NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

September 28, 2017

VIA ELECTRONIC FILING

Ms. Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: NERC Notice of Penalty regarding Boston Energy Trading and Marketing LLC, GenOn REMA 1, GenOn Power Midwest, and GenOn Northeast Management Company, FERC Docket No. NP17- ___ - 000

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby provides this Notice of Penalty[1] regarding Boston Energy Trading and Marketing LLC (BETM), GenOn REMA 1, GenOn Power Midwest, and GenOn Northeast Management Company (collectively, the Parties), NERC Compliance Registry ID# NCR00769,[2] NCR11141,[3] NCR11136,[4] and NCR11137,[5] respectively, with information and details regarding the nature and resolution of the violation discussed in detail in the Settlement Agreement attached hereto (Attachment A), in accordance with the Federal Energy Regulatory Commission's (Commission or FERC) rules, regulations and orders, as well as NERC Rules of Procedure including Appendix 4C (NERC Compliance Monitoring and Enforcement Program (CMEP)).[6]

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* (Order No. 672), III FERC Stats. & Regs. ¶ 31,204 (2006); *Notice of New Docket Prefix "NP" for Notices of Penalty Field by the North American Electric Reliability Corporation*, Docket No. RM05-30-000 (February 7, 2008). *See also* 18 C.F.R. Part 39 (2010). *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *reh'g denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A). *See* 18 C.F.R. § 39.7(c)(2).

[2] BETM was included on the NERC Compliance Registry as a Generator Owner (GO) and Generator Operator (GOP) on May 30, 2007.

[3] GenOn REMA 1 was included on the NERC Compliance Registry as a GO and GOP on June 14, 2011.

[4] GenOn Power Midwest was included on the NERC Compliance Registry as a GO and GOP on May 30, 2007.

[5] GenOn Northeast Management Company was included on the NERC Compliance Registry as a GO and GOP on October 4, 2007.

[6] *See* 18 C.F.R. § 39.7(c)(2).

NERC is filing this Notice of Penalty with the Commission because ReliabilityFirst Corporation (ReliabilityFirst) and the Parties have entered into a Settlement Agreement to resolve all outstanding issues arising from ReliabilityFirst's determination and findings of six total violations of the Operations and Planning NERC Reliability Standards.

According to the Settlement Agreement, the Parties neither admit nor deny the violations and agree to the assessed penalty of one hundred thousand dollars ($100,000), in addition to other remedies and actions under the terms and conditions of the Settlement Agreement.

Statement of Findings Underlying the Violations

This Notice of Penalty incorporates the findings and justifications set forth in the Settlement Agreement, by and between ReliabilityFirst and the Parties. The details of the findings and basis for the penalty are set forth in the Settlement Agreement and herein. This Notice of Penalty filing contains the basis for approval of the Settlement Agreement by the NERC Board of Trustees Compliance Committee (NERC BOTCC).

In accordance with Section 39.7 of the Commission's regulations, 18 C.F.R. § 39.7 (2017), NERC provides the following summary table identifying each violation of a Reliability Standard resolved by the Settlement Agreement. Further information on the subject violations are set forth in the Settlement Agreement.

Violation(s) Determined and Discovery Method *SR = Self-Report / SC = Self-Certification / CA = Compliance Audit / SPC = Spot Check / CI = Compliance Investigation								
NERC Violation ID	Standard	Req.	VRF/VSL	Applicable Function(s)	Discovery Method* Date	Violation Start-End Date	Risk	Penalty Amount
RFC2014014541	PRC-005-1	R2; R2.1; R2.2	Medium/ Severe	GO	CA 12/16/2014	2/21/2008-10/31/2015	Serious	$100,000
RFC2014014203	PRC-005-1	R2; R2.1	Lower/ Lower	GO	CA 8/5/2014	6/14/2011-10/13/2016	Moderate	
RFC2014013615	VAR-002-2b	R2	Medium/ Severe	GOP	SR 2/26/2014	10/12/2013-10/13/2013	Minimal	
RFC2014014540	VAR-002-2b	R2	Medium/ Severe	GO, GOP	CA 12/15/2014	7/17/2013-2/15/2014	Moderate	
RFC2015014838	VAR-002-3	R2	Medium/ Severe	GOP	SR 3/30/2015	10/2/2014-12/25/2014	Moderate	
RFC2015014839	VAR-002-3	R2	Medium/ Severe	GOP	SR 3/31/2015	10/28/2014-8/5/2015	Minimal	

<u>Background to the Violations</u>

ReliabilityFirst determined to resolve the violations for BETM and the GenOn Entities[7] together, as described in the Settlement Agreement. BETM and all of the GenOn Entities are wholly-owned subsidiaries of NRG Energy, Inc. (NRG).[8] NRG has implemented its Operations and Planning compliance program at each of these subsidiaries; and its personnel have been, and will continue to be, primarily responsible for each of the subsidiaries' compliance activities, including ensuring the successful completion of mitigation efforts.

NRG acquired BETM on April 1, 2014. Prior to the acquisition, BETM was owned by Edison Mission Energy (EME) and operated as Edison Mission Marketing & Trading (EMMT).[9] On December 17, 2012, EME, EMMT's parent company, filed for Chapter 11 bankruptcy in United States Bankruptcy Court for the Northern District of Illinois. NRG's April 1, 2014 acquisition of substantially all of the assets of EME, including EMMT, was executed as part of EME's bankruptcy reorganization. Following this acquisition,

[7] "GenOn Entities" collectively refers to GenOn REMA 1 (GR1), GenOn Power Midwest (GPM), and GenOn Northeast Management Company (GNMC).
[8] NRG is a competitive power producer in the US and has a diverse fleet of approximately 150 generation assets with a total capacity of over 50,000 MW
[9] For convenience, this Notice of Penalty will refer to BETM by its current name except where referring to EMMT in historical context.

EMMT began doing business as BETM. Immediately following the April 1, 2014 closing date, NRG began efforts to integrate and transition BETM's compliance program into the NRG compliance program.

From December 3, 2010, until December 14, 2012, GR1, GPM, and GNMC were all owned by GenOn Energy, Inc., which was formed after a merger of RRI Energy, Inc. and Mirant Corporation. On December 14, 2012, GenOn Energy, Inc. and NRG merged, resulting in NRG becoming the parent company of all of the GenOn Entities.

This Notice of Penalty resolves six violations, three of which concern BETM and three of which concern the GenOn Entities. All of the violations occurred either before NRG's acquisition of BETM or prior to the date on which BETM and the GenOn Entities transitioned to the unified NRG NERC compliance program. Generally, these six violations occurred in large part due to historical weaknesses in internal controls related to Protection System maintenance and testing as well as voltage regulation.

RFC2014014541 PRC-005-1 R2; R2.1; R2.2 – OVERVIEW

ReliabilityFirst determined that BETM failed to demonstrate that it followed its Protection System maintenance and testing program for the four facilities reviewed during the Compliance Audit. In some cases, ReliabilityFirst could not verify that all of the steps listed in BETM's maintenance and testing program were being completed. In other cases, BETM had no records showing that a number of generator/Protection System devices had ever been maintained and tested.

The cause of the violation was the fact that BETM's processes and procedures failed to provide sufficient direction regarding how to perform and document these type of tests.

ReliabilityFirst determined that this violation posed a serious and substantial risk to the reliability of the bulk power system (BPS). When a GO does not follow defined procedures for maintenance and testing of Protection System devices, the reliability of the Bulk Electric System (BES) is threatened because the systems installed may not be able to perform effectively. Further, all four of the plants reviewed during the Compliance Audit are of such significant capacity (i.e., an aggregate net capacity of 4,426 MW) that the failure to have a well-defined maintenance and testing program in place poses a severe risk to the BPS. ReliabilityFirst notes that all of these instances are legacy issues, which existed prior to NRG's acquisition of BETM and have been subsequently mitigated by NRG as detailed in its Mitigation Plan.

Attachments B and C2 include a description of the mitigation activities BETM took to address the violation. A copy of the Mitigation Plan is included as Attachment C2.

BETM certified that it had completed all mitigation activities. ReliabilityFirst verified on February 26, 2016, that BETM had completed all mitigation activities on November 17, 2015. Attachment C4 provides specific information on ReliabilityFirst's verification of BETM's completion of the activities.

RFC2014014203 PRC-005-1 R2.1 – OVERVIEW

ReliabilityFirst determined that GR1 had issues with its Protection System maintenance and testing program. First, GR1 performed maintenance and testing on a generator ground relay at its Werner generating station without having a relay setting sheet pursuant to which it could verify the correct settings. Second, GR1 failed to provide evidence that it had maintained and tested direct current control circuitry that was supposed to have been performed prior to 2012 for two relays at its Gilbert generating plant.

The cause of this violation was GR1's failure to have sufficient, defined processes and procedures in place for performing and documenting the maintenance and testing of its Protection Systems.

ReliabilityFirst determined that this violation posed a moderate and not a serious or substantial risk to the reliability of the BPS. Based on the fact that only three devices had insufficient maintenance and testing evidence, these issues appear to be isolated incidents and not indicative of a programmatic issue at GR1. Further, the lack of evidence related to maintenance and testing that was performed prior to NRG's acquisition of GR1. Although only three devices were affected, the incorrect setting of one these devices could have caused significant internal damage to the generator during a fault, thereby increasing the risk of this violation to moderate.

Attachment B includes a description of the mitigation activities GR1 took to address the violation.

GR1 submitted evidence of completion to ReliabilityFirst certifying it had completed mitigating activities on October 13, 2016.

RFC2014013615 VAR-002-2b R2 – OVERVIEW

ReliabilityFirst determined GPM exceeded its upper voltage limits on three occasions in violation of VAR-002-2b R2. ReliabilityFirst determined that during a scheduled periodic review of the station output at the Brunot Island Station, Units 3 & 4 were over their upper voltage limits on three occasions in October 2013.

The cause of the violation was GPM's insufficient internal controls to prevent, detect, and correct this type of issue.

ReliabilityFirst determined that this violation posed a minimal and not a serious or substantial risk to the reliability of the BPS. Although the voltage exceedances existed for significant periods, they were minor and not likely to cause harm to equipment or the BES. Further, the units at issue are small generators (46 MW and 106 MW, respectively), which reduces the likelihood that they could have materially affected the BES.

Attachments B and E2 include a description of the mitigation activities GPM took to address the violation. A copy of the Mitigation Plan is included as Attachment E2.

GPM certified that it had completed all mitigation activities. ReliabilityFirst verified on November 2, 2016, that GPM had completed all mitigation activities on June 17, 2014. Attachments B and E4 provide specific information on ReliabilityFirst's verification of GPM's completion of the activities.

RFC2014014540 VAR-002-2b R2 – OVERVIEW

ReliabilityFirst determined that BETM was in violation of VAR-002-2b R2. ReliabilityFirst identified several instances where BETM failed to maintain the generator voltage output as directed by its Transmission Operator. Specifically, two units at BETM's Waukegan plant operated outside their voltage schedule on four occasions. The maximum departure during these times was 2 kV above the plant's upper limit. The remaining three instances were minor departures for short periods. Nevertheless, when considered together, these instances demonstrate that BETM did not have appropriate controls in place to prevent this issue.

The cause of this violation was BETM's failure to have adequate internal controls in place to prevent, detect, and correct this type of issue.

ReliabilityFirst determined that this violation posed a moderate and not a serious or substantial risk to the reliability of the BPS. Although high system voltages could result in equipment damage, that was unlikely to occur in this case based on the extent and duration of the voltage excursions. Nevertheless, the fact that one of the voltage excursions exceeded the upper limit of the voltage schedule issued by the Transmission Owner prevents this issue from being minimal risk. ReliabilityFirst notes that all of these instances are legacy issues that occurred prior to NRG's acquisition of BETM. NRG has since implemented additional internal controls to prevent, detect, and correct this type of issue in the future.

Attachments B and F2 include a description of the mitigation activities BETM took to address the violation. A copy of the Mitigation Plan is included as Attachment F2.

BETM certified that it had completed all mitigation activities. ReliabilityFirst verified on January 28, 2016, that BETM had completed all mitigation activities on April 28, 2015. Attachments B and F4 provide specific information on ReliabilityFirst's verification of BETM's completion of the activities.

RFC2015014838 VAR-002-3 R2 – OVERVIEW

ReliabilityFirst determined BETM was in violation of VAR-002-3 R2. ReliabilityFirst determined that BETM had 88 instances where various generating plants operated outside their voltage schedules. BETM's Joliet, Powerton, and Waukegan generating plants achieved voltage levels above the scheduled maximums. BETM's Waukegan generating plant also achieved a voltage level below the scheduled minimum

The cause of this violation was BETM's failure to have adequate internal controls in place to prevent, detect, and correct this type of issue.

ReliabilityFirst determined that this violation posed a moderate and not a serious and substantial risk to the reliability of the BPS. Voltage excursions could result in damage to equipment or voltage collapse. In this case, these excursions were minimal and unlikely to have such effects. Nevertheless, considering the number of excursions together with the lack of effective internal preventative, detective, and corrective controls increases the risk from minimal to moderate.

Attachments B and G2 include a description of the mitigation activities BETM took to address the violation. A copy of the Mitigation Plan is included as Attachment G2.

BETM certified on May 18, 2017, that it had completed all mitigation activities. ReliabilityFirst verified on April 12, 2017, that BETM had completed all mitigation activities on August 28, 2015. Attachments B and G4 provide specific information on ReliabilityFirst's verification of BETM's completion of the activities.

RFC2015014839 VAR-002-3 R2 – OVERVIEW

ReliabilityFirst determined GNMC was in violation of VAR-002-3 R2. ReliabilityFirst determined that GNMC's Keystone Generating Station recorded one instance when it was outside the published voltage schedule and GNMC failed to timely report the excursion. Specifically, GNMC notified its interconnected entity within 60 minutes, rather than within the required 30 minutes. During the course of mitigation, GNMC also identified an additional instance of voltage excursion which occurred during the removal of a unit for maintenance outage while at minimum load.

The cause of the violation was the fact that the station control room operators did not have a rolling 30-minute average value displayed on its control screens to monitor that level. This fact contributed to the confusion as to when the plant was in and out of schedule.

ReliabilityFirst determined that this violation posed a minimal and not a serious and substantial risk to the reliability of the BPS. The voltage excursions were minor in degree and lasted a relatively short period. Further, with respect to the first instance of noncompliance, the voltage excursion occurred while the system was in a high voltage limit condition under low load conditions. Moreover, equipment constraints at the plants prevent them from being able to lower local voltages to bring the system voltage down. Finally, with respect to the second instance of noncompliance, GNMC had already notified both the Reliability Coordinator and the Transmission Operator of the upcoming maintenance outage and the unit was expected to be removed from service momentarily, which reduces the likelihood that the voltage excursion could have had any significant effect on the BPS.

Attachments B and H2 include a description of the mitigation activities GNMC took to address the violation. A copy of the Mitigation Plan is included as Attachment H2.

GNMC certified that it had completed all mitigation activities. ReliabilityFirst verified on November 10, 2016, that GNMC had completed all mitigation activities on December 30, 2015. Attachments B and H4 provide specific information on ReliabilityFirst's verification of GNMC's completion of the activities.

Regional Entity's Basis for Disposition

According to the Settlement Agreement, ReliabilityFirst has assessed a penalty of one hundred thousand dollars ($100,000) for the referenced violations, in addition to other remedies and actions under the terms and conditions of the Settlement Agreement. In reaching this determination, ReliabilityFirst considered the following factors:

1. Three of the violations were discovered through Self-Reports, and three of the violations were discovered through Compliance Audits;
2. The Parties neither admit nor deny the violations;

3. Five of the violations constitute the Parties' first occurrence of violations of the subject NERC Reliability Standards. BETM had one prior instance of noncompliance with PRC-005-1 R2,[10] and ReliabilityFirst aggravated the penalty for this violation;
4. All of the violations occurred either before NRG's acquisition of BETM or prior to the date on which BETM and the GenOn Entities transitioned to the unified NRG NERC compliance program. ReliabilityFirst provided extenuating circumstances credit to BETM and the GenOn Entities because NRG acquired a distressed company and immediately began taking steps to mitigate identified risks;
5. There was no evidence indicating any attempt to conceal a violation or evidence of intent to do so;
6. The Parties were highly cooperative, voluntarily providing ReliabilityFirst with an abundance of information regarding the violations in a manner that was detailed, thorough, thoughtful, organized, and timely;
7. One of the violations posed a serious risk, three posed a moderate risk, and two posed a minimal risk to the reliability of the BPS, as explained above and in Attachment B;
8. There were no other mitigating or aggravating factors or extenuating circumstances that would affect the disposition method.

After consideration of the above factors, ReliabilityFirst determined that, in these instances, the penalty amount of one hundred thousand dollars ($100,000), in addition to other remedies and actions under the terms and conditions of the Settlement Agreement, is appropriate and bears a reasonable relation to the seriousness and duration of the violations.

Statement Describing the Assessed Penalty, Sanction or Enforcement Action Imposed[11]

Basis for Determination

Taking into consideration the Commission's direction in Order No. 693, the NERC Sanction Guidelines and the Commission's July 3, 2008, October 26, 2009, and August 27, 2010 Guidance Orders,[12] the

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[10] Violation ID RFC201000443.

[11] *See* 18 C.F.R. § 39.7(d)(4).

[12] *North American Electric Reliability Corporation*, "Guidance Order on Reliability Notices of Penalty," 124 FERC ¶ 61,015 (2008); *North American Electric Reliability Corporation*, "Further Guidance Order on Reliability Notices of Penalty," 129 FERC ¶ 61,069 (2009); *North American Electric Reliability Corporation*, "Notice of No Further Review and Guidance Order," 132 FERC ¶ 61,182 (2010).

NERC BOTCC reviewed the Settlement Agreement and supporting documentation on September 14, 2017, and approved the Settlement Agreement. In approving the Settlement Agreement, the NERC BOTCC reviewed the applicable requirements of the Commission-approved Reliability Standards and the underlying facts and circumstances of the violations at issue.

For the foregoing reasons, the NERC BOTCC approved the Settlement Agreement and believes that the assessed penalty of one hundred thousand dollars ($100,000), in addition to other remedies and actions under the terms and conditions of the Settlement Agreement, is appropriate for the violations and circumstances at issue, and is consistent with NERC's goal to promote and ensure reliability of the BPS.

Pursuant to 18 C.F.R. § 39.7(e), the penalty will be effective upon expiration of the 30-day period following the filing of this Notice of Penalty with FERC, or, if FERC decides to review the penalty, upon final determination by FERC.

Attachments to be Included as Part of this Notice of Penalty

The attachments to be included as part of this Notice of Penalty are the following documents:

a) Settlement Agreement by and between ReliabilityFirst and the Parties, included as Attachment A;

b) Overview Documents for all violations, included as Attachment B;

c) Disposition Documents for RFC2014014541 (PRC-005-1 R2; R2.1; R2.2), included as Attachment C;

    1. Notice of Possible Violation, submitted on November 11, 2014;
    2. Mitigation Plan RFCMIT011655, submitted on June 17, 2015;
    3. Certification of the Mitigation Plan Completion, dated February 1, 2016;
    4. Mitigation Plan Verification for RFCMIT011655, dated February 26, 2016;

d) Disposition Document for RFC2014014203 (PRC-005-1 R2; R2.1), included as Attachment D:

    1. Notice of Possible Violation, submitted on August 5, 2014;

e) Disposition Documents for RFC2014013615 (VAR-002-2b R2), included as Attachment E:

    1. GenOn Power Midwest's Self-Report, submitted on February 26, 2014;
    2. Mitigation Plan RFCMIT010534, submitted on March 14, 2014;

3. Certification of the Mitigation Plan Completion, dated August 5, 2014;
4. Mitigation Plan Verification for RFCMIT010534, dated November 2, 2016;

f) Disposition Documents for RFC2014014540 (VAR-002-2b R2), included as Attachment F:

1. Notice of Possible Violation, submitted on November 19, 2014;
2. Mitigation Plan RFCMIT011610-1, submitted on July 20, 2015;
3. Certification of the Mitigation Plan Completion, dated July 21, 2015;
4. Mitigation Plan Verification for RFCMIT011610-1, dated January 28, 2016;

g) Disposition Documents for RFC2015014838 (VAR-002-3 R2), included as Attachment G:

1. Boston Energy Trading and Marketing LLC's Self-Report, submitted on March 30, 2015;
2. Mitigation Plan RFCMIT011873, submitted on December 11, 2015;
3. Certification of the Mitigation Plan Completion, dated December 11, 2015;
4. Mitigation Plan Verification for RFCMIT011873, dated January 28, 2016;

h) Disposition Documents for RFC2015014839 (VAR-002-3 R2), included as Attachment H:

1. GenOn Northeast Management Company's Self-Report, submitted on March 31, 2015;
2. Mitigation Plan RFCMIT011668-2, submitted on June 3, 2016;
3. Certification of the Mitigation Plan Completion, dated June 7, 2016; and
4. Mitigation Plan Verification for RFCMIT011668-2, dated November 10, 2016.

Notices and Communications: Notices and communications with respect to this filing may be addressed to the following:

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Patrick O'Connor* Counsel ReliabilityFirst Corporation 3 Summit Park Drive, Suite 600 Cleveland, OH 44131 216-503-0668 Phone 216-503-9207 Facsimile patrick.oconnor@rfirst.org Patricia Lynch* Director, Regulatory Compliance Boston Energy Trading and Marketing LLC GenOn REMA 1 GenOn Power Midwest GenOn Northeast Management Company 804 Carnegie Center Princeton, NJ 08540 patricia.lynch@nrg.com Martin Sidor* Director, Regulatory Compliance Boston Energy Trading and Marketing LLC GenOn REMA 1 GenOn Power Midwest GenOn Northeast Management Company 804 Carnegie Center Princeton, NJ 08540 martin.sidor@nrg.com Alan Johnson* Managing Director, Regulatory Compliance Boston Energy Trading and Marketing LLC 804 Carnegie Center Princeton, NJ 08540 Alan.Johnson@nrg.com	Kara Douglas* Sr. Manager, Regulatory Compliance Boston Energy Trading and Marketing LLC 804 Carnegie Center Princeton, NJ 08540 kara.douglas@nrg.com

Conclusion

NERC respectfully requests that the Commission accept this Notice of Penalty as compliant with its rules, regulations, and orders.

Respectfully submitted,

/s/ Edwin G. Kichline
Sonia C. Mendonça
Vice President, Deputy General Counsel, and Director of Enforcement
Edwin G. Kichline
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cc: Boston Energy Trading and Marketing LLC, GenOn REMA 1, GenOn Power Midwest, and GenOn Northeast Management Company
ReliabilityFirst Corporation

Attachments

Attachment A

Settlement Agreement by and between ReliabilityFirst and the Parties

In re: **BOSTON ENERGY TRADING AND MARKETING LLC**

and

GENON REMA 1

and

GENON POWER MIDWEST

and

GENON NORTHEAST MANAGEMENT COMPANY

NERC Registry ID Nos.:
NCR00769
NCR11141
NCR11136
NCR11137

Violation ID Nos.:

RFC2014014541 (PRC-005-1 R2, R2.1, R2.2)
RFC2014014203 (PRC-005-1 R2, R2.1)
RFC2014013615 (VAR-002-2b R2)
RFC2014014540 (VAR-002-2b R2)
RFC2015014838 (VAR-002-3 R2)
RFC2015014839 (VAR-002-3 R2)

SETTLEMENT AGREEMENT AMONG RELIABILITYFIRST CORPORATION AND BOSTON ENERGY TRADING AND MARKETING LLC, GENON REMA 1, GENON POWER MIDWEST, AND GENON NORTHEAST MANAGEMENT COMPANY

I. INTRODUCTION

1. ReliabilityFirst Corporation ("ReliabilityFirst"), Boston Energy Trading and Marketing ("BETM"), GenOn REMA 1, GenOn Power Midwest, and GenOn Northeast Management Company (collectively, the "Parties") enter into this Settlement Agreement ("Agreement") to resolve Alleged Violations by BETM

and the GenOn Entities[1] of the above-captioned Reliability Standard Requirements.[2]

2. The Parties stipulate to the facts in this Agreement for the sole purpose of resolving the Alleged Violations. BETM and the GenOn Entities neither admit nor deny that these facts constitute Alleged Violations of the above-captioned Reliability Standard Requirements.

