("Projects"). It is anticipated that the Committee will approve all of the following, provided, in each case, that the proposed expenditures for the individual Project do not exceed the Committee DOA Limit:

- IS Projects above $25 million
- Property Projects above $25 million
- Power Plant Operations Projects above $25 million.
- Gas Transmission and Distribution Projects above $25 million
- Electricity Transmission and Distribution Projects above $25 million
- LNG Projects above $25 million
- And any other Projects at its discretion without regard to whether such Projects exceed the $25 million threshold (including, without limitation, Critical Program Portfolio Projects; Projects that may be referred to it by the USSC; and Site Investigation and Remediation Projects that may be referred to it by the US Environmental Oversight Committee).

In addition, the Committee may adopt, from time to time, various project complexity criteria ("Complexity Criteria") to assist it in assessing whether a proposed project or other commitment should be considered by the Committee. Additional Complexity Criteria may be established for other projects or commitments. Complexity Criteria and related project limits, if established by the Committee, may be changed by the Committee at its discretion.

At its discretion, the Committee may choose to see any Projects that are deemed to be of a highly complex nature and additional projects and matters as appropriate for proper control on either a functional or Jurisdictional level.

g. If the total proposed expenditure for a Project exceeds the authority delegated to the Committee, the Project would need to be referred to the Board and/or other appropriate authority for approval. Prior to making any such referral, the Committee must review the Project and determine whether to recommend its approval by the Board or such other authority. If the Project recommended for approval is a non-discretionary Project, including, but not limited to any Site Investigation and Remediation Projects, the Committee shall also request that the approving authority provide or arrange for any notifications that may be required by the Statement of Delegations of Authority.

h. A project/expenditure may not be divided into smaller transactions to bypass the need for Committee or Board approval.

i. Individual contracts necessary to carry out the approved capital project/expenditure are also separately subject to the delegations of authority, but may be approved by the Committee as well to the extent of its delegated authority from the Board. These commitments can be approved at the time of project/expenditure approval, if the Committee so chooses.

j. The Committee will determine the procedures and forms to be used to submit projects/expenditures for review.

k. The Technical Secretary will prepare a quarterly summary of all on-going projects having a total cost exceeding $25 million previously reviewed and approved by the Committee. The Committee will coordinate as needed to assist the US Executive team with any quarterly or other reviews of such projects conducted by the US Executive team.

11. Interface with other Committees

The Committee shall interface with the USSC and other committees and/or areas of the business as appropriate.

12. Authority

Subject to any restrictions imposed by law, the Committee is authorized to seek any information it requires from any employee of the Company or its direct or indirect subsidiaries in order to perform its duties.

The Committee is authorized to call any employee to be present at a meeting of the Committee as and when required.

Subject to the Delegations of Authority, the Committee is authorized to obtain, as is reasonable, at the Company's expense, outside legal, financial or other professional advice on any matters within its Terms of Reference.

The Committee is authorized to delegate any of its powers to a sub-Committee, to another body or to an individual member if it considers this appropriate. In exercising its authority hereunder the Committee shall clearly set out the powers and authorities it is delegating.

The Committee shall review these Terms of Reference and consider its own effectiveness at least annually.

The provisions of these Terms of Reference may not vary any licenses or legal obligations that the business or the Company (including its direct or indirect subsidiaries) may have.

13. Fast Track Approval Process

Where the needs of the business demand it, papers may be approved via a fast track process administered by the Technical Secretary. Under this process, papers will pass through an abbreviated review and support cycle prior to being circulated to the Committee members, as appropriate. Fast track process approval for any paper shall be in written form (which may include, without limitation, electronic form) and approval shall be given by at least three Committee members. Papers approved by fast track process will be presented for ratification by the full Committee at its earliest convenience or at the next Committee meeting.

This fast track process must only be used in exceptional circumstances where a delay will impair safety, reputation and/or incur financial losses. The reason for the fast track submission should be clearly stated at the time of submission.

REDACTED

DoA - US Tertiary Delegations Matrix

[redacted]

Effective April 1st, 2018 the Exchange Rate for US conversion is $1.35 US to 1 Pound.

Legend

(A)	For non-discretionary expenditures, the DoA limit for NGUSA Board is increased to $[redacted]. In the event where an emergency has been declared, emergency policies and procedures supersede the tertiary DoA limits cascaded.
(B)	Refer to the DoA Statement and related policies/procedures for additional guidance and more restrictive DoA limits for certain expenditures, such as procuring for consultants, legal advisors, land & property, tax payments, etc.
(C)	Check payments which cannot be supported by approved requisition orders, purchase orders or invoices, and invoice payments not supported by goods receipts
(D)	Refer to the DoA Statement and related policies/procedures for additional guidance and DoA limits on NGV business development and investment activities.
(I)	Informed of the transaction by the reporting authority level
	Denotes limits voted by the plc Board
	Denotes lack of authority

Approved Exceptions to DoA Limits

[redacted]

PUC 1-12

Request:

Referencing page 60, please describe who within the Company are "project sponsors."

Response:

The portion of page 60 where the project sponsor is referenced includes: "Approval authority is administered in accordance with the Company's DOA governance policy, with projects over $1.0 million requiring a Project Sanction Paper (PSP). For complex projects (a project with a complexity score of 19 or greater), the Project Development group writes the PSP. For non-complex projects (a project with a complexity score of 18 or lower), the project sponsor writes the PSP.

The Sanction Procedures (see Attachment PUC 1-11-1, page 14 of 22, section 15.6) define Sponsor as a "…Vice President or above and is ultimately responsible for assuring that a project delivers its proposed scope, cost, schedule and benefits. The sponsor works in conjunction with the project manager getting commitment from and managing cross-functional support and resource needs, and clarifies business priorities and strategy. The sponsor provides a route to escalate any issues and acts as a decision maker for issues beyond the project team's scope and authority." While the Sanction Paper does reference a Vice President as a Project Sponsor, sanction papers are generally written by the Project or Program Manager.

Prepared by or under the supervision of: Patricia C. Easterly

---

PUC 1-13

Request:

Can a project sponsor recommend or propose a project that includes non-wires alternatives for any project, including projects for which the project sponsor writes the Project Sanction Paper (PSP) and projects under $1.0M that are authorized online? If so, does the Company have internal guidance for the consideration of such alternatives?

Response:

A non-wires alternative (NWA) is considered for all projects, regardless of whether the effort would receive a sanction paper or online authorization, in accordance with the following NWA screening criteria defined in Docket 4684 – The Narragansett Electric Company, d/b/a National Grid 2018-2020 Energy Efficiency and System Reliability Procurement Plan (SRP):

- The need is not based on asset condition;
- The wires solution, based on engineering judgment, will likely cost more than approximately $1 million; the cost floors may vary across different project types and time frames;
- If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area, or sub area in the event of a partial solution, of the defined need;
- Start of wires alternative construction is at least 30 months in the future;
- At its discretion, the Company may consider and, if appropriate, propose a project that does not pass one or more of these criteria if it has reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

While the criteria states that wires solution shall be greater than $1M in order to be eligible for an NWA opportunity, it also states that the project sponsor holds the discretion to progress a project that fails screening, including Cost Suitability, if it is expected that an NWA would be a viable solution.

Project sponsors have been provided guidance to consider NWAs as part of project development stages whether within an Area Planning Study or in response to emergent system performance concerns. When projects meet these initial criteria, project sponsors engage with NWA Solutions, a dedicated team focused on developing NWA opportunities, for further analysis.

Prepared by or under the supervision of: Kathy Castro and Daniel Marceau

---

PUC 1-14

Request:

Referencing page 60, please explain and describe how "variance ranges" are determined. Include in your response whether the approved variance range is determined on a case-by-case basis, and, if so, how it is determined.

Response:

Please see Attachment PUC 1-11-1 for the Sanction Procedure document. Section 18.0 Definitions defines Tolerance and Accuracy on page 20 of 22 as:

> The permissible upper and lower limit of variation in expected funding project spending is expressed in percent (e.g. +/- 10%). Do not confuse accuracy with tolerance. The more accurate the estimate the less of a contingency should be built in.
>
> - The tolerance for the request for money should always be (+/-10%), unless it can be justified otherwise by the author. (e.g. Bids not in, Permitting, etc.)
> - The accuracy for the total funding project cost on a partial sanction should be in line with the Capital Delivery process, unless otherwise justified by the author.
> - Full Sanction tolerances should always be at the project grade estimate (+/-10%), unless it can be justified otherwise by the author.

PUC 1-15

Request:

Referencing page 62, please explain the differences between bullet points 1 and 3 ("Relocating/adding company assets due to road or bridge-work" and "Construction as requested by the telephone company, public authorities, towns, municipalities, RIDOT, and other similar entities.") Also describe what "construction" activities the Company engages in.

Response:

While much of the construction work done by public authorities, towns, municipalities, and RIDOT projects relate to relocating or adding assets due to road and bridge work, there could also be new projects, such as to bury overhead lines requested by those agencies. This category may also include requests to set new poles by the telephone company.

Construction refers to the typical capital activities the Company undertakes to provide electric service.

PUC 1-16

Request:

Referencing pages 66-67, for both the "Substation Circuit Breaker and Recloser Strategy and Program" and the "Recloser Replacement Strategy and Program," are the reclosers advanced reclosers? If not, will they need to be in the future?

Response:

Yes, the "Substation Circuit Breaker and Recloser Strategy" and "Recloser Replacement Strategy and Program," replaces reclosers with standard advanced control devices. Controls may need setting modifications in the future to enable certain functions or protection schemes.

Prepared by or under the supervision of: Kathy Castro

PUC 1-17

Request:

Please describe how the Company updates its GIS system when new equipment is installed. For example, when new reclosers are installed how long does it take for that new equipment to be updated in the Company's GIS system, and how is that information relayed from the field to the GIS?

Response:

GIS is the asset register for geographical distribution asset information. There are two primary workflows to update asset data in GIS; through Planned and Unplanned work.
Unplanned work is documented during field construction, and then sent to the closeout teams to make updates to GIS.

Planned work has an upfront design plan in GIS and follows the work request life cycle through to completion. If the field work was completed according to the design plan, the work progresses to completion in GIS automatically once all work requirements are confirmed complete. If the field work was not completed according to the design plan, the changes are documented in the field and sent in to the closeout teams to modify the design plan in GIS, and progress to closure. The amount of time it takes to reflect equipment changes and installations in GIS depends on which workflow is required.

Prepared by or under the supervision of: Jane Bersani

PUC 1-18

Request:

Referencing page 67, please provide the following information:

a) Is the $0.5 million requested in FY 2021 to study and run the model, to install the reclosers, or both?
b) How many of the 38 Form3A reclosers will be replaced with the $0.5 million?
c) How much does the Company estimate that it will cost to replace all 38 Form 3A reclosers?
d) How long does the Company think it will take to replace all 38 Form 3A reclosers?

Response:

a) The Company will continue its replacement of Form 3A reclosers in FY 2021. The Company has already completed the review, selection, and preliminary scoping activities for the Form 3A reclosers to be replaced in FY 2021. The $0.5 million requested in FY 2021 will be used for detailed design activities, material procurement, and construction activities. Construction activities consist of removing the existing Form 3A reclosers and installing the new Company standard G&W Viper reclosers.

b) Seven (7) Form 3A reclosers will be replaced with the $0.5 million in FY 2021.

c) Please see the Company's response to DIV 1-16 in the FY 2020 ISR Plan, Docket No. 4915, and attached to this response as Attachment PUC 1-18. Specifically, the response states,

> Since the initial program kickoff, National Grid has identified (1) additional Form 3A recloser in service, making the total number of reclosers to be replaced through the program 39. To date, the Company has completed 29 of the 39 replacements, of which 3 were removals only. The spend to date is $1.847 million. The Company estimates that it will cost approximately $0.665 million to replace the remaining 10 Form 3A reclosers; therefore, the total cost to replace all 39 Form 3A reclosers through the program is estimated to be $2.512 million.

d) All 39 Form 3A reclosers will be replaced by the end of FY 2022. Of the remaining ten Form 3A reclosers, seven will be completed in FY 2021 and the remaining three will be completed in FY 2022.

Prepared by or under the supervision of: Kathy Castro

Division 1-16

Request:

For the Company's Recloser Replacement Program, provide an updated recloser criticality list indicating work completed, actual cost, and proposed work by year.

Response:

National Grid has replaced a total of 16 and removed 1 recloser locations since FY17.
Refer to following table for completed and proposed work by FY:

RI PTR-3A Program	RI		
	Incomplete: (22)		
	Target	Complete	%Complete
FY 2017	*0*	*4*	*100%*
FY 2018	*7*	*7*	*100%*
FY 2019	7	6	86%
FY 2020	7	0	0%
FY 2021	7	0	0%
FY 2022	6	0	0%
FY 2023	5	0	0%
Total	39	17	44%

Since commencement of the program, the Company identified (1) additional Form 3A recloser in service.

The intent of the criticality list developed for this program was to provide structure for the progression of work. Over the course of the program a variety of reasons may have impacted the execution by rank. These reasons include service failures, resource availability, and interconnection of DG requiring accelerated replacement. The Company will strive to complete the 23 remaining re-closers using the criticality list to prioritize execution to the furthest extent possible considering all the factors noted above.

Prepared by or under the supervision of: Kathy Castro

Division 1-16, page 2

Below are lists of all completed and remaining locations:

Table 1 Completed Recloser List

State	Dist	Town	Feeder	Voltage kV	Location	Main Score	Rank	WR	WR-Stat	Complete in Field?
RI	NE53	Providence	79F2	12.47	P.27 Camp St.	465	2	22934175	90	Yes
RI	NE53	Cranston	72F3	12.47	P27-50 Sockanosett Cross Rd	402	8	24532414	90	Yes
RI	NE53	Barrington	5F1	12.47	P.6 New Meadow Rd.	339	19	23220931	80	Yes
RI	NE53	Bristol	51F2	12.47	P.32 Franklin St.	334	20	23220996	90	Yes
RI	NE53	Scituate	34F1	12.47	P.97 Chopmist Hill Rd.	300	28	22923543	90	Yes
RI	NE56	Charlestown	68F3	12.47	P68 Old Post Road	262	62	25476746	80	Yes
RI	NE53	E. Providence	48F5	12.47	P.39 S. Broadway	233	104	24962121	90	Yes
RI	NE53	Scituate	34F1	12.47	P.204-1 Danielson Pike	218	127	22923589	90	Yes
RI	NE56	Coventry	54F1	12.47	P.143 Harkney Hill Rd.	218	128	24162389	90	Yes
RI	NE53	E. Providence	48F6	12.47	P.21 Sutton Ave	213	130	24962134	90	Yes
RI	NE53	Providence	79F2	12.47	P.13 Doyle AVE.	204	136	22934197	90	Yes
RI	NE56	Tiverton	33F2	12.47	P.119 Main Rd.	193	158	21100070	80	Yes
RI	NE56	Tiverton	33F2	12.47	P.114 Main Rd.	193	158	25004724	80	Yes
RI	NE53	Smithfield	38F4	12.47	P.29 Esmond St. (open tie)	188	162	22919861	90	Yes*
RI	NE53	Bristol	51F3	12.47	P.2 1/2 Popasquash Rd.	188	168	25888350	80	Yes
RI	NE53	Barrington	53-2291	23	P. 97 County Rd.	146	192	15732799	90	Yes
RI	NE53	Cranston	53-21F1	12.47	P 160-50 Phenix Ave	176	195	25852868	90	Yes
RI	NE53	Providence	53-76F8	12.47	P 20-50 Ernest Street	138	196	24938924	90	Yes

* Recloser removal only

Table 2 Remaining Recloser List

State	Dist	Town	Feeder	Voltage kV	Location	Main Score	Rank	WR	WR-Stat	Complete in Field?
RI	NE53	Providence	13F3	12.47	P3 East Frontage Rd	412	6	23988996	40	No
RI	NE56	E. Greenwich	61F3	12.47	P.63-1 S. County Trail	409	7	25812909	20	No
RI	NE56	South Kingston	59F3	12.47	P60 Commodore Oliver Hazard Perry Highway	386	10	26017727	50	No
RI	NE56	E. Greenwich	61F3	12.47	P.57-51 S. County Trail	356	17	25812912	20	No
RI	NE53	Cranston	7F2	12.47	P.1 Chestnut Hill	300	31	25846399	50	No
RI	NE53	Johnston	2211	23	P9764 ROW of Manton 6 Sub	291	36	TBD		No
RI	NE53	Smithfield	23F6	12.47	P13-25 Whipple Rd	240	79	24662755	50	No
RI	NE56	Tiverton	33F3	12.47	P.240 Nannaquaket Rd.	234	87	23132551	60	No
RI	NE56	Narragansett	17F2	12.47	P16 South Pier Rd	233	103	25046367	60	No
RI	NE53	Cranston	27F2	12.47	P.193 1/2 Pontiac Ave	233	105	25846596	50	No
RI	NE56	North Kingstown	83F2	12.47	P5 3/4 Roger Williams Way	226	112	25737575	#N/A	No*
RI	NE56	South Kingston	68F1	12.47	P2-50 Kingstown Road	216	129	25812911	50	No
RI	NE53	Gloucester	34F3	12.47	P.76-51 Reynolds Rd.	210.5	132	26018369	40	No
RI	NE56	W. Warwick	29F1	12.47	P.1 Pontiac Ave.	204	135	TBD	#N/A	No
RI	NE56	South Kingston	68F5	12.47	P43-1 Fairgrounds Road	202	142	TBD	#N/A	No
RI	NE56	W. Warwick	14F3	12.47	P. 92 Providence St	196	151	26686029	50	No*
RI	NE53	Smithfield	38F2	12.47	P48 Pleasant View Ave	196	152	TBD	#N/A	No
RI	NE53	Cranston	53-27F2	12.47	P 118 Pontiac Ave	186	174	26013303	50	No
RI	NE53	Providence	2211	23	P 9808 ROW of Cowens Plastics Tap	181	175	TBD	#N/A	No
RI	NE56	Smithfield	2227	23	P 9006 ROW off of P35 W. Greenville Rd	181	176	24689446	60	No
RI	NE56	W. Greenwich	63F2	12.47	P.219 New London Turnpike	166	184	25054558	60	No
RI	NE53	E. Providence	78F3	12.47	P.27 Woodward Ave	156	185	25183873	50	No

The Recloser Program spend to date is $1.28 million.

Prepared by or under the supervision of: Kathy Castro

PUC 1-19

Request:

Referencing page 68, please provide the following information:

a) Is the $4.0 million requested in FY 2021 to study and develop the strategy/solution, to replace or rehabilitate the cables, or both?
b) Does the Company have a projection of how much cable needs to be replaced or rehabilitated on an ongoing annual basis?
c) How much does the Company estimate that it will cost to replace or rehabilitate all of the cables requiring replacement or rehabilitation, and in what years will these costs be incurred?

Response:

a) The $4.0 million requested in FY2021 for the Underground Residential Development (URD) Cable Strategy is both for engineering and construction for specific URDs that have been identified as candidates for the program. Typically, a URD rehabilitation/replacement project spans multiple years with engineering in one year and construction in subsequent year(s). Spend may be going to engineering or construction depending on the maturity of a specific URD project.

b) The Company cannot project how much cable needs to be replaced on an ongoing annual basis. Rather the Company can provide an annual budget based on recent performance and resource allocation.

   The program is structured so that it responds to emergent issues specific to direct buried XLPE cables which have experienced multiple outages. Subject to further verification, the Company's records indicate approximately 300 URDs with this type of cable and construction. Out of the 300 URDs there are 31 that have met specific reliability criteria for inclusion within the program. It is unknown how many of the 300 URDs will ultimately experience the degradation of reliability that makes them a candidate for the program.

Prepared by or under the supervision of: Kathy Castro

PUC 1-19, page 2

c) As explained in Part b) the Company cannot provide an estimated cost to replace or rehabilitate all cables that may be addressed through this program.

The Company has a budgeted spend for FY2021 and forecasted spend for FY2022 to FY2025 to address the 31 URDs that have been identified and prioritized at this time.

See table below for 5 year spend:

FY2021	FY2022	FY2023	FY2024	FY2025
$4.0m	$4.0m	$4.0m	$2.14m	$1.35m

Prepared by or under the supervision of: Kathy Castro

PUC 1-20

Request:

Referencing page 69 and the Strategy to Replace Distribution Substation Batteries, please provide the following information:

a) Is this a new program? If not, how long has it been ongoing?

b) How many batteries does the Company expect to replace with the $.2 million?

c) How long does the Company expect the program to continue?

d) How much does the Company estimate that it will cost on an annual basis to replace substation batteries?

Response:

a) The Strategy to Replace Distribution Substation Batteries is an existing program. The program was originally sanctioned in 2004.

b) In FY2021 the Company expects to replace four distribution substation batteries.

c) This program is perpetual. According to the Company's Substation Battery Replacement Substation Maintenance Standard, Substation Batteries shall be replaced prior to the twenty years in service limit. The Company's records show approximately 90 Distribution Substation Battery systems in Rhode Island. The program will replace batteries annually prioritized by manufacture date and condition assessments.

d) The FY2021 budget for this program is $220,000. Future year forecasts will be adjusted based on the number of batteries prioritized for replacement in that year.

Prepared by or under the supervision of: Kathy Castro

PUC 1-21

Request:

Referencing page 71, does the peak include active demand response and/or storage? If so, are they accounted for in the forecast or in the spot loading additions and subtractions described on page 71?

Response:

Similar to energy efficiency and solar-photovoltaics, the forecast of peak load does explicitly incorporate projections for active demand response. Energy storage is not directly incorporated into the forecast at this time, but to the extent that energy storage is installed to date, it would also be reflected in historical data used by the model. There is also a small amount of energy storage that is captured as part of the projected active demand response programs.

Prepared by or under the supervision of: Kathy Castro and Joseph Gredder

---

PUC 1-22

Request:

Referencing all projects contained in Section 2, in particular System Capacity and Performance projects, what projects had a previous SRP proposal? Did the Company evaluate any non-wires alternatives for any projects, including responses to RFPs issued by the Company? If so, describe.

Response:

A Non-Wires Alternative (NWA) is considered for all projects in accordance with the NWA screening criteria defined in Docket 4684 – The Narragansett Electric Company, d/b/a National Grid 2018-2020 Energy Efficiency and System Reliability Procurement Plan (SRP).

The projects in Section 2 of the plan are driven by issues that cannot be resolved with a NWA. For example, the Aquidneck, East Providence Substation, Warren Substation, and New Lafayette Substation projects currently being advanced all have asset condition issues which did not pass the screening criteria for further NWA consideration and analysis.

Studies may result in multiple projects to address various issues. While feasible NWAs were not identified for the specific projects in Section 2, the Company is currently investigating viable alternative solutions, as committed to in the 2020 SRP, for other projects that originated from the East Bay, South County East, and Providence Area Studies. The wires solutions associated with these potential NWA solutions are not in the FY2021 ISR Plan.

Prepared by or under the supervision of: Kathy Castro

PUC 1-23

Request:

Referencing the new Lafayette Substation in particular, did the Company evaluate any non-wires alternatives for this project? If so, please describe, and, if not, please explain why no non-wires alternatives were evaluated.

Response:

The new Lafayette Substation project currently being progressed in the FY2021 ISR recommends a new 115/12.47 kV substation at the existing Lafayette substation site to address asset condition issues on the two 34.5kV circuits that currently supply the existing Lafayette substation. The new 115kV supplied substation will provide the capacity needed to retire the 34.5kV circuits. This specific project and other projects were screened for Non-Wire Alternatives (NWAs) during the Development and Project Estimating stage of the South County East Area Study. Because the Lafayette Substation project is an asset condition-driven project, it did not pass the screening criteria for consideration of NWAs.

Please see Section 5.2 of South County East Area Study provided as Attachment DIV R-I-10 in this docket for further detail on NWAs that were and are currently being evaluated.

PUC 1-24

Request:

Referencing page 74 and Blanket projects, please explain what drives Blanket project spending. Are specific projects known but too small to describe, or are the projects unspecific or unknown (but still anticipated) work?

Response:

Blanket funding projects consist of many work orders that are typically standard construction, and of short duration and small cost. Blanket work orders may be reactive in nature to address emerging situations. Gross expenditures under an electric blanket funding project work order are not to exceed $100,000.

PUC 1-25

Request:

Referencing page 75 and the Substation EMS/RTU Additions Program, please provide the following information:

a) Is this a new program or an expansion of an existing program? Please provide an update on any previous execution of this Program.
b) How long does the Company expect this Program to continue and how much does the Company expect it will cost on an ongoing annual basis?

Response:

a) The Substation EMS/RTU Additions Program is an existing program, which the Company proposes to continue.

   Refer to the following list of stations that have had EMS/RTU (SCADA) installations or enhancements as part of this program:

Substation	**Status**	**In Service Date**
Old Baptist	Complete	4/12/2014
Division Street	Complete	10/9/2014
Lincoln Ave	Complete	6/17/2015
Elmwood Outdoor	Complete	7/2/2015
Central Falls Sub	Complete	8/3/2015
Hospital Sub	Complete	5/25/2016
Hopkins Hill	Complete	3/27/2017
Clarkson	Complete	5/8/2017
Natick	Complete	9/13/2017
Warwick	Complete	9/14/2017
Coventry	Complete	10/6/2017
Harrison	Complete	1/26/2018
Davisville	Complete	3/28/2019
Washington	Complete	3/31/2015
Peacedale	Complete	3/31/2016

b) Currently there are 9 remaining stations identified in the EMS/RTU Additions Program. The Company consults the program list during the course of an Area Study to inform comprehensive plan development, which may result in modifications to the EMS/RTU

PUC 1-25, page 2

Additions Program. The program is expected to continue beyond FY2025, with a FY2021 proposed capital budget of $980,000, and FY2022 to FY2025 total capital forecast of $4.3 million. Forecast spend is subject to change once detailed engineering is completed for the stations being addressed in future years.

PUC 1-26

Request:

Referencing page 75 and the Volt/Var Optimization and Conservation Voltage Reduction Expansion, please provide the following information:

a) Please provide a BCA for the expansion.
b) Please provide the most up to date Volt/Var study results and indicate what portion of this information has not previously been provided to the PUC.
c) Please provide the results of and any lessons learned from the Putnam Pike and Tower Hill pilot projects.
d) Please provide and describe the ongoing O&M costs associated with this project.

Response:

a) BCA results are included as Attachment PUC 1-26-4.

b) The Company has previously shared the measurement and verification study results for the Volt/Var pilot deployment at Putnam Pike Substation in Docket No. 4592 and in Docket No. 4915. As a courtesy, the Company is providing this information as Attachment PUC 1-26-1.

The following attachments include the most up to date measurement and verification study results for two additional Volt/Var pilot deployments at the Langworthy Corner and Lincoln Avenue substations, which have not previously been provided to the PUC:

- Attachment PUC 1-26-2: Tetra Tech's Findings for National Grid Rhode Island Volt/VAR Optimization 90-Day M&V Period (FINAL) – Langworthy Corner, October 7, 2019
- Attachment PUC 1-26-3: Tetra Tech's Findings for National Grid Rhode Island Volt/VAR Optimization 90-Day M&V Period (FINAL) – Lincoln Avenue, November 4, 2019

For the Lincoln Avenue substation results, it should be noted that there were many more "off days" than "on days," when Volt/Var controls were running, due to frequent and sustained communication losses during the measurement and verification study period. The Company is planning to reevaluate the Lincoln Avenue Substation feeders in FY 2021.

Prepared by or under the supervision of: Stephen Lasher

c) A key component of the Volt/Var pilot project is enabling remote communications to the distribution devices. Prior to the beginning of the Volt/Var pilot in Rhode Island, National Grid had some experience deploying wireless networks in other service territories, most recently as part of the Smart Energy Solutions pilot in Worcester Massachusetts, but remote communications were still an area of investigation for National Grid and other utilities at that time. Therefore, the Volt/Var pilot originally utilized 'mesh' networks for remote communications using a third-party's 5 GHz mesh network at the Putnam Pike substation. This mesh network promised greater reliability (self-healing) and easier deployments than point-to-point communication (e.g., cellular radios).

However, a major lesson learned from the Putnam Pike deployment was that the mesh network was not suitable for Volt/Var applications due to: high bandwidth requirements, high CAPEX and OPEX from additional tower requirements, install heights entering the Primary space, and tower interference issues. Due to these communication-related issues, the original Volt/Var pilot project CAPEX and OPEX costs were higher than originally estimated. Additional lessons learned from the Putnam Pike deployment include: April-September energy savings/demand reduction exceeded 3%, and VVO regulator tap operations remained basically flat (not statistically significant). Based on these lessons learned, subsequent Volt/Var pilot deployments have leveraged cellular radio communications to the distribution devices, and future deployments have been reprioritized to maximize benefits to customers using the latest performance and cost information.

A major lesson learned from the Lincoln Ave Substation VVO deployment, and to a lesser extent the Langworthy Substation VVO deployment, is that the VVO commissioned feeders must be continually monitored for significant and minor outage events. All communications disabling events, which includes minor outage events, require that the VVO/CVR system be reset and re-enabled for it to work properly. Another important lesson learned from both the Lincoln Ave and Langworthy deployments is understanding and overcoming scaling issues, including improper regulator setting protocols, which can lead to tap failures on the regulators resulting in the inability to operate the VVO/CVR system.

Note that feeder reconfiguration projects due to customer work at Tower Hill has prevented measurement and verification for this deployment to date, but a complete measurement and verification study is planned for FY 2021.

PUC 1-26, page 3

d) Ongoing O&M costs associated with the projects proposed for FY 2021 are estimated to be $110,884 (nominal) per year based on the annual cost of the Utilidata AdaptiVolt software maintenance fee and the monthly cellular communications fees. This raises the total ongoing O&M costs of the VVO program to date to approximately $400,000.

nationalgrid

Raquel J. Webster
Senior Counsel

December 12, 2016

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4592 - FY 2017 Electric Infrastructure, Safety, and Reliability Plan
Volt Var Optimization Pilot

Dear Ms. Massaro:

I have enclosed the following documents regarding National Grid's[1] Volt Var Optimization (VVO) Pilot:

1. July 25, 2016 Power Point regarding the progress and initial results of the VVO Pilot (Attachment 1);

2. December 2, 2016 PowerPoint regarding the progress of the VVO Pilot, including final measurement and verification (M&V) results for two feeders in the pilot, and the cost and benefit estimates for expanding the VVO Pilot to additional substations (Attachment 2); and

3. Utilidata Measurement and Verification Results for the VVO Pilot (Attachment 3).

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

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

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.