II. OVERVIEW OF BETM AND THE GENON ENTITIES

A. BACKGROUND

3. ReliabilityFirst is resolving the Alleged Violations for BETM and the GenOn Entities together in this Agreement. BETM and all of the GenOn Entities are wholly-owned subsidiaries of NRG Energy, Inc. ("NRG").[3] NRG has implemented its Operations and Planning ("693") compliance program at each of these subsidiaries; and its personnel have been, and will continue to be, primarily responsible for each of the subsidiaries' compliance activities, including ensuring the successful completion of mitigation efforts.

B. RELEVANT HISTORY OF BETM

4. As referenced above, BETM is a wholly-owned subsidiary of NRG [4]specializing in proprietary trading and the provision of energy management services. BETM provided asset management services to EME subsidiary Midwest Generation (MWG).[5] BETM is registered on the NERC Compliance Registry (NCR00769) as a Generator Owner ("GO") and Generator Operator ("GOP"), and fulfilled these functions for the MWG assets. In its capacity as a GO and GOP, the BETM registration is subject to compliance with Reliability Standards PRC-005 and VAR-002.

5. NRG acquired BETM on April 1, 2014. Prior to the acquisition, BETM was owned by Edison Mission Energy ("EME") and operated as Edison Mission

[1] GenOn Entities collectively refers to GenOn REMA 1 ("GR1"), GenOn Power Midwest ("GPM"), and GenOn Northeast Management Company ("GNMC").

[2] This Agreement references the version of the Reliability Standard in effect at the time each Alleged Violation began. BETM and the GenOn Entities, however, committed to perform mitigating actions to comply with the most recent version of each Reliability Standard Requirement.

[3] NRG is a competitive power producer in the US and has a diverse fleet of approximately 150 generation assets with a total capacity of over 50,000 MW.

[4] NRG Energy Gas & Wind Holdings, Inc. ("NRG Energy Gas & Wind"), a Delaware corporation, directly owns 100% of the equity interests in BETM. NRG Acquisition Holdings, Inc. ("NRG Acquisition"), a Delaware corporation, directly owns 100% of the equity interest in NRG Energy Gas & Wind. NRG Acquisition is 100% owned by NRG Energy, Inc.

[5] MWG operated the generation assets associated with the BETM Alleged Violations and is now known as Midwest Generation, LLC.

Marketing & Trading ("EMMT").[6] On December, 17, 2012, EME, EMMT's parent company, filed for Chapter 11 bankruptcy in United States Bankruptcy Court for the Northern District of Illinois.

6. NRG's April 1, 2014 acquisition of substantially all of the assets of EME, including EMMT, was executed as part of EME's bankruptcy reorganization. Following this acquisition, EMMT began doing business as BETM. Immediately following the April 1, 2014 closing date, NRG began efforts to integrate and transition BETM's compliance program into the NRG compliance program. As part of the transition, the asset management services provided by BETM to the MWG assets were transitioned to NRG Power Marketing LLC, which assumed BETM's GO/GOP responsibilities under NCR00769.

C. RELEVANT HISTORY OF THE GENON ENTITIES

7. From December 3, 2010, until December 14, 2012, GR1, GPM, and GNMC were all owned by GenOn Energy, Inc., which was formed after a merger of RRI Energy, Inc. and Mirant Corporation. On December 14, 2012, GenOn Energy, Inc. and NRG merged, resulting in NRG becoming the parent company of all of the GenOn Entities.

8. GR1 is registered on the NERC Compliance Registry as a GO and GOP. GR1 is located in New Jersey and consists of the Gilbert Generating Station (288 MW) and the Sayreville Generating Station (224 MW). In its capacity as a GO and GOP, GR1 is subject to compliance with Reliability Standard PRC-005.

9. GPM is registered on the NERC Compliance Registry as a GO and GOP. GPM is located in Ohio and Pennsylvania and consists of the Avon Lake, Brunot Island, Cheswick, New Castle and the Niles Generating Facilities that have a combined generating capacity of 2569 MW and have interconnections with Duquesne Light Company and First Energy at various voltage levels. In its capacity as a GO and GOP, GPM is subject to compliance with Reliability Standard VAR-002.

10. GNMC is registered on the NERC Compliance Registry as a GO and GOP. GNMC is located in southwestern Pennsylvania and consists of the Keystone and Conemaugh generating stations, which have a combined generating capacity of 4,180 MW and have interconnections with FirstEnergy at various voltage levels. In its capacity as a GO and GOP, GNMC is subject to compliance with Reliability Standard VAR-002.

III. EXECUTIVE SUMMARY

Overview of Alleged Violations

11. This Agreement resolves 6 Alleged Violations of the Operations and Planning

[6] For convenience, this Agreement will refer to BETM by its current name except where referring to EMMT in historical context.

("693") Reliability Standards, 3 of which concern BETM and 3 of which concern the GenOn Entities. Two of the BETM issues were discovered at audit and one was self-reported. One of the GenOn Entities' issues was found at audit and two were self-reported. Because, as stated above, BETM and the GenOn Entities are all subsidiaries of NRG and have transitioned to one unified NRG 693 Compliance Program, all 6 of these Alleged Violations are being resolved together.

12. Of the three BETM Alleged Violations, one posed a serious risk and two posed a moderate risk to the reliability of the Bulk Electric System ("BES"). Of the three GenOn Alleged Violations, one posed a moderate risk, and two posed a minimal risk to the reliability of the BES. ReliabilityFirst discovered three of the Alleged Violations during compliance audits and the remaining three Alleged Violations were self-reported to ReliabilityFirst.

13. Generally, these 6 Alleged Violations occurred in large part due to historical weaknesses in internal controls related to protection system maintenance and testing as well as voltage regulation under GenOn's legacy NERC Compliance program. As described below, NRG has committed to comprehensive mitigation plans, which are expected to correct these historical issues.

Overview of Mitigation

14. BETM and the GenOn Entities have committed to comprehensive mitigation plans designed to effectively transition all entities to NRG's unified NERC Compliance Program. As stated above, these 6 Alleged Violations were the result of historical weaknesses in legacy internal controls related to protection system maintenance and testing as well as voltage regulation. In short, BETM and the GenOn Entities have committed to take the following steps to improve their preventative, detective, and corrective controls: (a) improve their fleet-wide protection system maintenance and testing program and associated documentation; and, (b) improve their voltage monitoring and alarming tools.

15. ReliabilityFirst noted that these Alleged Violations are attributable to historical weaknesses in certain key management practices (groupings of common, functional activities that Registered Entities perform to ensure reliability, security, and resiliency) which contributed to these Alleged Violations. Specifically, ReliabilityFirst determined that the Alleged Violations demonstrated historical weaknesses in grid maintenance[7] and grid operations.[8]

[7] Grid maintenance is a management practice that ensures equipment reliability and resilience by proactively monitoring equipment and resolving issues as they arise in a thorough and timely manner.

[8] Grid operations is a management practice that establishes thorough, repeatable and systematic processes to safely and reliably operate the grid.

Overview of Penalty and Sanction

16. ReliabilityFirst commends BETM and the GenOn Entities for their comprehensive response to the Alleged Violations. However, ReliabilityFirst recognizes that a monetary penalty is warranted due to the serious nature of and risk posed by one of the Alleged Violations.

17. ReliabilityFirst also recognizes that the monetary penalty imposed in this Agreement must take into account the unique facts and circumstances surrounding these Alleged Violations. Specifically, ReliabilityFirst highlights the fact that all of the Alleged Violations occurred either before NRG's acquisition of BETM or prior to the date on which BETM and the GenOn Entities transitioned to the unified NRG NERC Compliance Program.

IV. RISK HARM ASSESSMENT

18. ReliabilityFirst considered the risk and harm posed by the Alleged Violations to the reliability of the BES. As a result, ReliabilityFirst determined that one Alleged Violation posed a serious risk, three Alleged Violations posed a moderate risk, and two Alleged Violations posed a minimal risk to the reliability of the BES. The factual basis for each of these determinations is discussed in detail in **Attachment A**.

V. ALLEGED VIOLATIONS

19. The Alleged Violations resolved by this Agreement are fully described in **Attachment A**, which is incorporated herein by reference.

VI. ADJUSTMENT FACTORS

20. In addition to the facts and circumstances stated above, ReliabilityFirst considered the following factors in its penalty determination.

Self-Disclosure

21. Effective oversight of the reliability of the BES depends on robust and timely self-reporting by Registered Entities. ReliabilityFirst considered that three of the Alleged Violations were discovered through Self-Reports and applied some mitigating credit.

Cooperation

22. BETM and the GenOn Entities have been highly cooperative throughout the entire enforcement process. Throughout the enforcement process, BETM and the GenOn Entities have voluntarily provided ReliabilityFirst with an abundance of information regarding the Alleged Violations in a manner that was detailed, thorough, thoughtful, organized, and timely. BETM and the GenOn Entities have been open with ReliabilityFirst regarding their Alleged Violations, processes,

systems, and organization and this insight has allowed ReliabilityFirst to better analyze the Alleged Violations and assist BETM and the GenOn Entities with resolving the same. To encourage this sort of response by BETM and the GenOn Entities, and other Registered Entities, in the future, ReliabilityFirst awarded some mitigating credit.

Culture of Compliance

23. When assessing the penalty for the Alleged Violations at issue in this Agreement, ReliabilityFirst considered the presence and operation of a quality compliance program as well as other indicators of a culture of compliance at BETM and the GenOn Entities. This culture was evidenced by the fact that NRG developed and implemented a comprehensive NERC Compliance Program transition policy and plan that allowed it to incorporate three separate, legacy NERC compliance programs into one comprehensive, unified program.

Compliance History

24. When assessing the penalty for the Alleged Violations at issue in this Agreement, ReliabilityFirst considered whether the facts of these Alleged Violations constitute repetitive infractions. BETM has a history of Alleged Violations for PRC-005 R2.[9] This is the GenOn Entities' first violation of PRC-005 R2 and VAR-002 R2. In accordance with the Federal Energy Regulatory Commission's ("Commission") directive that NERC and ReliabilityFirst consider a violator's corporate affiliates when assessing repeat violations and because these Alleged Violations involved the same Reliability Standards and Requirements and arguably similar conduct as the violations resolved within this Agreement, ReliabilityFirst considered the repetitive infractions as an aggravating factor for penalty purposes.

VII. PENALTY AND SANCTION

25. Based upon the foregoing, BETM shall pay a monetary penalty of $100,000 to ReliabilityFirst.

26. ReliabilityFirst shall present an invoice to BETM within 20 days after the Agreement is approved by the Commission or affirmed by operation of law. Upon receipt, BETM shall have 30 days to remit payment. ReliabilityFirst will notify NERC if it does not timely receive the payment from BETM.

27. If BETM fails to timely remit the monetary penalty payment to ReliabilityFirst, interest will commence to accrue on the outstanding balance, pursuant to 18 C.F.R. § 35.19a (a)(2)(iii), on the earlier of (a) the 31st day after the date on the invoice issued by ReliabilityFirst to BETM for the monetary penalty payment or (b) the 51st day after the Agreement is approved by the Commission or operation

[9] RFC201000443.

of law.

VIII. ADDITIONAL TERMS

28. The Parties agree that this Agreement is in the best interest of BES reliability. The terms and conditions of the Agreement are consistent with the regulations and orders of the Commission and the NERC Rules of Procedure.

29. ReliabilityFirst shall report the terms of all settlements of compliance matters to NERC. NERC will review the Agreement for the purpose of evaluating its consistency with other settlements entered into for similar violations or under similar circumstances. Based on this review, NERC will either approve or reject this Agreement. If NERC rejects the Agreement, NERC will provide specific written reasons for such rejection and ReliabilityFirst will attempt to negotiate with BETM and the GenOn Entities a revised settlement agreement that addresses NERC's concerns. If a settlement cannot be reached, the enforcement process will continue to conclusion. If NERC approves the Agreement, NERC will (a) report the approved settlement to the Commission for review and approval by order or operation of law and (b) publicly post the Alleged Violations and the terms provided for in this Agreement.

30. This Agreement binds the Parties upon execution, and may only be altered or amended by written agreement executed by the Parties. BETM and the GenOn Entities expressly waive their right to any hearing or appeal concerning any matter set forth herein, unless and only to the extent that BETM or the GenOn Entities contend that any NERC or Commission action constitutes a material modification to this Agreement.

31. ReliabilityFirst reserves all rights to initiate enforcement action against BETM and the GenOn Entities in accordance with the NERC Rules of Procedure in the event that they fail to comply with any of the terms or conditions of this Agreement. BETM and the GenOn Entities retain all rights to defend against such action in accordance with the NERC Rules of Procedure.

32. BETM and the GenOn Entities consent to ReliabilityFirst's future use of this Agreement for the purpose of assessing the factors within the NERC Sanction Guidelines and applicable Commission orders and policy statements, including, but not limited to, the factor evaluating BETM's and the GenOn Entities' history of violations. Such use may be in any enforcement action or compliance proceeding undertaken by NERC or any Regional Entity or both, provided however that BETM and the GenOn Entities do not consent to the use of the conclusions, determinations, and findings set forth in this Agreement as the sole basis for any other action or proceeding brought by NERC or any Regional Entity or both, nor do BETM or the GenOn Entities consent to the use of this Agreement by any other party in any other action or proceeding.

33. BETM and the GenOn Entities affirm that all of the matters set forth in this Agreement are true and correct to the best of their knowledge, information, and belief, and that they understands that ReliabilityFirst enters into this Agreement in express reliance on the representations contained herein, as well as any other representations or information provided by BETM and the GenOn Entities to ReliabilityFirst during any interaction with ReliabilityFirst relating to the subject matter of this Agreement.

34. Upon execution of this Agreement, the Parties stipulate that each Possible Violation addressed herein constitutes an Alleged Violation. The Parties further stipulate that all required, applicable information listed in Section 5.3 of the CMEP is included within this Agreement.

35. Each of the undersigned agreeing to and accepting this Agreement warrants that he or she is an authorized representative of the party designated below, is authorized to bind such party, and accepts the Agreement on the party's behalf.

36. The undersigned agreeing to and accepting this Agreement warrant that they enter into this Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer, or promise of any kind by any member, employee, officer, director, agent, or representative of the Parties has been made to induce the signatories or any other party to enter into this Agreement.

37. The Agreement may be signed in counterparts.

38. This Agreement is executed in duplicate, each of which so executed shall be deemed to be an original.

[SIGNATURE PAGE TO FOLLOW][10]

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[10] An electronic version of this executed document shall have the same force and effect as the original.

ENDORSED BY:

______________________ 2/3/17

Jason Blake
Vice President and General Counsel
ReliabilityFirst Corporation

Date

AGREED TO AND ACCEPTED BY:

Boston Energy Trading & Marketing LLC:

Reem Fahey 6/9/17

Reem Fahey
SVP -Marketing & Trading
Boston Energy Trading and Marketing

Date

GenOn REMA 1:

______________________ 6/6/17

Judith Lagano
VICE President
NRG REMA LLC

Date

GenOn Power Midwest:

______________________ 6/6/17

Judith Lagano
VICE President
NRG Power Midwest GP LLC, as General Partner of NRG Power Midwest LP

Date

Gen On Northeast Management Company: ______________________ 6/9/17

James V. Locher
President
GenOn Northeast Management Company

Date

ReliabilityFirst Corporation

______________________ 2/3/17

Timothy R. Gallagher
President & Chief Executive Officer
ReliabilityFirst Corporation

Date

Attachment B

Overview Documents For All Violations

I. OVERVIEW OF ALLEGED VIOLATIONS

39. The Parties enter into this Agreement to resolve Alleged Violations by BETM and the GenOn Entities of the following Reliability Standards and Requirements:

BETM Alleged Violations	
Reliability Standard and Requirement	**Violation ID No.**
PRC-005-1 R2, R2.1, R2.2	RFC2014014541
VAR-002-2b R2	RFC2014014540
VAR-002-3 R2	RFC2015014838

GenOn Entities Alleged Violations	
Reliability Standard and Requirement	**Violation ID No. and Registered Entity**
PRC-005-1 R2	RFC2014014203 (GR1)
VAR-002-2b R2	RFC2014013615 (GPM)
VAR-002-3 R2	RFC2015014839 (GNMC)

II. ALLEGED VIOLATIONS FOR BETM

A. PRC-005-1 R2, R2.1, R2.2 (RFC2014014541)

40. PRC-005 increases the reliability of the Bulk-Power System by ensuring the maintenance and testing of all transmission and generation Protection Systems, which isolate segments of the Bulk Electric System ("BES") when faults occur.

41. A violation of PRC-005 has the potential to affect the reliable operation of the BES by allowing important Protection System devices to remain unmaintained and untested.

42. PRC-005-1 R2 states:

> **R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each [GO] that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
>
> **R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
>
> **R2.2**. Date each Protection System device was last tested/maintained.

Description of Alleged Violation and Risk Assessment

43. On December 16, 2014, ReliabilityFirst determined that BETM, as a GO, was in violation of PRC-005-1 R2, R2.1, and R2.2 as a result of a Compliance Audit conducted from November 10, 2014 through November 18, 2014. *See* PV Identification Form, **Attachment 1**. During the audit, BETM was unable to demonstrate that it followed its System Protection maintenance and testing program for all of its facilities.[11] In some cases, ReliabilityFirst could not verify that all of the steps listed in BETM's maintenance and testing program were being completed. In other cases, BETM had no records showing that a number of generator/system protection devices had ever been maintained and tested.

44. The major factor contributing to the cause of this violation was the fact that BETM's processes and procedures failed to provide sufficient direction regarding how to perform and document these type of tests. This major contributing factor implicates the management practice of grid maintenance, which focuses on defining reliability centered maintenance procedures.

45. The Alleged Violation began on February 21, 2008, the date BETM was required to comply with PRC-005-1 R2 and ended on October 31, 2015, the date BETM completed its Mitigation Plan.

46. ReliabilityFirst determined that the Alleged Violation posed a serious risk to the reliability of the BES based on the following factors.[12] First, when a GO does not follow defined procedures for maintenance and testing of System Protection devices, the reliability of the BES is threatened because the systems installed may not be able to perform effectively. Second, all four of these plants are of such significant capacity (i.e., an aggregate net capacity of 4,426MW) that the failure to have a well-defined maintenance and testing program in place poses a severe risk to the BES. ReliabilityFirst notes that all of these instances are legacy issues, which existed prior to NRG's acquisition of BETM and have been subsequently mitigated by NRG as detailed in its mitigation plan.

Mitigating Actions

47. On June 17, 2015, BETM submitted to ReliabilityFirst a Mitigation Plan to address the Alleged Violation of PRC-005-1 R2. *See* RFCMIT011655, **Attachment 2**. On July 1, 2015, ReliabilityFirst accepted the Mitigation Plan.

48. In the Mitigation Plan, BETM committed to take the following actions by October 31, 2015: (1) BETM will create documentation for trip checks and CT/PT testing based upon NRG fleet-wide templates for all NERC related protection schemes at

[11] RF reviewed evidence related to the following four plants: (1) Powerton (1,538MW); (2) Joliet (1,326MW); (3) Waukegan (801MW); and, (4) Will County (761MW). The insufficiencies in BETM's maintenance and testing program were present at each of these four plants.

[12] PRC-005-1 R2, R2.1 and R2.2 has a VRF of "Medium." ReliabilityFirst determined that this Alleged Violation warranted a "Severe" VSL.

the Joliet, Powerton, Waukegan and Will County Generating Stations and (2) BETM will perform testing detailed in the test plans.

49. On February 1, 2016, BETM certified to ReliabilityFirst that it completed this Mitigation Plan as of November 17, 2015. *See* Certification of Mitigation Plan Completion, **Attachment 3**. On February 26, 2016, ReliabilityFirst verified BETM's completion of this Mitigation Plan. *See* Mitigation Plan Verification for RFCMIT011655, **Attachment 4**.

B. VAR-002-2b R2 and VAR-002-3 R2 (RFC2014014540 and RFC2015014838)

50. VAR-002 ensures that generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources within applicable Facility Ratings in order to protect equipment and the reliable operation of the Interconnection.

51. A violation of VAR-002 has the potential to affect the reliable operation of the BES by allowing generator voltage or reactive power output at levels detrimental to the bulk power system's voltage or reactive power level.

52. VAR-002 R2 states:

> **R2.** Unless exempted by the Transmission Operator, each [GOP] shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.
>
> > **R2.1.** When a generator's AVR is out of service or the generator does not have an AVR, the [GOP] shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.
> >
> > **R2.2.** When instructed to modify voltage, the [GOP] shall comply or provide an explanation of why the schedule cannot be met.
> >
> > **R2.3.** Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the [GOP].

Description of Alleged Violation and Risk Assessment for RFC2014014540

53. On December 15, 2014, ReliabilityFirst determined that BETM, as a GO and GOP, had an issue of VAR-002-2b R2 as a result of a Compliance Audit conducted from November 10, 2014 through November 18, 2014. *See* PV Identification Form, **Attachment 5**. The evidence reviewed by ReliabilityFirst

during the audit identified several instances where BETM failed to maintain the generator voltage output as directed by its Transmission Operator, Commonwealth Edison. Specifically, two units at BETM's Waukegan plant operated outside their voltage schedule on four occasions, the most significant of which occurred on July 17, 2013, when unit 7 operated outside its voltage schedule from 3:12 – 9:04 am and again from 1:02 – 6:59 pm. The maximum departure during these times was 2kV above its upper limit. The remaining three instances were minor departures for very short periods of time, but when considered together, demonstrate that BETM did not have appropriate controls in place to prevent this issue.

54. The major factor contributing to the cause of this violation was BETM's failure to have adequate internal controls in place to prevent, detect, and correct this type of issue. This major contributing factor implicates the management practice of grid operations, which includes defining operating procedures and performing incident management and control.

55. The duration of this Alleged Violation is from July 17, 2013, the date BETM was required to comply with VAR-002-2b R2, to February 15, 2014, the date the last voltage excursion ended.

56. ReliabilityFirst determined that the Alleged Violation posed a moderate risk to the reliability of the BES based on the following factors.[13] Although high system voltages could result in equipment damage, that was unlikely to occur in this case based on the extent and duration of the voltage excursion. However, the fact that one of the voltage excursions exceeded the upper limit of the voltage schedule issued by the Transmission Owner and the duration of this excursion prevents this issue from being minimal risk. ReliabilityFirst notes that all of these instances are legacy issues which occurred prior to NRG's acquisition of BETM. NRG has since implemented additional internal controls to prevent, detect, and correct this type of issue in the future.

Mitigating Actions for RFC2014014540

57. On July 20, 2015, BETM submitted to ReliabilityFirst a Mitigation Plan to address the Alleged Violation of VAR-002-2b R2. *See* RFCMIT011610-1, **Attachment 6**. On July 31, 2015, ReliabilityFirst accepted the Mitigation Plan.

58. In the Mitigation Plan, BETM committed to take the following actions by April 30, 2015. First, BETM created a station specific document for response to voltage excursion. Second, BETM created a control room alarm for excursions. Third, BETM created a more user friendly method for operations personnel to monitor real time voltages. Fourth, BETM created a second alarm at the Commercial Operations Desk that will initiate twenty minutes after the first alarm is received of a unit being outside its voltage schedule. Fifth, BETM retained

[13] VAR-002-2b R2 has a VRF of "Medium" ReliabilityFirst determined that this Alleged Violation warranted a "Severe" VSL.

signed records of operator training on site and made rosters available upon request. Sixth, BETM created and delivered training to control room operators on logging and communication protocol, switchyard voltage limits, and voltage regulator trip to manual.

59. On July 20, 2015, BETM certified to ReliabilityFirst that it completed this Mitigation Plan as of April 28, 2015. *See* Certification of Mitigation Plan Completion, **Attachment 7**. On January 28, 2016, ReliabilityFirst verified BETM's completion of this Mitigation Plan. *See* Mitigation Plan Verification for RFCMIT011610-1, **Attachment 8**.

Description of Alleged Violation and Risk Assessment for RFC2015014838

60. On March 30, 2015, BETM submitted a Self-Report to ReliabilityFirst stating that, as a GOP, it was in violation of VAR-002-3 R2. *See*, Self-Report, **Attachment 9**. While reviewing evidence for an upcoming Self-Certification, BETM discovered 88 instances over the course of the last quarter of 2014 where various generating plants operated outside their voltage schedules. For the Joliet generating plant, the highest voltage level achieved was .27% above the scheduled maximum. For the Powerton generating plant, the highest voltage level achieved was .14% above the scheduled maximum. For the Waukegan generating plant, the lowest level achieved was 1.7% below the scheduled minimum and the highest level achieved was .46% above the scheduled maximum.

61. The major factor contributing to the cause of this violation was BETM's failure to have adequate internal controls in place to prevent, detect, and correct this type of issue. This major contributing factor implicates the management practice of grid operations, which includes defining operating procedures and performing incident management and control.

62. The duration of this Alleged Violation is from October 2, 2014, the date of the first voltage excursion, to December 25, 2014, the date the last voltage excursion ended. ReliabilityFirst also notes that although these voltage excursions occurred after NRG's acquisition of BETM, they still occurred before NRG completed the transition to its unified compliance program. At the end of 2014, NRG completed this transition and implemented additional internal controls to prevent, detect, and correct this type of issue in the future.

63. ReliabilityFirst determined that the Alleged Violation posed a moderate risk to the reliability of the BES based on the following factors.[14] Voltage excursions could result in damage to equipment or voltage collapse. In this case, these excursions were minimal and unlikely to have such effects. However, considering the number of excursions together with the lack of effective internal preventative, detective, and corrective controls increases the risk from minimal to moderate.

[14] VAR-002-3 R2 has a VRF of "Medium." ReliabilityFirst determined that this Alleged Violation warranted a "Severe" VSL.

Mitigating Actions for RFC2015014838

64. On December 11, 2015, BETM submitted to ReliabilityFirst a Mitigation Plan to address the Alleged Violation of VAR-002-3 R2. *See* RFCMIT011873, **Attachment 10**. On January 5, 2016, ReliabilityFirst accepted the Mitigation Plan.

65. In the Mitigation Plan, BETM committed to take the following actions by August 31, 2015. First, BETM created a second alarm at the Commercial Operations Desk that will initiate twenty minutes after the first alarm is received of a unit being outside its voltage schedule should the unit not be able to get within schedule. Second, BETM retained signed records of operator training on site and made rosters available upon request. Third, BETM provided additional training to the Control Room Operators as it relates to Switchyard Voltage Limits and had operators sign an acknowledgement. Fourth, BETM developed, implemented and trained station personnel on station specific response procedures to voltage excursions outside of the Voltage Schedule. Fifth, BETM incorporated a new step into the Unit Operating Procedures to monitor output voltage when placing a unit on-line. Sixth, BETM created a control room alarm to alert station operators that voltage is approaching a high or low limit. Seventh, BETM provided additional training to the Control Room Operators as it relates to Voltage Regulator Trip to Manual Incidents and had operators sign document for acknowledgment. Eighth, BETM created and delivered additional training to the Control Room Operators as it relates to Logging and communication Protocol and had operators sign document for acknowledgment. Ninth, BETM created a more user friendly method for operations personnel to monitor real time voltages. Lastly, BETM provided additional training to the Control Room Operators as it relates to NERC Standard VAR-002.

66. On December 11, 2015, BETM certified to ReliabilityFirst that it completed this Mitigation Plan as of August 28, 2015. *See* Certification of Mitigation Plan Completion, **Attachment 11**. On January 28, 2016, ReliabilityFirst verified BETM's completion of this Mitigation Plan. *See* Mitigation Plan Verification for RFCMIT011873, **Attachment 12**.

III. ALLEGED VIOLATIONS FOR GENON ENTITIES

A. PRC-005-1 R2, R2.1 (RFC2014014203)

67. PRC-005 increases the reliability of the Bulk-Power System by ensuring the maintenance and testing of all transmission and generation Protection Systems, which isolate segments of the BES when faults occur.

68. A violation of PRC-005 has the potential to affect the reliable operation of the BES by allowing important Protection System devices to remain unmaintained and untested.

69. PRC-005-1 R2 states:

> **R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each [GO] that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
>
> **R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
>
> **R2.2**. Date each Protection System device was last tested/maintained.

Description of Alleged Violation and Risk Assessment

70. On August 5, 2014, ReliabilityFirst determined that GR1, as a GO, had an issue of PRC-005-1 R2 and R2.1, as a result of a Compliance Audit conducted from July 14, 2014 through July 24, 2014. *See* PV Identification Form, **Attachment 13**. ReliabilityFirst identified various issues with GR1's Protection System maintenance and testing program. First, GR1 performed maintenance and testing on a generator ground relay at the Werner generating station on October 20, 2009, without having a relay setting sheet pursuant to which it could verify the correct settings. Second, GR1 failed to provide evidence that it had maintained and tested DC control circuitry that was supposed to have been performed prior to 2012 for 2 relays at the Gilbert generating plant.

71. The major factor contributing to the cause of this violation was GR1's failure to have sufficient, defined processes and procedures in place for performing and documenting the maintenance and testing of its Protection Systems. This major contributing factor implicates the management practice of grid maintenance, which focuses on defining reliability centered maintenance procedures.

72. The Alleged Violation began on June 14, 2011, the date GR1 was required to comply with PRC-005-1 R2. The Alleged Violation is scheduled to end by December 31, 2016, the date GR1 committed to complete its mitigating activities. The mitigating activities were completed by or on October 13, 2016.

73. ReliabilityFirst determined that the Alleged Violation posed a moderate risk to the reliability of the BES based on the following factors.[15] First, based on the fact that only 3 devices had insufficient maintenance and testing evidence, these issues appear to be isolated incidents and not indicative of a programmatic issue at GR1. Second, the lack of evidence related to maintenance and testing was performed prior to NRG's acquisition of GR1. In this case, although only 3 devices were affected, considering that an incorrect setting of one these devices could have

[15] PRC-005-1 R2 and R2.1 has a VRF of "Lower." ReliabilityFirst determined that this Alleged Violation warranted a "Lower" VSL.

caused significant internal damage to the generator during a fault increases the risk to moderate. As part of its mitigation, GR1 has transitioned to a unified compliance program including a fleet-wide maintenance and testing program.

Mitigating Actions

74. On October 3, 2014, GR1 submitted to ReliabilityFirst mitigating activities to address the Alleged Violation of PRC-005-1 R2 and R2.1.

75. GR1 committed to take the following actions by December 31, 2016:

    a. Proceeding forward, GR1 will establish fleet-wide maintenance and testing practices and programs in accordance with NRG's compliance program;

    b. While transitioning to the unified compliance program, GR1 will perform one of the following maintenance and testing activities for any devices without documented checks or testing:

        i. A visual inspection of the component to examine for evidence of concern about the ability to perform correctly; or

        ii. Perform an insulation resistance check on the device; or,

        iii. Verify or measure voltage or current input signals from the device to protective relays.

76. ReliabilityFirst will verify GR1's completion of these Mitigating Activities.

B. VAR-002-2b R2 and VAR-002-3 R2 (RFC2014013615 and RFC2015014839)

77. VAR-002 ensures that generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources within applicable Facility Ratings in order to protect equipment and the reliable operation of the Interconnection.

78. A violation of VAR-002 has the potential to affect the reliable operation of the BES by allowing generator voltage or reactive power output at levels detrimental to the bulk power system's voltage or reactive power level.

79. VAR-002 R2 states:

    R2. Unless exempted by the Transmission Operator, each [GOP] shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

R2.1. When a generator's AVR is out of service or the generator does not have an AVR, the [GOP] shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

R2.2. When instructed to modify voltage, the [GOP] shall comply or provide an explanation of why the schedule cannot be met.

R2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the [GOP].

Description of Alleged Violation and Risk Assessment for RFC2014013615

80. On February 26, 2014, GPM submitted a Self-Report to ReliabilityFirst stating that, as a GOP, it was in violation of VAR-002-2b R2. *See*, Self-Report, **Attachment 14**. During a scheduled periodic review of the station output at the Brunot Island Station, GPM discovered that Units 3 & 4 were over their upper voltage limits on 3 occasions in October 2013. Specifically, on October 12, 2013, Unit 3 exceeded its voltage schedule by .68% from 1:00 am until 6:30 pm, and by .67% from 7:30 pm until 8:00 am on October 13, 2013. Unit 4 exceeded its voltage schedule by .52% on October 12, 2013, from 4:15 am until noon, and exceeded it again by .12% on October 13, 2013, from 12:30 am until 7:15 am.

81. The major factor contributing to the cause of this violation was insufficient internal controls to prevent, detect, and correct this type of issue. This major contributing factor implicates the management practice of grid operations, which includes maintaining situational awareness of operations as well as performing incident management and control.

82. The duration of this Alleged Violation is from October 12, 2013, the date that the first voltage excursion occurred, until October 13, 2013, when the last voltage excursion ended.

83. ReliabilityFirst determined that the Alleged Violation posed a minimal risk to the reliability of the BES based on the following factors.[16] First, although the voltage exceedances existed for significant periods of time, they were minor and not likely to cause harm to equipment or the BES. Second, the units at issue are small generators (46MW and 106MW, respectively), which reduces the likelihood that could have had any material impact on the BES.

[16] VAR-002-2b R2 has a VRF of "Medium" ReliabilityFirst determined that this Alleged Violation warranted a "Severe" VSL.

Mitigating Actions for RFC2014013615

84. On March 14, 2014, GPM submitted to ReliabilityFirst a Mitigation Plan to address the Alleged Violation of VAR-002-2b R2. *See* RFCMIT010534, **Attachment 15**. On April 1, 2014, ReliabilityFirst accepted the Mitigation Plan.

85. In the Mitigation Plan, GPM committed to take the following actions by July 1, 2014. First, GPM created a second alarm at the Commercial Operations Desk that will initiate twenty minutes after the first alarm is received of a unit being outside its voltage schedule should the unit not be able to get within schedule. Second, GPM incorporated a new step into the unit operating procedures to monitor output voltage when placing a unit on-line using the Trader.ems software system. Third, GPM obtained Trader.ems login passwords for all operators. Fourth, GPM installed an additional computer display in the plant's control room which will be dedicated to displaying Trader.ems data for operations personnel to monitor real time station voltages. Fifth, GPM created a more user friendly method for operations personnel to monitor real time station voltages. Lastly, GPM created an alarm to alert station operators that voltage is approaching a limit.

86. On August 5, 2014, GPM certified to ReliabilityFirst that it completed this Mitigation Plan as of June 17, 2014. *See* Certification of Mitigation Plan Completion, **Attachment 16**. On November 2, 2016, ReliabilityFirst verified GPM's completion of this Mitigation Plan. *See* Mitigation Plan Verification for RFCMIT010534, **Attachment 17**.

Description of Alleged Violation and Risk Assessment for RFC2015014839

87. On March 31, 2015, GNMC submitted a Self-Report to ReliabilityFirst stating that, as a GOP, it was in violation of VAR-002-3 R2. *See*, Self-Report, **Attachment 18**. While reviewing evidence for an upcoming Self-Certification, GNMC discovered that the Keystone Generating Station recorded one instance when it was outside the published voltage schedule and failed to timely report the excursion. The incident began at 10:54 pm on October 28, 2014, and ended at 6:32 am on October 29, 2014. GNMC notified FirstEnergy within 60 minutes, rather the required 30 minutes. During this time period, GNMC exceeded its voltage schedule by a maximum of .198%.

88. During the course of mitigation, GNMC also identified an additional instance on voltage excursion, which occurred on August 5, 2015. Beginning at 10:56 pm, immediately preceding Unit 1's removal for a maintenance outage while at minimum load, the Keystone Generating Station notified the Real Time Desk of a voltage excursion at 11:08 pm that the plant was off schedule using the instantaneous voltage signal available at the plant. The Real Time Desk was monitoring the 30 minute rolling average, but received a response from the plant that the voltage was back in schedule at 11:30 pm. Therefore, no notification was made. However, the voltage reverted back to out of schedule until 11:46 pm, when corrections were made by FirstEnergy.

89. The major factor contributing to the cause of both instances of noncompliance was the fact that the station control room operators did not have a rolling 30 minute average value displayed on its control screens to monitor that level. This fact contributed to the confusion as to when the plant was in and out of schedule. This major contributing factor implicates the management practices of grid operations, which includes maintaining situational awareness of operations, and measurement and analysis, which includes specifying key metric measurement objectives.

90. The duration of the first instance of noncompliance is from October 28, 2014, when the first voltage excursion began, until October 29, 2014, when that excursion was corrected. The duration of the second instance of noncompliance is from 10:56 pm on August 5, 2015, when the voltage excursion began, until 11:46 pm on that same day, when the voltage excursion was corrected.

91. Reliability*First* determined that the Alleged Violation posed a minimal risk to the reliability of the BES based on the following factors.[17] First, these voltage excursions were minor in degree and lasted a relatively short period of time. Second, with respect to the first instance of noncompliance, the voltage excursion occurred while the system was in a high voltage limit condition under low load conditions. Furthermore, equipment constraints at the plants prevent them from being able to lower local voltages to bring the system voltage down. Third, with respect to the second instance of noncompliance, GNMC had already notified both PJM and the TO of the upcoming maintenance outage and the unit was expected to be removed from service momentarily, which reduces the likelihood that the voltage excursion could have had any significant impact on the BES.

Mitigating Actions for RFC2015014839

92. On June 3, 2016, GNMC submitted to ReliabilityFirst a Mitigation Plan to address the Alleged Violation of VAR-002-3 R2. *See* RFCMIT011668-2, **Attachment 19**. On June 6, 2016, ReliabilityFirst accepted the Mitigation Plan.

93. In the Mitigation Plan, GNMC committed to take the following actions by June 25, 2015. First, GNMC conducted a training session to provide a review of the importance of maintaining and reporting the generator voltage schedule and review of alarm response procedures. Second, GNMC added a 518kV Low off schedule "High Priority" Alarm after 15 minutes and conducted Operator and Supervisor training. Third, GNMC upgraded the 518kV Low off schedule High Priority Alarm after 5 Minutes to "High Priority" and conducted Operator and Supervisor training. Fourth, GNMC upgraded the 518kV Low off schedule URGENT Priority Alarm after 25 minutes to "Urgent Priority" and conducted Operator and Supervisor training. Fifth, GNMC added the 534kV High off schedule "High Priority" alarm After 15 minutes off schedule and conducted

[17] VAR-002-3 R2 has a VRF of "Medium." ReliabilityFirst determined that this Alleged Violation warranted a "Severe" VSL.

Operator and Supervisor training. Sixth, GNMC upgraded the 534kV High off schedule High Priority alarm after 5 minutes and conducted Operator and Supervisor training. Seventh, GNMC upgraded the 534kV High off schedule alarm to "Urgent Priority" after 25 minutes and conducted Operator and Supervisor training. Eighth, GNMC required operators to notify local dispatcher as soon as they are back within voltage schedule, acknowledge a control system prompt, and make a log book entry of the alarm and reporting information. Ninth, GNMC conducted additional training on the alarm response revisions associated with maintain and reporting generator voltage. Tenth, GNMC developed a more formal station specific 500kV voltage off schedule alarm response procedure. Lastly, GNMC added a 30 minute rolling average display in the Control Room for operations personnel and real time trader refresher training.

94. On June 6, 2016, GNMC certified to ReliabilityFirst that it completed this Mitigation Plan as of December 30, 2015. *See* Certification of Mitigation Plan Completion, **Attachment 20**. On November 10, 2016, ReliabilityFirst verified GNMC's completion of this Mitigation Plan. *See* Mitigation Plan Verification for RFCMIT011668-2, **Attachment 21**.

Attachment C

Disposition Documents for RFC2014014541 (PRC-005-1 R2; R2.1; R2.2)

c.1. Notice of Possible Violation, submitted on November 11, 2014

c.2. Mitigation Plan RFCMIT011655, submitted on June 17, 2015

c.3. Certification of the Mitigation Plan Completion, dated February 1, 2016

c.4. Mitigation Plan Verification for RFCMIT011655, dated February 26, 2016

RELIABILITY FIRST

[redacted]

Possible Violation (PV) / Find, Fix, and Track ("FFT") Identification Form

This document is to be completed upon identification of a possible violation, typically within 5 business days of the audit exit brief, and emailed to Shirley Ortiz (Paralegal) with a copy to Jim Uhrin (Director, Compliance Monitoring), Gary Campbell (Manager, Ops & Planning Monitoring or Ray Sefchik (Manager, CIP Monitoring) and Niki Schaefer (Managing Enforcement Attorney).

For non-FFT candidates: Upon receipt of this document, Enforcement will coordinate with the reporting auditor and Enforcement to initiate the Enforcement processing of this possible violation.

Violation Reported By: Kellen Phillips

Submittal Date: 11/11/2014

Candidate for FFT Treatment: YES ☐ NO ☒

Registered Entity: Boston Energy Trading and Marketing

NERC Registry ID#: NCR00769

Compliance Monitoring Process: Compliance Audit

Standard, Version and Requirement in Violation: PRC-005-1.1b R2, R2.1 and R2.2

Registered Function(s) in Violation: GO/GOP

Initial PV Date (Actual Date Discovered by ReliabilityFirst): 11/11/2014

Date for Determination of Penalty/Sanction (Beginning Date of Violation): 2/21/2008

End Date of Possible Violation: Not known at this time

For Non-FFT Candidate ONLY
Violation Risk Factor:
R2: Lower
R2.1: High
R2.2: High

Violation Severity Level:
R2: Severe
R2.1: N/A
R2.2: N/A

[redacted]

Potential Impact to Bulk Electrical System (BES): Severe

Provide Explanation for Selection:

When the Generator Owner (GO) does not follow its procedures for maintenance and testing of System Protection devices, as defined in the GO's maintenance and testing program, the reliability of the BES is threatened because the systems installed may not be able to effectively perform. EMMT's documentation shows procedures were selected based upon manufacturers' suggestions and good engineering practices which provide a reasonable assurance that the equipment if maintained per the program, will remain functional thus ensuring minimal risk to the BES. In the evidence that was provided, EMMT could not demonstrate that it followed its System Protection maintenance and testing program at all of its facilities except Will County Station in 2014. The audit team was unable to verify that all of the steps listed in EMMT's maintenance and testing program were being completed. In addition, there were a number of generator/system protection devices that had no records of ever being maintained and tested. All four plants owned by EMMT are online most of the time and are of significant capacity such that the net size of these plants is a factor in determining the risk to the BES is severe. The net capacity of each plant is: Powerton-1538MW, Joliet-1326MW, Waukegan-801MW, and Will County-761MW.

For Non-FFT and FFT Candidates

Basis for the PV:
R2: EMMT did not provide evidence that maintenance and testing was done on all System Protection devices per EMMT's Protection System maintenance and testing program.
R2.1: EMMT did not provide evidence that maintenance and testing was done within the defined intervals on all System Protection devices per EMMT's Protection System maintenance and testing program.
R2.2: EMMT did not provide evidence of the last date that each Protection System device was last tested/maintained.

Facts and Evidence pertaining to the PV:
The requirements state:

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

Evidence: Some evidence is listed by folder because each record was provided separately; any document mentioned in the narrative is listed individually in this list.

Initial Evidence folder:

- RSAW PRC-005-1.1b EMMT Final
- 2011 CT Checks Bus 70 9E-47604-Joliet
- 2011 CT Checks U7 Gen 9E-47600 (5MEG) (2)–Joliet

- 2010 PT-CT tests - 2010_09_07-Powerton
- 2011 PT-CT tests - 2011_05_23-Powerton
- Joliet relay test sheets – 16 documents
- Powerton relay test sheets – 7 documents
- Waukegan relay test sheets – 9 documents
- Will County relay test sheets – 7 documents

ER-005 Evidence folder:
- RF Request ER-005 102214
- EMMT Procedures – 4 documents
- Joliet- 4 CT-PT Checks, 5 Trip Checks
- Powerton- 29 NERC Trip Test documents, 3 CT-PT test documents
- 2013 ocb910 1011 CT test
- Will County – 4 relay testing documents

Facts:

The document *RSAW PRC-005-1.1b EMMT Final* included the RSAW and EMMT's System Protection maintenance and testing program (EMG-3008). The program included all required necessary devices, intervals, and a summary of maintenance and testing procedures. The documents listed in the initial evidence section above were the initial maintenance and testing documents reviewed by the audit team. Several relays chosen in the team's initial sampling request were not included in the initial submittal. Maintenance and testing records that were reviewed did not include some of the activities called for in EMMT's program. Many of the test sheets did not indicate that any visual inspection had been done on the relays or that the relay settings had been compared to the most recently issued settings as the EMMT maintenance and testing program requires. The audit team created evidence request ER-005 requesting EMMT provide the full maintenance and testing reports and cover letters for all relays highlighted in attachment C to show that all of EMMT's maintenance and testing procedures were done. The team requested EMMT provide CT/PT maintenance and testing reports for Will County and Waukegan as initially requested in the data sampling request, as these were not included in the initial submittal from EMMT. In addition, the audit team requested that EMMT provide official CT/PT maintenance and testing reports for Joliet. In the initial submittal, one-line diagrams were provided with what the entity described to the audit team as "Megger values" written on them. This was found to be insufficient evidence because there was insufficient detail, no dates, and in most cases no names associated with the written notes.

For ER-005, EMMT submitted the document *RF Request ER-005 102214* along with 16 other documents. In response to the audit team asking for the full maintenance and testing reports, EMMT stated that all of the pages for the testing reports were included in the original submittals and had no additional evidence to offer. No further evidence was provided for the CT/PT testing for Joliet either; the one-line diagrams were the only evidence EMMT could provide which the audit team deemed insufficient evidence that the maintenance and testing procedures listed in EMMT's program were being completed. For Waukegan, EMMT stated, "There are no documents available showing that CT/PT checks were performed either at the plant or from the vendors." For Will County the relay test sheets for the last maintenance and testing done in 2014 had CT/PT testing and trip checks (DC control circuitry) incorporated in them but the previous tests done in 2010 were done on one-lines similar to Joliet. The audit team found a Possible Violation for R2 because EMMT did not provide evidence that its maintenance and testing procedures were followed for relays. The audit team found a Possible Violation for R2.1 and R2.2 because EMMT did not provide evidence that CTs/PTs or DC Control circuitry were ever tested and maintained at Waukegan and the evidence provided for Powerton and

Joliet was insufficient to prove when the last test date was and that the devices were tested and maintained within the defined intervals.