______________________________ December 12, 2016
Joanne M. Scanlon Date

Docket No. 4592 National Grid's Electric Infrastructure, Safety and Reliability Plan FY 2017 - Service List as of 10/5/16

Name/Address	E-mail Distribution	Phone
Raquel J. Webster, Esq. **National Grid.** 280 Melrose St. Providence, RI 02907	raquel.webster@nationalgrid.com; celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7667
National Grid Jim Patterson Ryan Moe Amy Tabor Adam Crary	Jim.patterson@nationalgrid.com; Ryan.moe@nationalgrid.com; Amy.tabor@nationalgrid.com; Adam.crary@nationagrid.com; William.richer@nationalgrid.com;	
Division of Public Utilities & Carriers Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Steve.scialabba@dpuc.ri.gov; James.lanni@dpuc.ri.gov; Joseph.shilling@dpuc.ri.gov; John.spirito@dpuc.ri.gov; dmacrae@riag.ri.gov; Jmunoz@riag.ri.gov;	401-222-2424
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Greg Booth Linda Kushner PowerServices, Inc 1616 E. Millbrook Road, Suite 210 Raleigh, NC 27609	gbooth@powerservices.com; Lkushner@powerservices.com;	919-256-5900
Office of Energy Resources (OER) Andrew Marcaccio, Esq. Dept. of Administration	Andrew.marcaccio@doa.ri.gov;	401-222-3417

Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Daniel.majcher@doa.ri.gov;	
Christopher Kearns, OER Danny Musher Nick Ucci	Christopher.Kearns@energy.ri.gov; Danny.Musher@energy.ri.gov; Nicholas.Ucci@energy.ri.gov;	
File an original & nine copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107
Seth Handy, Esq.	seth@handylawllc.com;	401-626-4839

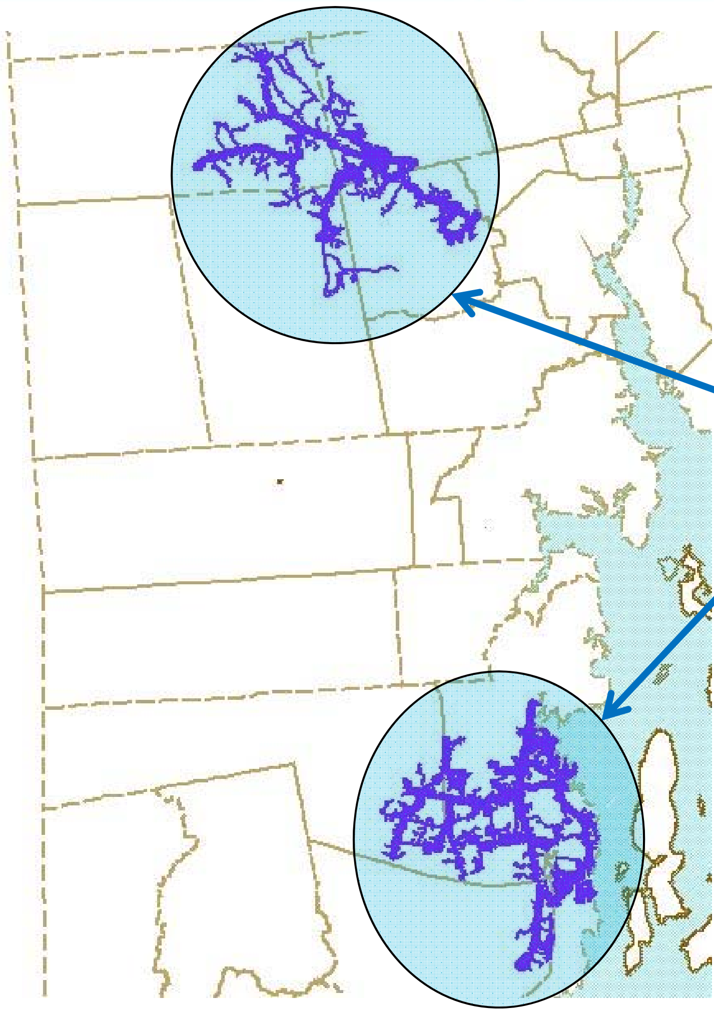
nationalgrid
HERE WITH YOU. HERE FOR YOU.

Rhode Island Volt VAR Optimization & Conservation Voltage Reduction (VVO/CVR)

Progress and Initial Results

July 25th 2016 – Jim Perkinson

RI VVO/CVR Project Scope



The project investigates two new technologies being investigated by the company:

- Centralized VVO/CVR
- Mesh based field communications

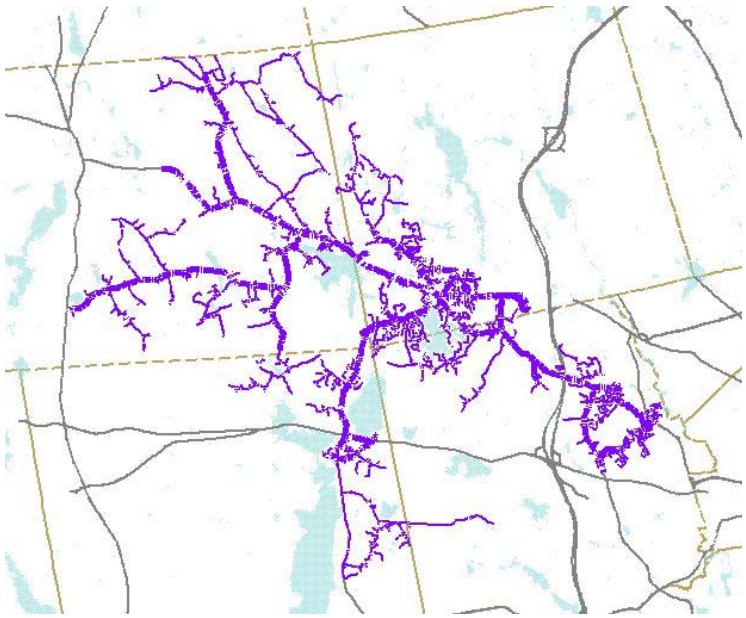
2 Substations/areas:

- 3 Feeders in Putnam Pike
- 4 Feeders in Tower Hill

Project includes:

- IS/IT Backoffice Infrastructure
- Field Area Network
- Central Controller Installed at Lincoln
- Operational Integration to the company Energy Management System (EMS)
- 40 Controllable field capacitors
- 30 controllable field regulators
- ~16k customers affected

Active Devices



Putnam Pike Area:

- All Field Devices Installed
- Communications established to 93% of installed devices
- 2/3 feeders 100% operational in EMS and active in the VVO application (38F3 and 38F5)
- Measurement and Verification Process began on April 1st 2016
- Preliminary results from April 1st 2016 to June 30th 2016 are presented

All the significant challenges to date have been related to the wireless mesh for the field area network:

- 'Hop' Limitation leading to extra 3rd party towers
- Poor Line of sight performance requiring additional repeaters
- Taller utility Poles
- 5Ghz Interference issues

nationalgrid
HERE WITH YOU. HERE FOR YOU.

M&V Summary

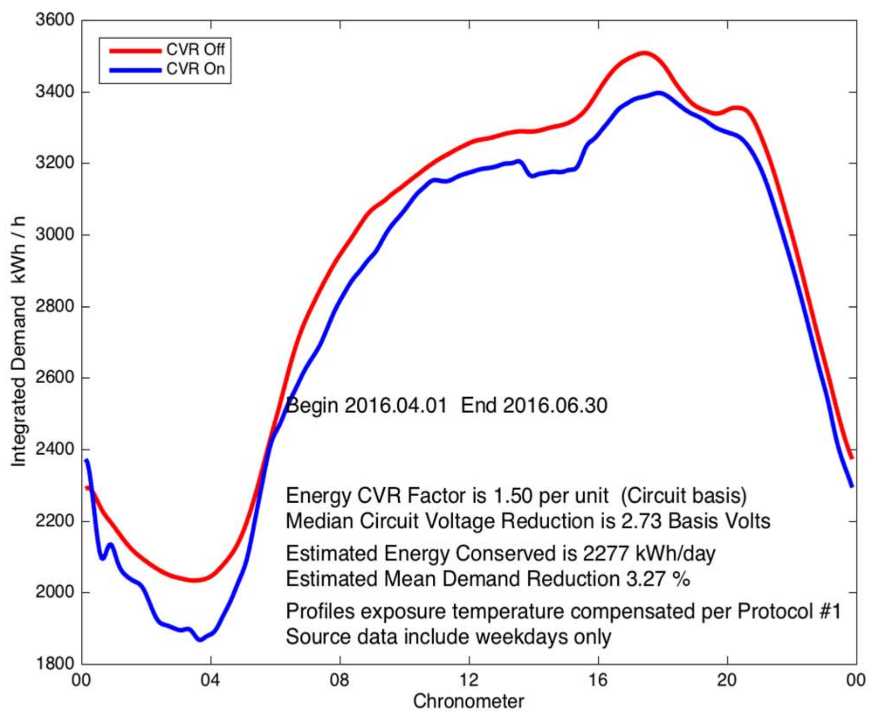
Metric	Feeder 38F3	Feeder 38F5
VVO Mode days	18	21
Non-VVO Mode days	27	19
Estimated CVR Factor (per unit)	1.50	1.40
Demand Reduction (%)	**3.27**	**3.39**
Voltage Reduction, spatial avg %	2.28	2.46
Voltage Leveling improvement (volts)	0.72	0.68

Measurement and Verification was performed utilizing filtered time series temperature compensated weekday date, following Automated CVR protocol #1.

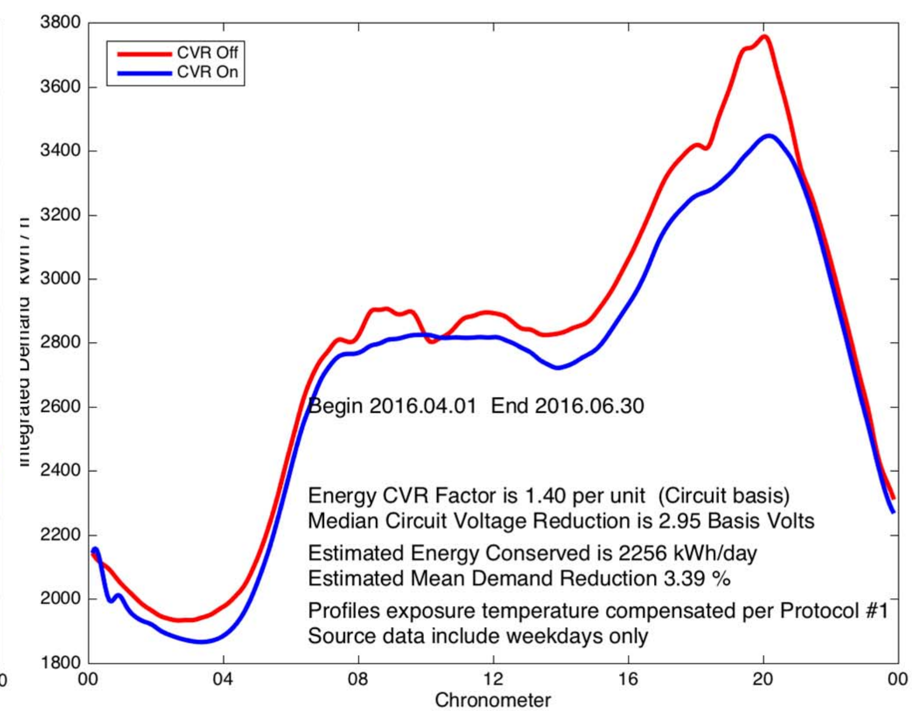
nationalgrid
HERE WITH YOU. HERE FOR YOU.

Robust, Estimated Demand Profiles, over 24 hrs

38F3

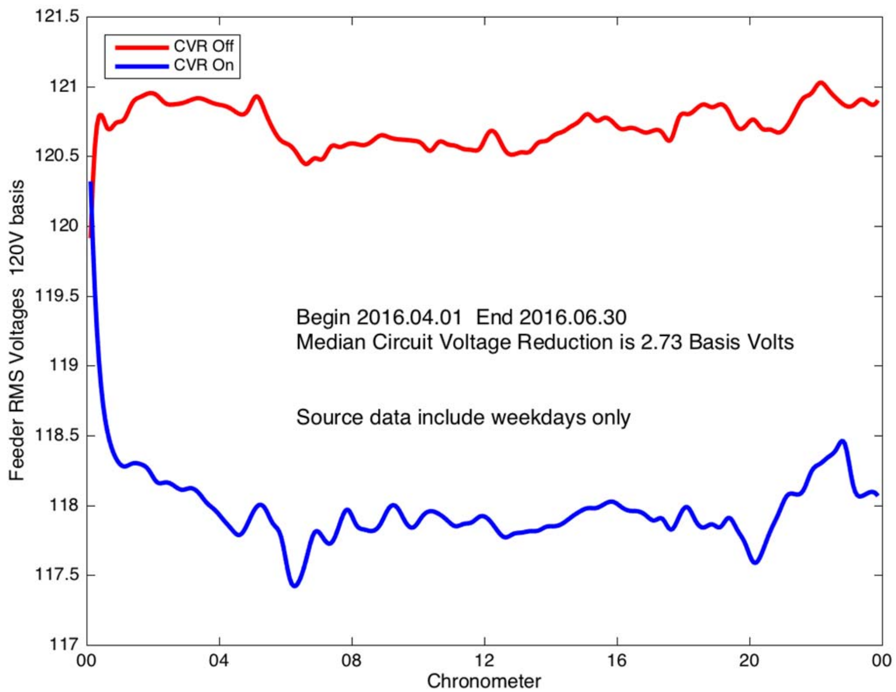


38F5

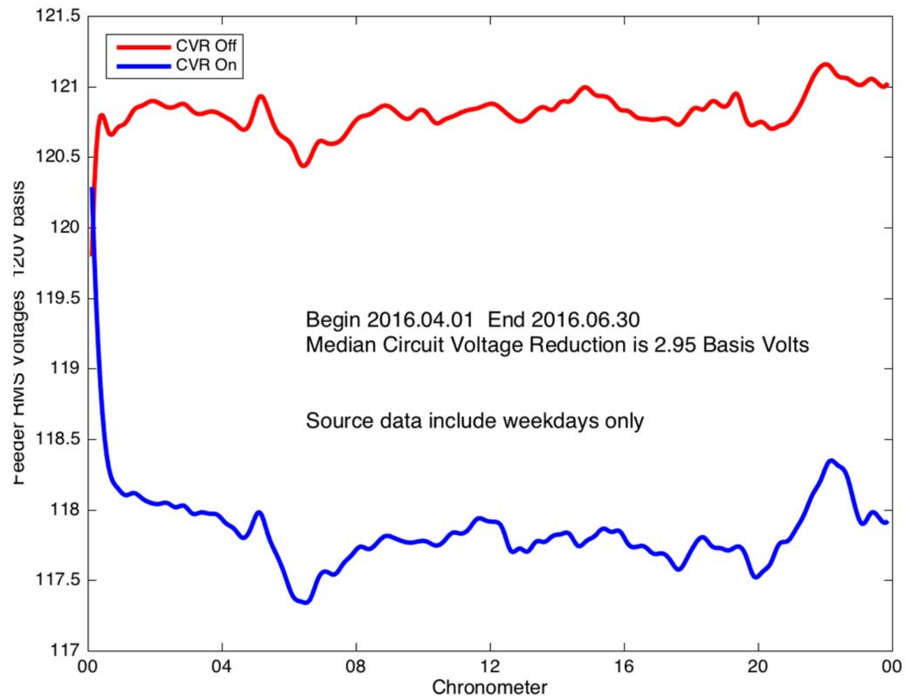


Median Circuit Voltage Profiles, Over 24hrs

38F3

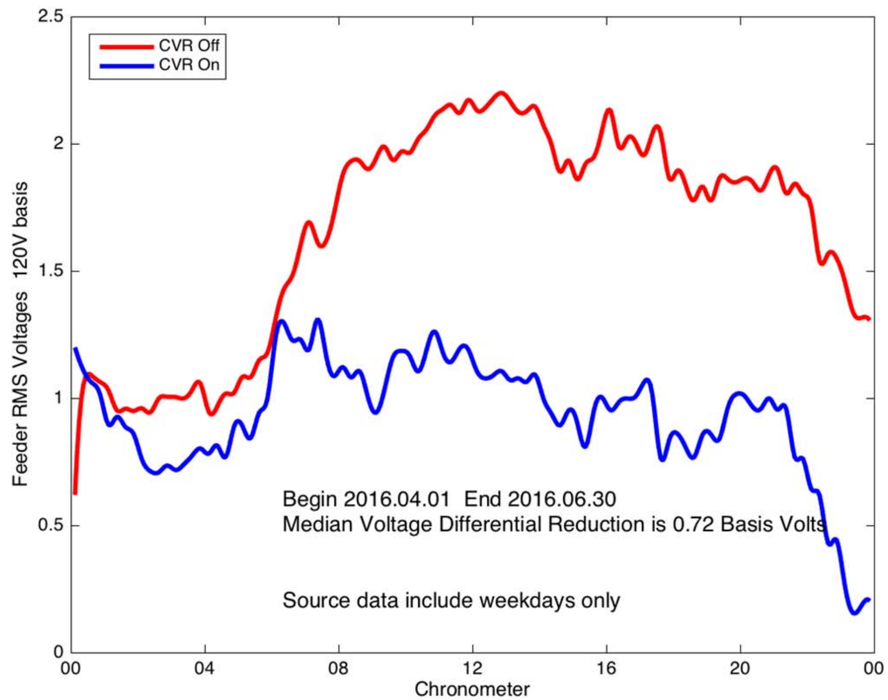


38F5

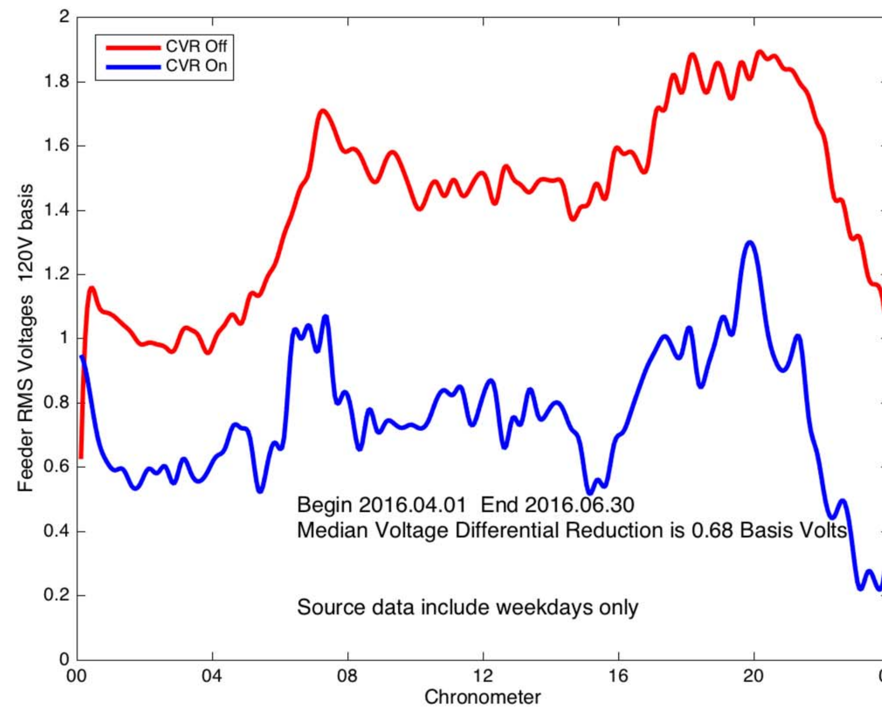


Median Voltage Differential Profiles

38F3



38F5



Preliminary Conclusions and Next Steps

Conclusions:

- Preliminary M&V shows greater than 3% reduction in demand when using CVR Protocol #1.
- CVR factor for these circuits is in the 1.4-1.5 range.

Next Steps:

- Continue M&V over the summer peak demand periods
- Complete the Putnam Pike and Tower Hill areas, utilizing cellular communications to resolve FAN challenges (to be completed FY17)
- Leverage IS/IT/OT infrastructure, and evaluate expanding VVO to future target areas in FY18 and beyond

nationalgrid
HERE WITH YOU. HERE FOR YOU.

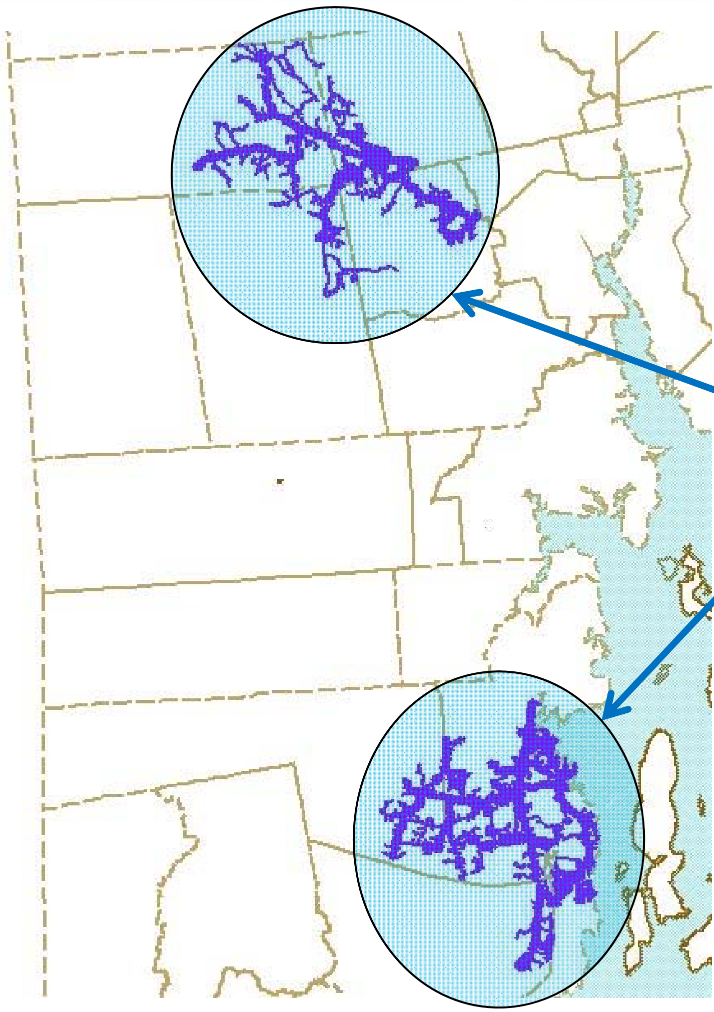
Rhode Island Volt VAR Optimization & Conservation Voltage Reduction (VVO/CVR)

December Update, 38F3 and 39F5 final M&V results, Cost and Benefit Estimates

Updates From July presentation in Red (slides 1-8), C/B information from slide 9 - end

Dec 2nd 2016 – Jim Perkinson

RI VVO/CVR Pilot Project Scope



The project investigates two new technologies being investigated by the company:

- Centralized VVO/CVR
- Mesh based field communications

2 Substations/areas:

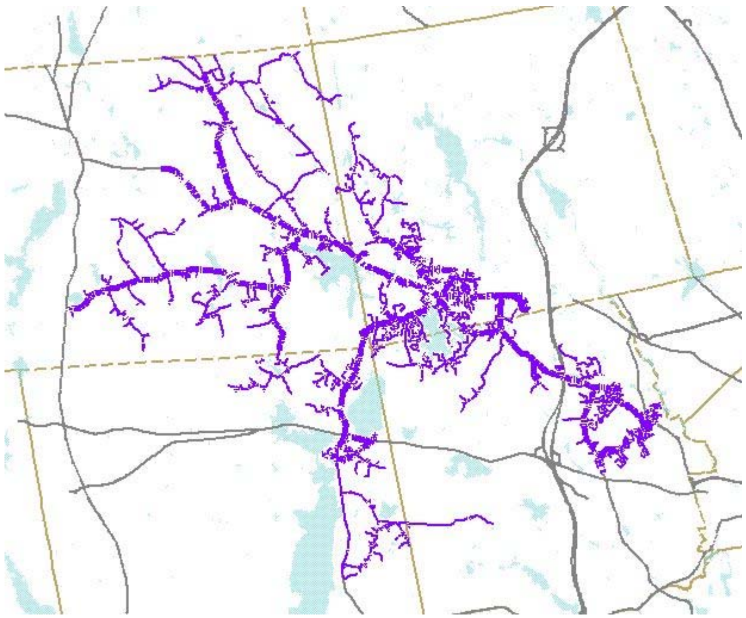
- 3 Feeders in Putnam Pike
- 4 Feeders in Tower Hill

Project includes:

- IS/IT Backoffice Infrastructure
- Field Area Network
- Central Controller Installed at Lincoln
- Operational Integration to the company Energy Management System (EMS)
- 40 Controllable field capacitors
- 30 controllable field regulators
- ~16k customers affected

nationalgrid
HERE WITH YOU. HERE FOR YOU.

Active Devices



Putnam Pike Area:

All Field Devices Installed

Communications established to 93% of installed devices

2/3 feeders 100% operational in EMS and active in the VVO application (38F3 and 38F5)

Measurement and Verification Process began on April 1st 2016

Final results from April 1st 2016 to Sept 30th 2016 are presented

All the significant challenges to date have been related to the wireless mesh for the field area network:

- **'Hop' Limitation leading to extra 3rd party towers**
- **Poor Line of sight performance requiring additional repeaters**
- **Taller utility Poles**
- **5Ghz Interference issues**

nationalgrid
HERE WITH YOU. HERE FOR YOU.

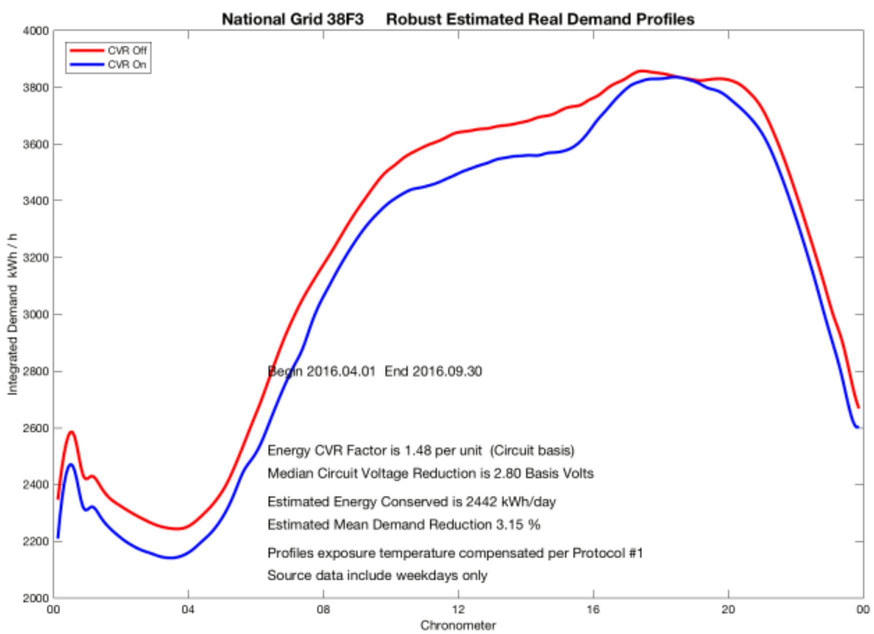
M&V Summary

Metric	Feeder 38F3	Feeder 38F5
VVO Mode days	29	36
Non-VVO Mode days	59	52
Estimated CVR Factor (per unit)	1.48	1.54
Demand Reduction (%)	**3.15**	**3.50**
Voltage Reduction, spatial avg %	2.33	2.33
Voltage Leveling improvement (volts)	0.45	0.95
VVO Regulator Tap operations, phase mean (daily)	14.6	13.1
Non- Regulator Tap operations, phase mean (daily)	16.3	14.0

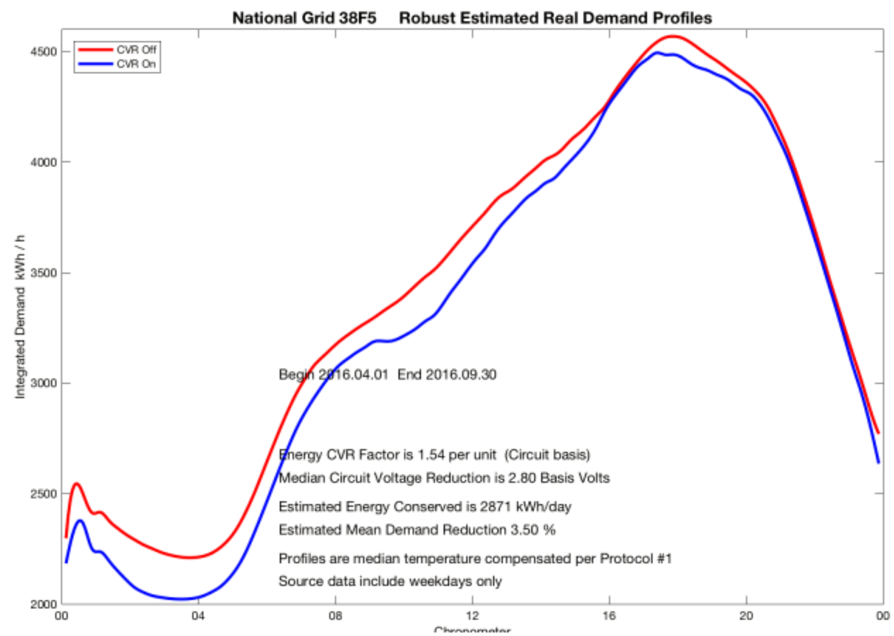
Measurement and Verification was performed utilizing filtered time series temperature compensated weekday date, following Automated CVR protocol #1.