Summary for each plant:

Powerton: 1538MW Net
Relays - Had all of the most recent maintenance and test records but did not follow the EMMT programs maintenance and testing procedures. No evidence of mechanical inspection, cleaning, or tightening of terminations was presented nor was the verification of the relay settings. From the samples selected EMMT was missing four out nine test records for previous tests. **R2**

CT/PTs – Had some maintenance and test records but did not follow the EMMT program (2010-2011). The most recent maintenance and test record, *2013 ocb910 1011 CT test* was an attestation letter dated 4-26-13 stating that the maintenance and testing of the CTs was done. The document has no company header and no signature; therefore the audit team found this to be insufficient substantiating evidence. **R2, R2.1, R2.2**

DC Control Circuitry - EMMT provided 29 documents as part of the response to ER-005 for evidence of Trip Tests at Powerton. The test records are from 2010 to 2013 and are all typed attestations. None of the attestations were on company letterhead or had any heading and only a few had signatures so the audit team found this to be insufficient substantiating evidence. **R2, R2.1, R2.2**

Joliet: 1326MW Net
Relays - Had maintenance and test records but six out of seven samples from the last maintenance and testing cycle (2010, 2011, and 2012) did not follow EMMT's program. The previous maintenance and test records from 2007 and 2008 demonstrated that EMMT was following the program at that time. **R2**

CT/PTs – The only records provided were hand written notes on one-line diagrams with no dates or signatures which the audit team found to be insufficient. Hand written notes on one lines are not sufficient evidence that the maintenance and testing activities of the DC Controls were completed. Records should be official documents that clearly display all of the maintenance and testing activities that took place with dates and signatures. Furthermore the notes written on the one-lines did not cover everything listed in their testing and maintenance procedures (Meggering the connected CT circuit, perform continuity test, in-service voltage and/or current to relay). **R2, R2.1, R2.2**

DC Control Circuitry - The only maintenance and test records provided were highlighted one-line diagrams with notes written on them; some have dates and/or signatures but not all. This evidence does not show that EMMT was following its program and the documentation is poor and insufficient. Highlighted one lines are not sufficient evidence that the maintenance and testing activities of the DC Controls were completed. Records should be official documents that clearly display the maintenance and testing activities that took place with dates and signatures. **R2, R2.1, R2.2**

Waukegan: 801MW Net
Relays - Had the last maintenance and test records (2010-2011) but they did not follow the EMMT program. No evidence of mechanical inspection, cleaning, or tightening of terminations was presented nor was the verification of the relay settings. EMMT did not provide any previous relay maintenance and test records for Waukegan. **R2, R2.1**

CT/PTs - Had no maintenance and test records as verified in EMMT's response to ER-005. **R2, R2.1, R2.2**

DC Control Circuitry - Had no evidence of maintenance and testing. **R2, R2.1, R2.2**

Will County: 761MW Net
Relays - The last maintenance and testing documentation from 2014 was good, but the previous maintenance and testing (2009-2010) did not follow the EMMT program. **R2**

CT/PTs - In 2014, maintenance and testing was done on the relays and the results were shown on the relay test sheets. The previous test sheets from 2009-2010 did not include maintenance and testing of CTs and PTs and no other evidence was provided. **R2, R2.1, R2.2**

DC Control Circuitry - In 2014 maintenance and testing was done on the relays and the results were shown on the relay test sheets. The previous test sheets from 2009-2010 included only one line diagrams that were highlighted to indicate trip checks were done which the audit team deemed insufficient. **R2, R2.1, R2.2**

Mitigation Plan

Mitigation Plan Summary

Registered Entity: Boston Energy Trading and Marketing LLC

Mit Plan Code	NERC Violation ID	Requirement	Violation Validated On	Mit Plan Version
	RFC2014014541	PRC-005-1 R2.		1

Mitigation Plan Submitted On: June 17, 2015
Mitigation Plan Accepted On:
Mitigation Plan Proposed Completion Date: October 31, 2015
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by EMMT On:
Mitigation Plan Completion Verified by RF On:
Mitigation Plan Completed? (Yes/No): No

Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Entity Information

Identify your organization:

Entity Name: Boston Energy Trading and Marketing LLC
NERC Compliance Registry ID: NCR00769

Address: 211 Carnegie Center
Princeton NJ 08540

Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Robert Burkhart
Title: Manager - Regulatory Compliance
Email: Robert.Burkhart@nrg.com
Phone: 724-597-8553

Violation(s)

This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
RFC2014014541	02/21/2008	PRC-005-1 R2.
Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:		

Brief summary including the cause of the violation(s) and mechanism in which it was identified:

The violation was identified during a ReliabilityFirst (RF) Fall 2014 Audit of the EMMT Registration. The source of the violations was due to improper documentation or missing information on NERC related CT / PT Checks and DC Trip Checks. The cause of the violation was due to EMMT procedures and protocols which did not provide sufficient direction on how to perform and document the testing activities.

Details:

RF conducted an Operations & Planning compliance engagement of Boston Energy Trading and Marketing LLC (EMMT), NCR00769, from November 10, 2014 to November 18, 2014. At the time of the compliance engagement, EMMT was registered for the functions of GO, GOP, and PSE. Commonwealth Edison (ComEd) is EMMT's Transmission Owner and Transmission Operator, and PJM Interconnection, L.L.C. (PJM) is the Reliability Coordinator. The RF Compliance Audit Team evaluated EMMT for compliance with 16 requirements in the 2014 NERC Compliance Monitoring and Enforcement Program (CMEP) and the ReliabilityFirst CMEP Implementation Plan. The RF Team assessed compliance with the NERC Reliability Standards applicable for the period of May 31, 2008 to November 18, 2014. The RF Team reviewed and evaluated all evidence provided by EMMT and assessed compliance with the Reliability Standards applicable to EMMT, at the time.

Taken from the RF Audit Team Report, the following information details the compliance findings for the PRC-005 Reliability Standard and Requirements identified in the scope of this compliance engagement, which have Possible Violations or Open Enforcement Actions. All other reliability standards and requirements in the scope for this compliance engagement were tested without exception.

Possible Violations - PRC-005-1.1b R2, R2.1, R2:

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days).

R2: EMMT did not provide evidence that maintenance and testing was done on all System Protection devices per EMMT's Protection System Maintenance and Testing Program.
R2.1: EMMT did not provide evidence that maintenance and testing was done within the defined intervals on all System Protection devices per EMMT's Protection System Maintenance and Testing Program.
R2.2: EMMT did not provide evidence of the last date that each Protection System device was last tested/maintained.

Relevant information regarding the identification of the violation(s):

Initial Evidence folder contained:

• RSAW PRC-005-1.1b EMMT Final
• 2011 CT Checks Bus 70 9E-47604-Joliet
• 2011 CT Checks U7 Gen 9E-47600 (5MEG) (2)-Joliet

• 2010 PT-CT tests - 2010_09_07-Powerton
• 2011 PT-CT tests - 2011_05_23-Powerton
• Joliet relay test sheets - 16 documents
• Powerton relay test sheets - 7 documents
• Waukegan relay test sheets - 9 documents
• Will County relay test sheets - 7 documents

Additional Evidence Request ER-005 Evidence folder:

• RF Request ER-005 102214
• EMMT Procedures - 4 documents
• Joliet- 4 CT-PT Checks, 5 Trip Checks
• Powerton- 29 NERC Trip Test documents, 3 CT-PT test documents
• 2013 ocb910 1011 CT test
• Will County - 4 relay testing documents

Discussion:

The document RSAW PRC-005-1.1b EMMT Final included the RSAW and EMMT's System Protection Maintenance and Testing Program (EMG-3008). The program included all required necessary devices, intervals, and a summary of maintenance and testing procedures. The documents listed in the initial evidence section above were the initial maintenance and testing documents reviewed by the audit team. Several relays chosen in the team's initial sampling request were not included in the initial submittal. Maintenance and testing records that were reviewed did not include some of the activities called for in EMMT's program. Many of the test sheets did not indicate that any visual inspection had been done on the relays or that the relay settings had been compared to the most recently issued settings as the EMMT Maintenance and Testing Program requires. The audit team created evidence request ER-005 requesting EMMT provide the full maintenance and testing reports and cover letters for all relays highlighted in Attachment C to show that all of EMMT's maintenance and testing procedures were done. The audit team found a Possible Violation for R2 because EMMT did not provide evidence that its maintenance and testing procedures were followed for relays.

The RF Team requested EMMT provide CT/PT maintenance and testing reports for Will County and Waukegan as initially requested in the data sampling request, as these were not included in the initial submittal from EMMT. In addition, the audit team requested that EMMT provide official CT/PT maintenance and testing reports for Joliet. In the initial submittal, one-line diagrams were provided with what the entity described to the audit team as "Megger values" written on them. This was found to be insufficient evidence because there was insufficient detail, no dates, and in most cases no names associated with the written notes and therefore the evidence could not be substantiated. For ER-005, EMMT submitted the document RF Request ER-005 102214 along with 16 other documents. In response to the audit team asking for the full maintenance and testing reports, EMMT stated that all of the pages for the testing reports were included in the original submittals and had no additional evidence to offer. No further evidence was provided for the CT/PT testing for Joliet either; the one-line diagrams were the only evidence EMMT could provide which the audit team deemed as insufficient because it could not substantiate the testing was completed. For Waukegan, EMMT stated, "There are no documents available showing that CT/PT checks were performed either at the plant or from the vendors." For Will County the relay test sheets for the last maintenance and testing done in 2014 had CT/PT testing and trip checks (DC control circuitry) incorporated in them but the previous tests done in 2010 were done on one-lines similar to Joliet.

The RF Audit Team found a Possible Violation for R2.1 and R2.2 because EMMT did not provide evidence that CTs/PTs or DC Control circuitry were ever tested and maintained at Waukegan and the evidence provided for Powerton and Joliet was insufficient to prove when the last test date was and that the devices were tested and maintained within the defined intervals.

Summary for each plant:

Powerton: 1538 MW Net

Relays - Had all of the most recent maintenance and test records but did not follow the EMMT programs maintenance and testing procedures. No evidence of mechanical inspection, cleaning, or tightening of terminations was presented nor was the verification of the relay settings. From the samples selected EMMT was missing four out nine test records for previous tests. (R2)

CT/PTs - Had some maintenance and test records but did not follow the EMMT program (2010-2011). The most recent maintenance and test record, 2013 ocb910 1011 CT test was an attestation letter dated 4-26-13 stating that the maintenance and testing of the CTs were done. The document has no company header and no signature; therefore the audit team found this to be insufficient substantiating evidence. (R2, R2.1, R2.2)

DC Control Circuitry - EMMT provided 29 documents as part of the response to ER-005 for evidence of Trip Tests at Powerton. The test records are from 2010 to 2013 and are all typed attestations. None of the attestations were on company letterhead or had any heading and only a few had signatures so the audit team found this to be insufficient substantiating evidence. (R2, R2.1, R2.2)

Joliet: 1326 MW Net

Relays - Had maintenance and test records but six out of seven samples from the last maintenance and testing cycle (2010, 2011, and 2012) did not follow EMMT's program. The previous maintenance and test records from 2007 and 2008 demonstrated that EMMT was following the program at that time. (R2)

CT/PTs - The only records provided were hand written notes on one-line diagrams with no dates or signatures which the audit team found to be insufficient. Hand written notes on one-lines are not sufficient evidence that the maintenance and testing activities of the DC Controls were completed. Records should be official documents that clearly display all of the maintenance and testing activities that took place with dates and signatures. Furthermore, the notes written on the one-lines did not cover everything listed in their testing and maintenance procedures, i.e., meggering the connected CT circuit, perform continuity test, in-service voltage and/or current to relay. (R2, R2.1, R2.2)

DC Control Circuitry - The only maintenance and test records provided were highlighted one-line diagrams with notes written on them; some have dates and/or signatures but not all. This evidence does not show that EMMT was following its program and the documentation is poor and insufficient. Highlighted one-lines are not sufficient evidence that the maintenance and testing activities of the DC Controls were completed. Records should be official documents that clearly display the maintenance and testing activities that took place with dates and signatures. (R2, R2.1, R2.2)

Waukegan: 801 MW Net

Relays - Had the last maintenance and test records (2010-2011) but they did not follow the EMMT program. No evidence of mechanical inspection, cleaning, or tightening of terminations was presented nor was the verification of the relay settings. EMMT did not provide any previous relay maintenance and test records for Waukegan. (R2, R2.1)

CT/PTs - Had no maintenance and test records as verified in EMMT's response to ER-005. (R2, R2.1, R2.2)

DC Control Circuitry - Had no evidence of maintenance and testing. (R2, R2.1, R2.2)

Will County: 761 MW Net

Relays - The last maintenance and testing documentation from 2014 was good, but the previous maintenance and testing (2009-2010) did not follow the EMMT program. (R2)

CT/PTs - In 2014, maintenance and testing was done with the relays and the results were shown on the relay test sheets. The previous test sheets from 2009-2010 did not include maintenance and testing of CTs and PTs and no other evidence was provided. (R2, R2.1, R2.2)

DC Control Circuitry - In 2014 maintenance and testing was done on the relays and the results were shown on the relay test sheets. The previous test sheets from 2009-2010 included only one line diagrams that were highlighted to indicate trip checks were done which the audit team deemed insufficient. (R2, R2.1, R2.2)

Plan Details

Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

Create documentation for trip checks and CT / PT testing based upon NRG fleet-wide templates for all NERC related protection schemes at the Joliet, Powerton, Waukegan and Will County Generating Stations; and, perform the testing detailed in these documents.

Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: October 31, 2015

Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Waukegan Unit 31 CT/PT Test Document	Create a detailed CT/PT Testing document for Waukegan Unit 31	06/01/2015	06/01/2015	See Attachment M - Waukegan Unit 31 Template NERC CT PT Checks	No
Waukegan Unit 31 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Waukegan Unit 31	06/01/2015	06/01/2015	See Attachment N - Waukegan Peaker Units 31 & 32 Template NERC DC Functional Test Plan	No
Waukegan Unit 32 CT/PT Test Document	Create a detailed CT/PT Testing document for Waukegan Unit 32	06/01/2015	06/01/2015	See Attachment M - Unit 32 Template NERC CT PT Checks	No
Waukegan Unit 32 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Waukegan Unit 32	06/01/2015	06/01/2015	See Attachment N - Waukegan Peaker Units 31 & 32 Template NERC DC Functional Test Plan	No
Waukegan Unit 7 CT/PT Test Document	Create a detailed CT/PT Testing document for Waukegan Unit 7.	06/01/2015	06/01/2015	See Attachment O - Waukegan Unit 7 Template NERC CT PT Checks	No
Waukegan Unit 7 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Waukegan Unit 7	06/01/2015	06/01/2015	See Attachment P - Waukegan Unit 7 Template NERC DC Functional Test Plan	No
Waukegan Unit 8 CT/PT Test	Create a detailed CT/PT Testing	06/01/2015	06/01/2015	See Attachment Q - Waukegan Unit 8 Template	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Document	document for Waukegan Unit 8			NERC CT PT Checks	
Waukegan Unit 8 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Waukegan Unit 8	06/01/2015	06/01/2015	See Attachment R - Waukegan Unit 8 Template NERC DC Functional Test Plan	No
Joliet Unit 6 CT/PT Testing	Create a detailed CT/PT Testing document for Joliet Unit 6.	06/05/2015	05/28/2015	See Attachment A - Unit 6 Template NERC CT PT Checks	No
Joliet Unit 6 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Joliet Unit 6.	06/05/2015	05/14/2015	See Attachment C - Unit 6 Template NERC DC Functional Test Plan	No
Joliet Unit 7 CT/PT Testing	Create a detailed CT/PT Testing document for Joliet Unit 7.	06/05/2015	05/27/2015	See Attachment E - Unit 7 Template NERC CT PT Checks	No
Joliet Unit 7 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Joliet Unit 7.	06/05/2015	04/02/2015	See Attachment G - Unit 7 Template NERC DC Functional Test Plan	No
Joliet Unit 8 CT/PT Testing	Create a detailed DC Functional Test Plan for Joliet Unit 8	06/05/2015	05/26/2015	See Attachment I - Unit 8 Template NERC CT PT Checks	No
Joliet Unit 8 DC Functional Plan	Create a detailed DC Functional Test Plan for Joliet Unit 8.	06/05/2015	04/15/2015	See Attachment K - Unit 8 Template NERC DC Functional Test Plan	No
Joliet Unit 6 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan	06/08/2015	06/02/2015	See Attachment B – Unit 6 CT_PT Test Results	No
Joliet Unit 6 DC Functional Testing	Perform the trip checks as described in the plan.	06/08/2015	05/17/2015	See Attachment D – Unit 6 DC Functional Circuitry Test Results	No
Joliet Unit 7 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan.	06/08/2015	05/29/2015	See Attachment F – Unit 7 CT_PT Test Results	No
Joliet Unit 7 DC Functional Test Plan	Perform the trip checks as described in the plan.	06/08/2015	04/08/2015	See Attachment H – Unit 7 DC Functional Circuitry Test Results	No
Joliet Unit 8 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan	06/08/2015	05/29/2015	See Attachment J – Unit 8 CT_PT Test Results	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Joliet Unit 8 DC Functional Test Plan	Perform the trip checks as described in the plan.	06/08/2015	05/03/2015	See Attachment L – Unit 8 DC Functional Circuitry Test Results	No
Powerton Unit 5 CT/PT Test Document	Create a detailed CT/PT Testing document for Powerton Unit 5	08/01/2015		The CT/PT Testing template will be submitted as evidence of completion of this mitigating activity.	No
Powerton Unit 5 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Powerton Unit 5.	08/01/2015		The DC Functional Test Plan template will be submitted as evidence of completion of this mitigating activity.	No
Powerton Unit 6 CT/PT Test Document	Create a detailed CT/PT Testing document for Powerton Unit 6	08/01/2015		The CT/PT Testing template will be submitted as evidence of completion of this mitigating activity.	No
Powerton Unit 6 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Powerton Unit 6.	08/01/2015		The DC Functional Test Plan template will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 31 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan.	09/01/2015		The results of the CT and PT Testing will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 31 DC Functional Testing	Perform the DC Functional Circuitry Trip checks as described in the DC Functional Test Plan on Unit 31	09/01/2015		This testing requires a unit outage of sufficient length to accommodate the coordination and testing of the protective relay trip circuitry. The next scheduled outage is 8/1/2016. The results of the testing will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 32 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan	09/01/2015		The results of the CT and PT Testing will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 32 DC Functional Testing	Perform the DC Functional Circuitry Trip checks as	09/01/2015		This testing requires a unit outage of sufficient length to accommodate the	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	described in the DC Functional Test Plan on Unit 32			coordination and testing of the protective relay trip circuitry. The next scheduled outage is 8/1/2016. The results of the testing will be submitted as evidence of completion of this mitigating activity.	
Waukegan Unit 7 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan.	09/01/2015		The results of the CT and PT Testing will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 7 DC Functional Testing	Perform the DC Functional Circuitry Trip checks as described in the DC Functional Test Plan on Unit 7	09/01/2015		This testing requires a unit outage of sufficient length to accommodate the coordination and testing of the protective relay trip circuitry. The next scheduled outage is 8/1/2016. The results of the testing will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 8 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan.	09/01/2015		The results of the CT and PT Testing will be submitted as evidence of completion of this mitigating activity.	No
Waukegan Unit 8 DC Functional Testing	Perform the DC Functional Circuitry Trip checks as described in the DC Functional Test Plan on Unit 8	09/01/2015		This testing requires a unit outage of sufficient length to accommodate the coordination and testing of the protective relay trip circuitry. The next scheduled outage is 8/1/2016. The results of the testing will be submitted as evidence of completion of this mitigating activity.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Will County Unit 4 CT/PT Test Document	Create a detailed CT/PT Testing document for Will County Unit 4	09/01/2015		The CT/PT Testing template will be submitted as evidence of completion of this mitigating activity.	No
Will County Unit 4 DC Functional Test Plan	Create a detailed DC Functional Test Plan for Will County Unit 4	09/01/2015		The DC Functional Test Plan template will be submitted as evidence of completion of this mitigating activity.	No
Powerton Unit 5 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan	10/31/2015		Submit the results of the CT and PT Testing as evidence of completion of this mitigating activity.	No
Powerton Unit 5 DC Functional Test Plan	Perform the trip tests as described in the plan.	10/31/2015		Submit the results of the testing as evidence of completion of this mitigating activity.	No
Powerton Unit 6 CT/PT Testing	Perform the tests on the CTs and PTs as described in the test plan	10/31/2015		Submit the results of the CT and PT Testing as evidence of completion of this mitigating activity	No
Powerton Unit 6 DC Functional Test Plan	Perform the trip checks as described in the plan.	10/31/2015		Submit the results of the testing as evidence of completion of this mitigating activity.	No

Additional Relevant Information

Until April 1, 2014, Edison Mission Energy (EME) was the parent company of Edison Mission Marketing and Trading (EMMT) which was audited by RF. On April 1, 2014, EME was purchased by NRG Energy, Inc., (NRG) making NRG the ultimate parent of EMMT. EMMT changed its name to Boston Energy Trading and Marketing LLC shortly after the acquisition, but retained the acronym EMMT.

NRG Energy, Inc. (NRG) has one Regulatory Compliance group that currently oversees three compliance programs: the NRG, GenOn, and EME programs. These will soon be brought together into one unified program. The NRG program applies to the legacy NRG generating plants and NRG Commercial Operations. The GenOn Program applies to the legacy GenOn plants. The EME program applies to the legacy EME/EMMT plants. The NRG program and structure places a great deal of authority with Regulatory Compliance to make independent assessments and report as necessary to regulatory authorities.

The creation of documentation for DC Functional Trip Checks and CT/PT testing based on NRG fleet-wide templates and the performance of testing against these protocols is an integral part of transitioning the subject power plants from the EME NERC ICP to the NRG ICP.

NOTE: Since Will County Unit 3 has since been retired, there are no plans to develop and implement detailed CT / PT and DC Functional Circuitry Test Plans.

Reliability Risk

Reliability Risk

While the Mitigation Plan is being implemented, the reliability of the bulk Power System may
remain at higher Risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are known or anticipated : (i) Identify any such risks or impacts, and; (ii) discuss any actions planned or proposed to address these risks or impacts.

In spite of the fact that detailed evidentiary documentation fell short, the testing was completed which leads us to believe that the amount of risk to the reliability of the bulk Power System is very minimal.

Prevention

Describe how successful completion of this plan will prevent or minimize the probability further violations of the same or similar reliability standards requirements will occur

Once in place the Stations will have the associated test reports readily available as evidence of completion of the necessary testing of protection system components, as well as future reference of the protocols to follow to show compliance to PRC-005. These documents will be stored in the ENOSERVE Database which is used to track required NERC-related documentation.

Describe any action that may be taken or planned beyond that listed in the mitigation plan, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements

There are no current actions planned beyond what is presented in this Mitigation Plan. However, should an issue arise we are ready to address it in a most expeditious manner.

Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

* Submits the Mitigation Plan, as presented, to the regional entity for acceptance and approval by NERC, and

* if applicable, certifies that the Mitigation Plan, as presented, was completed as specified.

Acknowledges:

1. I am qualified to sign this mitigation plan on behalf of my organization.
2. I have read and understand the obligations to comply with the mitigation plan requirements and ERO remedial action directives as well as ERO documents, including but not limited to, the NERC rules of procedure and the application NERC CMEP.
3. I have read and am familiar with the contents of the foregoing Mitigation Plan.

Boston Energy Trading and Marketing LLC Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authority.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Robert Burkhart

Title: Manager - Regulatory Compliance

Authorized On: June 17, 2015

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Boston Energy Trading and Marketing LLC

NERC Registry ID: NCR00769

NERC Violation ID(s): RFC2014014541

Mitigated Standard Requirement(s): PRC-005-1 R2.

Scheduled Completion as per Accepted Mitigation Plan: December 31, 2015

Date Mitigation Plan completed: November 17, 2015

RF Notified of Completion on Date: February 01, 2016

Entity Comment:

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Attachment A -Unit 6 Template NERC CT_PT Checks.pdf	ATTACHMENT A - Joliet Unit 6 CT/PT Detailed Step-By-Step Test Template	485,333
Entity	Attachment C -Unit 6 Template NERC DC Functional Test Plan.pdf	ATTACHMENT C - Joliet Unit 6 Template NERC DC Functional Test Plan	458,016
Entity	Attachment E -Unit 7 Template NERC CT_PT Checks.pdf	ATTACHMENT E - Joliet Unit 7 Template NERC CT PT Checks	545,280
Entity	Attachment G-Unit 7 Template NERC DC Functional Test Plan.pdf	ATTACHMENT G - Joliet Unit 7 Template NERC DC Functional Test Plan	417,707
Entity	Attachment I-Unit 8 Template NERC CT_PT Checks.pdf	ATTACHMENT I - Joliet Unit 8 Template NERC CT PT Checks	521,318
Entity	Attachment K-Unit 8 Template DC Functional Test Plan.pdf	ATTACHMENT K - Joliet Unit 8 Template NERC DC Functional Test Plan	297,785
Entity	Attachment B-Unit 6 2015 6 CT_PT Testing.pdf	ATTACHMENT B - Joliet Unit 6 CT_PT Test Results	2,758,184
Entity	Attachment D Unit 6 2015 DC Functional Testing.pdf	ATTACHMENT D - Joliet Unit 6 NERC DC Functional Test Results	4,716,781
Entity	Attachment F-2015 Unit 7 CT_PT Checks.pdf	ATTACHMENT F - Joliet Unit 7 CT_PT Test Results	3,355,389
Entity	Attachment H-2015 Unit 7 DC Functional Testing.pdf	ATTACHMENT H - Joliet Unit 7 DC Functional Circuitry Test Results	1,688,449
Entity	Attachment J-2015 Unit 8 CT_PT Checks.pdf	ATTACHMENT J - Joliet Unit 8 CT_PT Test Results	3,137,620

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Attachment L-2015 Unit 8 DC Functional Testing.pdf	ATTACHMENT L - Joliet Unit 8 DC Functional Circuitry Test Results	2,743,145
Entity	Attachment M - Waukegan Peaker NERC CT PT Checks.doc	ATTACHMENT M - Waukegan Peaker Units 31 & 32 Template NERC CT PT Checks	98,304
Entity	Attachment N - Waukegan Peaker NERC Trip Checks.doc	ATTACHMENT N - Waukegan Peaker Units 31 & 32 Template NERC DC Functional Test Plan	190,464
Entity	Attachment O - Waukegan Unit 7 NERC CT PT Checks.doc	ATTACHMENT O - Waukegan Unit 7 Template NERC CT PT Checks	93,184
Entity	Attachment P - Waukegan Unit 7 NERC Trip Checks.doc	ATTACHMENT P - Waukegan Unit 7 NERC DC Functional Test Plan	146,432
Entity	Attachment R - Waukegan Unit 8 NERC Trip Checks.doc	ATTACHMENT R - Waukegan Unit 8 Template NERC DC Functional Test Plan	156,160
Entity	Attachment Q - Waukegan Unit 8 NERC CT PT Checks.doc	ATTACHMENT Q - Waukegan Unit 8 Template NERC CT PT Checks	98,304
Entity	Waukegan Unit 8 2015 Relay Testing Attachment S.zip	ATTACHMENT S - Waukegan Unit 8 2015 CT/PT and Relay Test Results	630,044
Entity	Waukegan Peakers 31_32 2015 Relay Testing Attachment T.zip	ATTACHMENT T - Waukegan Peakers 31 & 32 2015 CT/PT and Relay Testing Results	953,906
Entity	Waukegan Peaker 31_32 Relay Cal Files Attachment U.zip	ATTACHMENT U - Waukegan Peaker 31 & 32 Relay Testing Results	1,517,374
Entity	Waukegan Unit 7 CT_PT Checks Attachment V.pdf	ATTACHMENT V - Waukegan Unit 7 CT/PT Test Results	1,516,824
Entity	NGR - Waukegan Unit 7 Relay Test Reports Attachment W.zip	ATTACHMENT W - Waukegan Unit 7 Relay Test Reports	3,768,358
Entity	ATTACHMENT X - Will County Unit 4 DC Trip Checks.pdf	Attachment X - Will County Unit 4 DC Functional Test Results	951,092
Entity	ATTACHMENT Y - Will County Unit 4 Instrument Transformer Checks.pdf	Attachment Y - Will County Unit 4 CT/PT Test Results	907,686
Entity	Attachment Z - Powerton U5 CT_PT Verifications - 2015_11_17.PDF	Attachment Z - Powerton Unit 5 CT/PT Test Results	8,333,092
Entity	Attachment AA - Powerton U5 NERC Trip Checks - 2015_05_11.PDF	Attachment AA - Powerton Unit 5 DC Functional Trip Test Results	254,946

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Attachment AB - Powerton U6 CT_PT Verifications - 2015_11_17.PDF	Attachment AB - Powerton Unit 6 CT/PT Test Results	8,320,088
Entity	Attachment AC - Powerton U6 NERC Trip Checks - 2015_09_30.PDF	Attachment AC - Powerton Unit 6 DC Functional Test Results	246,484

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Martin Sidor
Title: Director, Regulatory Compliance
Email: martin.sidor@nrg.com
Phone: 1 (609) 524-4629

Authorized Signature ______________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Mitigation Plan Verification for RFC2014014541

Boston Energy Trading and Marketing, LLC ("EMMT")

Standard/Requirement: PRC-005-1 R2

NERC Mitigation Plan ID: RFCMIT011655

Method of Disposition: Settlement Agreement

Relevant Dates					
Initiating Document	**Mitigation Plan Submittal**	**RF Acceptance**	**NERC Approval**	**Certification Submittal**	**Date of Completion**
PV Summary 11/11/14	06/17/15	07/01/15	08/06/15	02/01/16	11/17/15

Description of Issue

ReliabilityFirst (RF) identified this violation during a fall 2014 Audit of the EMMT Registration. In short, EMMT failed to provide adequate evidence that: (1) the CTs/PTs or DC Control circuitry were ever tested and maintained at one generation plant; and, (2) the same type of devices were tested at two other plants within the defined intervals.

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 1	Attachment A- Unit 6 Template NERC CT PT Checks	PRC-005-1 R2
File 2	Attachment B- Unit 6 2015 CT PT Testing	PRC-005-1 R2
File 3	Attachment C- Unit 6 Template NERC DC Functional Test Plan	PRC-005-1 R2
File 4	Attachment D- Unit 6 2015 DC Functional Testing	PRC-005-1 R2
File 5	Attachment E- Unit 7 Template NERC CT PT Checks	PRC-005-1 R2

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 6	Attachment F-2015 Unit 7 CT PT Checks	PRC-005-1 R2
File 7	Attachment G- Unit 7 Template NERC DC Functional Test Plan	PRC-005-1 R2
File 8	Attachment H- 2015 Unit 7 DC Functional Testing	PRC-005-1 R2
File 9	Attachment I- Unit 8 Template NERC CT PT Checks	PRC-005-1 R2
File 10	Attachment J- 2015 Unit 8 CT PT Checks	PRC-005-1 R2
File 11	Attachment K- Unit 8 Template DC Function Test Plan	PRC-005-1 R2
File 12	Attachment L- 2015 Unit 8 DC Functional Testing	PRC-005-1 R2
File 13	Attachment M- Waukegan Peaker NERC CT PT Checks	PRC-005-1 R2
File 14	Attachment N- Waukegan Peaker NERC Trip Checks	PRC-005-1 R2
File 15	Attachment O- Waukegan Unit 7 NERC CT PT Checks	PRC-005-1 R2
File 16	Attachment P- Waukegan Unit 7 NERC Trip Checks	PRC-005-1 R2
File 17	Attachment Q- Waukegan Unit 8 NERC CT PT Checks	PRC-005-1 R2
File 18	Attachment R- Waukegan Unit 8 NERC Trip Checks	PRC-005-1 R2
File 19	Waukegan Unit 8 2015 Relay Testing Attachment S	PRC-005-1 R2
File 20	Waukegan Unit 7 CT PT Checks Attachment V	PRC-005-1 R2
File 21	Waukegan Peakers 31 32 2015 Relay Testing Attachment T	PRC-005-1 R2
File 22	Waukegan Peaker 31 32 Relay Cal Files Attachment U	PRC-005-1 R2
File 23	NGR- Waukegan Unit 7 Relay Test Reports Attachment W	PRC-005-1 R2
File 24	Attachment Z- Powerton U5 CT PT Verifications 2015 11 17	PRC-005-1 R2
File 25	Attachment AC- Powerton U6 NERC Trip Checks 2015 09 30	PRC-005-1 R2

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 26	Attachment AB- Powerton U6 CT PT Verifications 2015 11 17	PRC-005-1 R2
File 27	Attachment AA- Powerton U5 NERC Trip Checks 2015 05 11	PRC-005-1 R2
File 28	Attachment Y- Will County Unit 4 Instrument Transformer Checks	PRC-005-1 R2
File 29	Attachment X- Will County Unit 4 DC Trip Checks	PRC-005-1 R2

Verification of Mitigation Plan Completion

Milestone 1: Waukegan Unit 31 CT/PT Test Document

File 13, *Attachment M - Waukegan Peaker NERC CT PT Checks.pdf*, consists of the detailed procedure issued June 1, 2015 for testing of the CTs/PTs for Waukegan Peakers & BOP.

Milestone #1 completion verified.

Milestone 2: Waukegan Unit 31 DC Functional Test Plan.

File 14, *Attachment N - Waukegan Peaker NERC Trip Checks.pdf*, consists of the detailed procedure issued June 1, 2015 for DC trip control circuitry and trip checks of Waukegan Peakers & BOP.

Milestone #2 completion verified.

Milestone 3: Waukegan Unit 31 CT/PT Test Document.

File 21, *Waukegan Peakers 31_32 2015 Relay Testing Attachment T*, consists of completed test records for Waukegan 31 and 32.

Milestone #3 completion verified.

Milestone 4: Waukegan Unit 32 DC Functional Test Plan

File 14, *Attachment N - Waukegan Peaker NERC Trip Checks.pdf*, consists of the detailed procedure issued June 1, 2015 for DC trip control circuitry and trip checks of Waukegan Peakers & BOP.

Milestone #4 completion verified.

Milestone 5: Waukegan Unit 7 CT/PT Test Document

File 15, *Attachment O - Waukegan Unit 7 NERC CT PT Checks.doc*, consists of the detailed procedure issued June 1, 2015 for testing of the CTs/PTs for Waukegan Unit 7.

Milestone #5 completion verified.

Milestone 6: Waukegan Unit 7 DC Functional Test Plan

File 16, *Attachment P - Waukegan Unit 7 NERC Trip Checks.doc*, consists of the detailed procedure issued June 1, 2015 for DC trip control circuitry and trip checks of Waukegan Unit 7.

Milestone #6 completion verified.

Milestone 7: Waukegan Unit 8 CT/PT Test Document

File 17, *Attachment Q - Waukegan Unit 8 NERC CT PT Checks.doc*, consists of the detailed procedure issued June 1, 2015 for testing of the CTs/PTs for Waukegan Unit 8.

Milestone #7 completion verified.

Milestone 8: Waukegan Unit 8 DC Functional Test Plan.

File 18, *Attachment R - Waukegan Unit 8 NERC Trip Checks.doc,* consists of the detailed procedure issued June 1, 2015 for DC trip control circuitry and trip checks of Waukegan Unit 8.

Milestone #8 completion verified.

Milestone 9: Joliet Unit 6 CT/PT Testing.

File 1, *Attachment A -Unit 6 Template NERC CT_PT Checks.pdf*, consists of the detailed procedure issued May 5, 2015 for testing of the CT/PTs for Joliet Unit 6.

Milestone #9 completion verified.

Milestone 10: Joliet Unit 6 DC Functional Test Plan.

File 3, *Attachment C -Unit 6 Template NERC DC Functional Test Plan.pdf*, consists of the detailed procedure issued May 14, 2015 for testing of the DC trip control circuitry and trip tests for Joliet Unit 6.

Milestone #10 completion verified.

Milestone 11: Joliet Unit 7 CT/PT Testing

File 5, *Attachment E -Unit 7 Template NERC CT_PT Checks.pdf*, consists of the detailed procedure issued March 23, 2015 for testing of the CT/PTs for Joliet Unit 7.

Milestone #11 completion verified.

Milestone 12: Joliet Unit 7 DC Functional Test Plan

File 7, *Attachment G-Unit 7 Template NERC DC Functional Test Plan.pdf,* issued April 2, 2015 for testing of the DC trip control circuitry and trip tests for Joliet Unit 7.

Milestone #12 completion verified.

Milestone 13: Joliet Unit 8 CT/PT Testing

File 9, *Attachment I -Unit 8 Template NERC CT_PT Checks.pdf*, consists of the detailed procedure issued April 9, 2015 for testing of the CT/PTs for Joliet Unit 8.

Milestone #13 completion verified.

Milestone 14: Joliet Unit 8 DC Functional Plan

File 11, *Attachment K-Unit 8 Template NERC CT_PT Checks.pdf*, consists of the detailed procedure issued April 15, 2015 for testing of the DC trip control circuitry and trip tests for Joliet Unit 8.

Milestone #14 completion verified.

Milestone 15: Joliet Unit 6 CT/PT Testing

File 2, *Attachment B-Unit 6 2015 6 CT_PT Testing.pdf*, consists of the completed tests records for Joliet Unit 6 dated May 3, 2015.

Milestone #15 completion verified.

RELIABILITY FIRST

Milestone 16: Joliet Unit 6 DC Functional Testing

File 4, *Attachment D Unit 6 2015 DC Functional Testing.pdf*, consists of the completed test records for Joliet 6 dated May 26, 2015.

Milestone #16 completion verified.

Milestone 17: Joliet Unit 7 CT/PT Testing

File 6, *Attachment F-2015-Unit 7 CT_PT Testing.pdf*, consists of the completed tests records for Joliet Unit 7 dated June 21, 2015.

Milestone #17 completion verified.

Milestone 18: Joliet Unit 7 DC Functional Test Plan

File 8, *Attachment H-2015-Unit 7 DC Functional Testing.pdf*, consists of the completed tests records for Joliet Unit 7 dated June 21, 2015.

Milestone #18 completion verified.

Milestone 19: Joliet Unit 8 CT/PT Testing

File 10, *Attachment J-2015 Unit 8 CT_PT Checks.pdf*, consists of the completed tests records for Joliet Unit 8 dated June 12, 2015.

Milestone #19 completion verified.

Milestone 20: Joliet Unit 8 DC Functional Test Plan

File 12, *Attachment L-2015-Unit 8 DC Functional Testing.pdf,* consists of the completed tests records for Joliet Unit 8 dated May 14, 2015.

Milestone #20 completion verified.

Milestone 21: Powerton Unit 5 CT/PT Test Document

File 24, *Attachment Z - Powerton U5 CT_PT Verifications - 2015_11_17.pdf*, consists of the completed test records for Powerton Unit 5 dated November 17, 2015.

Milestone #21 completion verified.

Milestone 22: Powerton Unit 5 DC Functional Test Plan

File 27, *Attachment AA - Powerton U5 NERC Trip Checks 2015_05_11.pdf*, consists of the detailed procedure and completed DC Functional test records for Powerton 5 dated May 11, 2015.

Milestone #22 completion verified.

Milestone 23: Powerton Unit 6 CT/PT Test Document

File 26, *Attachment AB - Powerton U6 CT_PT Verifications - 2015_11_17.pdf*, consists of the completed test records for Powerton Unit 6 dated November 17, 2015.

Milestone #23 completion verified.

Milestone 24: Powerton Unit 6 DC Functional Test Plan.

File 25, *Attachment AC - Powerton U6 NERC Trip Checks*, consists of the detailed procedure and completed DC Functional test records for Powerton 6 dated September 30, 2015.

Milestone #24 completion verified.

Milestone 25: Waukegan Unit 31 CT/PT Testing

File 21, *Waukegan Peakers 31_32 2015 Relay Testing Attachment T - WinZip Pro*, consists of completed test records for Waukegan 31 and 32.

File 22, *Waukegan Peakers 31_32 Relay Cal Files Attachment U - WinZip Pro*, consists of completed test records for Waukegan 31 and 32.

Milestone #25 completion verified.

Milestone 26: Waukegan Unit 31 DC Functional Testing

File 21, *Waukegan Peakers 31_32 2015 Relay Testing Attachment T - WinZip Pro*, consists of completed test records for Waukegan 31 and 32.

File 22, *Waukegan Peakers 31_32 Relay Cal Files Attachment U - WinZip Pro*, consists of completed test records for Waukegan 31 and 32.

Milestone #26 completion verified.

Milestone 27: Waukegan Unit 32 CT/PT Testing

File 21, *Waukegan Peakers 31_32 2015 Relay Testing Attachment T - WinZip Pro*, consists of completed test records for Waukegan 31 and 32.

Milestone #27 completion verified.

Milestone 28: Waukegan Unit 32 DC Functional Testing

File 21, *Waukegan Peakers 31_32 2015 Relay Testing Attachment T - WinZip Pro*, consists of completed test records for Waukegan 31 and 32.

Milestone #28 completion verified.

Milestone 29: Waukegan Unit 7 CT/PT Testing

File 20, *Waukegan Unit 7 CT_PT Checks Attachment V.pdf*, consists of the completed CT/PT test records for Waukegan 7 dated September 14, 2015.

Milestone #29 completion verified.

Milestone 30: Waukegan Unit 7 DC Functional Testing

File 23, *NGR - Waukegan Unit 7 Relay Test Reports Attachment W - WinZip Pro,* consists of the completed relay test reports in August 2015 for Waukegan 7.

Milestone #30 completion verified.

Milestone 31: Waukegan Unit 8 CT/PT Testing

File 19, *Waukegan Unit 8 2015 Relay Testing Attachment S.zip*, consists of the completed CT/PT test records dated July 21, 2015 for Waukegan 8.

Milestone #32 completion verified.

Milestone 32: Waukegan Unit 8 DC Functional Testing

File 19, *Waukegan Unit 8 2015 Relay Testing Attachment S.zip*, consists of the completed Relay Test records dated July 21, 2015 for Waukegan 8.

Milestone #32 completion verified.

Milestone 33: Will County Unit 4 CT/PT Test Document

File 28, *ATTACHMENT Y - Will County Unit 4 Instrument Transformer Checks.pdf*, consists of the detailed procedure for conducting CT/PT testing for Will County Unit 4.

Milestone #33 completion verified.

Milestone 34: Will County Unit 4 DC Functional Test Plan

File 29, *ATTACHMENT X - Will County Unit 4 DC Trip Checks.pdf*, consists of the detailed procedure for conducting trip checks for Will County Unit 4.

Milestone #34 completion verified.

Milestone 35: Powerton Unit 5 CT/PT Testing

File 24, *Attachment Z - Powerton U5 CT_PT Verifications - 2015_11_17.pdf*, consists of the completed test records for Powerton 5.

Milestone #35 completion verified.

Milestone 36: Powerton Unit 5 DC Functional Test Plan

File 27, *Attachment AA - Powerton U5 NERC Trip Checks 2015_05_11.pdf*, consists of the completed DC Functional test records for Powerton 5 dated May 11, 2015.

Milestone #36 completion verified.

Milestone 37: Powerton Unit 6 CT/PT Testing

File 26, *Attachment AB - Powerton U6 CT_PT Verifications - 2015_11_17.pdf*, consists of the completed CT/PT test records for Powerton 6.

Milestone #37 completion verified.

Milestone 38: Powerton Unit 6 DC Functional Test Plan

File 25, *Attachment AC - Powerton U6 NERC Trip Checks*, consists of the detailed procedure and completed DC Functional test records for Powerton 6 dated September 30, 2015.

Milestone #38 completion verified.

The Mitigation Plan is hereby verified complete.

Date: February 26, 2016

Tony Purgar
Manager, Risk Analysis & Mitigation
ReliabilityFirst Corporation

Attachment D

Disposition Document for RFC2014014203 (PRC-005-1 R2; R2.1)

d.1. Notice of Possible Violation, submitted on August 5, 2014

RELIABILITY FIRST

[redacted]

Possible Violation (PV) / Find, Fix, and Track ("FFT") Identification Form

This document is to be completed upon identification of a possible violation, typically within 5 business days of the audit exit brief, and emailed to Veronica Miller (Paralegal) with a copy to: Jim Uhrin (Director, Compliance Monitoring), Gary Campbell (Manager, Ops & Planning Monitoring or Ray Sefchik (Manager, CIP Monitoring) or and Niki Schaefer (Managing Enforcement Attorney).

For non-FFT candidates: Upon receipt of this document, Enforcement will coordinate with the reporting auditor and Enforcement to initiate the Enforcement processing of this possible violation.

Violation Reported By: Glenn Kaht

Submittal Date: 8/5/14

Candidate for FFT Treatment: YES ☐ NO ☒

Registered Entity: GenOn REMA 1

NERC Registry ID#: NCR11141

Compliance Monitoring Process: Compliance Audits

Standard, Version and Requirement in Violation: PRC-005-1.1b R2 and R2.1

Registered Function(s) in Violation: GO

Initial PV Date (Actual Date Discovered by ReliabilityFirst): 7-24-2014

Date for Determination of Penalty/Sanction (Beginning Date of Violation): 6-14-2011

End Date of Possible Violation: Unknown

For Non-FFT Candidate ONLY
Violation Risk Factor: Choose item.
Or
R2: Lower
R2.1: High

Violation Severity Level: Choose item.
Or
R2: This is unknown until additional information is obtained.
R2.1: N/A

RELIABILITY FIRST

[redacted]

Potential Impact to Bulk Electrical System (BES): Moderate

Provide Explanation for Selection: REMA 1's failure to verify or calibrate relay settings as required and to perform maintenance and testing on DC control circuitry is not known to have resulted in an adverse impact to BES reliability, but has the potential to do so, since required maintenance and testing was not performed to help ensure the Protection System will operate correctly when required.

For Non-FFT and FFT Candidates

Basis for the PV:

R2 (R2.1):

R2.1: REMA 1 performed maintenance and testing on a generator ground relay at the Werner generating station on 10/20/2009 without having a relay setting sheet to know the correct setting and therefore to verify if the setting was correct. In addition, REMA 1 did not provide evidence of maintenance and testing of DC control circuitry that was performed prior to 2012 for 2 relays at the Gilbert generating station selected by the audit team.

For the 2 examples listed, REMA 1 did not provide evidence that REMA 1 maintained and tested Protection Systems in accordance with REMA 1's Protection System maintenance and testing program within the intervals defined by REMA 1 for the entire audit period.

Prior to closing out this Possible Violation, REMA 1 should verify that all REMA 1 Protection Systems (not just the ones identified by the audit team to be deficient) are maintained and tested in accordance with REMA 1's defined intervals.

Facts and Evidence pertaining to the PV:

R2 Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Entity on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1 Evidence Protection System devices were maintained and tested within the defined intervals

Evidence:
- REMA 1 RSAW PRC-005-1 1b Bookmark REV 1
- Werner PRC-005 Requested Samples
- Gilbert PRC-005 Requested Samples

Facts:

REMA 1 RSAW PRC-005-1 1b Bookmark REV 1 includes REMA 1's Protection System maintenance and testing program. The intervals for maintenance of testing for relays (6 calendar years) is on PDF page 35 and for maintenance and testing of DC control circuitry (6 calendar years) is on PDF page 38. The summary of maintenance and testing for relays is on PDF pages 23-24 and 35. The summary of maintenance and testing for DC control circuitry is on PDF pages 31-32 and 38.