Robust, Estimated Demand Profiles, over 24 hrs

38F3



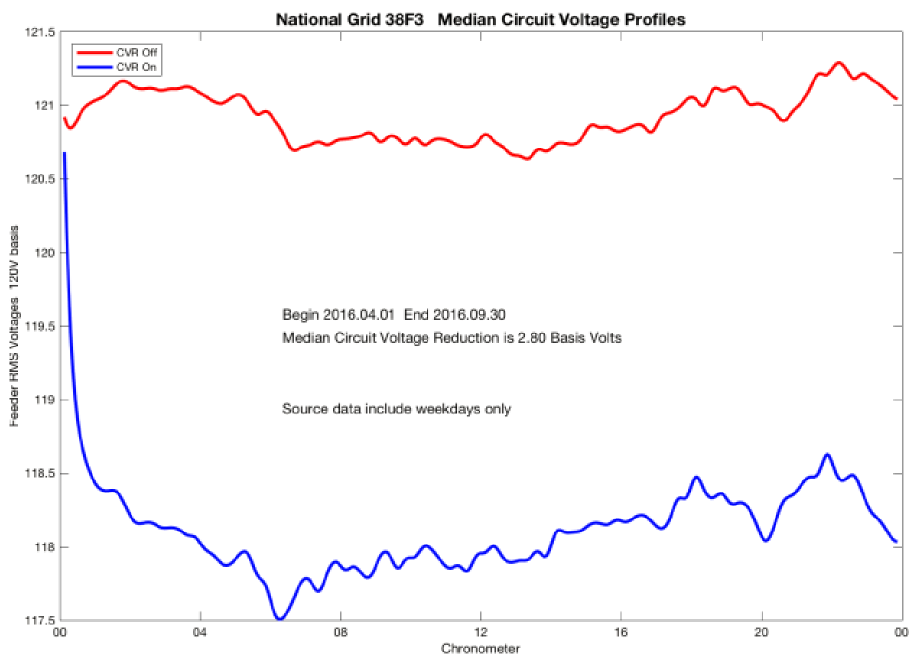
38F5



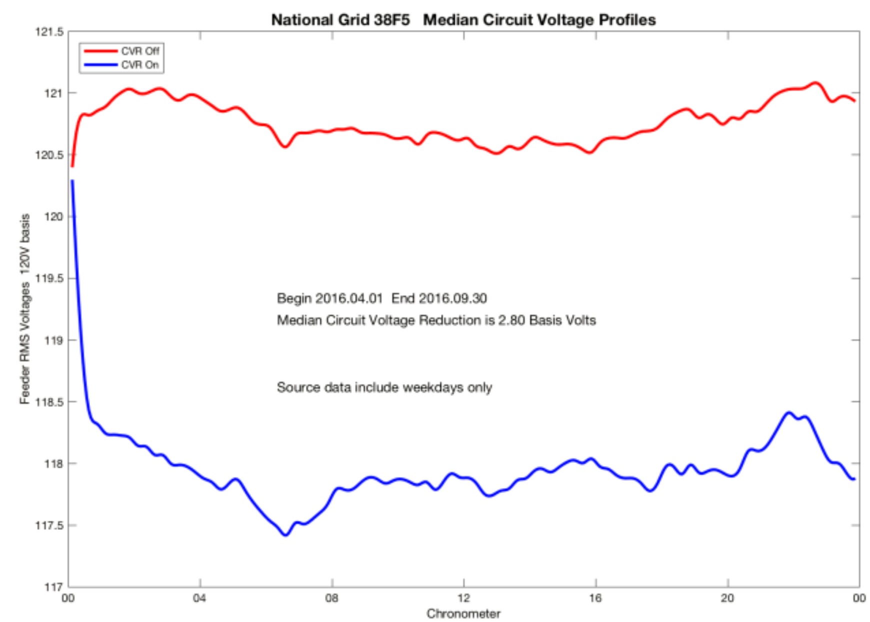
nationalgrid
HERE WITH YOU. HERE FOR YOU.

Median Circuit Voltage Profiles, Over 24hrs

38F3

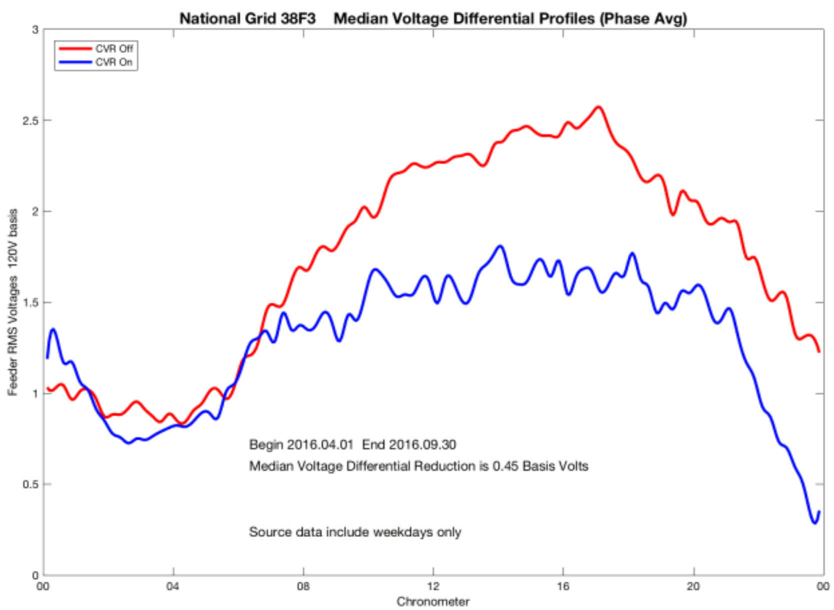


38F5

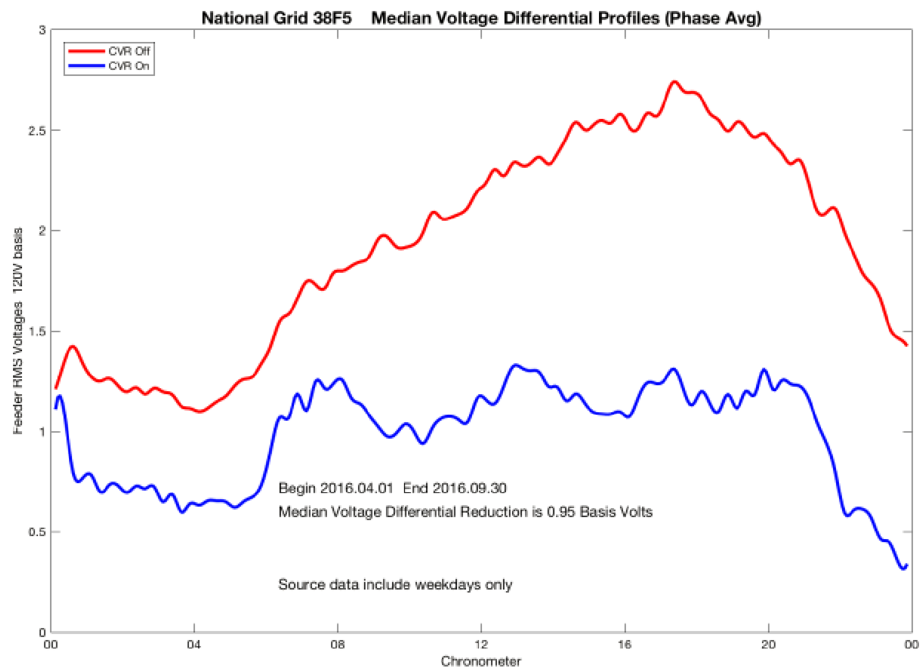


Median Voltage Differential Profiles

38F3



38F5



nationalgrid
HERE WITH YOU. HERE FOR YOU.

Preliminary Conclusions and Next Steps

Conclusions:

- Final M&V shows greater than 3% reduction in demand when using CVR Protocol #1.
- CVR factor for these circuits is in the 1.4-1.5 range.

Next Steps:

- Complete the Putnam Pike and Tower Hill areas, utilizing cellular communications to resolve communications challenges (to be completed FY17)
  - ~80% of devices ready for installation, remaining 20% to be finished in Dec.
  - ~30% of devices installed in Tower Hill. Remaining devices to be installed Dec-Feb
  - Remaining Putnam Pike devices to be commissioned by Jan
- Leverage IS/IT/OT infrastructure, and evaluate expanding VVO to future target areas in FY18 and beyond

Expansion Scope

The expansion proposed an additional 40 feeders

The Company anticipates spending **$8.6M of CAPEX (PV $10.4M)** to apply the technology to approximately 61,000 distribution customers over the next 4 years. When fully deployed, the program will have an annual O&M run the business cost of approximately **$0.300M**

The expected benefits include an estimated reduction in peak demand of 11.5 MW, and an annual energy reduction of 41 GWh. The equipment is expected to be in service for at least 15 years, and over that time horizon, this savings could yield a cumulative financial savings of **$24.7M** (PV) in avoided energy costs, as well as an estimated **$17.7M** (PV) in avoided capacity costs.

The expansion leverages the IS/OT infrastructure deployed during the pilot.

Expansion Scope

Over the next 4 years:

- 40 additional feeders will be brought online
- Each year, a grouping of substations and feeders will be selected for deployment within the following FY. This will ensure the company selects best value feeders to deploy the technology.
  - Feeders with high-benefit to cost ratios
  - Feeders that have recently gone through short and long term planning studies, and are unlikely to undergo major changes in the near term.
- FY18 substation and feeders have already been selected, and proposed in the proposed ISR.
  - Langworthy Corner #86, Tiogue Ave #100, Lincoln Ave #72 – (8 feeders total)
- FY19-FY21 Highest benefit-cost ratio substations were used to inform costs, refinement will be made before each FY to factor in recent system state.

nationalgrid
HERE WITH YOU. HERE FOR YOU.

Project Expansion Costs

	CAPEX	OPEX	COR	Total	Cumulative Feeders per year	Cumulative Customers Affected
FY17	$2,000,000	$0	$0	$2,000,000	0	0
FY18	$1,395,404	$265,870	$70,309	$1,731,583	8	20109
FY19	$1,267,572	$239,580	$75,011	$1,582,163	19	37300
FY20	$767,087	$148,673	$49,941	$965,701	27	46565
FY21	$1,594,411	$357,906	$83,166	$2,035,483	39	61324

- Costs include a $2M payment to Utilidata in FY17 to purchase licenses for the expansion at a discounted bulk price. These license will be applied to the projects from FY18-FY21
- Cost estimates are based on actual averages from installation of pilot devices.
- Pilot costs and benefits are not included in the benefit and cost analysis presented here.

Expansion Benefits

Benefits Monetized over a 15 year horizon:

- **Avoided Energy Costs**
  - **Utilized a conservative 3% energy reduction, realized starting the year following a feeder installation**
  - **Total of around 41 GWh (Based on 2015 loading)**
- **Avoided Capacity Costs**
  - **Utilized a conservative 3% demand reduction, benefit realized starting in 2021**
  - **Total of 11.5 MW of peak reduction (Based on 2015 loading)**
- **Benefits not Monetized:**
  - **Improved situational awareness of target feeders to better inform Operations**
  - **Improved interval data to better inform distribution planning and asset management**
  - **Direct Custom Bill Impacts are not considered as part of this analysis**

Avoided Energy Costs Calculation

Assumptions	
Losses	7.2%
Wholesale Risk Premium (WRP)	9.0%
Winter months/year	8
Summer months/year	4
Hrs/wk	168
Peak hrs/wk	80
Off-peak hrs/wk	88
Inflation	1.88%
Constant$ to Nominal$ Conversion Index	
2015	1
2016	1.02
2017	1.04
2018	1.06
2019	1.08
2020	1.10

Forecasted LMP AESC 2015 Appendix B: RI file pp. 320-321 Columns v-y 2015$/kWh
2015
0.0732
0.0649
0.0394
0.0302
2016
0.0665
0.0617
0.047
0.0305
2017
0.0636
0.059
0.0486
0.0361
2018
0.0539
0.0493

RI Wholesale Avoided Unit Cost of Electricity (grossed up for losses and WRP)							Annual Energy Savings from VVO GWh	Annual Avoided Energy Cost from VVO Nominal$
	Constant 2015$/kWh					All Hours Weighted Average Nominal$/GWh		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	All Hours Weighted Average			
lookup index>	1	2	3	4			nput Annual GWI	(Result)
2015	0.0855	0.0758	0.0460	0.0353	0.0671	$67,104.14	0	$0.00
2016	0.0777	0.0721	0.0549	0.0356	0.0648	$66,001.81	0	$0.00
2017	0.0743	0.0689	0.0568	0.0422	0.0640	$66,476.44	0.00	$0.00
2018	0.0630	0.0576	0.0556	0.0458	0.0569	$60,208.47	7.43	$447,572.77
2019	0.0620	0.0568	0.0553	0.0453	0.0562	$60,565.10	10.10	$611,632.86
2020	0.0605	0.0548	0.0556	0.0434	0.0547	$60,093.44	21.90	$1,316,293.41
2021	0.0630	0.0575	0.0589	0.0467	0.0576	$64,386.09	33.87	$2,180,628.63
2022	0.0667	0.0606	0.0620	0.0493	0.0608	$69,285.87	40.94	$2,836,730.17
2023	0.0684	0.0627	0.0665	0.0522	0.0633	$73,453.75	40.94	$3,007,373.01
2024	0.0708	0.0652	0.0666	0.0549	0.0654	$77,345.91	40.94	$3,166,727.45
2025	0.0754	0.0675	0.0727	0.0569	0.0690	$83,105.79	40.94	$3,402,550.89
2026	0.0770	0.0701	0.0778	0.0601	0.0718	$88,085.14	40.94	$3,606,417.34
2027	0.0785	0.0723	0.0751	0.0620	0.0729	$91,213.87	40.94	$3,734,514.90
2028	0.0804	0.0748	0.0804	0.0650	0.0757	$96,489.51	40.94	$3,950,512.35
2029	0.0849	0.0795	0.0839	0.0680	0.0799	$103,710.25	40.94	$4,246,146.96
2030	0.0930	0.0832	0.1024	0.0737	0.0877	$115,968.00	40.94	$4,748,008.57
2031	0.0964	0.0865	0.1071	0.0769	0.0912	$122,903.11	40.94	$5,031,948.66

nationalgrid
HERE WITH YOU. HERE FOR YOU.

Avoided Capacity Costs Calculation

Assumptions	
Incorporated Losses	8.0%
Wholesale Risk Premium (WRP)	9.0%
Reserve Margin	17.0%
Capacity Multiplier	1.38
Inflation	1.88%
Constant$ to Nominal$ Conversion Index	
2015	1
2016	1.02
2017	1.04
2018	1.06
2019	1.08
2020	1.10
2021	1.12
2022	1.14
2023	1.16

	Unit Cost of Electric Capacity (FCA price grossed up for RM, losses, a				
	Constant 2015$/kW-yr				
	FCA Price				
	(AESC 2015 App. B: RI file pp. 320-321 Column ab)	FCA Price grossed up for RM, losses, and WRP	Avoided Capacity Cost Nominal $/GW-yr	Annual Capacity Savings from VVO (Input GW-yr)	Annual Avoided Capacity Cost from VVO Nominal $
2015	$39.67	$54.64	$54,638,443.08	-	$ -
2016	$38.16	$52.56	$53,546,787.10	-	$ -
2017	$114.53	$157.74	$163,731,879.99	-	$ -
2018	$132.93	$183.09	$193,609,172.52	0.0027	$ -
2019	$123.29	$169.81	$182,944,649.72	0.0034	$ -
2020	$135.75	$186.97	$205,220,449.67	0.0065	$ -
2021	$138.60	$190.90	$213,468,089.48	0.0097	$ 2,072,942.01
2022	$139.90	$192.69	$219,521,157.35	0.0115	$ 2,529,761.40
2023	$137.73	$189.70	$220,179,130.83	0.0115	$ 2,537,343.89
2024	$140.57	$193.61	$228,943,957.98	0.0115	$ 2,638,349.74
2025	$143.50	$197.65	$238,109,859.72	0.0115	$ 2,743,977.57
2026	$144.08	$198.44	$243,566,813.36	0.0115	$ 2,806,863.50
2027	$142.75	$196.61	$245,855,239.20	0.0115	$ 2,833,235.31
2028	$146.18	$201.34	$256,495,791.95	0.0115	$ 2,955,857.02
2029	$151.86	$209.16	$271,471,735.15	0.0115	$ 3,128,439.76
2030	$153.53	$211.46	$279,616,895.44	0.0115	$ 3,222,304.57
2031	$147.00	$202.47	$272,757,330.04	0.0115	$ 3,143,254.96

For an efficiency program that produces reductions starting in 2016, there is no benefit of a reduction in peak demand until 2020, at which point the annual benefit is calculated as follows:

kW reduction at the meter during system peak in a given year × summer peak-hour losses from the ISO delivery points to the end use × the Avoided Unit Cost of Capacity for that year, which is the FCA price for that year adjusted upward by the reserve margin that ISO-NE requires for that year, distribution losses (user defined), by the PTF losses, and the wholesale risk premium (AESC 2015 p. A-8).

nationalgrid
HERE WITH YOU. HERE FOR YOU.

Benefit-Cost Ratios

Costs:

PV Project Installation Costs (Capex/Opex/CoR), FY17-FY21:

- $7.3M

PV Run The Business costs: FY17-FY31:

- $3.1M

- **PV Total Cost: $10.4M**

Benefits:

PV Avoided Energy Costs FY17-FY31:

- $24.7M

PV Avoided Capacity Costs : FY17-FY31:

- $17.7M

- **PV Total Benefit: $42.5M**

B:C ratio – 4.11

Measurement & Verification Results

National Grid – Putnam Pike April 2016 to September 2016

November 2016

This document contains Utilidata's measurement and verification analysis of National Grid's 38F3 and 38F5 feeders served by the Putnam Pike substation.

Contents

Executive Summary

Utilidata is pleased to provide results of the measurement and verification analysis for National Grid's 38F3 and 38F5 feeders served by the Putnam Pike substation. The following table summarizes the results of the study, which took place from April 1, 2016 to September 30, 2016.

Putnam Pike substation – Feeder analysis

Metric	Feeder 38F3	Feeder 38F5
VVO Mode days	29	36
Non-VVO Mode days	59	52
Real CVR Factor (per unit)	1.48	1.54
Demand Reduction (%)	3.15	3.50
Voltage Reduction, Spatial Avg %	2.33	2.33
Voltage Leveling Improvement (basis volts)	0.45	0.95
VVO Regulator tap ops, phase mean (daily)	14.6	13.1
Non-VVO Regulator tap ops, phase mean (daily)	16.3	14.0

These results are consistent with loads generally comprising significant air conditioning and refrigeration. As expected, favorable summer season CVR factors consistent with such loads are confirmed by this analysis. Although the sample size is small given the limited number of qualified experimental time series records, the residual variances estimated in this analysis are consistent with those typically observed in distribution circuit loads. The tap operations rate remained basically flat; that is, the differences in tap rate are not statistically significant.

The following sections contain more information on the experiment and individual graphs for tap operations and voltage profiles on each feeder.

We will continue to collect data and provide additional updates as requested.

General Observations

The following are general observations about the test results.

(1) The CVR factors estimated for the subject circuits are consistent with those expected for circuits serving mixed residential and light commercial loads in a temperate season; the demand response to reduced voltage clearly indicates the presence of air conditioning and mechanical refrigeration in the served load.

(2) The availability of integral signal records is marginal to average, because system operations were subject to some interruptions due to telemetry failures; energy conservation is optimized when such interruptions are rare.

(3) The residual variance in the stated estimates is typical for distribution circuits.

(4) There is no evidence of distinct demand processes in this experiment.

(5) The dependence of demand on ambient temperature for the subject circuits manifested minimal temperature dependence in the heating demand regime. The demand process, instead, behaved almost as expected for the neutral regime. This effect does not degrade the analysis in any way, since the procedure naturally accommodates such variations.

(6) Loads for which the estimated CVR factors exceed unity will generally manifest further efficiency improvements with additional voltage reductions; Utilidata anticipates that this is the case for the loads served by the subject circuits.

(7) Realized voltage reductions, and the consequent demand reductions, are not uniform across phases in either of the circuits under study. Circuit voltage uniformity was improved by AdaptiVolt; refer to the per-phase voltage graphics for details.

(8) Estimated demand profiles for circuit 38F3 were summed post-regression, since demand metering by phase was reported. Estimated demand profiles for circuit 38F5 were computed using three-phase aggregate demand signals as reported.

Analyst Notes

The following are notes about the test prepared by the Utilidata analyst.

(1) The conservation performance results are calculated using the analysis method outlined Automated CVR Protocol # 1. This method implements the MCD robust regression procedure across ensembles of time series of demand measurements and, in its present formulation, requires that each member record of an ensemble comprise a full 24-hour operational record. Any record in which either the CVR operation was interrupted or the data recordings were defective for any reason are excluded from these analyses. Regime voltages are estimated by minimizing the mutual summation of the Euclidean distances between all the voltage observations in each regime. This estimate is known as the L1 median.

(2) Time series records were smoothed prior to ensemble selection and regression. The smoothing procedure preserves the signal mean over the smoothing interval such that the signal of interest is not biased. (*Smoothing and differentiation by simplified least squares procedures,* Abraham Savitzky and M. J. E. Golay, Analytical Chemistry, Vol. 36, No. 8 [July 1964], pp. 1627–1639*)*)

(3) All reported demand profiles (real, reactive, current) are compensated for ambient temperature as specified in Protocol # 1. These profiles therefore represent the expected demands, not to be confused with the demands recorded for any individual day during the experiment.

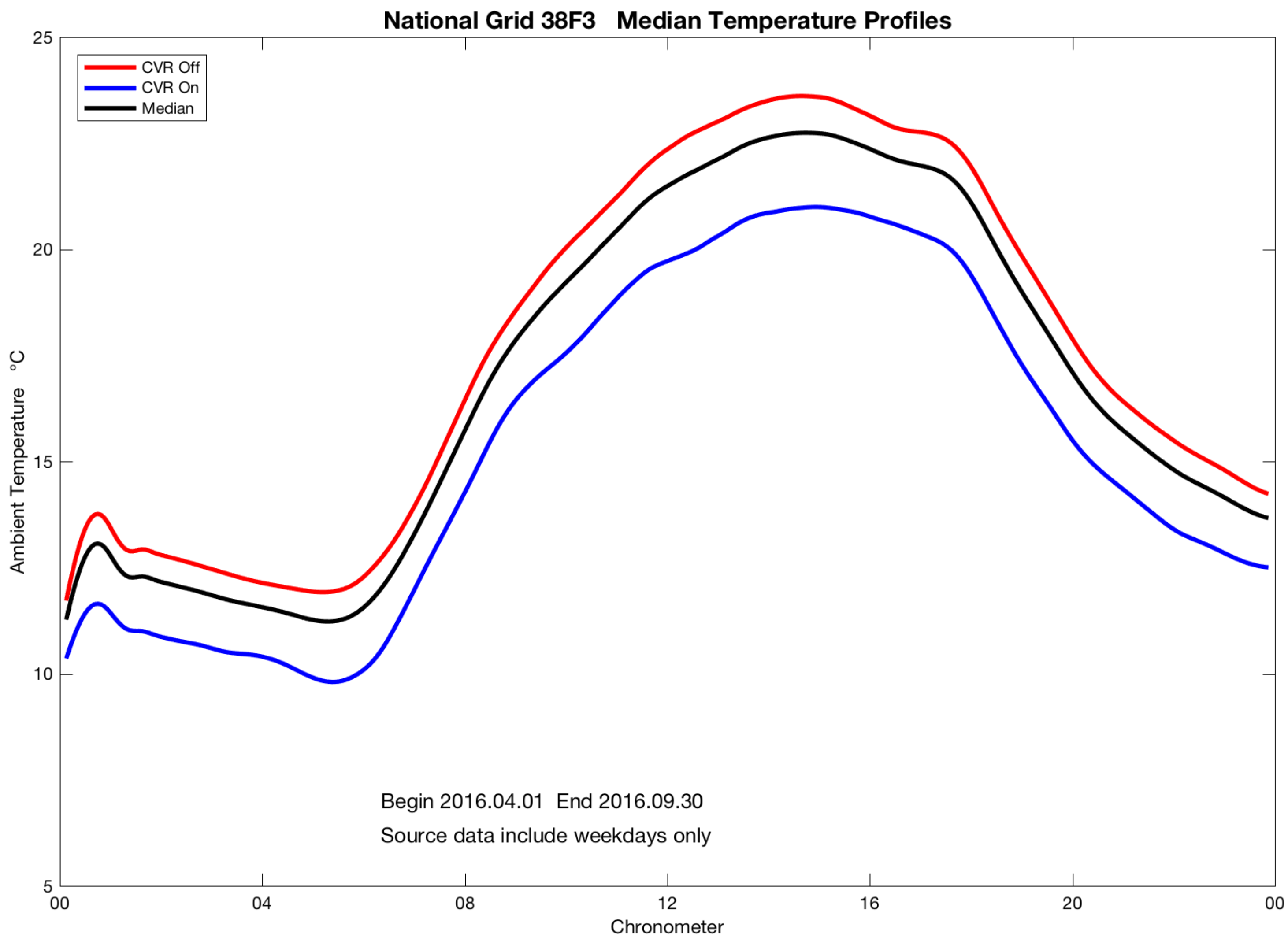
(4) Weekend demands are excluded from the present analysis; the distinctly different consumer weekend behavior results in an identifiably different demand process, which must be excluded in accordance with the requirements of Protocol #1.

Feeder 38F3 Results

This section contains graphs illustrating the results of the measurement and verification analysis for the 38F3 feeder served by the Putnam Pike substation.

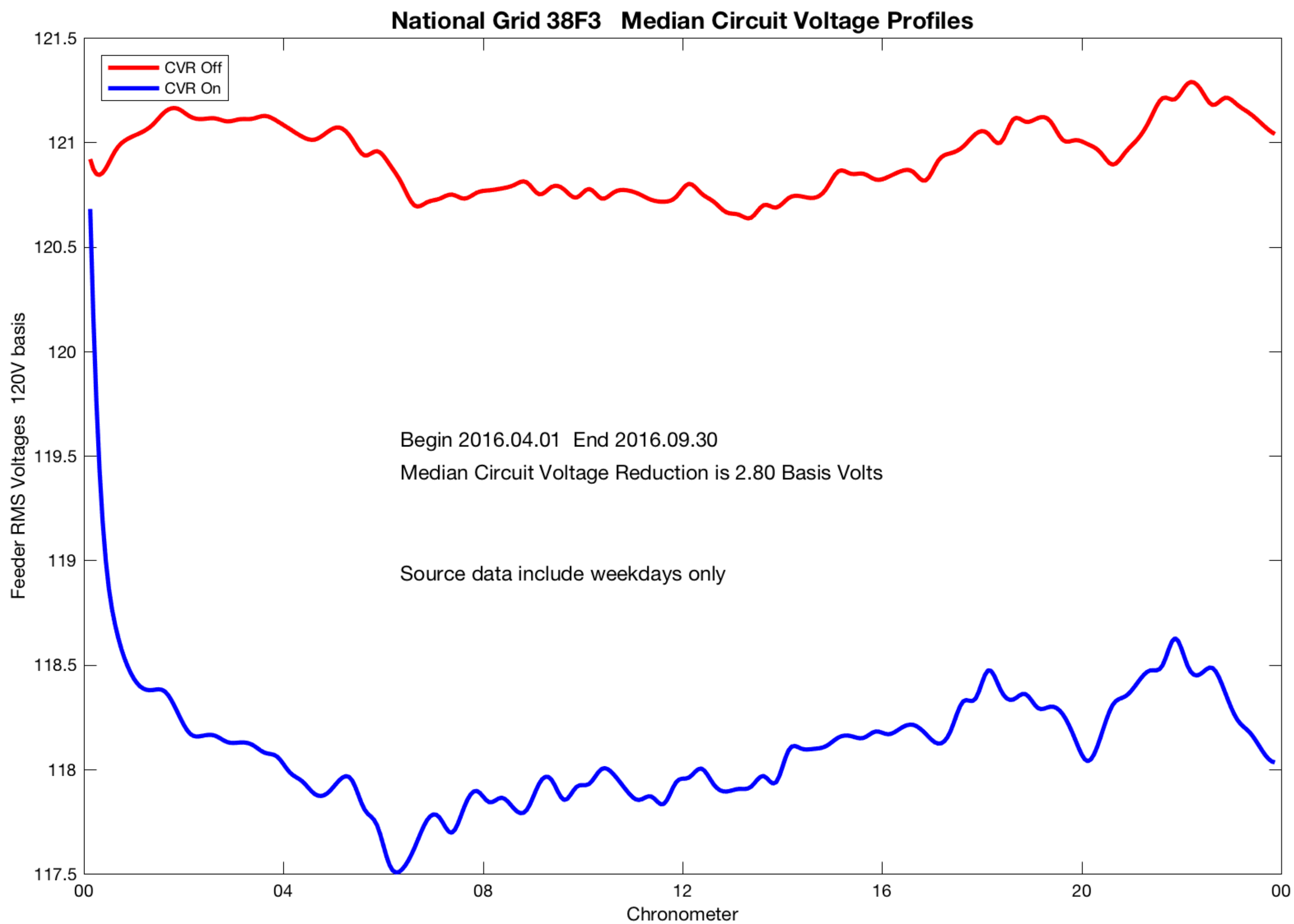
Feeder 38F3: Median Temperature Profiles

Graph 1



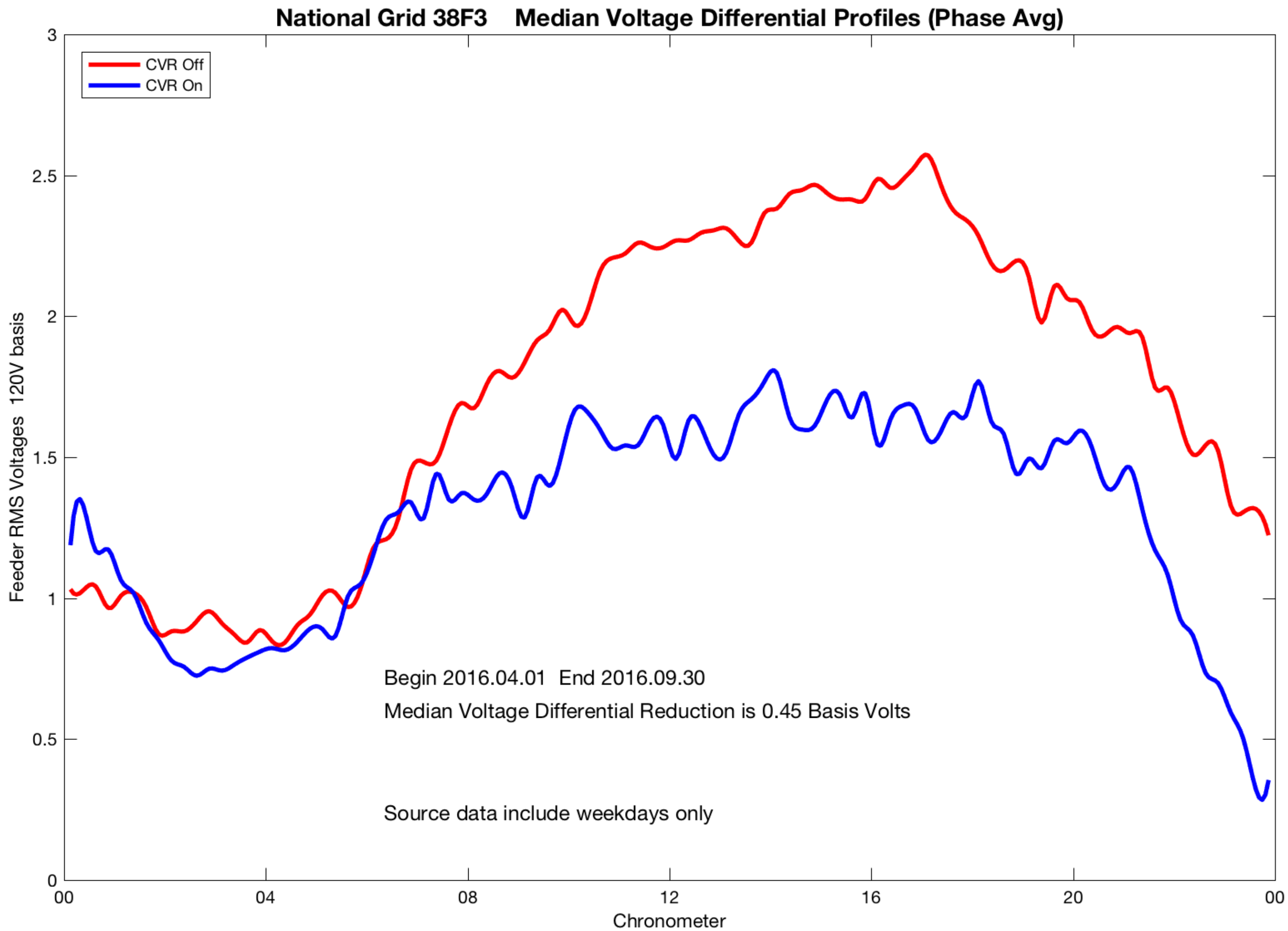
Feeder 38F3: Median Circuit Voltage Profiles