Werner PRC-005 Requested Samples is evidence of the implementation of maintenance and testing of Protection Systems at the Werner generating station that were selected by the audit team. "Index No 574 - Werner CT4 Gen Stator Ground (59G)" is a bookmark to show the maintenance and testing performed on a sample selected by the audit team. "10/20/2009 Cal Sheet" is a bookmark to show the maintenance and testing performed (it is a relay test sheet) on the Werner CT4 stator ground relay on 10/20/2009. There is a box on the test sheet to "Set relays in accordance with coordination study supplied by owner" and that box is checked N (for No). There is a comments section on the relay test sheet and it includes the comment "No settings provided by Customer, tested and left as found." REMA 1 did not implement its own maintenance and testing on the relay "Calibrate as required" since REMA 1 did not even know the required setting. For the maintenance and testing performed on this same relay in 2012 (bookmarked as "12/03/2012 Cal Sheet") it is unclear if the setting for the relay was known, since the test sheet to "Set relays in accordance with coordination study supplied by owner" is blank.

Gilbert PRC-005 Requested Samples is evidence of the implementation of maintenance and testing of Protection Systems at the Gilbert generating station that were selected by the audit team. "Gilbert Combined Cycle (STAG) DC Trip Tests (2012)" is a bookmark that provided evidence of maintenance and testing of DC control circuitry on relays associated with index 58 (Gilbert CC6 Gen Diff (87G-2)) and 100 (Gilbert CC8 8A Overload (51T-8A)). The audit team requested evidence of maintenance and testing of the DC control circuitry associated with these 2 relays to show that REMA 1 maintained and tested the DC control circuitry within the defined intervals for the entire audit period, and was not provided with relevant evidence.

For FFT Candidates ONLY

1. Why did this possible violation pose a minimal risk:

   Click here to enter text.

2. Has Registered Entity mitigated this possible violation: YES ☐ NO ☐
   a. If yes, describe mitigating actions and state the date that Registered Entity completed the mitigating actions:

   Click here to enter text.

3. Please answer the following questions to determine whether this possible violation constitutes a "clear on its face" FFT candidate or a "close call." If the answer to any of the following questions is yes, this possible violation will be treated as a "close call." Otherwise, this possible violation will be treated as a "clear on its face" FFT candidate.

RELIABILITY FIRST

[redacted]

A. Is there any disagreement amongst the audit team on whether the PV is a "clear on its face" or "close call" candidate: YES ☐ NO ☐

   a. If yes, explain why:

      Click here to enter text.

B. Does this possible violation reveal a serious shortcoming in registered entity's reliability-related processes (e.g. a systematic compliance program failure):

   YES ☐ NO ☐

   a. If yes, explain why:

      Click here to enter text.

C. Are there any additional facts the audit team needs to know in order to comfortably designate this possible violation for FFT treatment: YES ☐ NO ☐

   a. If yes, state those facts:

      Click here to enter text.

4. Did audit team inform registered entity that this possible violation qualifies for FFT treatment? YES ☐ NO ☐

   a. If so, on what date? Enter Date.

Attachment E

Disposition Documents for RFC2014013615 (VAR-002-2b R2)

e.1. GenOn Power Midwest's Self-Report, submitted on February 26, 2014;

e.2 Mitigation Plan RFCMIT010534, submitted on March 14, 2014;

Self Report - 2014

Entity Name: GenOn Power Midwest
NERC ID: NCR11136
Active: Yes
Violation Started in Program Year: 2013
Standard: VAR-002-2b
Requirement: R2
Date Submitted: February 26, 2014
Has this violation previously been reported or discovered?: No

Entity Information:

Joint Registration Organization (JRO) ID:

Coordinated Functional Registration (CFR) ID:

Contact Name: Robert Burkhart
Contact Phone: 7247472357
Contact Email: robert.burkhart@nrgenergy.com

Violation:

Violation Start Date: October 12, 2013
End/Expected End Date: October 13, 2013
Region Initially Determined a Violation On: December 04, 2013
Reliability Functions: Generator Operator (GOP)
Is Possible Violation still occurring?: No
Has this Possible Violation been reported to other Regions?: No
Which Regions:
Date Reported to Regions:
Detailed Description and Cause of Possible Violation:

When operating Brunot Island Unit 3, the voltage output exceeded the Voltage Schedule from 0100 to 1830 on 10/12/2013; and, from 1930 on 10/12/2013 to 0800 on 10/13/2013. The highest level achieved during these periods was 0.68% (970V) and 0.67% (960V) above the scheduled maximum level, respectively. See Attachment 1.

When operating Brunot Island Unit 4, the voltage output exceeded the Voltage Schedule from 0415 to 1200 on 10/12/2013. The highest level achieved during this period was 0.52% (750V) above the scheduled maximum level. See Attachment 2.

When operating Brunot Island Unit 4, the voltage output exceeded the Voltage Schedule from 0030 to 0715 on 10/13/2013. The highest level achieved during this period was 0.12% (170V) above the scheduled maximum level. See Attachment 3.

These excursions were not recognized by the operators at the plant, or by the Commercial Desk at Princeton, NJ. No phone calls were made to the Transmission Operator to alert them to the fact that we could not maintain Voltage Schedule during any of these periods.

Mitigating Activities:

Self Report - 2014

Description of Mitigating Activities and Preventative Measure: Having occurred unnoticed, no mitigating actions were taken during the periods in question to curtail the incidents.

Date Mitigating Activities Completed:

Impact and Risk Assessment:

Potential Impact to BPS: Severe

Actual Impact to BPS: Minimal

Description of Potential and Actual Impact to BPS: Brunot Island was unable to maintain the directed values contained in the Voltage Schedule in all three (3) instances.

Risk Assessment of Impact to BPS: GenOn Power Midwest maintains that this Self Report resulted in a low risk to the reliable operation of the BES since the capabilities of these units to influence the system voltage is considered minimal at their Points of Interconnection. Unit 3 is rated at 46MW @ 66MVA while Unit 4 is rated at 106MW @ 160MVA.

Additional Entity Comments: GenOn Power Midwest adheres to a strong culture of compliance as described within GenOnâ€™s NERC Internal Compliance Program (ICP) â€“ Governance Document / Legacy GenOn NERC ICP (Attachment 4). It is GenOnâ€™s goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability.

Additional Comments		
From	Comment	User Name
Entity	During a scheduled internal review of compliance to the Duquesne Light Voltage Schedule on 12/4/2013, it was discovered that Units 3 & 4 had operated out of schedule for the periods noted. Having occurred unnoticed, no mitigating actions were taken during the periods in question to curtail the incidents.	Bob Burkhart

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Attachment 1 - BI Unit 3 Voltage Readings.pdf	Printout of voltage output of Brunot Island Unit 3 from 10/12/2013 thru 10/13/2013.	2,126,181
Entity	Attachment 2 - BI Unit 4 Voltage Readings 101213.pdf	Printout of voltage output of Brunot Island Unit 4 on 10/12/2013.	1,710,414
Entity	Attachment 3 - BI Unit 4 Voltage Readings 101313.pdf	Printout of voltage output of Brunot Island 4 on 10/13/2013.	898,392
Entity	Attachment 4 - Legacy GenOn NERC ICP.pdf	NRG NERC Internal Compliance Program Governance Document Applicable to Legacy GenOn Assets	734,151
Entity	SOM-2-01-1 1 Attach 5 RRI Energy Voltage Schedule (2).doc	Duquesne Light Voltage Schedule	182,272

Mitigation Plan

Registered Entity: GenOn Power Midwest

Mit Plan Code	NERC Violation ID	Requirement	Violation Validated On	Mit Plan Version
null	RFC2014013615	VAR-002-2b R2	null	1

Mitigation Plan Submitted On: March 14, 2014
Mitigation Plan Accepted On:
Mitigation Plan Proposed Completion Date: July 01, 2014
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by GPM On:
Mitigation Plan Completion Verified by RFC On:
Mitigation Plan Completed? (Yes/No): No

Section A: Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Section B: Registered Entity Information

B.1 Identify your organization:

Entity Name: GenOn Power Midwest
NERC Compliance Registry ID: NCR11136
Address: 1000 Main Street
Houston TX 77002

B.2 Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Robert Burkhart
Title: Manager - Regulatory Compliance
Email: robert.burkhart@nrgenergy.com
Phone: 724-597-8553

Section C: Identification of Reliability Standard Violation(s) Associated with this Mitigation Plan

C.1 This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
RFC2014013615	10/12/2013	VAR-002-2b R2
Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within applicable Facility Ratings as directed by the Transmission Operator.		

C.2 Brief summary including the cause of the violation(s) and mechanism in which it was identified above:

On December 3, 2013, Brunot Island Station personnel were conducting a scheduled periodic (quarterly) review of the station output to be able to provide attestations and evidence of compliance to VAR-002 / Maintaining Voltage Schedule for the company's records. During this review it was discovered that Brunot Island Units 3 & 4 were over the upper voltage limits on three (3) occasions in October, 2013. Not being noticed by the plant operators during these episodes, no mitigating actions were taken to curtail the incidents. No phone calls were ever made to the TO (Duquesne Light Company) or PJM regarding our inability to stay inside the voltage limits. The Commercial Operations Desk in Princeton, NJ cannot provide any evidence on how they also did not notice these exceedances of the Volatge Schedule upper limits.

C.3 Provide any relevant information regarding the identification of the violation(s) associated with this Mitigation Plan:

When operating Brunot Island Unit 3, the voltage output exceeded the Voltage Schedule from 0100 to 1830 on 10/12/2013; and, from 1930 on 10/12/2013 to 0800 on 10/13/2013. The highest level achieved during these periods was 0.68% (970V) and 0.67% (960V) above the scheduled maximum level, respectively.

When operating Brunot Island Unit 4, the voltage output exceeded the Voltage Schedule from 0415 to 1200 on 10/12/2013. The highest level achieved during this period was 0.52% (750V) above the scheduled maximum level.

When operating Brunot Island Unit 4, the voltage output exceeded the Voltage Schedule from 0030 to 0715 on 10/13/2013. The highest level achieved during this period was 0.12% (170V) above the scheduled maximum level.

Current controls at the station do not provide readily available voltage indication for the 138kV system. No warning alarms exist for high or low voltage.

Section D: Details of Proposed Mitigation Plan

D.1 Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

1. Incorporate a new step into the unit operating procedures to monitor output voltage when placing a unit on-line using the Trader.ems software system.
2. Obtain Trader.ems login passwords for all operators.
3. Install an additional computer display in the plant's control room which will be dedicated to displaying Trader.ems data for operations personnel to monitor real time station voltages.
4. Create a more user friendly method (DCS vs. Trader.ems) for operations personnel to monitor real time station voltages.
5. Create an alarm to alert station operators that voltage is approaching a limit.
6. An alarm is intiated at the Commercial Operations Desk in Princeton, NJ when any unit is outside its Voltage Schedule. A second alarm will be added to intiate twenty minutes after the first alarm should the unit not be able to get within schedule. This will give the Commn Ops Desk sufficient time to contact the TO of our situation.

D.2 Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: July 01, 2014

D.3 Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Additional Alarm at Comm Ops Desk	Create a second alarm at the Comm Ops Desk that will intiate twenty minutes after the first alarm is received of a unit being outside its Voltage Schedule. This second alarm will activate should the unit not be able to get within schedule.	11/13/2013	11/13/2013
Operating Procedure Revisions	Incorporate a new step into the unit operating procedures to monitor output voltage when placing a unit on-line using the Trader.ems software system	01/10/2014	01/10/2014
Login Passwords	Obtain Trader.ems login passwords for all operators. The voltage values in Trader.ems are the same ones used by PJM.	01/10/2014	01/10/2014
Additional Computer Display	Install an additional computer display in the plant's control room which will be dedicated to displaying Trader.ems data for operations personnel to monitor real time station voltages.	02/28/2014	02/28/2014

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Voltage Monitoring	Create a more user friendly method for operations personnel to monitor real time station voltages.	04/01/2014	
Voltage Limit Alarm	Create an alarm to alert station operators that voltage is approaching a limit.	07/01/2014	

D.4 Additional Relevant Information (Optional)

Section E: Interim and Future Reliability Risk

E.1 Abatement of Interim BPS Reliability Risk

While your organization is implementing the Mitigation Plan proposed in Section D of this form, the reliability of the Bulk Power System may remain at higher risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are, or may be, known or anticipated: (i) identify any such risks or impacts; and (ii) discuss any actions that your organization is planning to take or is proposing as part of the Mitigation Plan to mitigate any increased risk to the reliability of the bulk power system while the Mitigation Plan is being implemented:

The risk to the reliability of the BES will be minimal since the NRG Commercial Operations Desk in Princeton, NJ has a second alarm sounding 20 minutes following the initial alarm if any unit has not adjusted itself back into the Voltage Schedule.

E.2 Prevention of Future BPS Reliability Risk

Describe how successful completion of the Mitigation Plan as laid out in Section D of this form will prevent or minimize the probability that your organization incurs further violations of the same or similar reliability standards requirements in the future:

Improved indications and alarms at the station will provide the operators with more tools to monitor and correct station voltage discrepancies. The additional alarm at the Comm Ops Desk in Princeton, NJ will provide backup to the statikon.

E.3 Your organization may be taking or planning other action, beyond that listed in the Mitigation Plan, as proposed in Section D.1, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements listed in Section C.1, or of other reliability standards. If so, identify and describe any such action, including milestones and completion dates:

Additional refresher trainng will conducted and documented. Providing additional training under such circumstances is standard procedure at GenOn / NRG Energy.

Section F: Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

(a) Submits the Mitigation Plan, as laid out in Section D, to the Regional Entity for acceptance and approval by NERC, and

(b) If applicable, certifies that the Mitigation Plan, as laid out in Section D of this form, was completed (i) as laid out in Section D of this form and (ii) on or before the date provided as the 'Date of Completion of the Mitigation Plan' on this form, and

(c) Acknowledges:

1. I am Manager - Regulatory Compliance of GenOn Power Midwest
2. I am qualified to sign this Mitigation Plan on behalf of GenOn Power Midwest
3. I have read and understand GenOn Power Midwest's obligations to comply with Mitigation Plan requirements and ERO remedial action directives as well as ERO documents, including, but not limited to, the NERC Rules of Procedure and the NERC CMEP currently in effect or the NERC CMEP-Province of Manitoba, Schedule B currently in effect, whichever is applicable.
4. I have read and am familiar with the contents of the foregoing Mitigation Plan.
5. GenOn Power Midwest Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authorities in Canada.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Robert Burkhart

Title: Manager - Regulatory Compliance

Authorized On: March 14, 2014

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name:	GenOn Power Midwest
NERC Registry ID:	NCR11136
NERC Violation ID(s):	RFC2014013615
Mitigated Standard Requirement(s):	VAR-002-2b R2,
Scheduled Completion as per Accepted Mitigation Plan:	July 01, 2014
Date Mitigation Plan completed:	June 17, 2014
RFC Notified of Completion on Date:	August 05, 2014
Entity Comment:	The last of six (6) Milestone Activities was completed on June 17, 2014.

Additional Comments

From	Comment	User Name
Entity	GenOn Power Midwest adheres to a strong culture of compliance as described within GenOnâ€™s NERC Internal Compliance Program (ICP) â€“ Governance Document / Legacy GenOn NERC ICP. It is GenOnâ€™s goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability.	Bob Burkhart

Additional Documents

From	Document Name	Description	Size in Bytes
Entity	IMG_1242.jpg	This document addresses Milestone Activity # 4 / Additional Computer Display. This screenshot shows the new Operator Display Screen in the Station Control Room.	2,399,123
Entity	IMG_1243.jpg	This document addresses Milestone Activity # 4 / Additional Computer Display. This screenshot is a close-up photo of the new Operator Display Screen in the Station Control Room.	2,467,011
Entity	Startup, Cold, Integrated Checklist, 1-081913.pdf	This document addresses Milestone Activity # 2 / Operating Procedure Revisions. This procedure contains guidelines for operating personnel to follow after notification by Dispatch for operation of the Combined Cycle Plant (Units 2A, 2B, 3 & 4). From notification from Dispatch to first CT on the bus should take approximately 90 minutes. The sequence is recommended, however several systems may have been placed in-service and/or steps may have been performed in advance.	148,192

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Startup, Warm, Integrated Checklist - 1-061013.pdf	This document addresses Milestone Activity # 2 / Operating Procedure Revisions. This procedure contains guidelines for operating personnel to follow after notification by Dispatch for operation of the Combined Cycle Plant (Units 2A, 2B, 3 & 4). For environmental compliance purposes a â€œWarm Startâ€ is defined as an event that occurs after the combustion turbine has not been operating for more than 8 hours but less than 24 hours. A warm start-up shall not last longer than 5 hours after ignition.	137,253
Entity	Startup, Hot, Integrated Checklist - , 1-061013.pdf	This document addresses Milestone Activity # 2 / Operating Procedure Revisions. This procedure contains guidelines for operating personnel to follow after notification by Dispatch for operation of the Combined Cycle Plant (Units 2A, 2B, 3 & 4). For environmental compliance purposes a â€œHot Startâ€ is defined as an event that occurs after the combustion turbine has not been operating for less than or equal to 8 hours. A hot start-up shall not last longer than 3 hours after ignition.	137,381
Entity	Unit 1A Startup Checklist 1-051413.pdf	This document addresses Milestone Activity # 2 / Operating Procedure Revisions. This Operating Procedure provides guidelines for the startup, normal operation and shutdown of Unit 1A, a simple cycle unit.	82,911
Entity	BI Trader Screens.pdf	This document addresses Milestone # 5 Activity / Voltage Monitoring. This document shows the screens in Trader.ems that display Actual Voltages versus Scheduled Voltages for each of the Brunot Island Units along with Unit statuses.	689,910
Entity	Comm Ops Desk New Voltage Moniotoring Screen.pdf	This document addresses Milestone Activity # 1 / Additional Alarm at Comm Ops Desk. This document shows snapshots of the new voltage monitoring screens used by the Commercial Operations Desk in Princeton, NJ to actively monitor 30-minute rolling average voltage levels. This document details how the various screens operate and are used.	644,343
Entity	DLCo Voltage Schedule.pdf	This document addresses Milestone Activity # 4 / Additional Computer Display. The voltage limits shown in this Duquesne Light Company Voltage Schedule that the Brunot Island Station is required to follow were utilized to develop the DCS screen.	468,601
Entity	Trader Password Chang.msg	This document addresses Milestone Activity # 3 / Login Passwords. It is a copy of an email to the station control room operators informing them of the password to be used to log on to Trader.ems to access the Voltage Schedule Compliance Page.	61,440

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Tools to maintain proper voltage corrective actions for NERC violation.pdf	This document is the roster of operators and supervisors at the Brunot Island Facility that completed refresher training on maintaining volatge schedules. This training incorporated all of the corrective actions that were implemented as a part of this Mitigation Plan. This training pertains to the commitment to conduct refresher training as noted in Section E, subparagraph E.3.	37,647

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Alan Johnson

Title: NRG Regulatory Compliance Officer

Email: Alan.Johnson@nrgenergy.com

Phone: 1 (609) 524-4876

Authorized Signature ______________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Mitigation Plan Verification for RFC2014013615

GenOn Power Midwest ("GenOn")

Standard/Requirement: VAR-002-2b R2

NERC Mitigation Plan ID: RFCMIT010534

Method of Disposition: Not yet determined

Relevant Dates					
Initiating Document	**Mitigation Plan Submittal**	**RF Acceptance**	**NERC Approval**	**Certification Submittal**	**Date of Completion**
Self-Report 02/26/14	03/14/14	04/01/14	04/25/14	08/05/14	06/17/14

Description of Issue

On December 3, 2013, Brunot Island Station personnel were conducting a scheduled quarterly review of the station output to be able to provide attestations and evidence of compliance to VAR-002 / Maintaining Voltage Schedule for the company's records. During this review it was discovered that Brunot Island Units 3 & 4 were over the upper voltage limits on three (3) occasions in October 2013. The plant operators failed to identify these voltage excursions and thus they did not notify the TO or PJM.

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 1	BI Trader Screens	VAR-002-2b R2
File 2	Comm Ops Desk New Voltage Monitoring Screen	VAR-002-2b R2
File 3	DLCo Voltage Schedule	VAR-002-2b R2
File 4	IMG 1242	VAR-002-2b R2
File 5	IMG 1243	VAR-002-2b R2
File 6	Startup, Cold, Integrated Checklist, 1-081913	VAR-002-2b R2
File 7	Startup, Hot, Integrated Checklist, 1-061013	VAR-002-2b R2

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 8	Startup, Warm, Integrated Checklist, 1-061013	VAR-002-2b R2
File 9	Unit 1A Startup Checklist 1-051413	VAR-002-2b R2
File 10	Tools to maintain proper voltage corrective actions for NERC violation	VAR-002-2b R2
File 11	DCS Voltage Level Alarm Logic	VAR-002-2b R2
File 12	Real Time voltage Monitoring Screens	VAR-002-2b R2
File 13	RE Trader Password Change	VAR-002-2b R2
File 14	RE Additional Information	VAR-002-2b R2

Verification of Mitigation Plan Completion

Milestone 1: Additional Alarm at Comm Ops Desk

File 11, *DCS Voltage Level Alarm Logic*, illustrates the conditions and timing sequence for Unit 1A, Unit 2A, Unit 2V, Unit 3 and Unit 4.

Milestone #1 completion verified.

Milestone 2: Operating Procedure Revisions

File 14, *RE: Additional Information*, includes Doc20160819085422.pdf as an attachment which consists of the completed Brunot Island Power Station Integrated Startup Procedure and Checklist dated April 14, 2015. Note on Page 7, refers to setup of the voltage display using the Trader application. Attachment Unit 1A, Startup Checklist 1-051413.pdf, consists of the Brunot Island Plant Operating Procedure, OPS-003 1A Operation approved by the Operations Supervisor on March 26, 2013. Note on Page 8, refers to setup of the voltage display using the Trader application. This demonstrates completion of this milestone.

Milestone #2 completion verified.

Milestone 3: Login Passwords

File 13, *RE Trader Password Change*, includes an internal email string. Email dated December 4, 2013, involves changing of Trader password by Smart/Trader Support. Email dated December 5, 2013, is notification to all operators of password change.

Milestone #3 completion verified.

Milestone 4: Additional Computer Display

File 4, *IMG_1242*, is screenshot of new Operator Display Screen titled "PJM Historical Voltage Monitoring", BRUNOTIS-3 Actual vs. Schedule Voltage.

File 5, *IMG_1243*, is close-up of the display provided in File 4.

File 3, *DLCo Voltage Schedule*, includes the DLCO voltage schedule that Brunot Island Station is required to follow per SOM-2-01, Attachment 5, RRI Energy Voltage Schedule, Revision 1.1, Effective Date: September 20, 2010.

Milestone #4 completion verified.

Milestone 5: Voltage Monitoring

File 1, *BI Trader Screens*, illustrates the EMS screens that display Actual vs Scheduled voltages with unit statuses.

Milestone #5 completion verified.

Milestone 6: Voltage Limit Alarm

File 12, *Real Time Voltage Monitoring Screens*, includes Balance of Plant - Voltage Schedule for the Brunot Island units which indicates the scheduled, actual and high and low alarm limits.

Milestone #6 completion verified.

The Mitigation Plan is hereby verified complete.

Date: November 2, 2016

Tony Purgar
Manager, Risk Analysis & Mitigation
ReliabilityFirst Corporation

Attachment F

Disposition Documents for RFC2014014540 (VAR-002-2b R2)

f.1. Notice of Possible Violation, submitted on November 19, 2014;

f.2 Mitigation Plan RFCMIT011610-1, submitted on July 20, 2015;

f.3 Certification of the Mitigation Plan Completion, dated July 21, 2015;

f.4 Mitigation Plan Verification for RFCMIT011610-1, dated January 28, 2016;

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[redacted]

Possible Violation (PV) / Find, Fix, and Track ("FFT") Identification Form

This document is to be completed upon identification of a possible violation, typically within 5 business days of the audit exit brief, and emailed to Shirley Ortiz (Paralegal) with a copy to Jim Uhrin (Director, Compliance Monitoring), Gary Campbell (Manager, Ops & Planning Monitoring or Ray Sefchik (Manager, CIP Monitoring) and Niki Schaefer (Managing Enforcement Attorney).