Graph 2



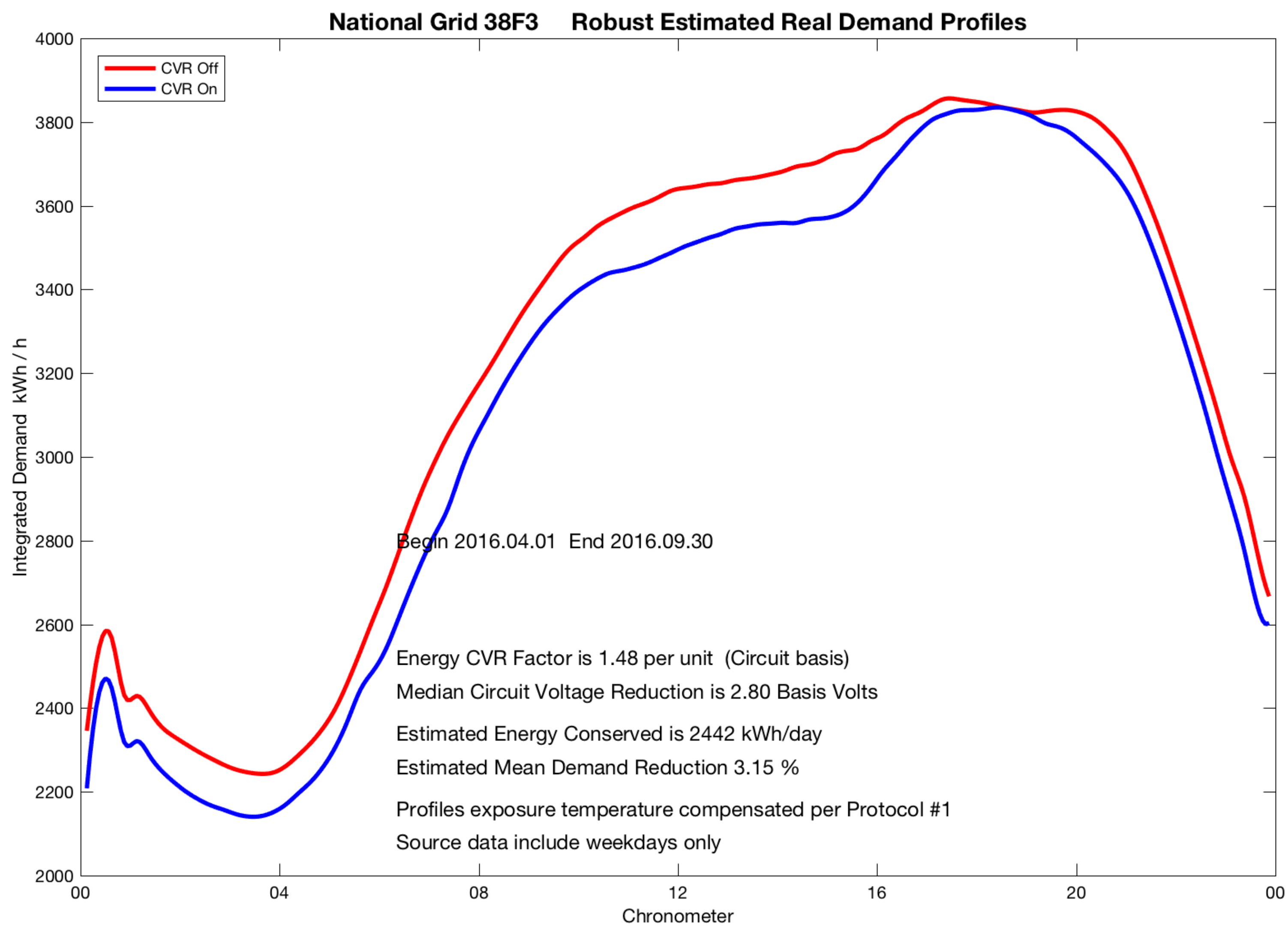
Feeder 38F3: Median Voltage Differential Profiles (Phase Avg)

Graph 3



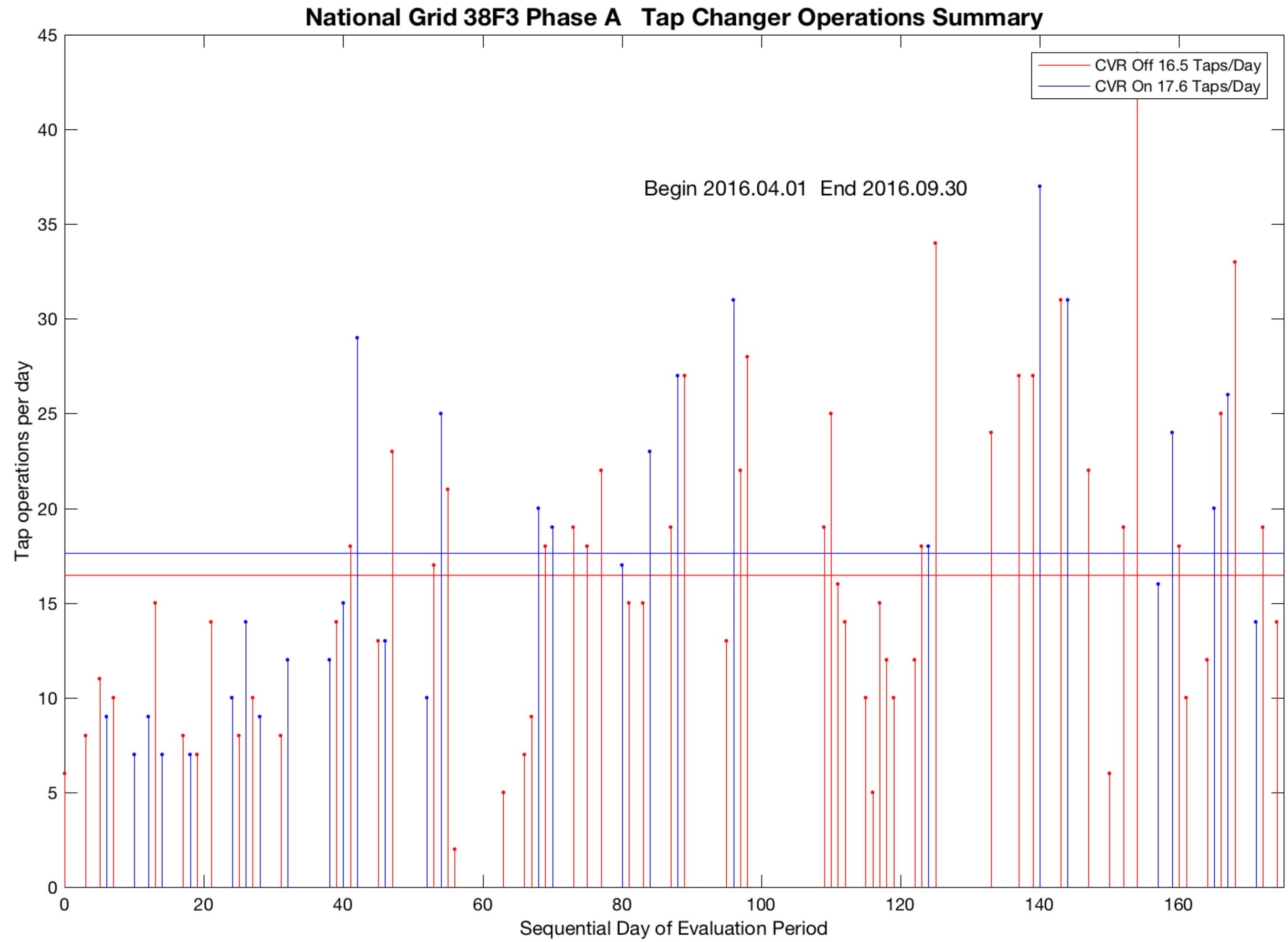
Feeder 38F3: Robust Estimated Real Demand Profiles

Graph 4



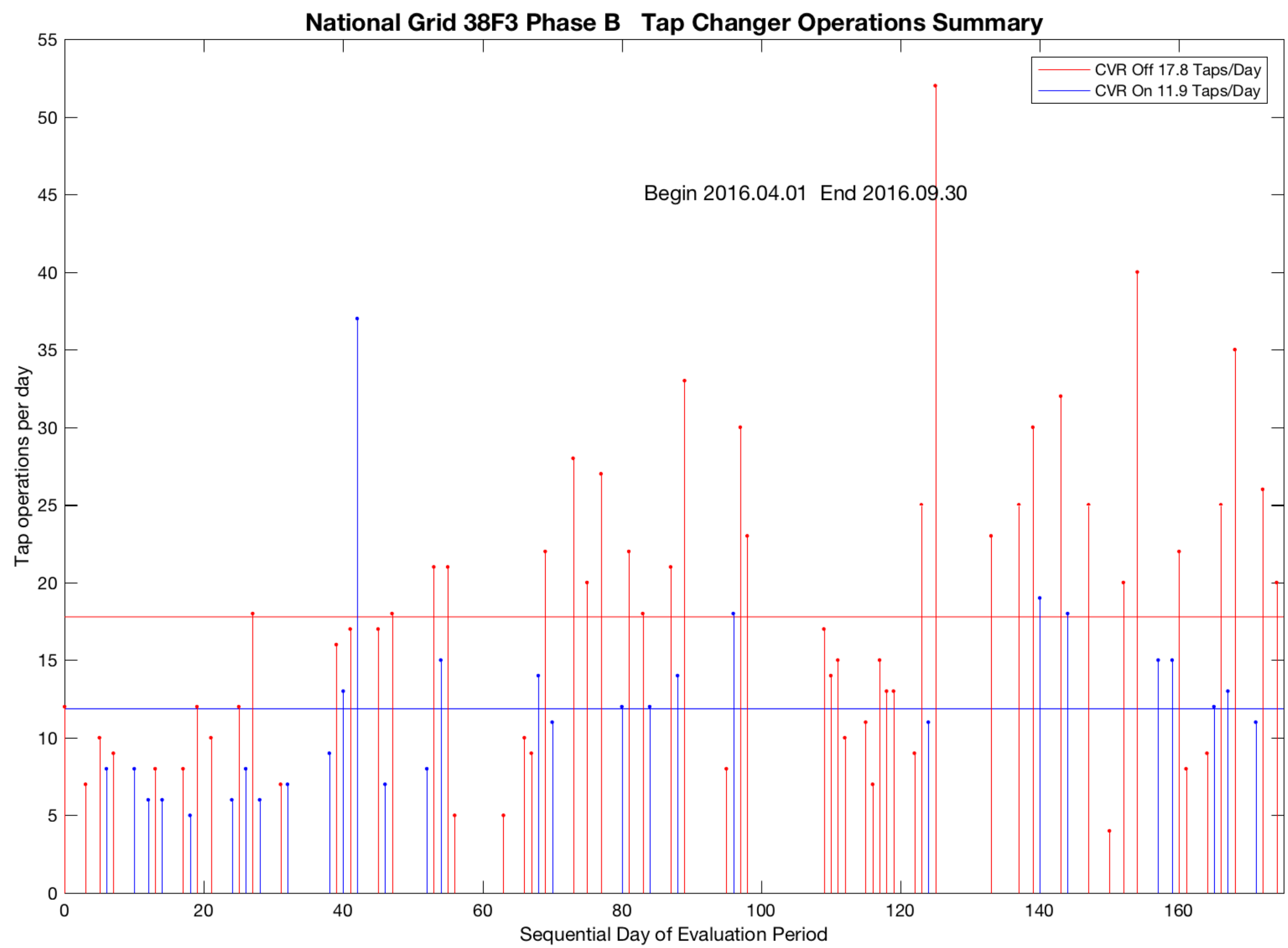
Feeder 38F3: Phase A – Tap Changer Operations Summary

Graph 5



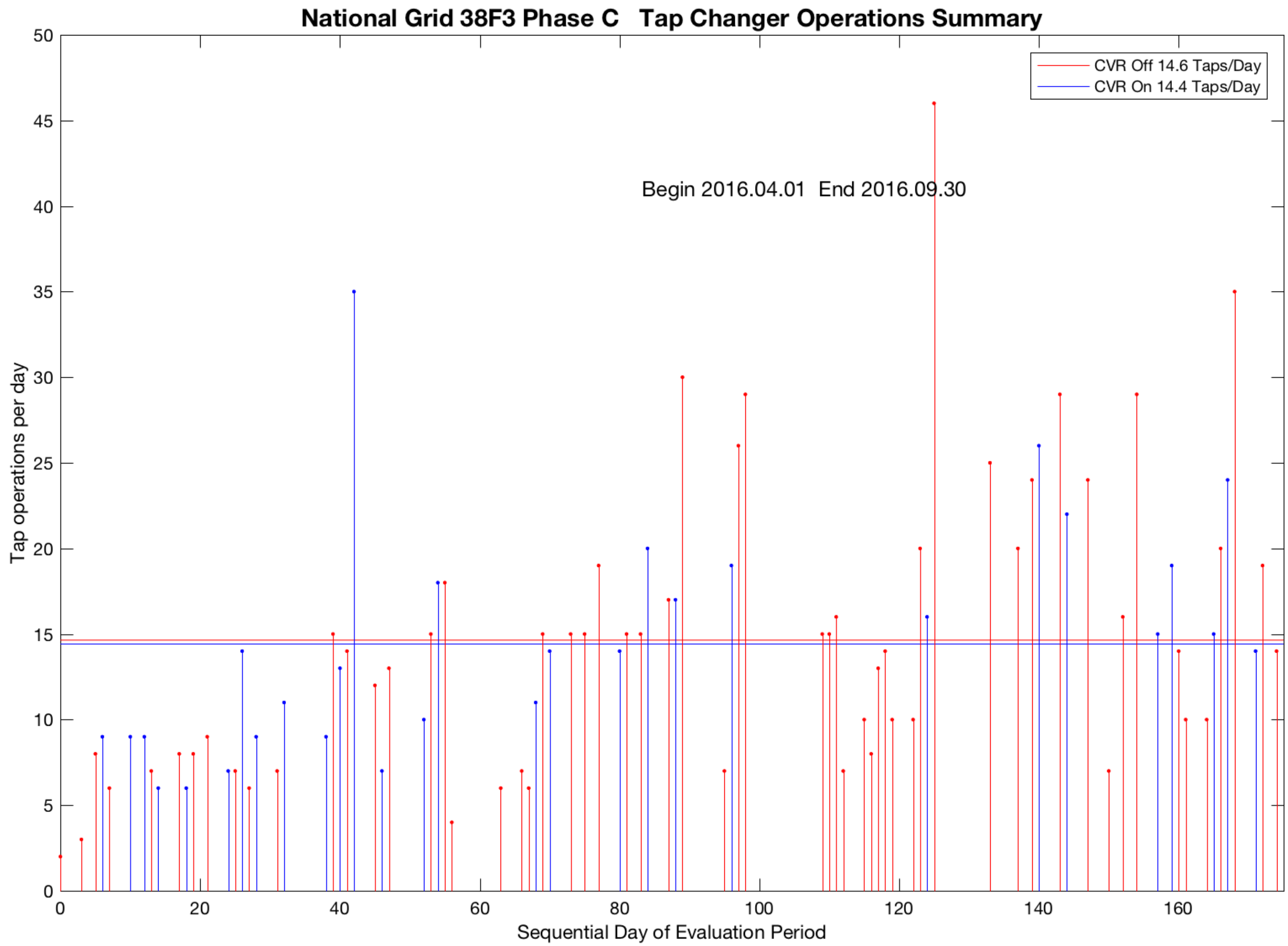
Feeder 38F3: Phase B – Tap Changer Operations Summary

Graph 6



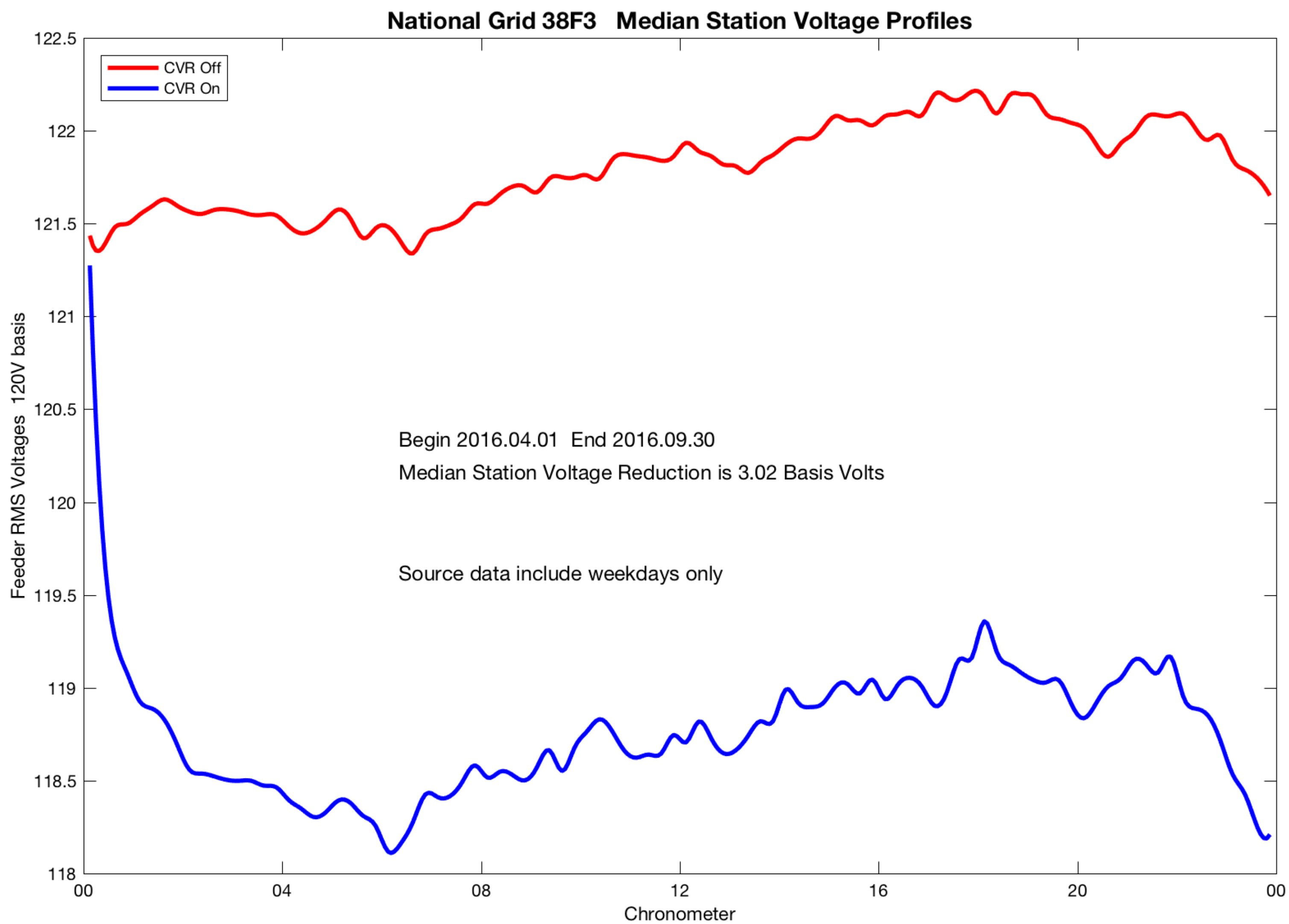
Feeder 38F3: Phase C – Tap Changer Operations Summary

Graph 7



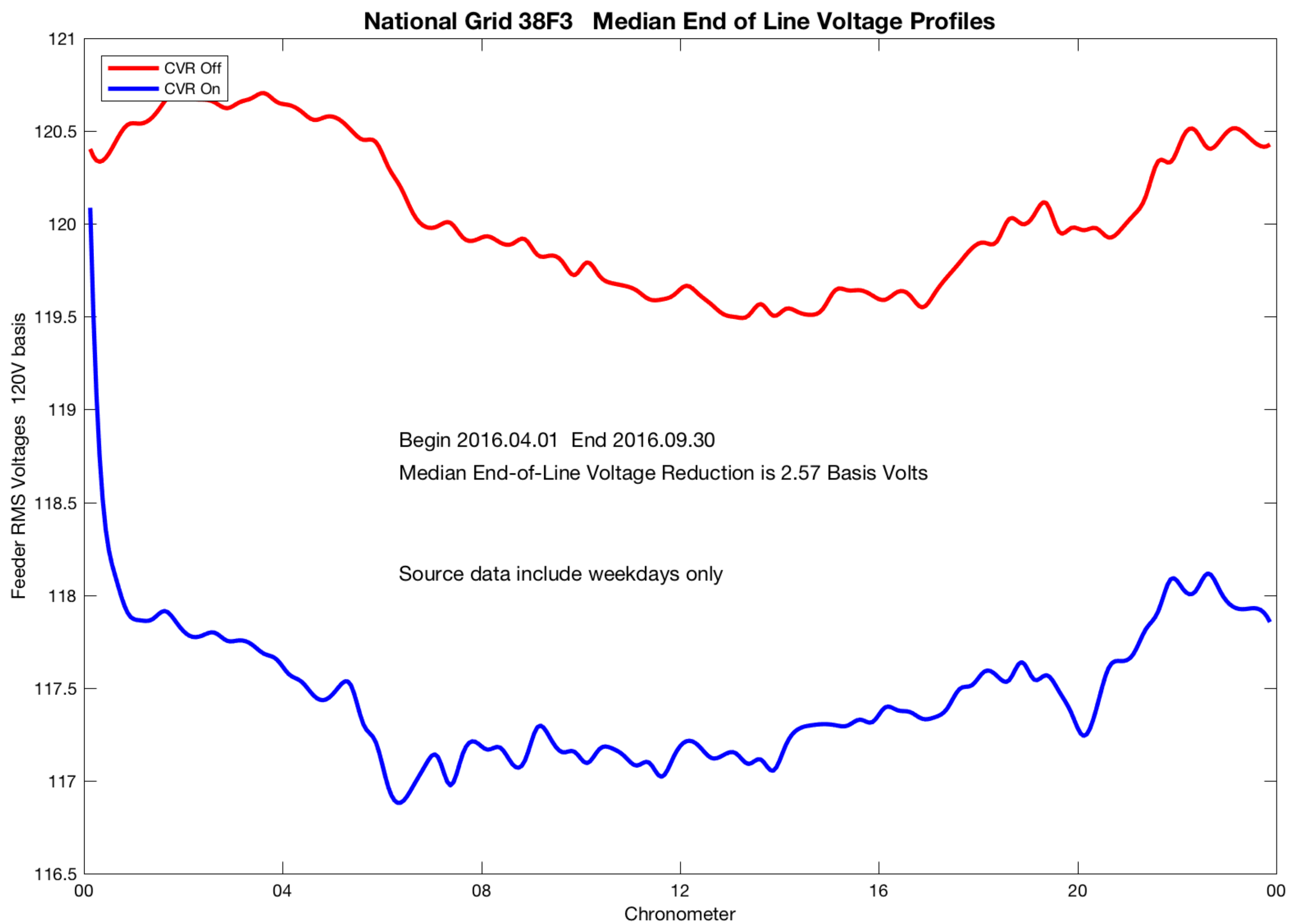
Feeder 38F3: Median Station Voltage Profiles

Graph 8



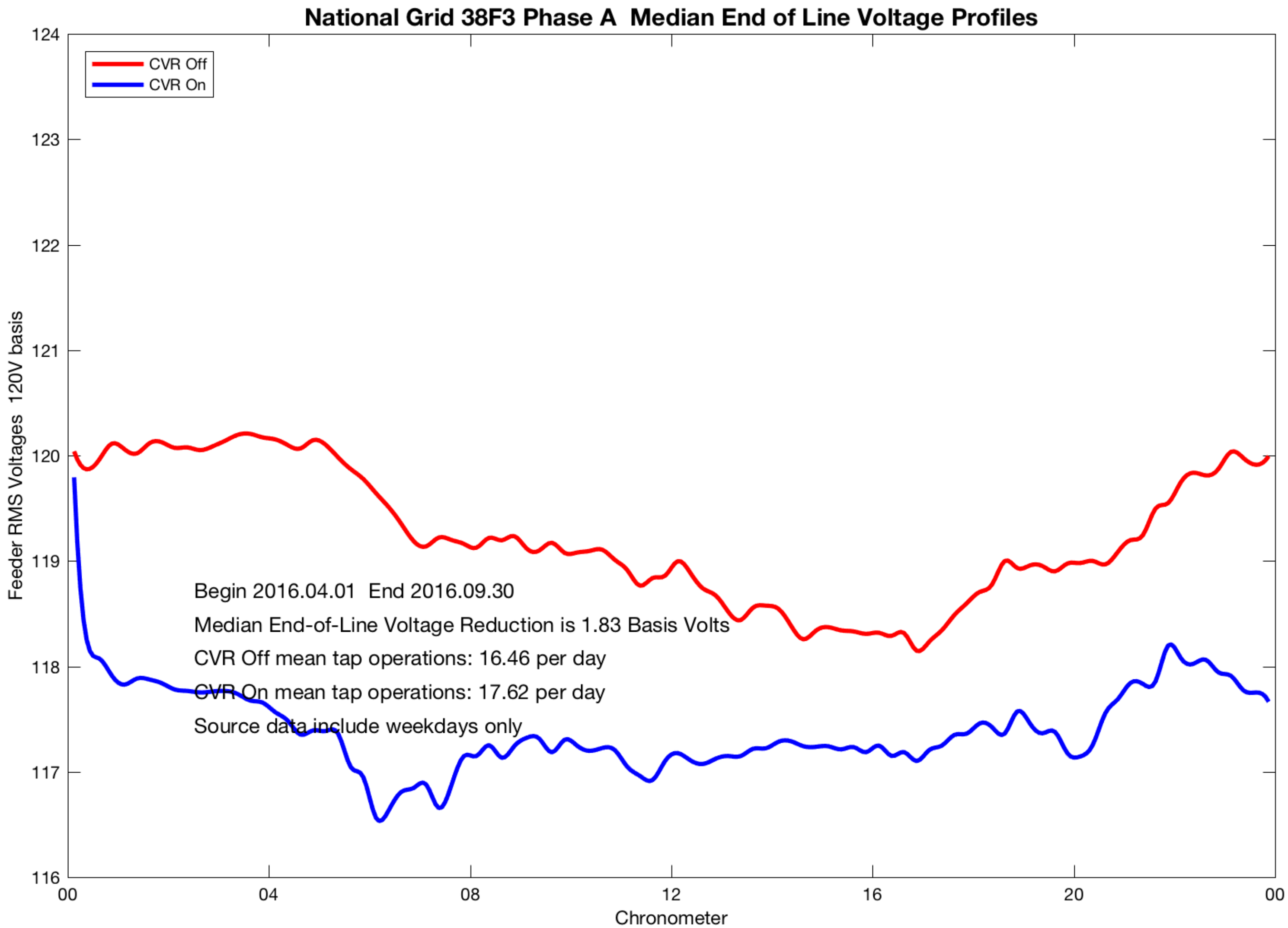
Feeder 38F3: Median End of Line Voltage Profiles (Phase Avg)

Graph 9



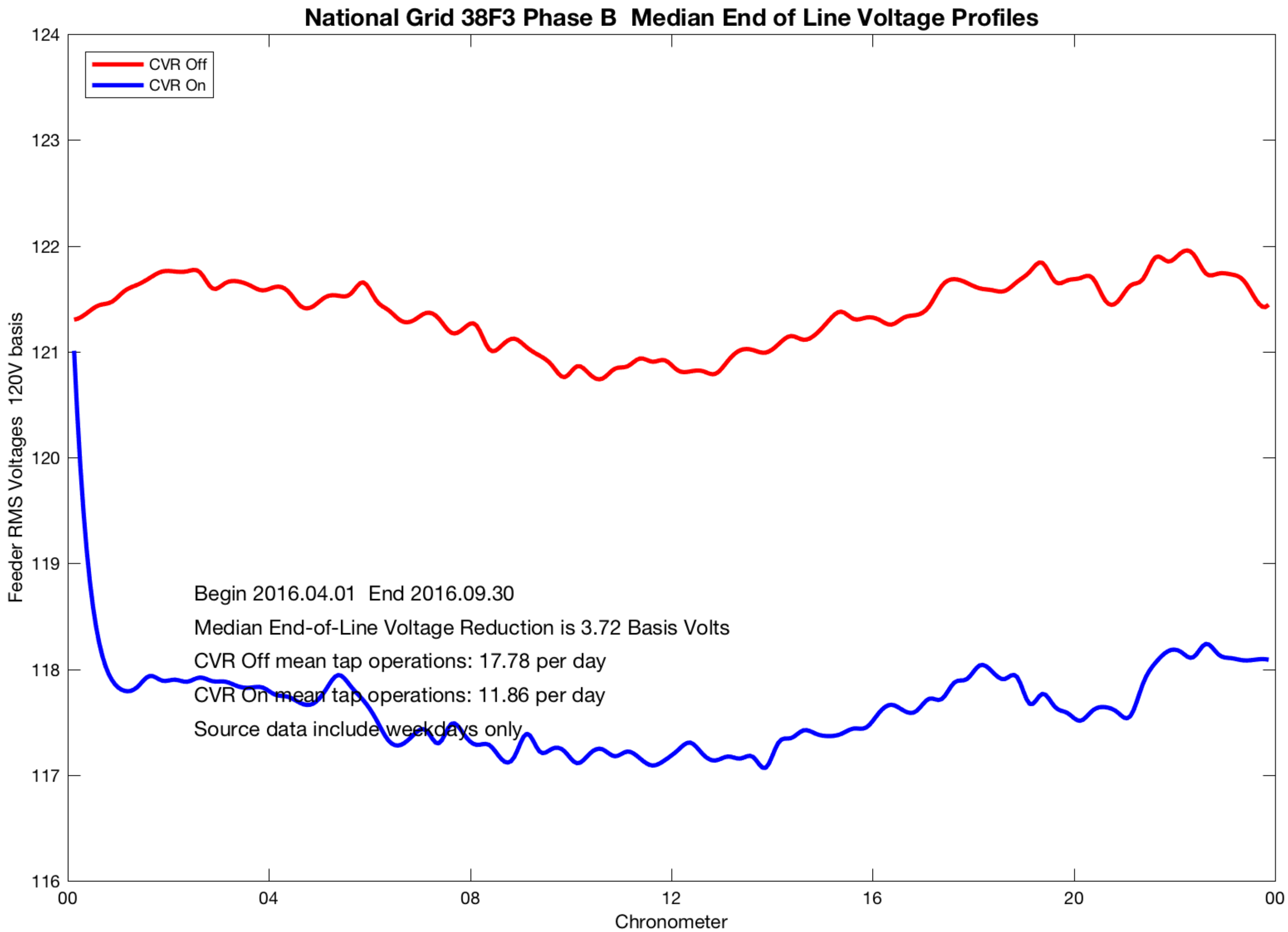
Feeder 38F3: Phase A – Median End of Line Voltage Profiles