For non-FFT candidates: Upon receipt of this document, Enforcement will coordinate with the reporting auditor and Enforcement to initiate the Enforcement processing of this possible violation.

Violation Reported By: Kellen Phillips

Submittal Date: 11/19/14

Candidate for FFT Treatment: YES ☐ NO ☒

Registered Entity: Boston Energy Trading and Marketing, LLC

NERC Registry ID#: NCR00769

Compliance Monitoring Process: Compliance Audits

Standard, Version and Requirement in Violation: VAR-002-2b R2

Registered Function(s) in Violation: GO/GOP

Initial PV Date (Actual Date Discovered by ReliabilityFirst): 11/11/14

Date for Determination of Penalty/Sanction (Beginning Date of Violation): 7/17/13

End Date of Possible Violation: Click here to enter text.

For Non-FFT Candidate ONLY

Violation Risk Factor: VRF - Medium

Violation Severity Level: Severe VSL

Potential Impact to Bulk Electrical System (BES): Moderate

Provide Explanation for Selection:
Four out of the five samples requested for Waukegan had periods where the voltage was outside of the voltage schedule. The voltage issues in three of the four samples were short in duration and may have posed minimal risk but the fourth sample was more extreme. On July 17, 2013 Waukegan Unit 7 was outside of the schedule for almost 12 hours total and by 2kV for part of that time.

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[redacted]

For Non-FFT and FFT Candidates

Basis for the PV:
R2: The Generator Operator did not maintain the generator voltage as directed by the Transmission Operator. EMMT's Waukegan Unit 7 operated outside of their voltage schedule on July 17, 2103 from 03:12:00 to 09:04:00 and again from 13:02:00 to 18:59:00.

Facts and Evidence pertaining to the PV:

The requirement states:

R2 Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.

Evidence:
- RFC Evidence Waukegan Steam High Side Voltage Readings HIGHLIGHTEDv2
- RSAW VAR-002-2b EMMT Final
- RF Request ER-003 102214, dated October 22, 2014

R2 Based on the sampling evidence, *RFC Evidence Waukegan Steam High Side Voltage Readings HIGHLIGHTEDv2*, EMMT did not maintain the generator voltage output as directed by the Transmission Operator (TOP) Commonwealth Edison (ComEd). EMMT's Waukegan Unit 7 operated outside of their voltage schedule on July 17, 2013 from 03:12:00 to 09:04:00 and from 13:02:00 to 18:59:00. During the 03:12:00 to 09:04:00 timeframe the voltage exceeded 145kV. The document *RSAW VAR-002-2b EMMT Final* showed the voltage schedule provided by ComEd for the Waukegan Station as 141kV +/- 2 kV. The monitoring team created ER-003 evidence request and asked EMMT the following questions: Did EMMT receive an exemption from the TOP to operate outside of the schedule? Were any actions taken to correct the voltage issue? In response to ER-003, EMMT submitted *RF Request ER-003 102214.* EMMT stated "Waukegan has no records indicating it received an exemption from the TOP to operate outside of the voltage schedule and while there were times during the period that Waukegan approached operating limits, there was no overall operating limitation."

The monitoring team found the performance of Waukegan Station to be a Possible Violation due to:

1. The extended period that Waukegan Unit 7 was out of its voltage schedule on July 17, 2013 and that it operated at 145kV exceeding 143kV upper limit.

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[redacted]

2. The evidence request revealed that EMMT did not have an exemption from the TOP nor did they make any attempt to correct the voltage issue.
3. Furthermore Waukegan unit 7 was briefly out of its voltage schedule on March 28, 2014 and unit 31 was out of its voltage schedule on January 7, 2014 and February 15, 2014 showing that EMMT does not have sufficient controls in place at Waukegan to monitor and correct voltage issues.
4. Four out of the five samples requested for Waukegan had periods where the voltage was outside of the schedule and although three were minor instances it shows a greater systemic problem at Waukegan.

Mitigation Plan

Mitigation Plan Summary

Registered Entity: Boston Energy Trading and Marketing LLC

Mit Plan Code	NERC Violation ID	Requirement	Violation Validated On	Mit Plan Version
	RFC2014014540	VAR-002-2b R2.		2

Mitigation Plan Submitted On: July 20, 2015
Mitigation Plan Accepted On:
Mitigation Plan Proposed Completion Date: April 30, 2015
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by EMMT On: July 20, 2015
Mitigation Plan Completion Verified by RF On:
Mitigation Plan Completed? (Yes/No): No

Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Entity Information

Identify your organization:

Entity Name: Boston Energy Trading and Marketing LLC
NERC Compliance Registry ID: NCR00769

Address: 211 Carnegie Center
Princeton NJ 08540

Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Robert Burkhart
Title: Manager - Regulatory Compliance
Email: Robert.Burkhart@nrg.com
Phone: 724-597-8553

Violation(s)

This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
RFC2014014540	07/17/2013	VAR-002-2b R2.
Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within applicable Facility Ratings as directed by the Transmission Operator.		

Brief summary including the cause of the violation(s) and mechanism in which it was identified:

Based on the sampling evidence (RFC Evidence Waukegan Steam High Side Voltage Readings HIGHLIGHTEDv2) provided during the Fall 2014 Audit of the Boston Energy Trading and Marketing Registration, EMMT did not maintain the generator voltage output as directed by the Transmission Operator (TOP), Commonwealth Edison (ComEd). EMMT's Waukegan Unit 7 operated outside of its voltage schedule on July 17, 2013 from 03:12:00 to 09:04:00 and from 13:02:00 to 18:59:00. During the 03:12:00 to 09:04:00 timeframe the voltage exceeded 145kV. The document, RSAW VAR-002-2b EMMT Final showed the voltage schedule provided by ComEd for the Waukegan Station as 141kV +/- 2 kV. The RF monitoring team created an evidence request (ER-003) and asked EMMT the following questions: Did EMMT receive an exemption from the TOP to operate outside of the schedule? Were any actions taken to correct the voltage issue? In response to ER-003, EMMT submitted RF Request ER-003 102214. EMMT stated "Waukegan has no records indicating it received an exemption from the TOP to operate outside of the voltage schedule and while there were times during the period that Waukegan approached operating limits, there was no overall operating limitation." Upon review of the incident, the lack of appropriate controls/procedures is the likely cause of the violations.

Relevant information regarding the identification of the violation(s):

The RF monitoring team found the performance of Waukegan Station to be a Possible Violation due to:

• The extended period that Waukegan Unit 7 was out of its voltage schedule on July 17, 2013 and that it operated at 145kV exceeding 143kV upper limit.
• The evidence request revealed that EMMT did not have an exemption from the TOP nor did they make any attempt to correct the voltage issue.
• Furthermore Waukegan unit 7 was briefly out of its voltage schedule on March 28, 2014 and unit 31 was out of its voltage schedule on January 7, 2014 and February 15, 2014 showing that EMMT does not have sufficient controls in place at Waukegan to monitor and correct voltage issues.
• Four out of the five samples requested for Waukegan had periods where the voltage was outside of the schedule and although three were minor instances it shows a greater systemic problem at Waukegan.

Plan Details

Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

To prevent further violations additional voltage monitoring alarms (both on-site and remote) and a comprehensive training plan have been created for the control room operators. This includes instruction on transmission system voltage limits, response to voltage excursions, alarms / voltage monitoring, response to AVR trips to manual, proper log and record keeping protocol, storage of signed training documents, and a site specific checklist outlining proper response to voltage excursions. This plan has been reviewed by NRG Compliance group and has been found acceptable.

Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: April 30, 2015

Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Station Specific Document for Response to Voltage Excursion	Create a station specific document for Waukegan Operator response.	04/14/2015	04/14/2015	Voltage Response Checklist is complete and has been attached to this Plan. See Attachment D.	No
Voltage Excursion Alarm	Create control room alarm for excursions.	04/14/2015	04/14/2015	Alarms have been initiated and confirmed operational. See Attachment C.	No
Voltage Monitoring	Create a more user friendly method for operations personnel to monitor real time voltages.	04/14/2015	04/14/2015	Voltage has been added to Unit Operators main overhead screen that will turn yellow when unit voltage is approaching its limit and turn red when at its limit. Additionally, a flashing red buss voltage high / low tag was added to the Unit Operator's overhead screen when the unit is outside its voltage schedule. See Attachment C.	No
Additional Alarm at Comm Ops Desk	Create a second alarm at the Comm Ops Desk in Princeton, NJ that will initiate twenty minutes after the first alarm is received of a	04/30/2015	04/01/2015	The Midwest Generator Units have been added to the NRG Trader EMS Voltage Performance Monitoring System at the Dispatch Desk in Princeton, NJ. A descriptive email and	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	unit being outside its voltage schedule. This second alarm will activate should the unit not be able to get within schedule.			associated screenshot of the Voltage Schedule Display is attached to this Plan. See Attachments A, B, F & G.	
Documentation Storage Verification	Retain signed records of operator training on site; and, make rosters available upon request.	04/30/2015	04/28/2015	Hardcopies of training rosters are maintained in the Training file in the Station Admin area.	No
Logging and Communication Protocol Training	Create and deliver training to control room operators; and, have operators sign document for acknowledgement.	04/30/2015	04/28/2015	Training is complete. Steps for logging included in the Voltage Response Checklist. See Attachments D & E.	No
Operator Training on Switchyard Voltage Limits	Create and deliver training to control room operators; and, have the operators sign document for acknowledgement.	04/30/2015	04/28/2015	Training is complete. NERC VAR-002 Standard, Unit Voltage Response Checklist, and ComEd Voltage Schedule reviewed. See Attachment E.	No
Voltage Regulator Trip to Manual Training	Create and deliver training to control room operators; and, have operator sign document for acknowledgement.	04/30/2015	04/28/2015	Training is complete. NERC VAR-002 Standard reviewed. See Attachment E.	No

Additional Relevant Information

N/A

Reliability Risk

Reliability Risk

While the Mitigation Plan is being implemented, the reliability of the bulk Power System may remain at higher Risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are known or anticipated : (i) Identify any such risks or impacts, and; (ii) discuss any actions planned or proposed to address these risks or impacts.

The risk to the reliability of the BES will be minimal since the NRG Commercial Operations Desk in Princeton, NJ has a second alarm sounding 20 minutes following the initial alarm if any unit has not adjusted itself back into the Voltage Schedule.

Prevention

Describe how successful completion of this plan will prevent or minimize the probability further violations of the same or similar reliability standards requirements will occur

Improved indications and alarms at the station will provide the operators with more tools to monitor and correct station voltage discrepancies. The additional alarm at the Comm Ops Desk in Princeton, NJ will provide backup to the station.

Describe any action that may be taken or planned beyond that listed in the mitigation plan, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements

N/A

Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

* Submits the Mitigation Plan, as presented, to the regional entity for acceptance and approval by NERC, and

* if applicable, certifies that the Mitigation Plan, as presented, was completed as specified.

Acknowledges:

1. I am qualified to sign this mitigation plan on behalf of my organization.
2. I have read and understand the obligations to comply with the mitigation plan requirements and ERO remedial action directives as well as ERO documents, including but not limited to, the NERC rules of procedure and the application NERC CMEP.
3. I have read and am familiar with the contents of the foregoing Mitigation Plan.

Boston Energy Trading and Marketing LLC Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authority.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Robert Burkhart

Title: Manager - Regulatory Compliance

Authorized On: July 20, 2015

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Boston Energy Trading and Marketing LLC

NERC Registry ID: NCR00769

NERC Violation ID(s): RFC2014014540

Mitigated Standard Requirement(s): VAR-002-2b R2.

Scheduled Completion as per Accepted Mitigation Plan: April 30, 2015

Date Mitigation Plan completed: April 28, 2015

RF Notified of Completion on Date: July 20, 2015

Entity Comment: All of the Milestone Activities were completed during the month of April, 2015.

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Comm Ops Desk New Voltage Monitoring Screen.pdf	Attachment A - New Trade Desk Voltage Monitoring Screens	644,343
Entity	Trade Desk Voltage Schedule Display.pdf	Attachment B - Trade Desk Voltage Schedule Display	440,589
Entity	Unit Voltage Controls and Alarms Screen Shots.docx	Attachment C - Unit Voltage Controls and Alarm Screen Shots	6,901,583
Entity	Unit Voltage Response.pdf	Attachment D - Unit Voltage Response Procedure	126,791
Entity	VAR-002 Voltage Training.pdf	Attachment E - VAR-002 Voltage Training Documentation	2,725,250
Entity	Attachment F - Example 1 - Comm Ops Desk New Voltage Monitoring Screen.pdf	Attachment F - Clearer Example of Comm Ops Desk New Voltage Monitoring Screen	159,686
Entity	Attachment G - Example 2 - Comm Ops Desk New Voltage Monitoring Screen.pdf	Attachment G - Another clear example of Comm Ops Desk New Voltage Monitoring Screen	156,967

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Robert Burkhart

Title: Manager - Regulatory Compliance

Email: Robert.Burkhart@nrg.com

Phone: 1 (724) 597-8553

ReliabilityFirst

[redacted] July 21, 2015

Authorized Signature ______________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Mitigation Plan Verification for RFC2014014540

Boston Energy Trading and Marketing, LLC ("EMMT")

Standard/Requirement: VAR-002-2b R2

NERC Mitigation Plan ID: RFCMIT011610-1

Method of Disposition: To be determined

Relevant Dates					
Initiating Document	**Mitigation Plan Submittal**	**RF Acceptance**	**NERC Approval**	**Certification Submittal**	**Date of Completion**
PV Summary 11/19/14	07/20/15	07/31/2015	9/3/15	07/20/2015	04/28/15

Description of Issue

A Fall 2014 Audit of EMMT shows that it did not maintain the generator voltage output as directed by the Transmission Operator (TOP), Commonwealth Edison (ComEd). EMMT's Waukegan Unit 7 operated outside of its voltage schedule on July 17, 2013 from 03:12:00 to 09:04:00 and from 13:02:00 to 18:59:00. During the 03:12:00 to 09:04:00 timeframe, the voltage exceeded 145kV. The document, RSAW VAR-002-2b EMMT Final showed the voltage schedule ComEd provided for the Waukegan Station as 141kV +/- 2 kV. The RF monitoring team inquired as to whether EMMT received an exemption from the TOP to operate outside of the schedule, and whether EMMT took any actions to correct the voltage issue. EMMT stated that "Waukegan has no records indicating it received an exemption from the TOP to operate outside of the voltage schedule and while there were times during the period that Waukegan approached operating limits, there was no overall operating limitation." Upon review of the incident, the lack of appropriate controls/procedures is the likely cause of the violations.

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 1	Attachment F Example 1-Comm Ops Desk New voltage Monitoring Screen	VAR-002-2b R2
File 2	Attachment G Example 2- Comm Ops Desk New voltage Monitoring Screen	VAR-002-2b R2
File 3	Comm Ops Desk New voltage Monitoring Screen	VAR-002-2b R2
File 4	Trade Desk Voltage Schedule Display	VAR-002-2b R2
File 5	Unit Voltage Controls and Alarms Screen Shots	VAR-002-2b R2
File 6	Unit Voltage Response	VAR-002-2b R2
File 7	VAR-002 Voltage Training	VAR-002-2b R2

Verification of Mitigation Plan Completion

Milestone 1: Create a station specific document for Waukegan Operator response.

File 6, *Unit Voltage Response.pdf*, consists of the signed and dated voltage response procedure for Waukegan Station effective April 14, 2015.

Milestone #1 completion verified.

Milestone 2: Voltage Excursion Alarm

File 3, *Comm Ops Desk New Voltage Monitoring Screen.pdf*, includes screenshots of PJM's Actual verses Scheduled Voltage with description of voltage alarming capability, and File 5, *Unit Voltage Controls and Alarm Screen Shots*, includes various screenshots with bus voltage alarms.

Milestone #2 completion verified.

Milestone 3: Voltage Monitoring

File 1, *Attachment F - Example 1 - Common Ops Desk New Voltage Monitoring Screen.pdf*, and File 2, *Attachment G - Example 2 - Comm Ops Desk New Voltage Monitoring Screen.pdf*, are screenshots of PJM's Actual verses Scheduled Voltage which include voltage trends for all generating facilities, 1-Min avg (actual voltage), Rolling 30-min avg (scheduled voltage), and Rolling 30-min avg (actual voltage).

Milestone #3 completion verified.

Milestone 4: Additional Alarm at Comm Ops Desk.

File 4, *Trade Desk Voltage Schedule Display.pdf,* consists of an internal email which describes the Trader EMS Voltage Performance monitoring system that includes another alarm twenty minutes later as a reminder that some sort of action is required.

Milestone #4 completion verified.

Milestone 5: Documentation Storage Verification.

File 7, *VAR-002 Voltage Training.pdf*, includes operator signoff sheet dated April 14, 2015.

Milestone #5 completion verified.

Milestone 6: Logging and Communication Protocol Training.

File 7, *VAR-002 Voltage Training.pdf*, includes AVR Compliance Reporting for NRG Generating Plants presentation, Unit Voltage Response procedure, Target Voltage Schedule and Ranges, and operator signoff sheet dated April 14, 2015.

Milestone #6 completion verified.

Milestone 7: Operator Training on Switchyard Voltage Limits.

File 7, *VAR-002 Voltage Training.pdf*, includes AVR Compliance Reporting for NRG Generating Plants presentation, Unit Voltage Response procedure, Target Voltage Schedule and Ranges, and operator signoff sheet dated April 14, 2015.

Milestone #7 completion verified.

Milestone 8: Voltage Regulator Trip Manual Training

File 7, *VAR-002 Voltage Training.pdf*, includes AVR Compliance Reporting for NRG Generating Plants presentation, Unit Voltage Response procedure, Target Voltage Schedule and Ranges, and operator signoff sheet dated April 14, 2015.

Milestone #8 completion verified.

The Mitigation Plan is hereby verified complete.

Date: January 28, 2016

Tony Purgar
Manager, Risk Analysis & Mitigation
ReliabilityFirst Corporation

Attachment G

Disposition Documents for RFC2015014838 (VAR-002-3 R2)

g.1 Boston Energy Trading and Marketing LLC’s Self-Report, submitted on March 30, 2015;

g.2 Mitigation Plan RFCMIT011873, submitted on December 11, 2015;

g.3 Certification of the Mitigation Plan Completion, dated December 11, 2015;

g.4 Mitigation Plan Verification for RFCMIT011873, dated January 28, 2016;

Self Report

Entity Name: Boston Energy Trading and Marketing LLC (EMMT)

NERC ID: NCR00769

Standard: VAR-002-3

Requirement: VAR-002-3 R2.

Date Submitted: March 30, 2015

Has this violation previously been reported or discovered?: No

Entity Information:

Joint Registration Organization (JRO) ID:

Coordinated Functional Registration (CFR) ID:

Contact Name: Robert Burkhart

Contact Phone: 7245978553

Contact Email: robert.burkhart@nrg.com

Violation:

Violation Start Date: October 02, 2014

End/Expected End Date: December 25, 2014

Region Initially Determined a Violation On: March 16, 2015

Reliability Functions: Generator Operator (GOP)

Is Possible Violation still occurring?: No

Number of Instances: 88

Has this Possible Violation been reported to other Regions?: No

Which Regions:

Date Reported to Regions:

Detailed Description and Cause of Possible Violation: Per NERC Requirement VAR-002-3 R2, all Generators are directed to participate in maintaining an adequate voltage profile as provided by the Transmission Operator unless exempted by the Transmission OwnerOperator or unless the Generators Operator meets the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator (Attachment 2). While reviewing evidence to complete the Self-Certifications for the VAR-002-3 Standard for the last quarter of 2014 in the RF Region, it was discovered that that there were instances when the Joliet Generating Station, Powerton Generating Station, Waukegan Generating Station, and Will County Grenerating Station recorded instances when they were outside the published Voltage Schedule during the period of October through December 2014. For example, the highest voltage level achieved on Joliet Unit 6 (143.388kV) was .27% above the scheduled maximum level of 143kV. The highest voltage level achieved on Powerton Unit 6 (362.510kV) was 0.14% above the scheduled maximum level of 362kV. The lowest level achieved on Waukegan Unit 8 (136.457kV) was 1.7% below the scheduled minimum level of 139kV, but only for 34 minutes. The highest level achieved on Waukegan Unit 7 (143.652kV) was 0.46% above the scheduled maximum level of 143kV (Attachment 1). In addition there is no evidence that phone calls were made to the Transmission Operator seeking a change to the Voltage schedule or range.

Mitigating Activities:

Self Report

Description of Mitigating Activities and Preventative Measure:	The stations have already begun implementing changes to the plant alarms, trending and logging procedures which will be detailed in the Mitigation Plan(s).
Date Mitigating Activities Completed:	

Impact and Risk Assessment:

Potential Impact to BPS:	Severe
Actual Impact to BPS:	Minimal
Description of Potential and Actual Impact to BPS:	The Joliet, Powerton, Waukegan and Will County Stations were unable to maintain the directed values contained in the Voltage Schedule (Attachment 2). There is no evidence of the stations making any phone calls to the appropriate entities when they were not able to maintain output voltages.
Risk Assessment of Impact to BPS:	BETM / NRG maintains that this Self Report resulted in a low risk to the reliable operation of the BES. Referencing Attachment 1, examples would include: The highest voltage level achieved on Joliet Unit 6 (143.388kV) was .27% above the scheduled maximum level of 143kV. The highest voltage level achieved on Powerton Unit 6 (362.510kV) was 0.14% above the scheduled maximum level of 362kV. The lowest level achieved on Waukegan Unit 8 (136.457kV) was 1.7% below the scheduled minimum level of 139kV, but only for 34 minutes. The highest level achieved on Waukegan Unit 7 (143.652kV) was 0.46% above the scheduled maximum level of 143kV.
Additional Entity Comments:	It is BETM's / NRG Energy's goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability.

Additional Comments		
From	Comment	User Name
Entity	NRG Energy adheres to a strong culture of compliance with the goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability. The Mitigation Plan that will be submitted will not only strengthen the obligations and actions that must be taken by our plant operations staff, but also reinforce NRG's strong culture of compliance. In addition to adding Out of Voltage Schedule alarms to the respective station DCSs, increasing communication and awareness training throughout our plants will better equip our personnel to identify when a generator is deviating from its schedule. Going forward NRG will have evidence to show that the Voltage or Reactive Power schedule provided by the Transmission Operator has been met (Attachment 2); or, shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule.	Robert Burkhart

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	2014 Midwest Generation Voltage Schedule Letter.pdf	Attachment 2 - 2014 Midwest Generation Voltage Schedule	34,041
Entity	EME VAR-002 Voltage	Attachment 1 - EME VAR-002 Voltage Schedule Out	21,507

Self Report

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Schedule Out of Range FINAL.xlsx	of Range	21,507

Mitigation Plan

Mitigation Plan Summary

Registered Entity: Boston Energy Trading and Marketing LLC

Mit Plan Code	NERC Violation ID	Requirement	Violation Validated On	Mit Plan Version
RFCMIT011873	RFC2015014838	VAR-002-3 R2.		1

Mitigation Plan Submitted On: December 11, 2015
Mitigation Plan Accepted On:
Mitigation Plan Proposed Completion Date: August 31, 2015
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by EMMT On: December 11, 2015
Mitigation Plan Completion Verified by RF On:
Mitigation Plan Completed? (Yes/No): No

Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Entity Information

Identify your organization:

Entity Name: Boston Energy Trading and Marketing LLC

NERC Compliance Registry ID: NCR00769

Address: 211 Carnegie Center
Princeton NJ 08540

Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Robert Burkhart
Title: Manager - Regulatory Compliance
Email: Robert.burkhart@nrg.com
Phone: 724-597-8553

Violation(s)

This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
RFC2015014838	10/02/2014	VAR-002-3 R2.
Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.		