Graph 10



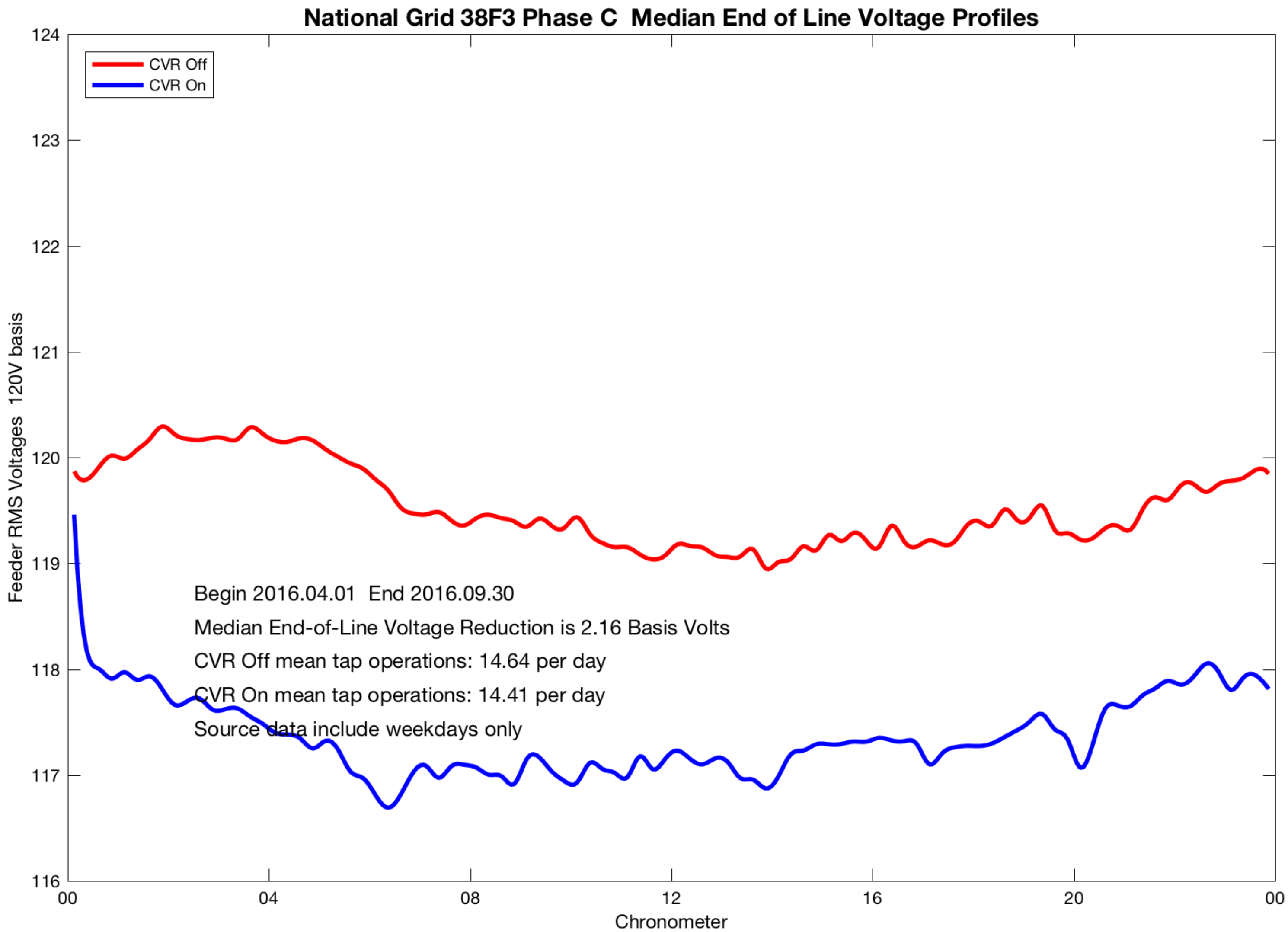
Feeder 38F3: Phase B – Median End of Line Voltage Profiles

Graph 11



Feeder 38F3: Phase C – Median End of Line Voltage Profiles

Graph 12

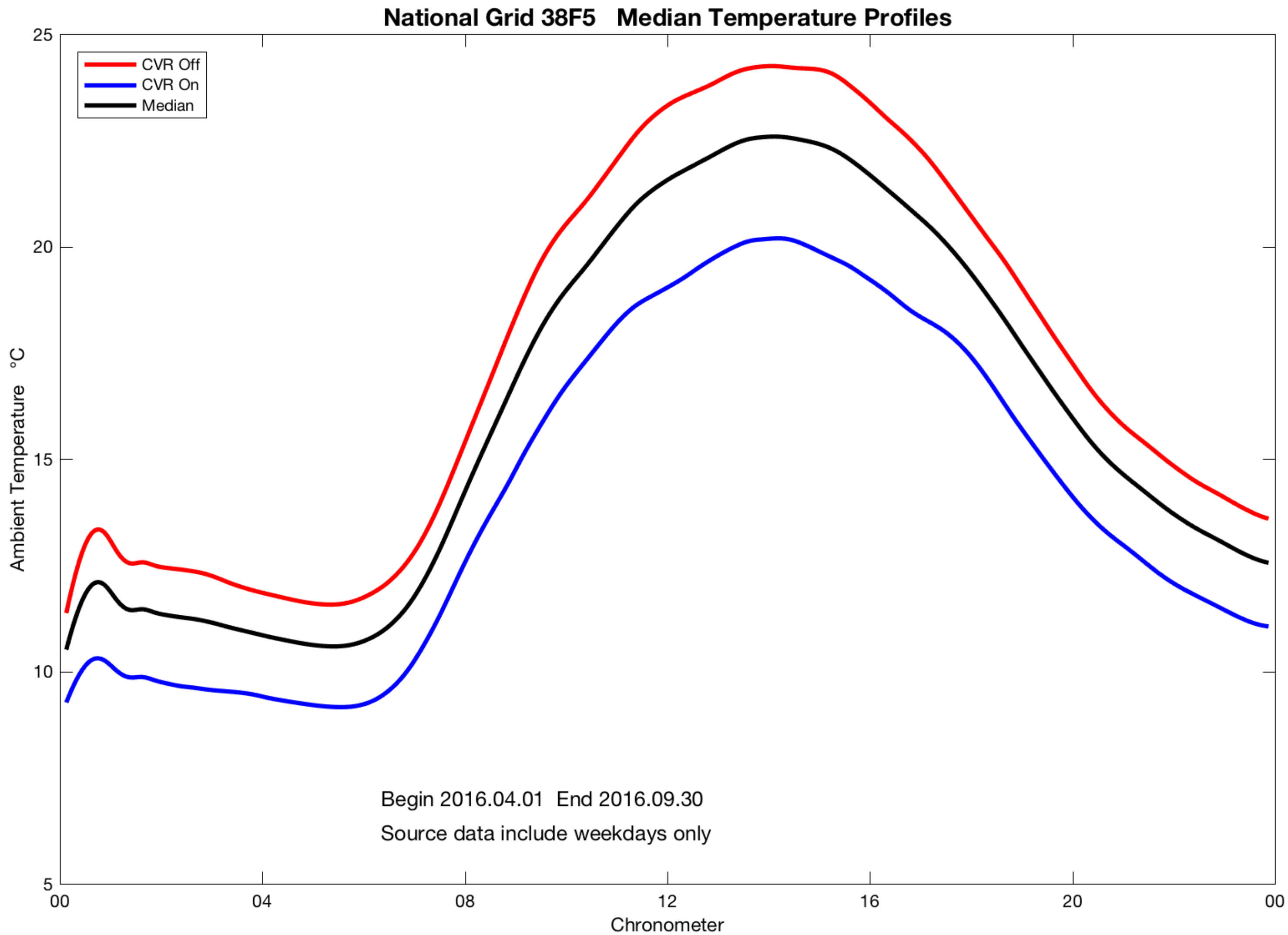


Feeder 38F5 Results

This section contains graphs illustrating the results of the measurement and verification analysis for the 38F5 feeder served by the Putnam Pike substation.

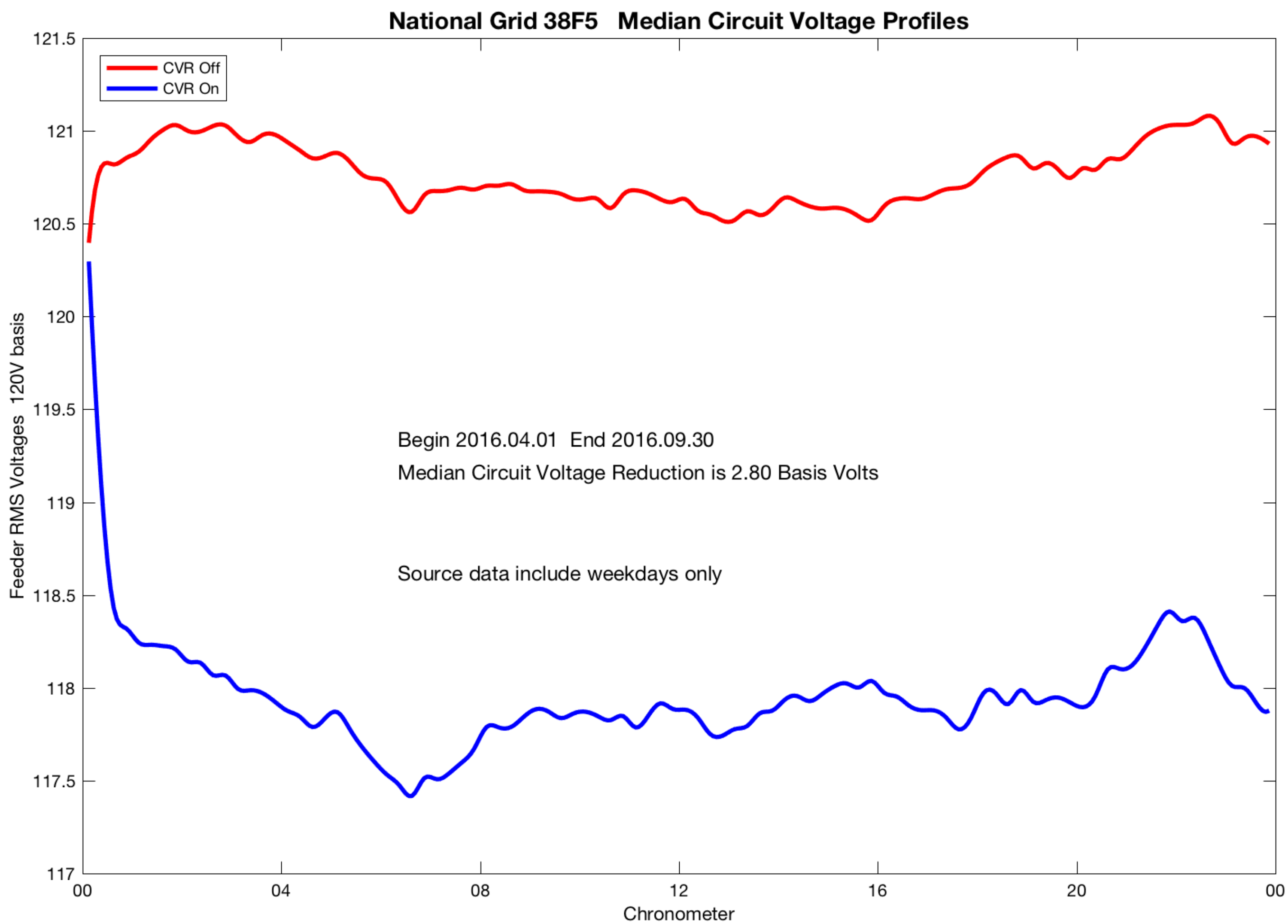
Feeder 38F5: Median Temperature Profiles

Graph 13



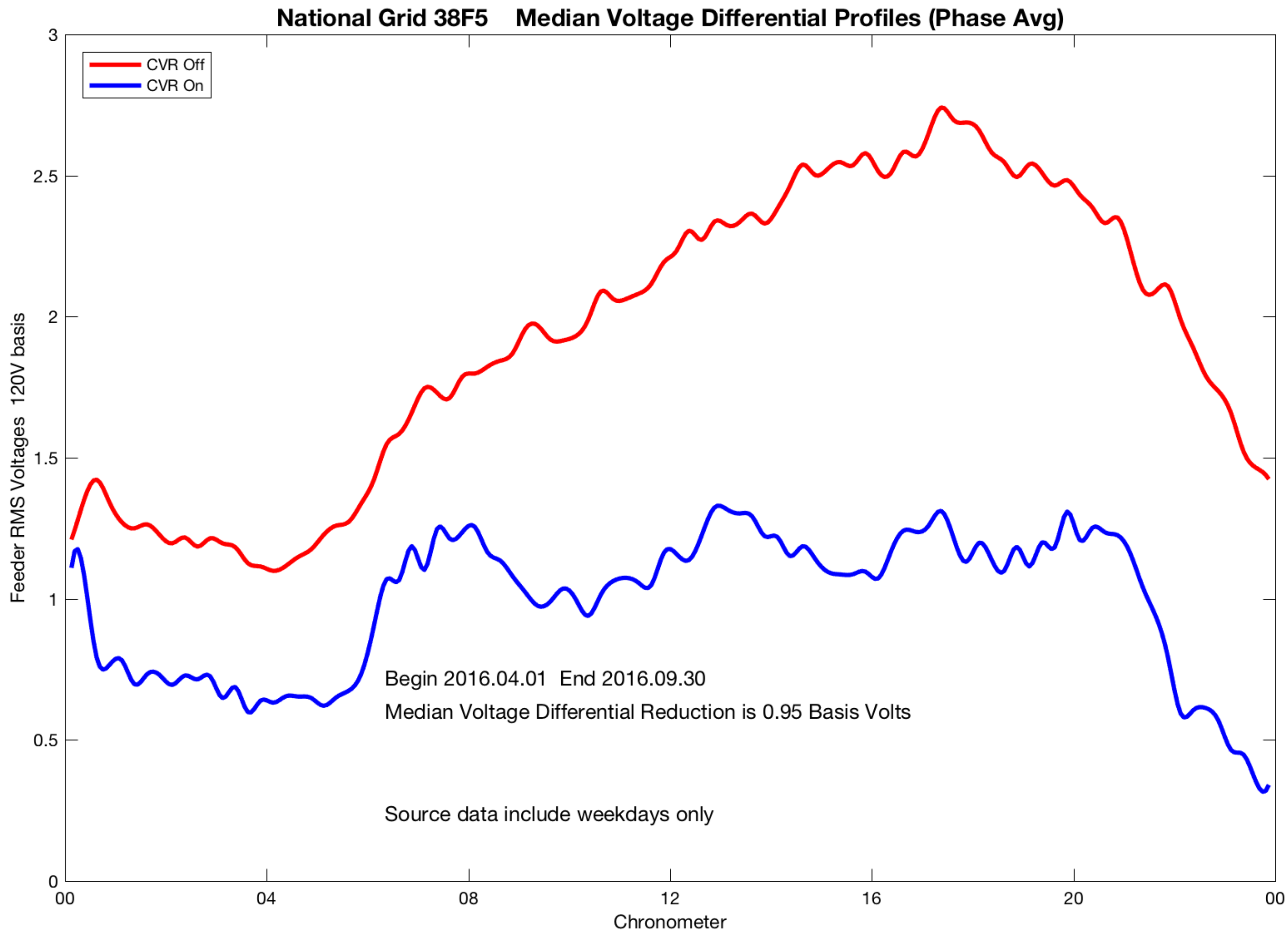
Feeder 38F5: Median Circuit Voltage Profiles

Graph 14



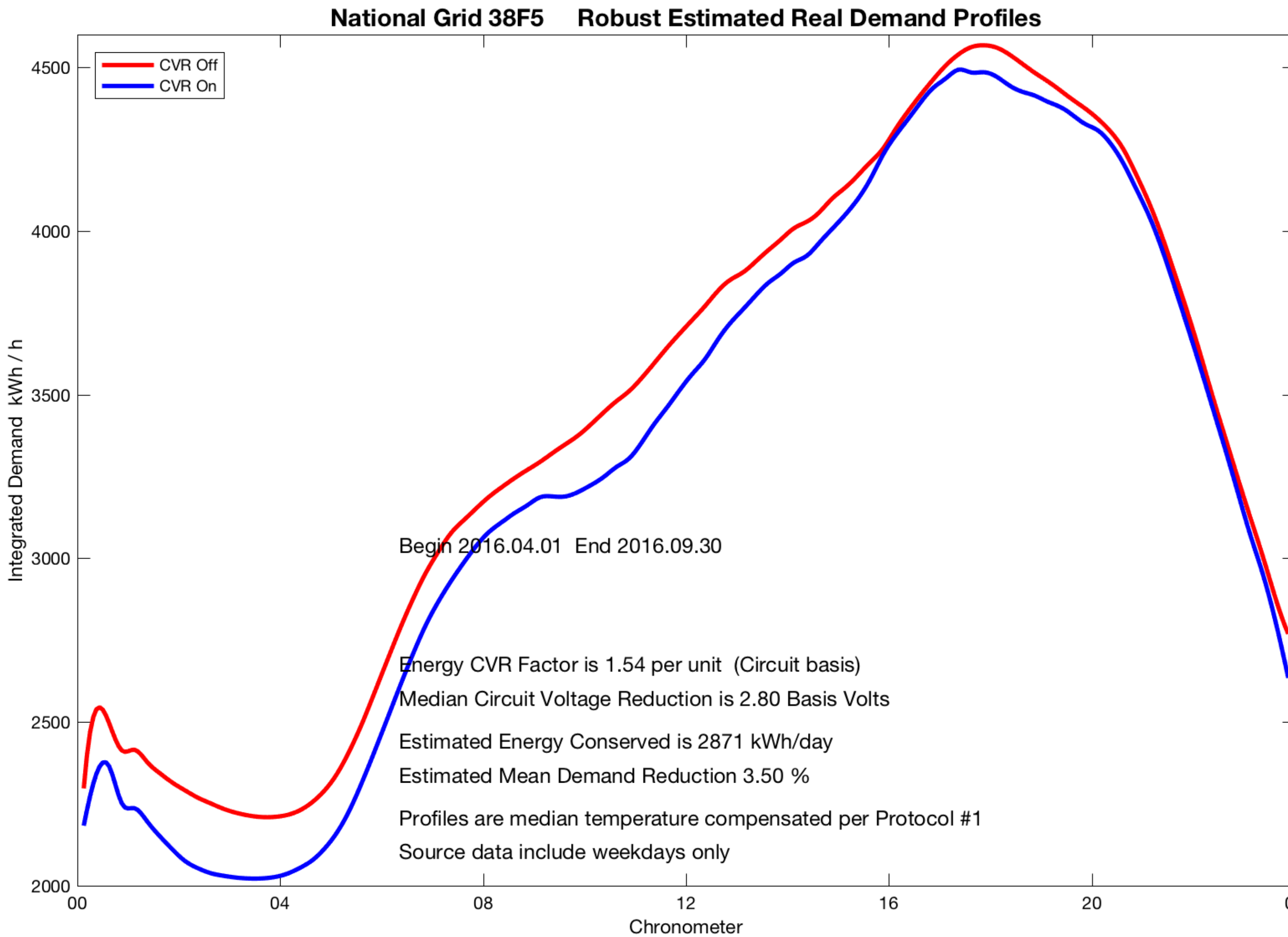
Feeder 38F5: Median Voltage Differential Profiles (Phase Avg)

Graph 15



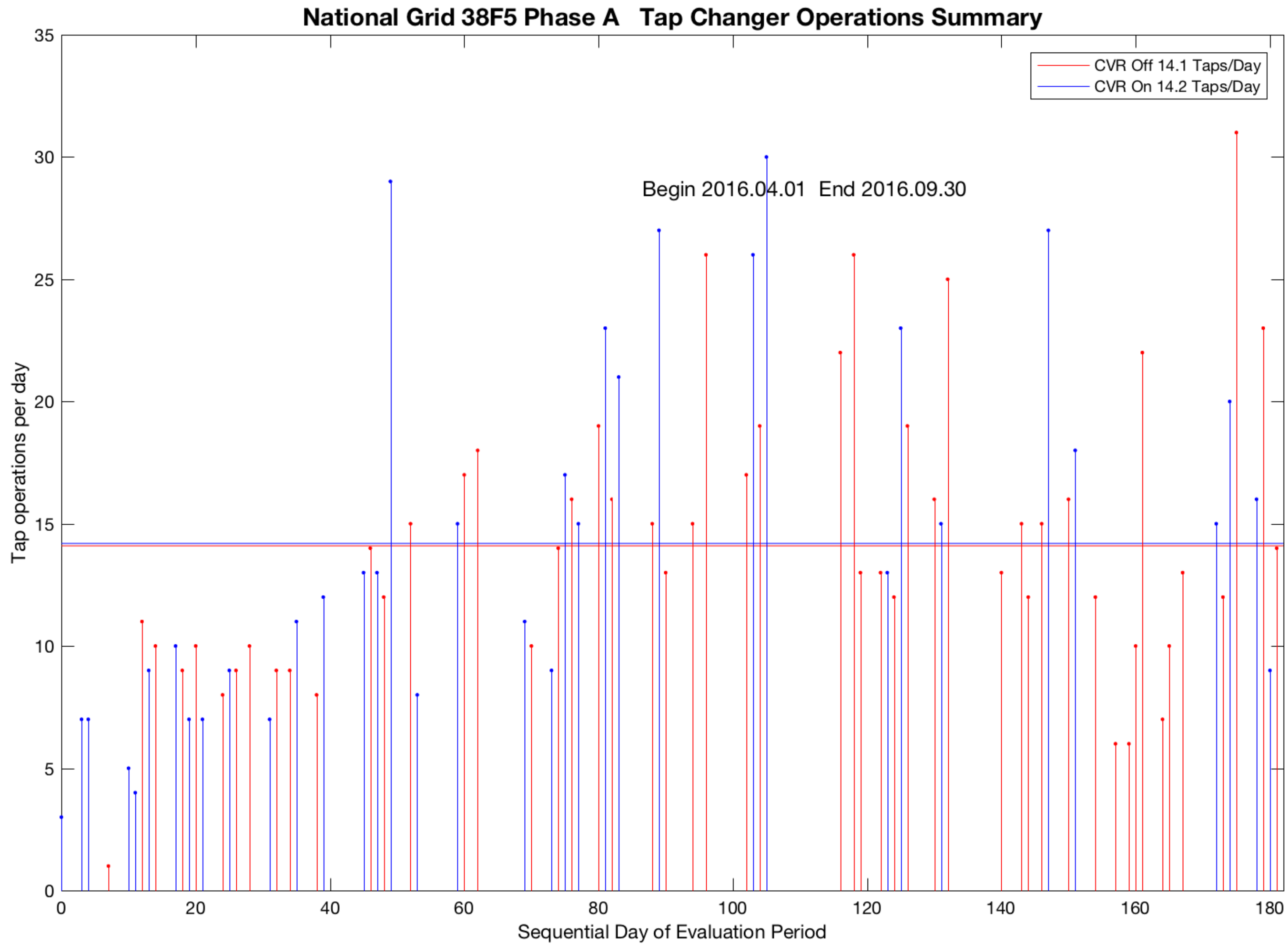
Feeder 38F5: Robust Estimated Real Demand Profiles

Graph 16



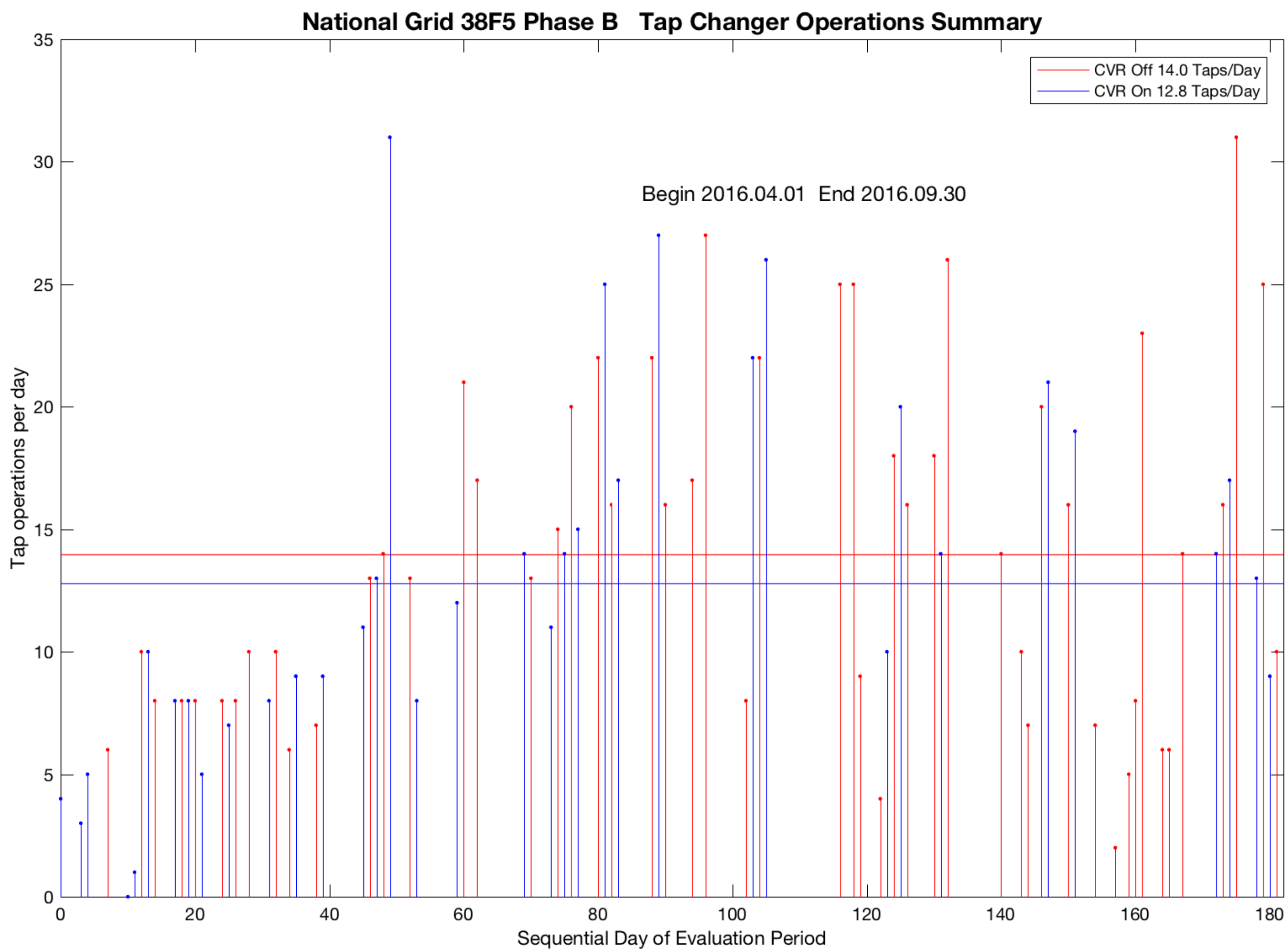
Feeder 38F5: Phase A – Tap Changer Operations Summary

Graph 17



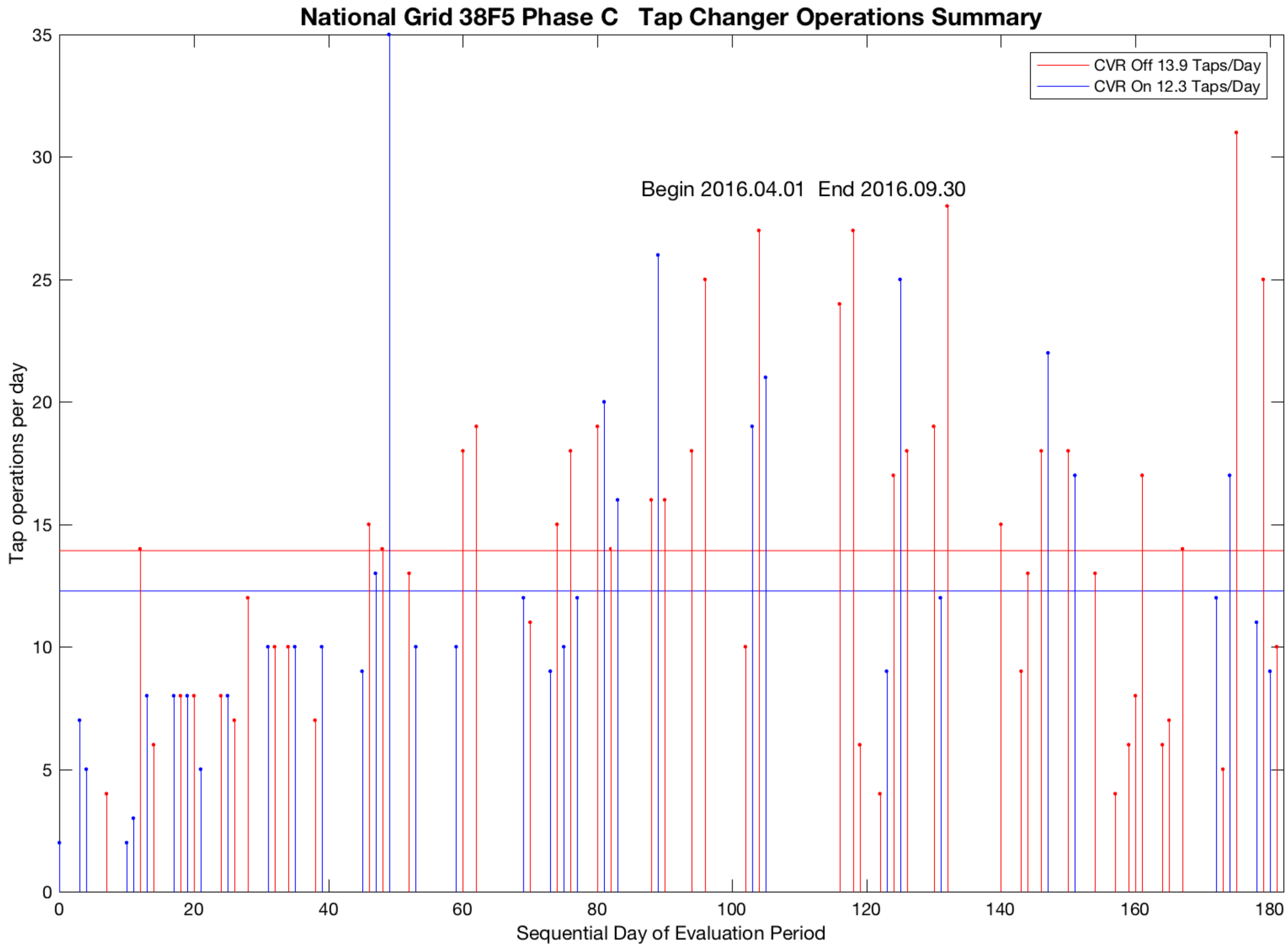
Feeder 38F5: Phase B – Tap Changer Operations Summary

Graph 18



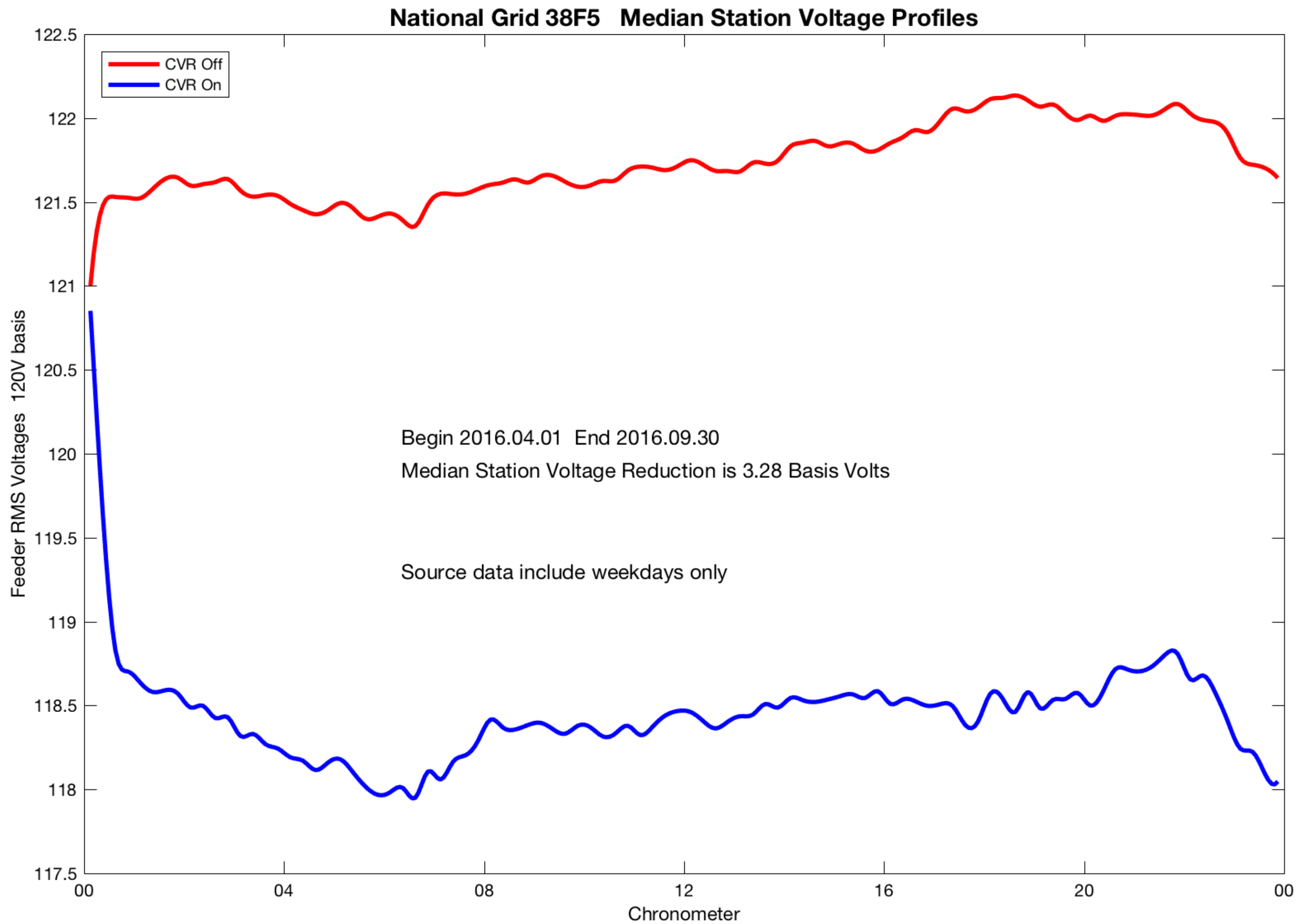
Feeder 38F5: Phase C – Tap Changer Operations Summary

Graph 19



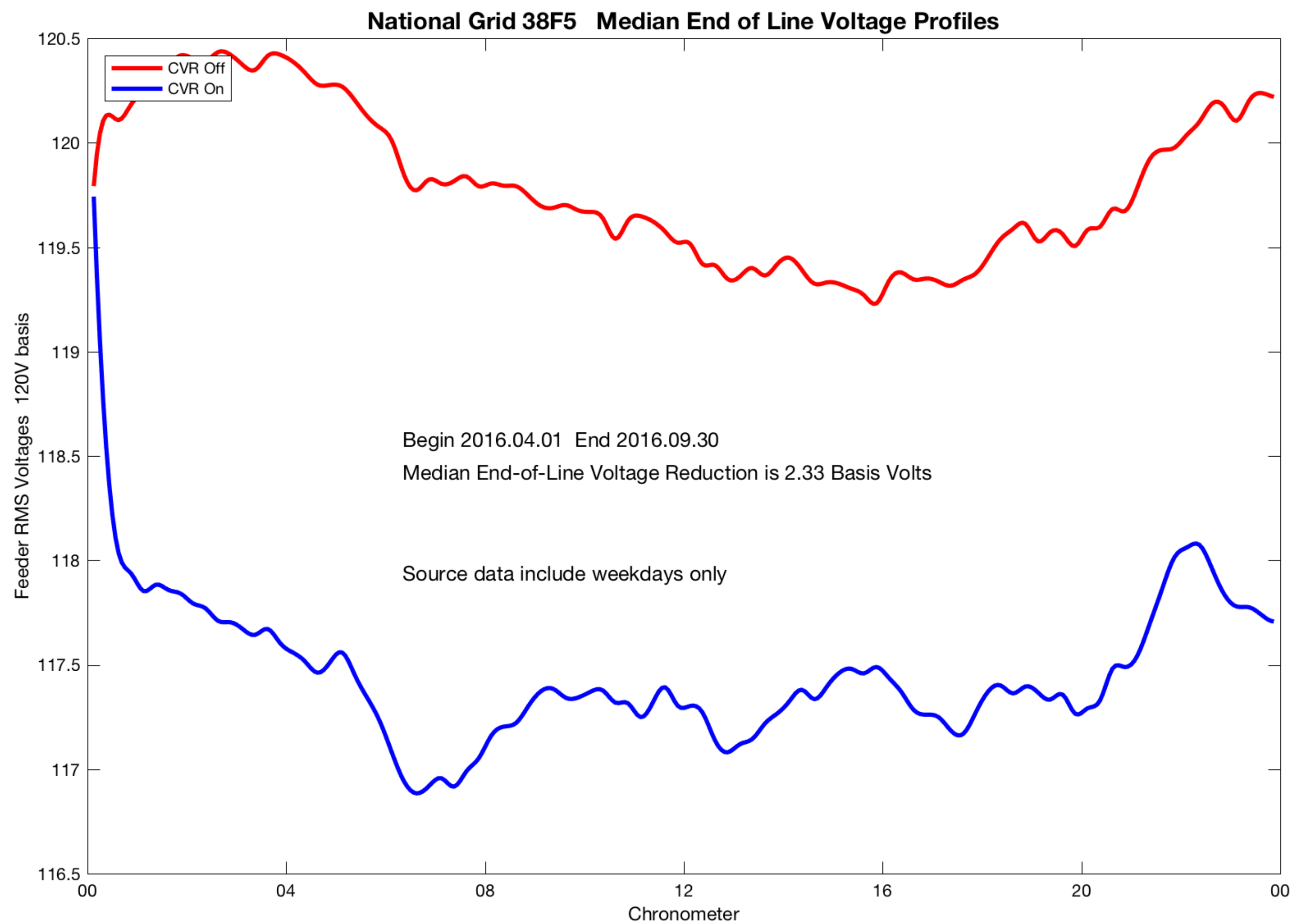
Feeder 38F5: Median Station Voltage Profiles

Graph 20



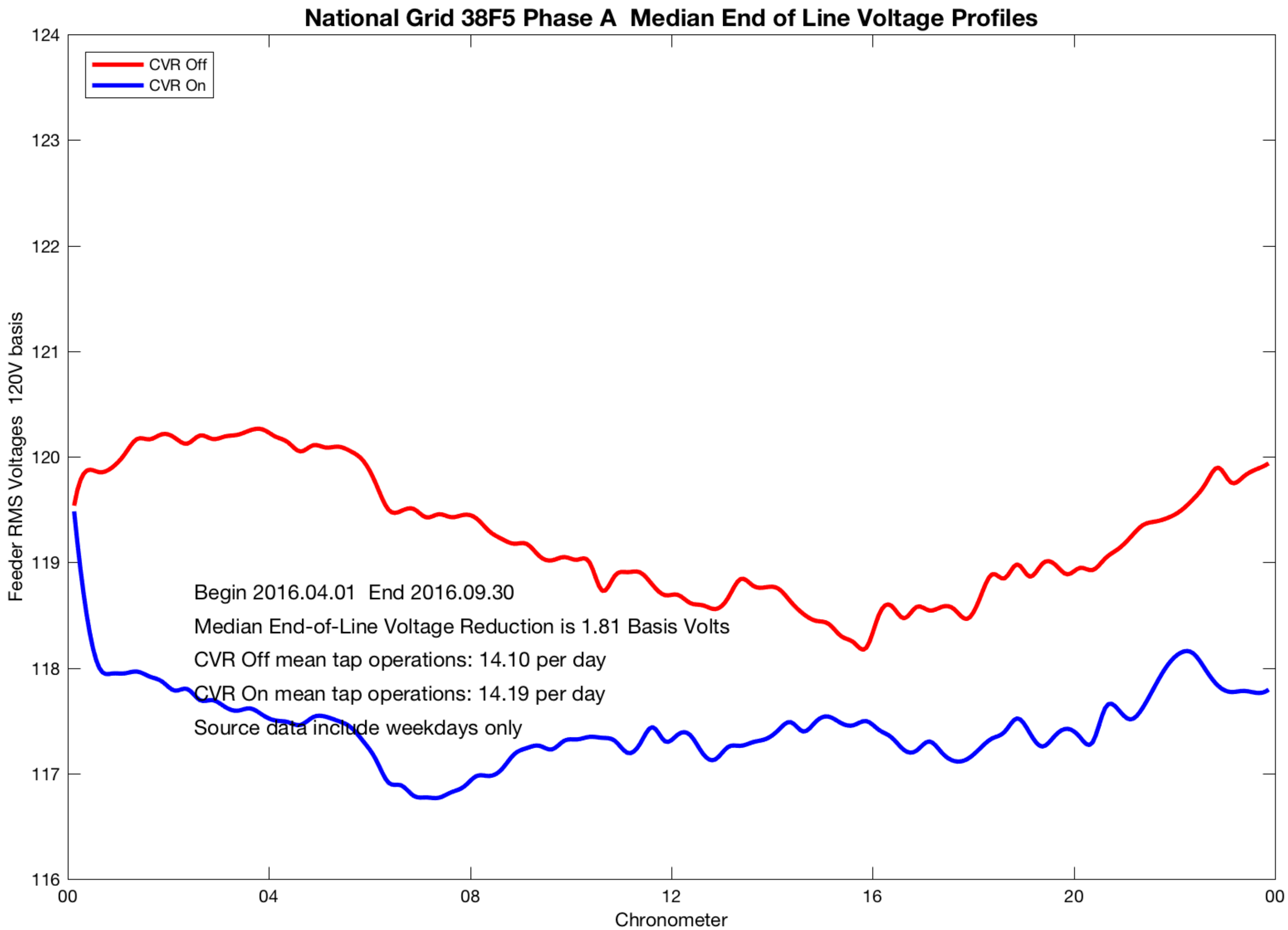
Feeder 38F5: Median End of Line Voltage Profiles (Phase Avg)

Graph 21



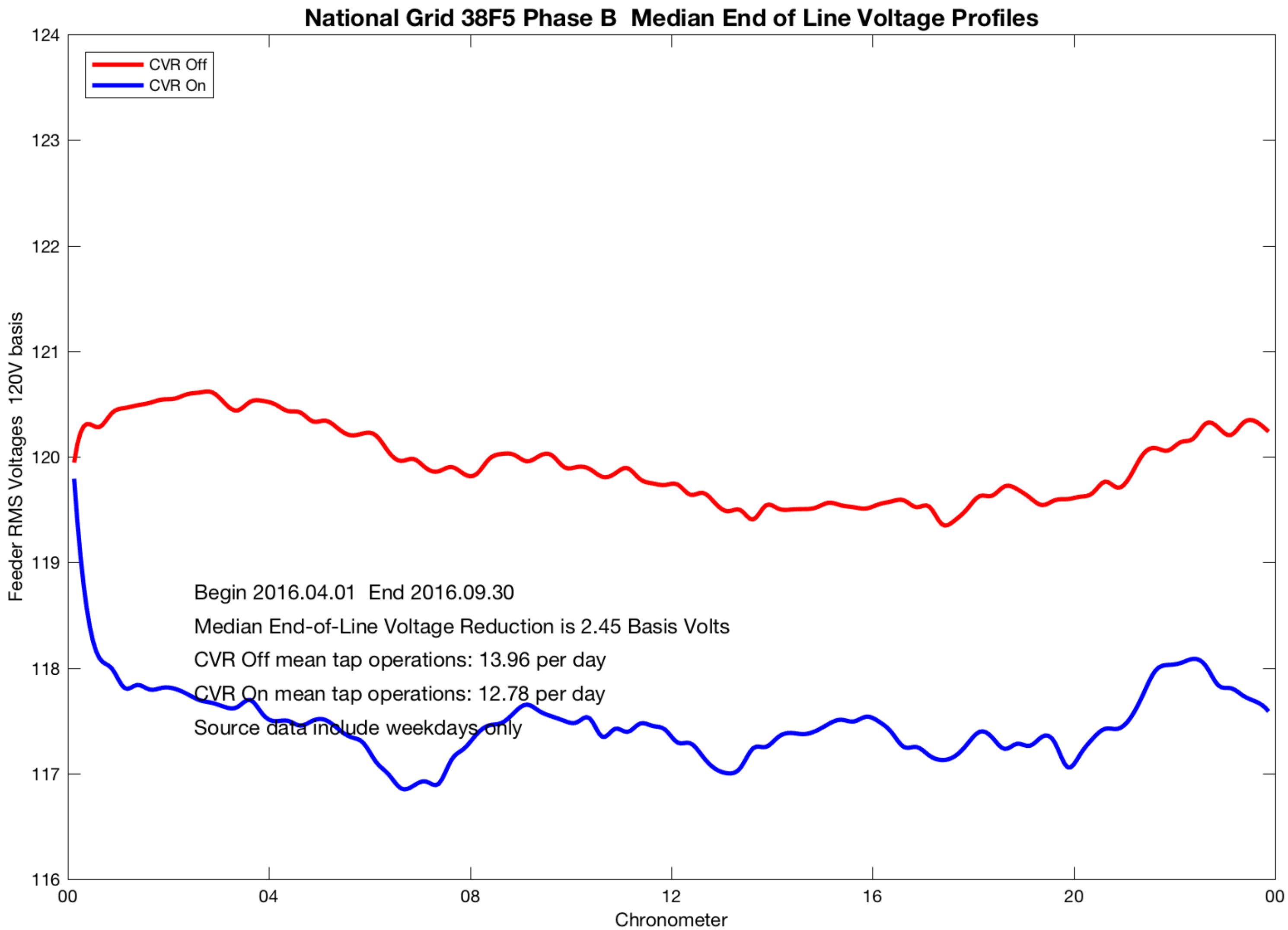
Feeder 38F5: Phase A – Median End of Line Voltage Profiles

Graph 22



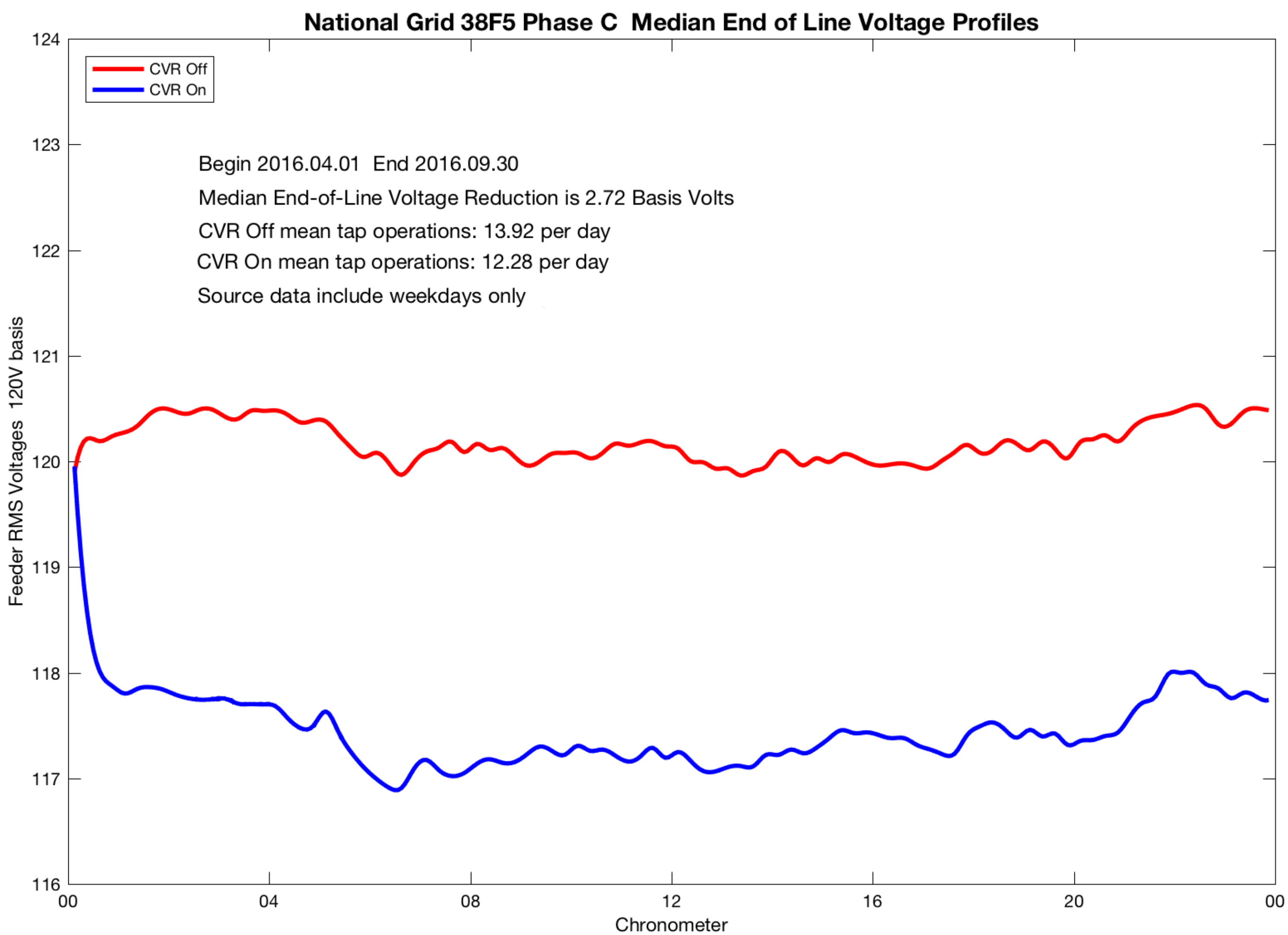
Feeder 38F5: Phase B – Median End of Line Voltage Profiles

Graph 23



Feeder 38F5: Phase C – Median End of Line Voltage Profiles

Graph 24



TETRA TECH

To:	Richard Marcaccio, Utilidata
From:	Jonathan Hoechst and Sue Hanson, Tetra Tech
Date:	October 7, 2019
Subject:	Tetra Tech's Findings for National Grid Rhode Island Volt/VAR Optimization 90-Day M&V Period (FINAL) – Langworthy Corner

Utilidata retained Tetra Tech to perform evaluation services in connection with National Grid Rhode Island's Volt/VAR Optimization (VVO) project. Utilidata and National Grid Rhode Island deployed the VVO technology at three substations—Tiogue Avenue, Langworthy Corner, and Lincoln Avenue. This memo provides results for the Langworthy Corner substation; analysis of Lincoln Avenue substation was previously provided,[1] and results for Tiogue Avenue substation will be provided at a later date. Within each substation, every feeder using the AdaptiVolt VVO system is designed to operate on alternating days (i.e., one day on, one day off) for one 90-day measurement and verification (M&V) period.

Utilidata has been responsible for providing technical expertise in the implementation and operation of the system, providing project support, and performing the M&V analysis to estimate impacts. Tetra Tech is performing the independent analysis of the 90-day M&V period using the evaluation methodology found in the memo titled, "National Grid Rhode Island Volt/VAR Optimization 90-Day M&V Period Evaluation Methodology," dated July 18, 2019.

LANGWORTHY CORNER SUBSTATION

This memo presents the evaluation, measurement, and verification (EM&V) impact findings for National Grid Rhode Island's Volt/VAR Optimization 90-day M&V period for the Langworthy Corner substation. Per Utilidata's standard protocol, the VVO technology was initially implemented in a test (i.e., measurement and verification, M&V) period to operate on alternating days (i.e., one day on, one day off) for a specified 90-day M&V period. However, the Langworthy Corner substation's M&V period ran over a staggered period spanning February 21, 2019 through July 24, 2019. Tetra Tech, under contract to Utilidata, evaluated the system performance for this time period. To facilitate analysis, Utilidata provided data extracts through July 24, 2019 to Tetra Tech to provide additional data points due infrastructural issues observed from February through April. Tetra Tech ultimately used VVO data for the final 90-day period in the data frame (April 20 through July 24).

The remainder of this memo is organized in the following main topic areas:

- Key Findings
- Detailed Results.

[1] Results for Lincoln Avenue substation were provided on July 24, 2019.

KEY FINDINGS

Below we present key findings from our analysis:

- Langworthy Corner substation observed savings of 3.48 percent of kWh and a voltage reduction of 3.63 percent. The CVR factor across all days was 0.96.

DETAILED RESULTS

Below we present the results of the impact analysis.

Table 1. Day On, Day Off Status by Feeder*

Feeder	Days On	Days Off
Langworthy Corner Substation		
Feeder 86F1	37	53

* Day on, day off status corresponds with the CVR.X.ENGAGED status for each feeder at the 12:00 PM hour for days spanning April 20 through July 24.

ENERGY SAVINGS AND CVR FACTORS

Table 2 highlights estimated energy and voltage[2] reductions alongside CVR factors for the 90-day M&V period for the feeder at the Langworthy Corner substation. Estimated energy savings following Automated CVR Protocol #1 were 3.48 percent during days when the AdaptiVolt system was "on" compared to "off," across weekdays and weekends. In particular:

- The CVR factor on weekends was 0.63, while weekdays resulted in a CVR factor of 1.11.
- Energy savings ranged from 2.40 percent on weekends to 3.95 percent on weekdays.
- Voltage reductions ranged from 3.80 on weekends to 3.56 on weekdays.

Table 2. Energy Savings and CVR Factor using Automated CVR Protocol #1*

	Weekdays			Weekends			Combined		
Feeder	%Δ kWh	%Δ Voltage	CVRf	%Δ kWh	%Δ Voltage	CVRf	%Δ kWh	%Δ Voltage	CVRf
Langworthy Corner Substation									
Feeder 86F1	-3.95%	-3.56%	1.11	-2.40%	-3.80%	0.63	-3.48%	-3.63%	0.96

* All cells are statistically significant (p < 0.10).

[2] LVM devices experienced system outages across multiple feeders. Therefore, REG device readings of voltage using signals V.LD.SEC.A, V.LD.SEC.B, and V.LD.SEC.C were utilized in this analysis, as these remained operational during the times in which the LVM devices experienced system outages.

Table 3 below shows total energy savings that can be attributed to the feeder at Langworthy Corner during the 90-day M&V period.

Table 3. Energy Savings (kWh) by Feeder*

Feeder	Weekday Savings	Weekend Savings	Combined Energy Savings
Langworhty Corner Substation			
Feeder 86F1	48,682	25,343	74,023

* All cells are statistically significant ($p < 0.10$).

TETRA TECH

To:	Richard Marcaccio, Utilidata
From:	Jonathan Hoechst, and Sue Hanson, Tetra Tech
Date:	November 4, 2019
Subject:	Tetra Tech's Findings for National Grid Rhode Island Volt/VAR Optimization 90-Day M&V Period (FINAL) – Lincoln Avenue

Utilidata retained Tetra Tech to perform evaluation services in connection with National Grid Rhode Island's Volt/VAR Optimization (VVO) project. Utilidata and National Grid Rhode Island deployed the VVO technology at three substations—Tiogue Avenue, Langworthy Corner, and Lincoln Avenue. This memo provides results for the Lincoln Avenue substation; analysis of Tiogue Avenue and Langworthy Corner substations will be provided at a later date. Within each substation, every feeder using the AdaptiVolt VVO system is designed to operate on alternating days (i.e., one day on, one day off) for one 90-day measurement and verification (M&V) period.

Utilidata has been responsible for providing technical expertise in the implementation and operation of the system, providing project support, and performing the M&V analysis to estimate impacts. Tetra Tech is performing the independent analysis of the 90-day M&V period using the evaluation methodology found in the memo titled, "National Grid Rhode Island Volt/VAR Optimization 90-Day M&V Period Evaluation Methodology," dated July 18, 2019.

LINCOLN AVENUE SUBSTATION

This memo presents the evaluation, measurement, and verification (EM&V) impact findings for National Grid Rhode Island's Volt/VAR Optimization 90-day M&V period for the Lincoln Avenue substation. Per Utilidata's standard protocol, the VVO technology was initially implemented in a test (i.e., measurement and verification, M&V) period to operate on alternating days (i.e., one day on, one day off) for a specified 90-day M&V period. However, the substations' M&V period ran over a staggered period spanning February 21, 2019 through June 20, 2019 and spanned six feeders. Tetra Tech, under contract to Utilidata, evaluated the system performance for this time period. To facilitate analysis, Utilidata provided data extracts through June 27, 2019 to Tetra Tech to provide additional data points due infrastructural issues observed from February through April.

The remainder of this memo is organized in the following main topic areas:

- Key Findings
- Detailed Results.

KEY FINDINGS

Below we present key findings from our analysis:

- Lincoln Avenue substation observed savings of 1.51 percent of kWh and a voltage reduction of 3.18 percent. The weighted average CVR factor across all days was 0.47.

DETAILED RESULTS

Below we present the results of the impact analysis.

Table 1. Day On, Day Off Status by Feeder*

Feeder	Days On	Days Off
Lincoln Avenue Substation		
Feeder 72F1	57	61
Feeder 72F2	48	70
Feeder 72F3	43	75
Feeder 72F4	23	95
Feeder 72F5	57	61
Feeder 72F6	17	101
Average	**41**	**77**

* Day on, day off status corresponds with the CVR.X.ENGAGED status for each feeder at the 12:00 PM hour for days spanning February 21 through June 27.

ENERGY SAVINGS AND CVR FACTORS

Table 2 highlights estimated energy and voltage[1] reductions alongside CVR factors for the 90-day M&V period for each feeder. Estimated energy savings following Automated CVR Protocol #1 ranged from 1.15 percent to 2.20 percent during days when the AdaptiVolt system was "on" compared to "off," across weekdays and weekends. In particular:

- CVR factors across weekends and weekdays ranged from 0.37 for feeder 72F3 on weekdays to 0.92 for feeder 72F1 on weekends.
- The total combined energy savings ranged from 1.15 percent for feeder 72F4 to 2.20 percent for feeder 72F2.
- Combined voltage reductions ranged from 2.67 percent for feeder 72F6 to 3.72 percent for feeder 72F1.
- Corresponding combined CVR factors ranged from 0.36 for feeder 72F5 to 0.59 for feeder 72F1.

Overall weighted average outcomes at the Lincoln Avenue substation were 1.51 percent energy savings, 3.18 percent voltage reduction, and a CVR factor of 0.47.

[1] LVM devices experienced system outages across multiple feeders. Therefore, REG device readings of voltage using signals V.LD.SEC.A, V.LD.SEC.B, and V.LD.SEC.C were utilized in this analysis, as these remained operational during the times in which the LVM devices experienced system outages.

Table 2. Energy Savings and CVR Factor using Automated CVR Protocol #1*

Feeder	Weekdays			Weekends			Combined		
	%Δ kWh	%Δ Voltage	CVRf	%Δ kWh	%Δ Voltage	CVRf	%Δ kWh	%Δ Voltage	CVRf
Lincoln Avenue Substation									
Feeder 72F1	-1.74%	-3.74%	0.47	-3.37%	-3.68%	0.92	-2.20%	-3.72%	0.59
Feeder 72F2	-1.51%	-3.54%	0.43	-0.63%	-3.54%	0.18	-1.26%	-3.54%	0.36
Feeder 72F3	-1.26%	-3.35%	0.37	-2.34%	-3.25%	0.72	-1.56%	-3.32%	0.47
Feeder 72F4	-2.63%	-3.47%	0.76	-0.20%	-3.61%	0.06	-1.95%	-3.51%	0.56
Feeder 72F5	-1.51%	-3.13%	0.48	-0.23%	-2.97%	0.08	-1.15%	-3.09%	0.37
Feeder 72F6	-1.43%	-2.56%	0.56	-1.11%	-2.95%	0.37	-1.34%	-2.67%	0.51
Average	**-1.68%**	**-3.30%**	**0.51**	**-0.95%**	**-3.33%**	**0.29**	**-1.58%**	**-3.31%**	**0.48**
Weighted Average**	**-1.67%**	**-3.16%**	**0.53**	**-0.57%**	**-3.24%**	**0.18**	**-1.51%**	**-3.18%**	**0.47**

* Highlighted cells are not statistically significant ($p < 0.10$).

** Tetra Tech weighted energy savings, voltage savings, and CVR factors for each feeder by each feeder's load contribution. Statistically insignificant results are treated as zero.

TETRA TECH

Table 3 below shows total energy savings that can be attributed to each feeder during the 90 day M&V period.

Table 3. Energy Savings (kWh) by Feeder*

Feeder	Weekday Savings	Weekend Savings	Combined Energy Savings
Lincoln Avenue Substation			
Feeder 72F1	62,159	31,242	93,401
Feeder 72F2	70,483	11,213	70,483
Feeder 72F3	66,710	47,639	114,349
Feeder 72F4	172,982	4,870	172,982
Feeder 72F5	98,729	5,782	98,729
Feeder 72F6	158,627	44,527	158,627
Total	**629,690**	**78,881**	**708,571**

* Highlighted cells are not statistically significant (p < 0.10). Statistically insignificant results are treated as zero and do not contribute to total kWh savings.

** Tetra Tech weighted energy savings and CVR factors for each feeder by each feeder's load contribution.

Table 4 shows the energy savings and CVR factor results from Automated CVR Protocol #1 combined across both weekdays and weekends. The weighted average energy savings amounted to 1.51 percent, and weighted average voltage reductions were 3.18 percent. The corresponding weighted average CVR factor amounted to 0.47 for the 90-day M&V period.

Table 4. Combined Energy Savings and CVR Factor Results Comparison

Feeder	Automated CVR Protocol #1		
	%Δ kWh	%Δ Voltage	CVRf
Lincoln Avenue Substation			
Feeder 72F1	-2.20%	-3.72%	0.59
Feeder 72F2	-1.26%	-3.54%	0.36
Feeder 72F3	-1.56%	-3.32%	0.47
Feeder 72F4	-1.95%	-3.51%	0.56
Feeder 72F5	-1.15%	-3.09%	0.37
Feeder 72F6	-1.34%	-2.67%	0.51
Average	**-1.58%**	**-3.31%**	**0.48**
Weighted* Average	**-1.51%**	**-3.18%**	**0.47**

* Tetra Tech weighted energy savings and CVR factors for each feeder by each feeder's load contribution. Statistically insignificant results are treated as zero.

Docket 4600 Benefit-Cost Framework

Project Name: VVO Farnum Pike Substation
Area Study: Program

Problem: The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralize control of the regulating devices to provide customer energy savings and lower electric bills.

Preferred Plan: The Farnum Pike Substation circuits (6) have been selected for the next installation of volt-var optimization functionality. The circuits and substation have suitable load levels, customer counts, and existing substation automation resulting in a cost effective likihood of customer energy savings as shown by the benefit-cost ratio below.

Alternate Plan: N/A

Summary of Benefit - Cost Analysis

Preferred Plan
Benefit Cost Ratio 3.51
Net Benefit/Cost $ 4,798,204.20

Alternate Plan
Benefit Cost Ratio N/A
Net Benefit/Cost N/A

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis
1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. Transmission costs are currently calculated on a regional basis. The analysis will be refined to prorate the cost on a Rhode Island specific basis.

3. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

4. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

5. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

6. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Docket 4600 Benefit-Cost Framework

Project Name: VVO Farnum Pike Substation
Area Study: Program

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (1,915,082.07)	Distribution Project costs (C, R, OM) and yearly expense to operate a maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Not Applicable	$ -	This project does not have associated Transmission project costs.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not have non-energy costs that impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 2,928,107.60	This benefit is the value of avoided energy across the six feeders served by the Farnum Pike substation.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This project does not impact REC costs/value.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This project does not directly impact retail supplier risk premium.
Benefit	Power System	Forward Commitment: Capacity Value	Applicable/Quantifiable	$ 791,284.13	This project has a peak capacity reduction effect.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This project does not impact utility / third party developer renewable energy, efficiency, or DER costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This project does not impact transmission costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This project does not directly impact option values of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Applicable/Quantifiable	$ 165,605.17	This project has an energy and capacity DRIPE effect.
Benefit	Power System	Greenhouse gas compliance costs	Applicable/Quantifiable	$ 396,539.80	This project results in a greenhouse gas compliance benefit associated with the energy reduction.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system safety.
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system voltage performance.
Benefit	Power System	Utility low income	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Not Applicable	$ -	This project does not impact customer reliability or resilience.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 2,012,035.00	This project results in a greenhouse gas externality benefit associated with the energy reduction.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 41,416.18	This project results in air pollutant externality benefit associated with the energy reduction.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This project results in air pollutant I38:I41externality benefit associated with the energy reduction.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ 378,298.39	This project results in a societal public health benefit associated with the emissions reductions.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This project does not impact National Security.

Docket 4600 Benefit-Cost Framework

Project Name: VVO Pontiac Substation
Area Study: Program

Problem: The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralize control of the regulating devices to provide customer energy savings and lower electric bills.

Preferred Plan: The Pointiac Substation circuits (6) have been selected for the next installation of volt-var optimization functionality. The circuits and substation have suitable load levels, customer counts, and existing substation automation resulting in a cost effective likihood of customer energy savings as shown by the benefit-cost ratio below.

Alternate Plan: N/A

Summary of Benefit - Cost Analysis

Preferred Plan
Benefit Cost Ratio 3.18
Net Benefit/Cost $ 4,412,241.93

Alternate Plan
Benefit Cost Ratio N/A
Net Benefit/Cost N/A

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis
1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. Transmission costs are currently calculated on a regional basis. The analysis will be refined to prorate the cost on a Rhode Island specific basis.

3. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

4. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

5. CO_2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

6. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Docket 4600 Benefit-Cost Framework

Project Name: **VVO Pontiac Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (2,023,132.45)	Distribution Project costs (C, R, OM) and yearly expense to operate a maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Not Applicable	$ -	This project does not have associated Transmission project costs.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not have non-energy costs that impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 2,803,464.91	This benefit is the value of avoided energy across the six feeders served by the Pontiac substation.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This project does not impact REC costs/value.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This project does not directly impact retail supplier risk premium.
Benefit	Power System	Forward Commitment: Capacity Value	Applicable/Quantifiable	$ 757,601.01	This project has a peak capacity reduction effect.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This project does not impact utility / thrid party developer renewable energy, efficiency, or DER costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This project does not impact transmission costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This project does not directly impact option values of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Applicable/Quantifiable	$ 158,555.74	This project has an energy and capacity DRIPE effect.
Benefit	Power System	Greenhouse gas compliance costs	Applicable/Quantifiable	$ 380,761.62	This project results in a greenhouse gas compliance benefit associated with the energy reduction.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system safety.
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system voltage performance.
Benefit	Power System	Utility low income	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Not Applicable	$ -	This project does not impact customer reliability or resilience.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 1,931,976.82	This project results in a greenhouse gas externality benefit associated with the energy reduction.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 39,768.25	This project results in air pollutant externality benefit associated with the energy reduction.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This project results in air pollutant I38:I41externality benefit associated with the energy reduction.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ 363,246.03	This project results in a societal public health benefit associated with the emissions reductions.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This project does not impact National Security.

PUC 1-27

Request:

Referencing pages 76-7, please explain whether there is anything new in this year's program, or if this is just an expansion to new substations provide an updated priority list.

Response:

The 3V0 Program and Accelerated 3V0 program under DER Strategic Investments are one in the same. The Company is proposing the expansion of the existing program included in prior ISR plans. The Company intentionally put this program in the FY 2021 ISR Plan as separate line items to highlight the expansion of the program to include additional substations and incremental spend.

Please see the updated priority list below.

Priority	Substation	Station Voltage (kV)	Station Class	Carryover from existing program
1	Quonset	34.5/12.47	D – Sub	Yes
2	Chopmist	23/12.47	D – Sub	No
3	Peacedale	34.5/12.47	D – Sub	Yes
4	Gate 2	69/23/4.16	T & D Sub	No
5	Warwick Mall	23/12.47	D – Sub	Yes
6	Staples	115/13.8	T & D Sub	Yes
7	Point Street	115/12.47	T & D Sub	Yes
8	Putnam Pike	115/12.47	T & D Sub	No
9	Clarke Street	23/4.16	D Sub	No
10	Eldred	23/4.16	D Sub	No
11	Anthony	23/12.47	D – Sub	No
12	Valley	115/23/13.8	T & D Sub	No
13	West Greenville	23/12.47	D – Sub	No
14	Wampanoag	115/12.47	T & D Sub	No
15	Warwick	23/12.47	D – Sub	No
16	Bristol	115/23/12.47	T & D Sub	No
17	Hope	23/12.47	D – Sub	No
18	Lippitt Hill	23/12.47	D – Sub	No
19	Hospital	23/4.16	D – Sub	No
20	Hunt River	34.5/12.47	D – Sub	No
21	Manton	23/12.47	D – Sub	No

Prepared by or under the supervision of: Kathy Castro

PUC 1-27, page 2

A review of eligibility based on DER-to-load ratio and prioritization will occur on an annual basis to ensure the program is being executed prudently.

The other Strategic DER investments including, Mobile 3V0, Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors, and Advanced Recloser Controls are new to the FY 2021 ISR plan.

Prepared by or under the supervision of: Kathy Castro

PUC 1-28

Request:

Referencing pages 76-77 and the 3V0 Program, please provide the following information:

a) How many substations will have 3V0 installed for the $0.5 million?
b) Please explain how the Company makes the "priority" determination.
c) How long does the Company expect this program to continue and how much does the Company expect to spend on an ongoing annual basis?

Response:

a) The $0.5 million budget in the existing 3V0 program is proposed to complete the construction of 3V0 on the T1 and T2 Quonset Substation transformers and start and complete design and construction on the Chopmist T2 Substation Transformer.

b) Stations are selected and prioritized based on the following criteria:

   1. The high side transformer configuration was identified for each station. Stations with a high side Wye-ground transformer configuration were excluded.
   2. The stations were investigated for existing 3V0 protection. Substations equipped with a high side protection scheme capable of detecting line to ground faults and tripping the low side breaker were excluded from consideration.
   3. The substations were selected on the basis of DER to minimum load ratio. If the ratio of the nameplate distributed generation of a station to the minimum load exceeded 50%, the station was considered for 3V0 implementation.

c) The total capital distribution budget of the existing 3V0 and proposed Accelerated 3V0 program for the selected stations is $7.32 million. The estimated spending forecast is shown below, which will be reviewed after the first year for any forecast changes.

	FY21	FY22	FY23	FY24	FY25	**Total**
Capex	$1,033,125	$1,491,500	$1,520,000	$1,567,500	$1,710,000	**$7,322,125**

Prepared by or under the supervision of: Kathy Castro

PUC 1-29

Request:

Please provide a list of 3V0 installations that were funded as part of the existing 3V0 Program. If known, for each installation, please provide:

a) the amount of generation that was interconnected to the installation site before 3V0 was installed,
b) the amount of generation in queue that would potentially interconnect to the installation site at the time the site was selected for inclusion in ISR 3V0 Program, and
c) the amount of generation that has been interconnected or is in construction for interconnection at the installation site since the time the site was selected for inclusion in ISR 3V0 Program.

Response:

Below is the list of 3V0 installations that were funded as part of the 3V0 Program, including data requested in Parts a, b, and c:

Substation/Transformer	Project Start (FY)	In Service Date	**a) kW**	**b) kW**	**c) kW**
Tiverton	2019	7/1/2019	3,188	4,177	3,592
Kilvert	2019	12/1/2018	5,488	9,247	5,527
Old Baptist Road	2019	12/1/2018	4,850	2,079	7,617
Davisville	2019	7/2020	14,645	1,933	9,240
Wolf Hill	2020	4/2020	4,182	9,606	3,373
Pontiac	2020	3/2020	1,726	3,659	2,970
Riverside	2020	3/2020	4,003	11,732	10,613
Quonset	2020	5/2020	638	9,455	200

Interconnected DER prior to in service dates for stations with future in service dates is as of 2/1/2020.

Per Quonset, several projects totaling 9,182 kW withdrew following the review of stations that were progressing in 2020, with approximately 40% withdrawing after the start of FY2020. Total interconnected DER at Quonset to date is 705 kW with 620 kW in queue.

Prepared by or under the supervision of: Kathy Castro

PUC 1-30

Request:

Please describe the differences between the ongoing 3V0 Program described on pages 76-7, the Accelerated 3V0 Proposal, and the Mobile 3V0. Differences should include at least brief explanation of the differences in purposes, need, priority lists, total costs, and per-unit costs.

Response:

The 3V0 Program described on pages 76-7 and Accelerated 3V0 program under DER Strategic Investments are one in the same. The Company is proposing the expansion of the existing program included in prior ISR Plans. The Company intentionally put the Accelerated 3V0 program in the FY 2021 ISR Plan as a separate line item to highlight the expansion of the program to include additional substations and incremental spend.

The total capital distribution budget of the existing 3V0 and proposed Accelerated 3V0 program for the selected stations is $7.32 million. The estimated spending forecast is shown below, which will be reviewed after the first year for any forecast changes.

	FY21	FY22	FY23	FY24	FY25	**Total**
Capex	$1,033,125	$1,491,500	$1,520,000	$1,567,500	$1,710,000	**$7,322,125**

As DER penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex, sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is a factor, the duration of the 3V0 work can create unexpected financial impact to the DER development community. Recent legislation in the state of Rhode Island with required interconnection timelines also presents execution challenges for the Company. The existing and accelerated programs propose to advance the installation of 3V0 at targeted substations to enable DER interconnections. To further support DER enablement, National Grid is proposing to purchase mobile 3V0 units, which will expedite the installation of 3V0 and DER interconnection at those stations waiting to be implemented with the permanent protective equipment.

The Mobile 3V0 investment proposes the one-time purchase of (4) mobile distribution supplied 3V0 units to have the flexibility to expedite 3V0 at stations within the 3V0 programs described above or for a 3V0 installation due to a specific DER project if needed. It is expected that the 4 units can be used to expedite 2 - 4 stations a year. The units will consist of one (1) 34.5kV and three (3) 23 kV units.

Each mobile 3V0 unit would cost approximately $300,000. The total cost of purchasing four mobile 3V0 units will be approximately $1.2 million in FY 2021.

Prepared by or under the supervision of: Kathy Castro

PUC 1-31

Request:

Referencing page 77, please define: programmatic investments, major system modifications, and potential DER project reductions. Are these terms describing alternative ways to address the rising complexity described or something else?

Response:

The programmatic investments referred to on page 77 are the proposed DER Strategic Advancement programs, including Accelerated 3V0, Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors, and Advanced Recloser Controls.

In the context of DER interconnection studies, system modifications refer to alterations or additions to Company facilities required to facilitate DER additions in a safe and reliable manner. On page 77, major system modifications refer to such requirements with significant costs that could make a DER project uneconomical and/or with construction timelines that are not in line with DER in-service need dates. Some examples of major system modifications include primary re-conductoring and upgrading substation equipment like Transformers.

Potential DER project reductions refer to the reduction of proposed DER project sizes, also known as curtailment, in order to avoid hosting capacity limitations and compliance issues due to aggregation of DER. DER developers may opt to reduce DER project size rather than proceed with major system modifications.

All of these terms describe solutions to issues stemming from hosting capacity limitations and compliance violations which the Company is experiencing due to the aggregation of DER interconnections on the distribution system.

Prepared by or under the supervision of: Kathy Castro

PUC 1-32

Request:

Referencing the Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors on page 77:

a) How are the Feeder Monitor Sensors included in the Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors different from previous Company proposals for feeder monitor sensors. Do these sensors provide a different or incremental function to Advance Meter Functionality (AMF) being considered in the Company's AMF study?
b) How are the investments in Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors different from Volt/VAR investments? Do these provide different or incremental functions not provided by Volt/VAR investments?

Response:

a) The Feeder Monitor Sensors included in the Advanced Capacitor/Regulator Controls are being proposed to provide situational awareness needed to ensure system service requirements, such as capacity management and voltage compliance, are being met with the continued aggregation of distributed energy resources (DER). The sensors will provide interval monitoring data that allows system planners to make more informed hosting capacity assessments and recommendations with respect to the coincidence of load and DER. This visibility will be most beneficial if interval monitoring data is provided throughout the circuit – at the head and remote ends of circuits, and at circuit midpoints. Because interval monitoring data will also be provided by advanced capacitor, regulator and recloser controllers installed at circuit midpoints, the Company is proposing to install the sensors only at the head and remote ends of distribution circuits.

   AMF meters can also provide interval power monitoring at the customer level or at remote-ends of the feeders. If AMF is approved in Rhode Island, then the scope of this program will be reduced to the installation of sensors at the head of distribution circuits.

b) While the Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors and Volt/VAR investments utilize the same advanced controlled devices, the main driver and strategic deployment of equipment under each program is different.

   Advanced Volt VAR Optimization and Conservation Voltage Reduction (VVO/CVR) is a program where centralized, coordinated control is deployed to manage existing distribution assets with the intent of better optimizing the performance of the system, and deliver energy at a voltage which results in peak efficiency for the customer - saving the customer an estimated 3% on their energy and demand charges. The Company's VVO/CVR program prioritizes VVO/CVR deployment according to where these program goals (energy savings) are most expected to be realized.

With the proliferation of DER comes an increasing complexity in managing core compliance obligations such as system load, voltage, and protection systems that are the key to system safety and reliability. The Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors program will proactively upgrade capacitor controls and regulator controls and install sensing to sufficiently manage load and voltage. These advanced field devices, along with robust communications systems and centralized operations and processing capabilities, would facilitate protection and voltage compliance associated with DER interconnections.

The Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors program will initially focus execution in rural areas with less robust electric systems which are more susceptible to power quality and voltage fluctuation issues due to the aggregation of DER. While the equipment deployed to address these compliance issues can also be utilized under a VVO/CVR scheme, addressing compliance issues due to the aggregation of DER leads to a focus on equipment installations in different areas and substations than under the VVO/CVR program.

Under the VVO/CVR program, VVO/CVR will subsequently be implemented in areas addressed by the Strategic DER investments where an incremental benefit can be realized by providing customer savings on energy and demand charges.

Prepared by or under the supervision of: Kathy Castro

PUC 1-33

Request:

Regarding Mobile 3V0, Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors, and Advanced Recloser Controls included in the Strategic DER Advancement proposal (page 77):

a) Please explain if each investment is part of a multi-year strategy and provide any such multi-year investment strategy for each.

b) Please explain what each investment does, and which of these functionalities are incremental to existing equipment, and note which functionalities are the driving purpose of the investment.

c) For the functionalities that are the driving purpose of investment provided in response to part b, please provide when each functionality is expected to be operational and in-use.

Response:

Please see Attachment PUC 1-33 for the Strategic DER Advancement white papers for program justification, proposed plans, and estimated costs and schedule for a 5-year period.

a) Each document explains how each investment is part of multi-year strategy within the "Proposed Plan" section. The multi-year investments are shown in the "Estimated Costs and Schedules" section.

b) The "Purpose and Scope" and "Background" sections of the documents explain the issues or driving purposes of the investment, that the issue is new or incremental, and what the investments will do.

c) The 3V0 and Mobile 3V0 investments provide the expected benefits upon installation. For the "Advanced Capacitor, Regulator, Sensor, and Reclosers" Strategic DER Advancement proposal, the realization of benefits is multi-staged as described in Section 4 of the proposal. These investments provide an initial localized loading, voltage, and protection system management benefit. They are also designed to be easily integrated into a centralized wide area control systems such as an Advanced Distribution Management System (ADMS) for greater loading, voltage, and protection system management benefits. The Docket 4600 analysis for the Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors only considered the first stage of localized benefits that would be realized by this program.

Prepared by or under the supervision of: Kathy Castro

Strategic Distributed Energy Resources Advancement Accelerated 3V0 Program

Distribution Planning and Asset Management

Issue	Date	Summary of Changes/Reasons	Coordinator
2	2/1/2020	Minor revisions based on Stakeholder review	Kathy Castro
1	12/11/2019	Initial Issue	Kathy Castro

Table of Contents Page

1. Executive Summary

The addition of distributed energy resources (DER) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. For certain transmission faults, additional transmission protection, zero sequence overvoltage or “3V0” protection, is required to prevent the DER from contributing to fault overvoltage conditions. As DER penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is a factor, the duration of the 3V0 work can also impact the viability of proposed DER projects. Recent legislation in the state of Rhode Island (RI) with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developer need, National Grid developed a proactive 3V0 program to advance the installation of 3V0, which typically takes 60 to 72 weeks to engineer and construct, at targeted substations to enable DER interconnections. The initiative detailed in this paper accelerates and expands the existing program which has installed 3V0 at 6 of the 12 originally proposed substations since FY2019. The original list including the remaining substations pending 3V0 installation was revised into an updated list which now includes the installation of 3V0 at 21 substations over a 5-year program duration.

In order to implement the program a ranking methodology was developed by comparing maximum generation at a station to its minimum load. Since more than 90% of DER is solar minimum load is defined as daytime minimum. Aggregate DER approaching more than 50% of the station transformer’s minimum load indicates a potentially imminent need for 3V0 protection. Therefore the 50% DER to minimum load criteria was determined to be appropriate for a proactive 3V0 installation effort. Substations meeting this criterion were considered for 3V0 implementation. For stations with multiple transformers, if the requirement for 3V0 was identified for one transformer, the entire substation was considered for 3V0 modifications to realize engineering and construction efficiencies. This program has revised the prior program’s list to now include 21 RI substations in need of 3V0 implementation between FY2021 and FY2025. Depending on future DER interconnections to other RI substations the list will be expanded to include stations that exceed the DER to minimum load ratio threshold of 50%. This list will be reviewed on an annual basis.

The cost estimates for the accelerated program were developed from historical costs based on previous Conceptual Engineering Reports at similar stations and a high-level review of the existing protection schemes of the individual stations on the selected list. The costs were distributed over a 5-year period. The total program costs for the selected stations are $11.183M, broken down into $10.623 Capex and $0.559M Opex. There are no removal costs typically associated with this work. The estimated spending forecast is shown in Table 1 below, which will be reviewed after the first year for any forecast changes.

Table 1 Total Estimated Forecasted Spending

	FY21	FY22	FY23	FY24	FY25	**Total**
Capex	$2,031	$2,180	$2,280	$2,423	$1,710	**$10,623**
Opex	$107	$115	$120	$128	$90	**$559**
Removal	-	-	-	-	-	**-**
Total	**$2,138**	**$2,295**	**$2,400**	**$2,550**	**$1,800**	**$11,183**

2. Program Justification

2.1 Purpose and Scope

The addition of distributed energy resources (DER) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, the substation transformer. This effectively turns a station transformer (designed to step transmission voltage down to distribution voltage for serving load) into a generation step-up transformer pushing excess power onto the transmission system. In certain cases, generation can contribute to faults which may cause potential protection challenges on the supply line of the substation transformer.

National Grid has an existing program to advance the installation of 3V0 at targeted substations to enable DER interconnections. The scope of the existing program included the installation of 3V0 at 12 RI substations between FY2019 and FY2023. This program focuses on expanding and accelerating the existing 3V0 program list of Rhode Island substations in need of 3V0 protection based on total aggregate distribution generation connected on a transformer that has a delta or an ungrounded-wye connection on the transmission side.

2.2 Background

In today's evolving electric grid where there is an influx of distributed energy resources located on the customer side, National Grid's distribution systems must work with a variety of non-utility generation sources. The widespread application of renewable energy sources such as photovoltaic and wind technologies have caused a dramatic increase in the use of inverter-based systems. In addition, typical synchronous systems such as small hydro, diesel, methane, and natural gas-powered generator systems are still being installed. Multiple generation sources and the resulting bi-directional power flow bring significant benefits and challenges for the existing and emerging power grids. In particular, the effect of distributed generation on protection concepts and approaches needs to be understood and accounted for.

DERs on Delta-Wye (or Ungrounded Wye-Wye) connected transformers cannot contribute zero sequence ground fault current during single line to ground faults on a transmission line, resulting in the voltages on the unfaulted phases to rise significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the substation and transmission line equipment, and the maximum continuous operating voltage of surge arresters. In order to detect these overvoltage conditions, ground fault overvoltage, otherwise known as 3V0 protection, on the primary side of the transformer is a standard method employed by National Grid. In the event of a transmission-side overvoltage, this 3V0 protection will open all feeder protective devices in order to disconnect all possible DER sources from the substation bus, thereby stopping the DER from contributing to the transmission-side fault condition.

National Grid implements standard equipment and installation methods in its substations for 3V0 protection equipment as good utility practice. Installation of 3V0 equipment typically requires a significant engineering and construction effort by National Grid, which presently spans 15-18 months. From the industry perspective, DER developers are continually seeking to interconnect in the most time efficient fashion. As such, the development community has a strong desire to shorten construction timelines wherever possible. Recent legislation in the state of Rhode Island with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developer need, it was important to develop a program that will proactively implement 3V0 in an expedited manner.

Aggregate DER approaching more than 50% of the station transformer's minimum load provides an indication of a near term need for 3V0 protection. In accordance with National Grid guideline document GL 309B.0917, DERs that exceeds a 67% DER to minimum load ratio trigger the need for 3V0 installation at the substation. The intent of this program is to proactively install 3V0 at substations that are approaching that threshold. Therefore a 50% DER to minimum load ratio was determined to be appropriate for the purposes of this program. This strategy results in an effective approach that promotes deployment prior to the violation of 3V0 policy/criteria.

2.3 Program

2.3.1 Proposed Plan

This program focuses on expanding and accelerating the execution of the 3V0 program for Rhode Island substations in need of 3V0 protection based on total aggregate distribution generation connected on a transformer that has a delta or an ungrounded-wye connection on the transmission side. This program has revised the existing list to now include 21 RI substations in need of 3V0 implementation between FY2021 and FY2025. This list is not exhaustive. Depending on future DER interconnections to other RI substations the list will be expanded to include stations that exceed the DER to minimum load ratio threshold of 50%. This list will be reviewed on an annual basis.

2.3.2 Methodology

In order to implement the program a simple ranking methodology was developed by comparing maximum generation of a station to its minimum load. An initial review of all the transmission and distribution substations in Rhode Island was done to identify ongoing project work, rebuild work or projected retirement work. 3V0 protection was added to the scope of ongoing project work where possible. The stations that were projected to be retired in the upcoming years were excluded from consideration for 3V0 implementation. The following steps were followed while developing a list of substations:

- The high side transformer configuration was identified for each station. Stations with a high side Wye-ground transformer configuration were excluded.
- The stations were investigated for existing 3V0 protection. Substations equipped with a high side protection scheme capable of detecting line to ground faults and tripping the low side breaker were excluded from consideration.
- The substations were selected on the basis of DER to minimum load ratio. If the ratio of the nameplate distributed generation of a station to the minimum load exceeded 50%, the station was considered for 3V0 implementation.

This methodology was applied in the same manner to the original program, but due to the level and increasing pace of DER adoption, the number of candidate substation increased from the original 12 to the 21 proposed in this paper.

nationalgrid

2.3.3 Identification

This program has revised the existing 3V0 program list and identified additional substations in need of 3V0 implementation. Table 2 below shows the revised selected substation list.

Table 2 Substation Identification

Priority	Substation	Station Voltage (kV)	Station Class
1	Quonset	34.5/12.47	D – Sub
2	Peacedale	34.5/12.47	D – Sub
3	Gate 2	69/23/4.16	T & D Sub
4	Warwick Mall	23/12.47	D – Sub
5	Chopmist	23/12.47	D – Sub
6	Staples	115/13.8	T & D Sub
7	Point Street	115/12.47	T & D Sub
8	Putnam Pike	115/12.47	T & D Sub
9	Clarke Street	23/4.16	D Sub
10	Eldred	23/4.16	D Sub
11	Anthony	23/12.47	D – Sub
12	Valley	115/23/13.8	T & D Sub
13	West Greenville	23/12.47	D – Sub
14	Wampanoag	115/12.47	T & D Sub
15	Warwick	23/12.47	D – Sub
16	Bristol	115/23/12.47	T & D Sub
17	Hope	23/12.47	D – Sub
18	Lippitt Hill	23/12.47	D – Sub
19	Hospital	23/4.16	D – Sub
20	Hunt River	34.5/12.47	D – Sub
21	Manton	23/12.47	D – Sub

The substations were selected on the basis of distributed generation to minimum load ratio. The total connected and in-queue DER capacity (in Kilowatts, kW) was determined for each station transformer by adding up the distributed generation on each individual feeder for that particular transformer. The DER "Nameplate Rating" in kW was obtained from the September 2019 version of the "DG_on_Feeder" list stored on the Retail Connections Engineering department's shared drive. The minimum load for the station transformer was determined using historical data available in the Company's FeedPro or PI load data repositories. If FeedPro/PI data was insufficient to determine minimum loading, 25% of the peak transformer loading was assumed to be the minimum load (a National Grid typical value determined by analysis of actual peak loads across our systems). If the ratio of the total distributed generation of a station transformer to the minimum load exceeded 50%, the station was considered for

3V0 implementation. For stations with multiple transformers, if the requirement for 3V0 was identified for one transformer, the entire substation was considered for 3V0 modifications.

It is recognized that DER can change in future years. Depending on future DER interconnections to other RI substations the list will be expanded to include stations that exceed the DER to minimum load ratio threshold of 50%. This list and its prioritization will be reviewed on an annual basis.

3. Estimated Costs and Schedules

The cost estimates for the accelerated program were developed from historical costs based on previous Conceptual Engineering Reports at similar stations and a high-level review of the existing protection schemes of the individual stations on the selected list.

The total program costs for the selected stations are $11.183M, broken down into $10.623 Capex and $0.559M Opex. There are no removal costs typically associated with this work. The estimated spending forecast is shown in Table 3 below, which will be reviewed after the first year for any forecast changes.

Table 3 Total Estimated Forecasted Spending

	FY21	FY22	FY23	FY24	FY25	**Total**
Capex	$2,031	$2,180	$2,280	$2,423	$1,710	**$10,623**
Opex	$107	$115	$120	$128	$90	**$559**
Removal	-	-	-	-	-	**-**
Total	**$2,138**	**$2,295**	**$2,400**	**$2,550**	**$1,800**	**$11,183**

Refer to Appendix A for projected cash flows including the Capital and O&M cost for each station on the priority list. The costs have been divided into transmission (T-Sub) and distribution (D-Sub) spending categories. Table 3 represents the total (T-sub and D-sub) cost for 3V0 implementation.

4. Conclusions and Recommendations

This paper proposes an acceleration of the existing program to install 3V0 protective equipment at Rhode Island substations. The estimated cost is $11.183M over five years. The program will be reviewed on an annual basis to include substations where DG related projects have triggered the need for 3V0 protection. Individual work orders created under each project will be managed according to complexity and a Project Manager will track the progress.

The average cost of the 3V0 upgrades will be assessed at the end of the first construction year to refine existing estimates. Distribution Planning will review the optimal amount of yearly spend with the Resource Planning Department every year through the re-sanctioning process. As with any program, actual implementation will be coordinated with Resource Planning and

Investment Planning. Spending levels may slightly decrease or increase the actual duration of this proposed program.

nationalgrid

Appendix A Cash Flow

Priority	Substation	Station Voltage (kV)	Spend Type	Estimated Costs			Capital Cash Flows					
				Capital	O&M	Total	FY21	FY22	FY23	FY24	FY25	Total
1	Quonset	34.5/12.47	T-Sub	$0	$0	**$0**	$0					$0
			D-Sub	$320,625	$16,875	**$337,500**	$320,625					$320,625
2	Peacedale	34.5/12.47	T-Sub	$0	$0	**$0**	$0					$0
			D-Sub	$427,500	$22,500	**$450,000**	$427,500					$427,500
3	Gate 2	69/23/4.16	T-Sub	$285,000	$15,000	**$300,000**	$285,000					$285,000
			D-Sub	$285,000	$15,000	**$300,000**	$285,000					$285,000
4	Warwick Mall	23/12.47	T-Sub	$0	$0	**$0**	$0					$0
			D-Sub	$427,500	$22,500	**$450,000**	$427,500					$427,500
5	Chopmist	23/12.47	T-Sub	$0	$0	**$0**	$0					$0
			D-Sub	$285,000	$15,000	**$300,000**	$285,000					$285,000
6	Staples	115/13.8	T-Sub	$308,750	$16,250	**$325,000**		$308,750				$308,750
			D-Sub	$47,500	$2,500	**$50,000**		$47,500				$47,500
7	Point Street	115/12.47	T-Sub	$522,500	$27,500	**$550,000**		$522,500				$522,500
			D-Sub	$66,500	$3,500	**$70,000**		$66,500				$66,500
8	Putnum Pike	115/12.47	T-Sub	$570,000	$30,000	**$600,000**		$570,000				$570,000
			D-Sub	$95,000	$5,000	**$100,000**		$95,000				$95,000
9	Clarke Street	23/4.16	T-Sub	$0	$0	**$0**		$0				$0
			D-Sub	$570,000	$30,000	**$600,000**		$570,000				$570,000
10	Eldred	23/4.16	T-Sub	$0	$0	**$0**			$0			$0
			D-Sub	$570,000	$30,000	**$600,000**			$570,000			$570,000
11	Anthony	23/12.47	T-Sub	$0	$0	**$0**			$0			$0
			D-Sub	$570,000	$30,000	**$600,000**			$570,000			$570,000
12	Valley	115/23/13.8	T-Sub	$760,000	$40,000	**$800,000**			$760,000			$760,000
			D-Sub	$95,000	$5,000	**$100,000**			$95,000			$95,000
13	West Greenville	23/12.47	T-Sub	$0	$0	**$0**			$0			$0
			D-Sub	$285,000	$15,000	**$300,000**			$285,000			$285,000
14	Wampanoag	115/12.47	T-Sub	$570,000	$30,000	**$600,000**				$570,000		$570,000
			D-Sub	$95,000	$5,000	**$100,000**				$95,000		$95,000
15	Warwick	23/12.47	T-Sub	$0	$0	**$0**				$0		$0
			D-Sub	$570,000	$30,000	**$600,000**				$570,000		$570,000
16	Bristol	115/23/12.47	T-Sub	$285,000	$15,000	**$300,000**				$285,000		$285,000
			D-Sub	$332,500	$17,500	**$350,000**				$332,500		$332,500
17	Hope	23/12.47	T-Sub	$0	$0	**$0**				$0		$0
			D-Sub	$570,000	$30,000	**$600,000**				$570,000		$570,000
18	Lippit Hill	23/12.47	T-Sub	$0	$0	**$0**					$0	$0
			D-Sub	$570,000	$30,000	**$600,000**					$570,000	$570,000
19	Hospital	23/4.16	T-Sub	$0	$0	**$0**					$0	$0
			D-Sub	$570,000	$30,000	**$600,000**					$570,000	$570,000
20	Hunt River	34.5/12.47	T-Sub	$0	$0	**$0**					$0	$0
			D-Sub	$285,000	$15,000	**$300,000**					$285,000	$285,000
21	Manton	23/12.47	T-Sub	$0	$0	**$0**					$0	$0
			D-Sub	$285,000	$15,000	**$300,000**					$285,000	$285,000
			D-Sub	**$7,322,125**	**$385,375**	**$7,707,500**	$1,745,625	$779,000	$1,520,000	$1,567,500	$1,710,000	**$7,322,125**
			T-Sub	**$3,301,250**	**$173,750**	**$3,475,000**	$285,000	$1,401,250	$760,000	$855,000	$0	**$3,301,250**
			Total	**$10,623,375**	**$559,125**	**$11,182,500**	$2,030,625	$2,180,250	$2,280,000	$2,422,500	$1,710,000	**$10,623,375**

Strategic Distributed Energy Resources Advancement
Mobile 3V0 Trailer Procurement

Distribution Planning and Asset Management

Issue	Date	Summary of Changes/Reasons	Coordinator
2	2/1/2020	Minor revisions based on Stakeholder review	Kathy Castro
1	12/11/2019	Initial Issue	Kathy Castro

Table of Contents Page

1. Executive Summary

The addition of distributed energy resources (DER) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. For certain transmission faults, additional transmission protection, zero sequence overvoltage or “3V0” protection, is required to prevent the DER from contributing to fault overvoltage conditions. As DER penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex, sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is a factor, the duration of the 3V0 work can create unexpected financial impact to the DER development community. Recent legislation in the state of Rhode Island (RI) with required interconnection timelines also presents execution challenges for the Company. National Grid has an existing program to advance the installation of 3V0 at targeted substations to enable DER interconnections. To further support DER enablement, National Grid is proposing to purchase mobile 3V0 units which will expedite the installation of 3V0 and DER interconnection at those stations waiting to be implemented with the permanent protective equipment.

The Company has revised the existing 3V0 program’s list to now include 21 RI substations in need of 3V0 implementation between FY2021 and FY2025. The program expects the installation of 3V0 at 5 substations per year. There are 17 substations, approximately 80%, in the accelerated 3V0 program that are distribution supplied. Currently the Company has four (4) 115kV/69kV mobile 3V0 units which can be utilized, so that DER interconnection to transmission supplied stations can be expedited if needed. This program proposes to purchase (4) mobile distribution supplied 3V0 units to have the flexibility to expedite 3V0 at those stations if needed. It is expected that the 4 units can be uses to expedite 2 - 4 stations a year. The units will consist of one (1) 34.5kV and three (3) 23 kV units.

Each mobile 3V0 unit would cost approximately $300,000. The total cost of purchasing four mobile 3V0 units will be approximately $1.2M in FY 2021.

2. Program Justification

2.1 Purpose and Scope

The addition of distributed energy resources (DER) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, the substation transformer. This reverse power flow effectively turns a station transformer (designed to step transmission voltage down to distribution voltage for serving load) into a generation step-up transformer pushing excess power onto the transmission system. In certain cases, generation can contribute to faults which may cause potential protection challenges on the supply line of the substation transformer.

National Grid has an existing program to advance the installation of 3V0 at targeted substations to enable DER interconnections. To further support DER enablement, National Grid is proposing to purchase mobile 3V0 units which will expedite the installation of 3V0 and DER interconnection at those stations waiting to be implemented with the permanent protective equipment.

2.2 Background

In today's evolving electric grid where there is an influx of distributed energy resources located on the customer side, National Grid's distribution systems must work with a variety of non-utility generation sources. The widespread application of renewable energy sources such as photovoltaic and wind technologies have caused a dramatic increase in the use of inverter-based systems. In addition, typical synchronous systems such as small hydro, diesel, methane, and natural gas-powered generator systems are still being installed. Multiple generation sources and the resulting bi-directional power flow bring significant benefits and challenges for the existing and emerging power grids. In particular, the effect of distributed generation on protection concepts and approaches needs to be understood and accounted for.

DERs on Delta-Wye (or Ungrounded Wye-Wye) connected transformers cannot contribute zero sequence ground fault current during single line to ground faults on a transmission line, resulting in the voltages on the unfaulted phases to rise significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the substation and transmission line equipment, and the maximum continuous operating voltage of surge arresters. In order to detect these overvoltage conditions, ground fault overvoltage, otherwise known as 3V0 protection, on the primary side of the transformer is a standard method employed by National Grid. In the event of a transmission-side overvoltage, this 3V0 protection will open all feeder protective devices in order to disconnect all possible DER sources from the substation bus, thereby stopping the DER from contributing to the transmission-side fault condition.

National Grid implements standard equipment and installation methods in its substations for 3V0 protection equipment as good utility practice. Installation of 3V0 equipment typically requires a significant engineering and construction effort by National Grid, which presently spans 18-24 months. From the industry perspective, DER developers are continually seeking to interconnect in the most time efficient fashion. As such, the development community has a strong desire to shorten construction timelines wherever possible. Recent legislation in the state of Rhode Island with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developmental need, it is important to invest in methods that will shorten implementation of the 3V0 with temporary measures until a permanent installation can be completed.

3. Proposed Plan

A mobile 3V0 unit consists of a tractor trailer skid containing all the primary and secondary equipment required to implement 3V0 protection at any given substation transformer. The mobile unit is typically put in place on a temporary basis until the permanent 3V0 installation has taken place. A mobile 3V0 solution can be used to shorten the timeline for any DER project interconnection.

The benefits of using a mobile 3V0 unit are:

- Reduced Implementation Time
  - A mobile 3V0 unit has very short implementation timeline (8-12 weeks) compared to a typical 3V0 installation (60-72 weeks)
  - Adds a window of opportunity for internal resources to complete the engineering, design and construction of the permanent protection scheme
  - Enables critical or high-profile customers to be operational in accordance with their need dates, which may increase DER project viability
  - Can resolve emergent or existing issues resulting from the aggregation of DER in a timely manner, reducing existing risk to Company equipment that cannot be mitigated through developer-funded investments
- Flexibility
  - Install regardless of arrangement, with limited to no substation modifications.
  - Flexible relaying, wiring, and EMS options
- Repeatability
  - Design concept can be reused or adjusted to fit the needs of similar voltage configurations

The Company has revised the existing 3V0 program's list to now include 21 RI substations in need of 3V0 implementation between FY2021 and FY2025. The program expects the installation of 3V0 at 4-5 substations per year. There are 17 substations, approximately 80%, in the accelerated 3V0 program that are distribution supplied. Currently the Company has four (4) 115kV/69kV mobile 3V0 units which can be utilized, so that DER interconnection to transmission supplied stations can be expedited if needed. This program proposes the one time purchase of (4) mobile distribution supplied 3V0 units to have the flexibility to expedite 3V0 at those stations if needed. It is expected that the 4 units can be uses to expedite 2 - 4 stations a year. The units will consist of one (1) 34.5kV and three (3) 23 kV units. If mobile units are used to expedite permanent 3V0 installations associated with specific DER projects then the installation cost associated with installing the mobile unit will be borne by the DER developer.

4. Estimated Costs and Schedules

Based on previously procured mobile 3V0 unit costs, each mobile 3V0 unit would cost approximately $300,000. The total cost of purchasing four mobile 3V0 units will be approximately $1.2M in FY 2021.

5. Conclusions and Recommendations

This paper recommends the purchase of four mobile 3V0 units at a cost of $1.2M in FY 2021. The procurement of these units will enable the strategic deployment of mobile 3V0 units at distribution substations to facilitate the interconnection of DER.

Strategic Distributed Energy Resources Advancement
Advanced Capacitor, Regulator, Sensor, and Reclosers

Distribution Planning and Asset Management

Coordinator: Kathy Castro

December 12, 2019

Table of Contents — Page

nationalgrid

1. Executive Summary

With the proliferation of distributed energy resources (DER) comes an increasing complexity in managing core compliance obligations such as system load, voltage, and protection systems that are the key to system safety and reliability. Under the traditional design of the Electric Power system, automated equipment and system control has limited use. With the interconnection and increase of DER and localized unique demand requirements in certain areas of the system comes a change in loading, voltage, and protection profiles. The issues can have location, time, and direction components such that existing infrastructure and control methods are unable to manage loading, voltage, and protection needs. As DER continue to develop, more components of the distribution, sub-transmission, and potentially transmission system become impacted, and the distribution system is continuously reconfigured for other reasons (reliability, thermal, voltage, and arc flash performance, etc.) it becomes increasingly difficult to assign certain system infrastructure development costs to any one DER interconnection project.

The Company is now putting forth this effort which will proactively upgrade recloser controls, install new reclosers at circuit connection points, upgrade capacitor controls and regulator controls, and install sensing to sufficiently manage load, voltage, and protection needs. These advanced field devices, along with robust communications systems and centralized operations and processing capabilities, would facilitate protection and voltage compliance associated with DER interconnections. These investments are in line with standard actions that the Company currently performs to maintain and address immediate system performance and reliability needs for all customers.

The near-term deployment of line devices will be targeted to those areas and circuits with significant existing DER penetration and the greatest load and protection risk. Analysis has shown the greatest compliance risk to be the sub-transmission sourced feeders predominantly located in the western areas of the state.

Table 1 shows a high-level proposed cash flow for these investments.

Table 1 Proposed Cash Flow

		FY21	FY22	FY23	FY24	FY25
Subtotal - Voltage & Load Compliance	# Devices	36	36	36	36	36
	Capex	**$1,970**	**$1,970**	**$1,970**	**$1,970**	**$1,970**
	Opex	**$197**	**$197**	**$197**	**$197**	**$197**
	Removal	**$99**	**$99**	**$99**	**$99**	**$99**
	RTB[1]	**$12**	**$12**	**$12**	**$12**	**$12**
	RTB - Telecom	**$4**	**$4**	**$4**	**$4**	**$4**
	Total	**$2,282**	**$2,282**	**$2,282**	**$2,282**	**$2,282**

[1] RTB: Run the Business

2. Program Justification

2.1 Purpose and Scope

With the proliferation of DER comes an increasing complexity in managing core compliance obligations such as system load, voltage, and protection systems that are the key to system safety and reliability. National Grid's Distribution Planning and Asset Management engineers analyze the impact of DER on the electrical distribution power system's performance at the commencement of discrete System Impact Study (SIS) agreements. The analysis conducted identifies potential concerns due to specific DER interconnections and provide system modifications required to maintain compliance. Studies consider all interconnected and proposed DER within the analysis. System modifications are assigned to the project which upsets the balance of any compliance issue. Modifications range from significant infrastructure upgrades to DER project curtailment. As DER continue to develop, more components of the distribution, sub-transmission, and potentially transmission system become impacted, and the distribution system is continuously reconfigured for other reasons (reliability, thermal, voltage, and arc flash performance, etc.) it becomes increasingly difficult to assign certain system infrastructure development costs to any one DER interconnection project.

The Company is now putting forth this effort which will proactively install required equipment and controls that are needed to enable the interconnection of DER while allowing the Company to meet its core compliance obligations. These investments are in line with standard actions that the Company currently performs to maintain and address immediate system performance and reliability needs for all customers.

The pace of DER interconnections and changing customer needs and expectations requires the Company to take this initial action to inform more comprehensive and structured programmatic investments for the future.

2.2 Background

National Grid's existing distribution Electric Power System (EPS) has traditionally been designed and arranged to handle possible loading and voltage situations for one-way power flow. Under such a design, automated equipment and system control has limited use. With the interconnection and increase of DER and localized unique demand requirements in certain areas of the system comes a change in loading, voltage, and protection profiles. The issues can have location, time, and direction components such that existing infrastructure and control methods will be unable to manage loading, voltage, and protection needs.

The Company is experiencing DER interconnections on the distribution system that are becoming increasingly complex, stemming from hosting capacity limitations and compliance issues due to heavy saturation (aggregate impact of DER). Ideally these issues are identified during preemptive system impact study analysis, but the aggregation of simple and complex DER has led to the emergence of power quality and voltage issues that can not be tied back to a specific DER installation. Solutions increasingly draw on the application of advanced capacitors, regulators and reclosers control technologies, and feeder monitoring to maintain compliance obligations.

In addition to compliance challenges on the distribution area EPS the increase in DER interconnections have presented the same concerns with back feed of generation onto the Transmission System. Because of these concerns and the desire to operate the Transmission EPS safely and reliably, there has been an increase in the need for Affected System Operator (ASO) studies. Like distribution SIS, transmission analysis identifies potential concerns due to DER interconnections and provides system modifications required to maintain core compliance obligations.

As an example, New England Power (NEP) recently completed a transmission level cluster analysis of approximately 400MW in the Western area of the Massachusetts jurisdiction. Analysis identified unacceptable voltage concerns which could have required significant transmission infrastructure upgrades and installation of Dynamic Volt-Amp reactive compensation at several area substations prior to interconnection of any DER. Advanced capacitor and regulator programs (supported by the MA DPU) were leveraged to mitigate voltage concerns and avoid timely and expensive transmission upgrades. This experience highlighted the need for more extensive integrated transmission and distribution System Planning to appropriately leverage the most efficient solutions to resolve transmission system compliance issues due to the aggregation of DER. In the example above the efficient solution applied distribution advanced control technologies to avoid major transmission upgrades.

The Company has deployed the same advanced monitoring and control technologies to deliver voltage optimization and power loss savings to its customers through the volt-var optimization (VVO) program. These needs have prompted the Company to modify distribution standards so that all new capacitor, regulator and reclosers include these advanced controls. Assets associated with new standards are deployed when prompted by project rebuilds, expansions and acute system performance concerns.

3. Proposed Plan

As a result of the issues described above, National Grid plans to upgrade recloser controls, install new reclosers at circuit connection points, upgrade capacitor controls and regulator controls, and install sensing to sufficiently manage load, voltage, and protection needs. These advanced field devices, along with robust communications systems and centralized operations and processing capabilities, would facilitate voltage compliance associated with existing and future DER interconnections. The Company's pending Grid Modernization Plan (GMP) proposes such a comprehensive plan. This specific proposal aims to install the automated field devices at key feeder and substation locations in advance of the centralized controls. The field devices will create immediate benefits through advanced autonomous control with even greater DER integration benefits obtained when the field devices are linked with the central controller.

The near-term deployment of line devices will be targeted to those areas and circuits with significant existing DER penetration and the greatest load and protection risk. Analysis has shown the greatest compliance risk to be the sub-transmission sourced feeders predominantly located in the western areas of the state. Sub-transmission sourced distribution circuits or circuits with otherwise high source impedance can be most susceptible to voltage and fault current level impacts. These high-risk areas, which also are identified as limited hosting capacity areas, would be targeted first. The Company does install similar technology through existing VVO and Recloser replacement programs, but these programs do not necessarily focus on areas with system characteristics driving the need for the DER enabling investments. Once advanced field devices have been deployed on a circuit, future enablement of VVO will be more efficiently executed in these areas, extending additional benefits of these investments to all customers in these areas.

Beyond immediate compliance issues this programmatic approach will provide the Company with the experience needed to enhance the standard installation and program development as well as build familiarity with operation and maintenance of new equipment.

nationalgrid

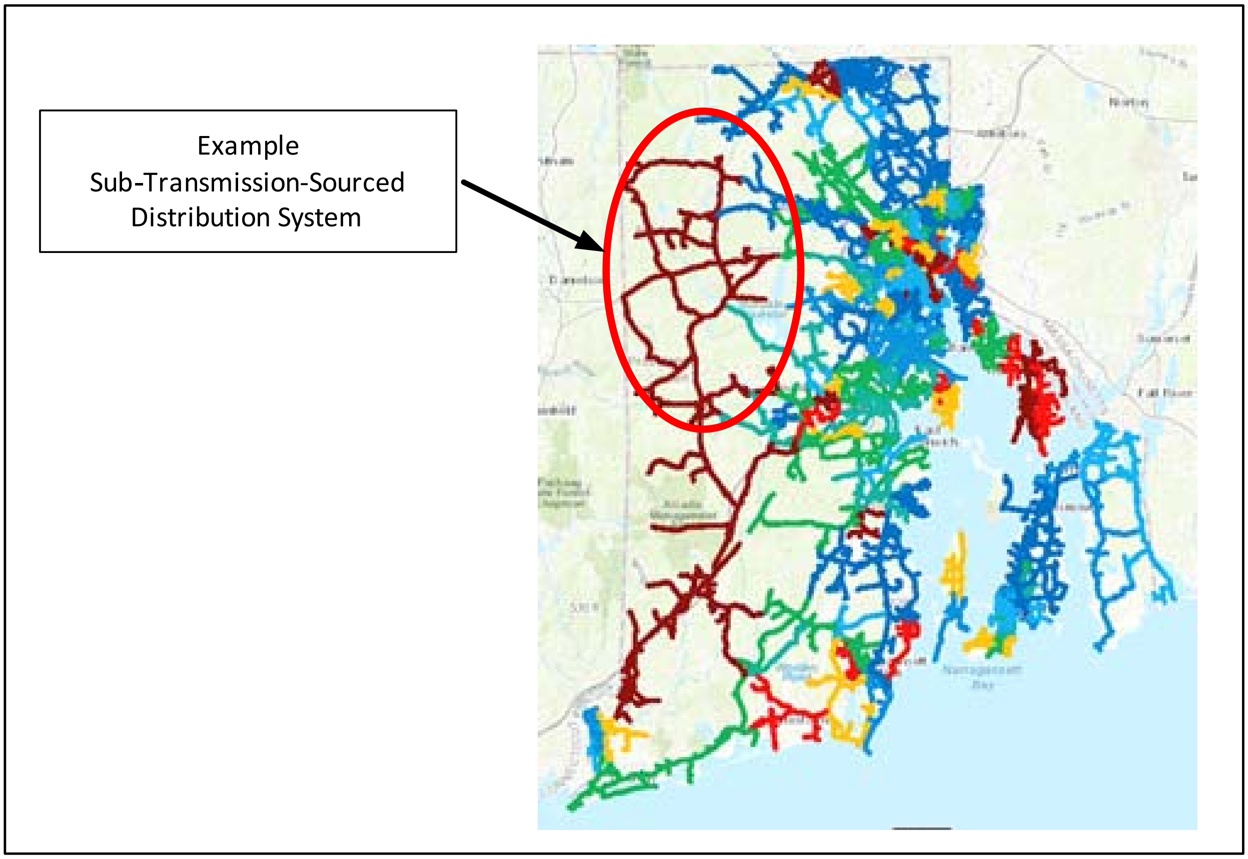


Figure 1Hosting Capacity Map with Sub-transmission Area

(deeper red shaded hosting capacity means limited DER interconnection potential)

4. Benefits

4.1 Societal Benefits

Load, voltage, and protection management are fundamental utility compliance requirements for safe and reliable electric service. The proposed program enables the Company to install the distribution line equipment that will ensure loading levels, voltage levels, and protection systems are sufficient across all times of a year in all areas of the distribution system with various levels of DER penetration. Once integrated with an Advanced Distribution Management System (ADMS) the plan allows this fundamental requirement to be achieved in a way that enables greater customer choice and a cleaner economy. It is expected that investments will avoid limitations which are occurring now as shown by the distribution and transmission examples described above. The proposed plan is the initial step required to avoid major infrastructure upgrades or DER downsize to allow DER interconnection. In the case of DER curtailment, the advanced capacitors, regulators, and sensors would help limit the necessary times to shut-down and the advanced reclosers would refine and minimize the shutdown switching.

4.2 Additional Customer Benefits

While meeting the core compliance needs, the Company sees opportunities for optimization to maximize customer value. For example, the same advanced reclosers used for load management can be incorporated into a Fault Location, Isolation and Restoration (FLISR) system for improved outage performance. Similarly, advanced capacitors used for voltage compliance can be incorporated into Volt-Var Optimization (VVO) systems to save customers money by reducing energy usage.

5. Estimated Costs and Schedules

The near-term deployment of line devices will target sub-transmission sourced areas and circuits with existing DER penetration and the greatest voltage compliance risk. This paper proposes a five-year program totaling $11.4M. Refer to Appendix A for the near-term cash flow.

6. Conclusions and Recommendations

The proliferation of DER on the distribution system requires innovative and proactive solutions to address compliance issues and maintain a safe and reliable system. This paper proposes a five-year program to install advanced field devices at strategic locations on the distribution system where they have the greatest potential to enable DER interconnections and address compliance issues that cannot effectively be attributed to a single developer or DER installation. Through this program the Company will proactively upgrade recloser controls, install new reclosers at circuit connection points, upgrade capacitor controls and regulator controls, and install sensing to sufficiently manage load, voltage, and protection needs. These investments will address compliance issues attributable to DER aggregation, resolve core compliance concerns, and facilitate future optimization efforts progressed under the Company's GMP.

nationalgrid

Appendix A Cash Flow

CATEGORY	DEVICE	Cost Type ($K)	FY2021	FY2022	FY2023	FY2024	FY2025
Distribution Grid Control-Voltage Compliance	Smart Capacitors	# Devices	10	10	10	10	10
		Capex	$300	$300	$300	$300	$300
		Opex	$30	$30	$30	$30	$30
		Rem	$15	$15	$15	$15	$15
		RTB	$4	$4	$4	$4	$4
		RTB - Telecom	$1	$1	$1	$1	$1
Distribution Grid Control-Voltage Compliance	Advanced Regulators	# Devices	4	4	4	4	4
		Capex	$400	$400	$400	$400	$400
		Opex	$40	$40	$40	$40	$40
		Rem	$20	$20	$20	$20	$20
		RTB	$0	$0	$0	$0	$0
Distribution Grid Control-Voltage Compliance	Feeder Monitors	# Devices	4	4	4	4	4
		Capex	$100	$100	$100	$100	$100
		Opex	$10	$10	$10	$10	$10
		Rem	$5	$5	$5	$5	$5
		RTB	$2	$2	$2	$2	$2
		RTB - Telecom	$0	$0	$0	$0	$0
Distribution Grid Control-Load/Protection Management	Advanced Reclosers	# Devices	18	18	18	18	18
		Capex	$1,170	$1,170	$1,170	$1,170	$1,170
		Opex	$117	$117	$117	$117	$117
		Rem	$59	$59	$59	$59	$59
		RTB	$7	$7	$7	$7	$7
		RTB - Telecom	$2	$2	$2	$2	$2

CATEGORY	DEVICE	Cost Type ($K)	FY2021	FY2022	FY2023	FY2024	FY2025
Subtotal - Voltage & Load Compliance		**# Devices**	**36**	**36**	**36**	**36**	**36**
		Capex	**$1,970**	**$1,970**	**$1,970**	**$1,970**	**$1,970**
		Opex	**$197**	**$197**	**$197**	**$197**	**$197**
		Rem	**$99**	**$99**	**$99**	**$99**	**$99**
		RTB	**$12**	**$12**	**$12**	**$12**	**$12**
		RTB - Telecom	**$4**	**$4**	**$4**	**$4**	**$4**
		Total	**$2,282**	**$2,282**	**$2,282**	**$2,282**	**$2,282**

PUC 1-34

Request:

Referencing page 81, please describe Project # CO51909 and explain why it has a negative expense.

Response:

For FY 2021, the Company expects to implement a new process that will offset distributed generation (DG) capital project costs with related contributions in aid of construction (CIACs) received in the month of the capital expenditure at the work order level. Therefore, the Company expects that the net capital activity for any fiscal year will be the net difference between capital expenditures and CIACs received, which the Company expects to be a minimal amount. For FY 2021, the Company estimated this net activity to be $1 million. Since this process has not been implemented yet, the DG project capital spending budget as of the time the Company prepared the FY 2021 ISR Plan is shown for each project separately with the offsetting CIAC amounts shown in Project # C051909, which would be a credit (or "negative expense" as used in this Request) to arrive at total estimated DG project expenditures of $1 million.

PUC 1-35

Request:

Referencing page 81, for each project please describe how the costs and the ratepayer obligation are derived.

Response:

Capital spending budgets for blanket projects are estimated based on historical trends, updated for inflation and any expected one-time adjustments.

Specific projects in the Customer Request/Public Requirement category, which have been identified and estimated prior to the Company's budget cycle, are placed into the ISR Plan for the dollars expected to be spent in the upcoming fiscal year(s), net of any customer Contributions in Aid of Construction (CIAC). Reserves for emerging specific projects (>$100k) in the classifications within Customer Requests/Public Requirements category are budgeted based on spending trends for these type of items in the prior fiscal years, which would also be net of any CIAC received.

Ratepayer obligations are derived from the revenue requirement on the amount of plant forecasted to be placed into service during the upcoming fiscal year. In the reconciliation filing submitted in August, the revenue requirement is updated to include the fiscal year's actual plant in service. Meters and transformers are placed in service when purchased. All other projects are placed in service based on capital costs, net of CIAC, when the project qualifies as used and useful. Projects are considered used and useful when they are energized and can support electric load.

Prepared by or under the supervision of: Patricia C. Easterly and Melissa Little

PUC 1-36

Request:

Referencing page 154 and the Company's focus on pockets of poor performance, please describe what the Company plans to track and the criteria the Company will use to evaluate whether the program should continue. Does the Company know why there are areas of poor performance? Please explain how the Company plans to "focus on trees outside [its] normal scope of work.

Response:

The Company will track reliability performance in the areas where work is performed. This includes tree-related events, customers interrupted, and minutes interrupted. This will be compared to the previous three years of tree-related reliability in the same area. If the Company sees significant reliability improvement in these areas, and the Public Utilities Commission agrees, then the Company will propose to continue the program.

There are many reasons why these areas of poor performance exist. In some areas, there are tree species which may grow faster than others. These areas require more frequent maintenance than the current four-year pruning cycle allows. It is also common to see general tree decline in small areas. This decline can be due to several factors including, light levels, soil pH and nutrient availability, topography, or invasive species, such as Gypsy Moth. Gypsy Moth infestations have spread throughout the state, and the Company has removed large numbers of oak trees, which have been killed on three-phase portions of circuits; however, there are still large quantities of dead oaks on single-phase sections of circuits that need to be addressed. Lastly, there are areas which experience drought, high winds, or large quantities of rain or snow. These weather events can cause healthy trees to fail and weaken others that make them susceptible to failure during future weather events. Having the ability to respond quickly in any of these scenarios will provide a great reliability benefit to many customers in Rhode Island.

The Company currently operates on a four-year cycle in the State of Rhode Island. The current pruning specification calls for creating a minimum clearance of six feet to the side and ten to fifteen feet above the conductors. There are some species that grow faster than others; therefore, these clearances are not enough for a four-year cycle. This program will seek to create larger clearances, or in some cases remove trees that are not compatible with their location. This type of work does not fall into the current scope of the Company's cycle pruning program.

Prepared by or under the supervision of: Ryan A. Moe

PUC 1-36, page 2

In addition, the Company's Enhanced Hazard Tree Mitigation (EHTM) program targets dead, diseased, or dying trees on the three-phase portions of circuits, which have had reliability issues in the past. This program will target danger trees on single-phase sections of circuits. These areas do not serve as many customers as three-phase sections, so they don't fall into the defined scope of work of the EHTM program.

Prepared by or under the supervision of: Ryan A. Moe