Brief summary including the cause of the violation(s) and mechanism in which it was identified:

Per NERC Requirement VAR-002-3 R2, all Generators are directed to participate in maintaining an adequate voltage profile as provided by the Transmission Operator unless exempted by the Transmission Owner/Operator or unless the Generators Operator meets the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator (Attachment A1). While reviewing evidence to complete the Self-Certifications for the VAR-002-3 Standard for the last quarter of 2014 in the RF Region, it was discovered that there were instances when the Joliet Generating Station, Powerton Generating Station, Waukegan Generating Station, and Will County Generating Station recorded occurrences when they were outside the published Voltage Schedule during the period of October through December 2014 but failed to document and make the required phone calls to the TOP of not being able to maintain the published Voltage Schedule for those occurrences.

It has been determined that the root cause of these incidents is based upon "Human Performance" errors. Two contributing factors are insufficient initial/refresher training and postponed upgrades to the plant voltage monitoring systems using the modern Station Digital Control Systems.

Relevant information regarding the identification of the violation(s):

Attachment A2 is a spreadsheet detailing the voltage excursions mentioned below.

Joliet Station:

The highest voltage level (143.388kV) outside the Voltage Schedule during the 4th Quarter of 2014 at the Joliet Generating Station (Unit 6) occurred on 11/21/2014, 0.27% above the scheduled maximum level of 143kV. There were no occurrences when the station was unable to meet the lower voltage limit of 139kV during this period.

Powerton Station:

The highest voltage level achieved during the same time period at the Powerton Generating Station Unit 6 (363.198kV) occurred on 12/24/14 and was 0.33% above the scheduled maximum level of 362kV. There were no occurrences when the station was unable to meet the lower voltage limit of 356kV during this period.

Waukegan Station:

The lowest level achieved at the Waukegan Generating Station on Unit 8 (135.789kV) occurred on 11/26/14 and was 2.3% below the scheduled minimum level of 139kV. The highest level achieved at the Waukegan Generating Station on Unit 7 (144.406kV) occurred three times on 10/3, 10/4, and 10/13/14. All three voltage levels were 0.98% above the scheduled maximum level of 143kV.

Will County Station:

The lowest level achieved at the Will County Generating Station on Unit 3 (138.323kV) occurred on 11/3/14 and was 0.49% below the scheduled minimum level of 139kV. The highest level achieved at the Will County Generating Station on Unit 3 (143.520kV) occurred on 10/26/14 and was 0.36% above the scheduled maximum level of 143kV.

There is no evidence that phone calls were made to the Transmission Operator seeking a change to the Voltage schedule or range in any of these instances.

Plan Details

Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

To prevent further violations additional voltage monitoring alarms (both on-site and remote) and a comprehensive training plan were created for the control room operators. Included were instruction on transmission system voltage limits, response to voltage excursions, alarms / voltage monitoring, response to AVR trips to manual, proper log and record keeping protocol, storage of signed training documents, and a site specific checklist outlining proper response to voltage excursions. This plan has been reviewed by NRG Compliance group and has been found acceptable.

Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: August 31, 2015

Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Additional Alarm at Comm Ops Desk for Powerton Station	Create a second alarm for the Powerton Station at the Comm Ops Desk in Princeton, NJ that will initiate twenty minutes after the first alarm is received of a unit being outside its voltage schedule. This second alarm will activate should the unit not be able to get within schedule.	04/01/2015	04/01/2015	An alarm is initiated at the Commercial Operations Desk in Princeton, NJ when any unit is outside its Voltage Schedule. A second alarm has been added to initiate twenty minutes after the first alarm should the unit not be able to get within schedule. This will give the Comm Ops Desk sufficient time to contact the TO of our situation. Refer to Attachments A3 thru A6.	No
Additional Alarm at Comm Ops Desk for Will County Station	Create a second alarm for the Will County Station at the	04/01/2015	04/01/2015	An alarm is initiated at the Commercial Operations Desk in Princeton, NJ when	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	Comm Ops Desk in Princeton, NJ that will initiate twenty minutes after the first alarm is received of a unit being outside its voltage schedule. This second alarm will activate should the unit not be able to get within schedule.			any unit is outside its Voltage Schedule. A second alarm has been added to initiate twenty minutes after the first alarm should the unit not be able to get within schedule. This will give the Comm Ops Desk sufficient time to contact the TO of our situation. Refer to Attachments A3 thru A6.	
Additional Alarm at Comm Ops Desk for the Joliet Station	Create a second alarm for the Joliet Station at the Comm Ops Desk in Princeton, NJ that will initiate twenty minutes after the first alarm is received of a unit being outside its voltage schedule. This second alarm will activate should the unit not be able to get within schedule.	04/01/2015	04/01/2015	An alarm is initiated at the Commercial Operations Desk in Princeton, NJ when any unit is outside its Voltage Schedule. A second alarm has been added to initiate twenty minutes after the first alarm should the unit not be able to get within schedule. This will give the Comm Ops Desk sufficient time to contact the TO of our situation. Refer to Attachments A3 thru A6.	No
Document Storage Verification at the Will County Station	Retain signed records of operator training on site; and, make rosters available upon request.	06/01/2015	05/15/2015		No
Joliet Station Operator Training on Switchyard Voltage Limits	Provide additional training to the Joliet Control Room Operators as it relates to Switchyard Voltage Limits; and, have operators sign document for acknowledgement.	06/01/2015	04/02/2015	Refer to Attachments A1; J1; J2; and, J6.	No
Joliet Station Specific Document for Response to Voltage Excursions	Develop, implement and train station personnel on station specific response	06/01/2015	04/02/2015	Refer to Attachments A1, J1 & J2.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	procedures to voltage excursions outside of the Voltage Schedule				
Joliet Station Unit Operating Procedure Revisions	Incorporate a new step into the Unit Operating Procedures to monitor output voltage when placing a unit on-line.	06/01/2015	04/29/2015	Refer to page 32 of 46 of Attachment J3 for Joliet Unit 6; and, page 26 of 47 of Attachment J4 for Joliet Units 7 & 8.	No
Joliet Station Voltage Excursion Alarm	Create a control room alarm to alert station operators that voltage is approaching a high or low limit.	06/01/2015	03/21/2015	Refer to Attachments J1 & J2.	No
Joliet Station Voltage Regulator Trip to Manual Training	Provide additional training to the Joliet Control Room Operators as it relates to Voltage Regulator Trip to Manual Incidents; and, have operators sign document for acknowledgement.	06/01/2015	04/02/2015	Refer to Attachments A7 and J5.	No
Logging and Communication Protocol Training at Joliet Station	Create and deliver additional training to the Joliet Control Room Operators as it relates to Logging and Communication Protocol; and, have operators sign document for acknowledgement.	06/01/2015	04/29/2015	Refer to Attachments J1 & J2; J3; and, Step 22 on pages 24 & 25 of 47 of Attachment J4.	No
Logging and Communication Protocol Training at Powerton Station	Create and deliver additional training to the Powerton Control Room Operators as it relates to Logging and Communication Protocol; and, have operators sign	06/01/2015	04/02/2015	Refer to Attachments P1.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	document for acknowledgement.				
Logging and Communication Protocol Training at Will County	Create and deliver additional training to the Will County Control Room Operators as it relates to Logging and Communication Protocol; and, have operators sign document for acknowledgement.	06/01/2015	07/01/2015	Refer to Attachment WC1.	No
Powerton Station Operator Training on Switchyard Voltage Limits	Provide additional training to the Powerton Control Room Operators as it relates to Switchyard Voltage Limits; and, have operators sign document for acknowledgement.	06/01/2015	03/17/2015	Refer to Attachments P1, P2, P3, P4 & P8.	No
Powerton Station Specific Document for Response to Voltage Excursions	Develop, implement and train station personnel on station specific response procedures to voltage excursions outside of the Voltage Schedule	06/01/2015	06/19/2015	Refer to Attachments P1 thru P4.	No
Powerton Station Voltage Excursion Alarm	Create a control room alarm to alert station operators that voltage is approaching a high or low limit.	06/01/2015	04/22/2015	Refer to Attachments P1 thru P4.	No
Voltage Monitoring at Joliet Station	Create a more user friendly method for operations personnel to monitor real time voltages	06/01/2015	04/30/2015	Refer to Attachment J6 / screen shots of the DSC Control Screen.	No
Voltage Monitoring at Powerton Station	Create a more user friendly method for operations personnel to monitor real time	06/01/2015	04/22/2015	Refer to Attachments P2, P3 & P4.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	voltages				
Voltage Monitoring at Will County Station	Create a more user friendly method for operations personnel to monitor real time voltages	06/01/2015	03/01/2015	Refer to Attachments WC2 & WC3. Will County has two (2) Yard Voltage Analog Inputs in the DCS / PI for each unit, coming from the primary and backup revenue metering equipment for their respective units. The excursions shown are based off the primary revenue meter. On the U3 Gen Bench board, there are two digital meters that show yard voltage on BUS 2 (Unit 3) and Bus 3 (Unit 4) along with frequency. These meters are fed from ComEd's 138kV bus pot transformers, which is a different source than the revenue metering equipment that the station is using to alarm and monitor yard voltage. The voltage shown on the alarm point is used as a basis for any excitation changes. It is not assumed that the yard voltage is okay because the meter on the bench board differs by O.5kV and is within the threshold. The value in the DCS is what the station is using to demonstrate compliance.	No
Will County Operator Training on Switchyard Voltage Limits	Provide additional training to the Will County Control Room Operators as it relates to Switchyard Voltage Limits; and, have operators sign document for acknowledgement.	06/01/2015	05/30/2015	Refer to Attachment WC2 & WC3.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Will County Station Specific Document for Response to Voltage Excursions	Develop, implement and train station personnel on station specific response procedures to voltage excursions outside of the Voltage Schedule	06/01/2015	03/01/2015	Refer to Attachments WC2 & WC3.	No
Will County Station Unit Operating Procedure Revisions	Incorporate a new step into the Unit Operating Procedures to monitor output voltage when placing a unit on-line.	06/01/2015	07/22/2015	Refer to the following steps in Attachment WC4: step 11.0 on page 2 of 4; and, step 20.0 on page 3 of 4.	No
Will County Station Voltage Regulator Trip to Manual Training	Provide additional training to the Will County Control Room Operators as it relates to Voltage Regulator Trip to Manual Incidents; and, have operators sign document for acknowledgement.	06/01/2015	07/22/2015	Refer to Attachment WC5.	No
Will County Voltage Excursion Alarm	Create a control room alarm to alert station operators that voltage is approaching a high or low limit.	06/01/2015	03/01/2015	Refer to Attachments WC2 & WC3.	No
Document Storage Verification at the Powerton Station	Retain signed records of operator training on site; and, make rosters available upon request.	06/15/2015	06/30/2015		No
Powerton Station Voltage Regulator Trip to Manual Training	Provide additional training to the Powerton Control Room Operators as it relates to Voltage Regulator Trip to Manual Incidents; and, have operators	06/30/2015	06/26/2015	Refer to Attachments P5 & P7.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	sign document for acknowledgement.				
Joliet Station VAR-002 Training	Provide additional training to the Joliet Control Room Operators as it relates to NERC Standard VAR-002	07/10/2015	07/10/2015	Refer to Attachment J7 (corporate fleet wide computer based training on the VAR-002 Standard / Maintaining Voltage Schedule roster).	No
Powerton Station VAR-002 Training	Provide additional training to the Powerton Control Room Operators as it relates to NERC Standard VAR-002	07/10/2015	07/10/2015	Refer to Attachment P7 (corporate fleet wide computer based training on the VAR-002 Standard / Maintaining Voltage Schedule roster).	No
Waukegan Station VAR-002 Training	Provide additional training to the Waukegan Control Room Operators as it relates to NERC Standard VAR-002	07/10/2015	07/10/2015	Refer to Attachment WA1 (fleet-wide corporate computer based training on the VAR-002 Standard).	No
Will County Station VAR-002 Training	Provide additional training to the Will County Control Room Operators as it relates to NERC Standard VAR-002	07/10/2015	07/10/2015	Refer to Attachment WC6 (corporate fleet wide computer based training on the VAR-002 Standard / Maintaining Voltage Schedule roster).	No
Powerton Station Unit Operating Procedure Revisions	Incorporate a new step into the Unit Operating Procedures to monitor output voltage when placing a unit on-line.	07/15/2015	08/28/2015	Refer to Step 205 on pages 32 & 33 of 45 in Attachment P6.	No
Document Storage Verification at the Joliet Station	Retain signed records of operator training on site; and, make rosters available upon request.	07/30/2015	07/16/2015		No

Additional Relevant Information

Reliability Risk

Reliability Risk

While the Mitigation Plan is being implemented, the reliability of the bulk Power System may remain at higher Risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are known or anticipated : (i) Identify any such risks or impacts, and; (ii) discuss any actions planned or proposed to address these risks or impacts.

The Transmission System Operator (Commonwealth Edison) has a 24 hour Transmission Switching Dispatcher as well as 24 hour Reliability Dispatcher whose primary job is to monitor system voltages in their area. They use the same signal as the plants for monitoring voltages, which is the Commonwealth Edison Revenue Metering Signal. There are times when the plant(s) receive calls from the Reliability Dispatcher to adjust VARS. If the plants call the Transmission Dispatcher with a voltage issue, he will connect them with the Reliability Dispatcher in the event any one of the plants is running close to a limit so they can take an action, i.e. switching capacitors or shifting vars to another companies generators. NRG believes this item contributes to this being a low reliability risk.

In addition, the NRG Commercial Operations Desk in Princeton, NJ has a second alarm sounding 20 minutes following an initial alarm if any unit has not adjusted itself back into the Voltage Schedule.

Prevention

Describe how successful completion of this plan will prevent or minimize the probability further violations of the same or similar reliability standards requirements will occur

Improved indications and alarms at the stations will provide the operators with more tools to monitor and correct station voltage discrepancies. The additional alarm at the Comm Ops Desk in Princeton, NJ will provide backup to the stations.

Describe any action that may be taken or planned beyond that listed in the mitigation plan, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements

Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

* Submits the Mitigation Plan, as presented, to the regional entity for acceptance and approval by NERC, and

* if applicable, certifies that the Mitigation Plan, as presented, was completed as specified.

Acknowledges:

1. I am qualified to sign this mitigation plan on behalf of my organization.
2. I have read and understand the obligations to comply with the mitigation plan requirements and ERO remedial action directives as well as ERO documents, including but not limited to, the NERC rules of procedure and the application NERC CMEP.
3. I have read and am familiar with the contents of the foregoing Mitigation Plan.

Boston Energy Trading and Marketing LLC Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authority.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Robert Burkhart

Title: Manager - Regulatory Compliance

Authorized On: December 11, 2015

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Boston Energy Trading and Marketing LLC

NERC Registry ID: NCR00769

NERC Violation ID(s): RFC2015014838

Mitigated Standard Requirement(s): VAR-002-3 R2.

Scheduled Completion as per Accepted Mitigation Plan: August 31, 2015

Date Mitigation Plan completed: August 28, 2015

RF Notified of Completion on Date: December 11, 2015

Entity Comment: All Milestone Activities have been completed. All pertinent evidence has been attached to this Plan.

Additional Documents

From	Document Name	Description	Size in Bytes
Entity	ATTACHMENT A3 - Comm Ops Desk New Voltage Monitoring Screen.pdf	Attachment A3 - Comm Ops Desk / New Voltage Monitoring Screen - View 1	1,515,019
Entity	ATTACHMENT A1 - 2014 Midwest Generation Voltage Schedule Letter.pdf	Attachment A1 - 2014 Midwest Generation Voltage Schedule Letter from ComEd dated 5/9/2014	909,604
Entity	ATTACHMENT A2 - EME VAR-002 Voltage Schedule Out of Range.pdf	Attachment A2 - Midwest Generation Assets - 4Q 2014 Voltage Out of Range Spreadsheet	287,538
Entity	ATTACHMENT A4 - Comm Ops Desk New Voltage Monitoring Screen.pdf	Attachment A4 - Comm Ops Desk / New Voltage Monitoring Screen - View 2	1,031,733
Entity	ATTACHMENT A5 - Comm Ops Desk New Voltage Monitoring Screen.pdf	Attachment A5 - Comm Ops Desk / New Voltage Monitoring Screen - View 3	1,028,996
Entity	ATTACHMENT A6 - Trade Desk Voltage Schedule Display.pdf	Attachment A6 - Trade Desk Voltage Schedule Display	1,311,250
Entity	ATTACHMENT A7 - NRG AVR Reporting 03152015[1].pdf	Attachment A7 - NRG AVR Compliance Reporting Presentation of 3/15/2015	1,064,818
Entity	ATTACHMENT J1 - Joliet 6 Unit Voltage Response[1].pdf	Attachment J1 - Joliet Unit 6 Voltage Response Procedure JOL-ELECT-6-001	629,913
Entity	ATTACHMENT J2 - Joliet 78 Unit Voltage Response[1].pdf	Attachment J2 - Joliet Units 7 & 8 Voltage Response Procedure JOL-ELECT-78-001	620,418

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	ATTACHMENT J3 - Joliet 6 Boiler Turbine Startup[1].pdf	Attachment J3 - Joliet Unit 6 Boiler Startup Technical Instruction JO-06-2005-039	356,704
Entity	ATTACHMENT J4 - Joliet 78 Unit Startup REv 4-29-2015[1].pdf	Attachment J4 - Joliet Units 7 & 8 Startup Technical Instruction JO-78-2013-018	1,393,473
Entity	ATTACHMENT J5 - Follow-up for AVR and Voltage Compliance Reporting[1].pdf	Attachment J5 - Follow-up for AVR and Voltage Compliance Reporting	1,284,744
Entity	ATTACHMENT J6 - Joliet Station Voltage Monitoring DCS Screen Prints[1].pdf	Attachment J6 - Joliet Station Voltage Monitoring DCS Screen Shots	874,925
Entity	ATTACHMENT J7 - Joliet VAR-002 Training Roster[1].pdf	Attachment J7 - Joliet VAR-002 Training Roster	71,474
Entity	ATTACHMENT P1 - Unit Switchyard Voltage Response[1].pdf	Attachment P1 - Powerton Unit Switchyard Voltage Response Checklist POW-ELEC-0001	31,329
Entity	ATTACHMENT P2 - FW_ 2015 Voltage Schedule E-Mail to Shift Supervisors and Unit Operators 5-15-2015[1].pdf	Attachment P2 - Powerton 2015 Voltage Schedule E-Mail to Shift Supervisors and Unit Operators dated 5/15/2015	1,425,927
Entity	ATTACHMENT P3 - FW_ U5_6 PJM Control screen and monitoring Bus 2 and 10 kV 4222015[1].pdf	Attachment P3 - Powerton Unit 5 & 6 PJM Control Screen and Monitoring - Bus 2 and 10	2,007,214
Entity	ATTACHMENT P4 - Powerton PJM Control Screens[1].pdf	Attachment P4 - Powerton PJM Control Screen Update	218,373
Entity	ATTACHMENT P5 - FW_ Follow-up for AVR and Voltage Compliance Reporting[1].pdf	Attachment P5 - Follow-up for AVR and Voltage Compliance Reporting at Powerton	2,219,275
Entity	ATTACHMENT P6 - PO-0-2005-029 First Boiler Unit Startup[1].pdf	Attachment P6 - Powerton First Boiler and Unit Startup Technical Instruction PO-00-2005-029	1,215,485
Entity	ATTACHMENT P7 - Powerton VAR-002 Training Roster[1].pdf	Attachment P7 - Powerton VAR-002 Training Roster	16,241
Entity	ATTACHMENT P8 - ComEd Target Voltage Schedule Range[1].pdf	Attachment P8 - ComEd Target Voltage Schedule Range dated 5/9/2014	697,969
Entity	ATTACHMENT WA1 - Waukegan VAR-002 Training Roster[1].pdf	Attachment WA1 - Waukegan VAR-002 Training Roster	20,949
Entity	ATTACHMENT WA2 - Unit	Attachment WA2 - Waukegan Unit Voltage Response	872,722

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Voltage Response[1].pdf	Checklist WAU-BOP-ELECT-0001	872,722
Entity	ATTACHMENT WC1 - Logbook Use[1].pdf	Attachment WC1 - Will County Control Room Logbook Use email dated 6/12/2015	956,771
Entity	ATTACHMENT WC2 - Yard Voltage Control[1].pdf	Attachhment WC2 - Will County 138kV Voltage Control Email Directive dated 2/11/2015	845,942
Entity	ATTACHMENT WC3 - ComEd Voltage Control[1].pdf	Attachment WC3 - ComEd Target Voltage Schedule & Range Letter dated 5/12/2015	782,495
Entity	ATTACHMENT WC4 - U4 Generator Reg's[1].pdf	Attachment WC4 - Will County Synchronizing Unit 4 Generators to the System Technical Instruction WC-04-2009-002	1,890,443
Entity	ATTACHMENT WC5 - Voltage Regulators[1].pdf	Attachment WC5 - Will County Unit 4 Voltage Regular Monitoring Control Room Operator Responsibilities	609,490
Entity	ATTACHMENT WC6 - Will County VAR-002 Training Roster[1].pdf	Attachment WC6 - Will County VAR-002 Training Roster	12,551

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Robert Burkhart

Title: Manager - Regulatory Compliance

Email: Robert.burkhart@nrg.com

Phone: 1 (724) 597-8553

Authorized Signature ______________________________ Date ________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Mitigation Plan Verification for RFC2015014838

Boston Energy Trading and Marketing, LLC (“Boston Energy”)

Standard/Requirement: VAR-002-3 R2

NERC Mitigation Plan ID: RFCMIT011873

Method of Disposition: Settlement Agreement

Relevant Dates					
Initiating Document	**Mitigation Plan Submittal**	**RF Acceptance**	**NERC Approval**	**Certification Submittal**	**Date of Completion**
Self-Report 03/30/15	12/11/15	01/05/16	Not yet approved	12/11/15	08/28/15

Description of Issue

While reviewing evidence to complete the Self-Certifications for the VAR-002-3 Standard for the last quarter of 2014 in the RF Region, Boston Energy discovered instances when the Joliet Generating Station, Powerton Generating Station, Waukegan Generating Station, and Will County Generating Station recorded being outside the published Voltage Schedule during October through December 2014. Boston Energy failed to document these instances and give the required notice to the TOP.

The root cause of these incidents is based upon "Human Performance" errors, including insufficient initial/refresher training and postponed upgrades to the plant voltage monitoring systems using the modern Station Digital Control Systems.

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 1	Attachment A1- 2014 Midwest Generation Voltage Schedule Letter	VAR-002-3 R2

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 2	Attachment A2- EME VAR-002 Voltage Schedule Out of Range	VAR-002-3 R2
File 3	Attachment A3- Comm Ops Desk New Voltage Monitoring Screen	VAR-002-3 R2
File 4	Attachment A4- Comm Ops Desk New voltage Monitoring Screen	VAR-002-3 R2
File 5	Attachment A5- Comm Ops Desk New Voltage Monitoring Screen	VAR-002-3 R2
File 6	Attachment A6- Trade Desk Voltage Schedule Display	VAR-002-3 R2
File 7	Attachment A7- NRG AVR Reporting 03152015[1]	VAR-002-3 R2
File 8	Attachment J1- Joliet 6 Unit Voltage Response[1]	VAR-002-3 R2
File 9	Attachment J2- Joliet 78 Unit Voltage Response[1]	VAR-002-3 R2
File 10	Attachment J3- Joliet 6 Boiler Turbine Startup[1]	VAR-002-3 R2
File 11	Attachment J4- Joliet 78 Unit Startup Rev 4-29-2015[1]	VAR-002-3 R2
File 12	Attachment J5- Follow up for AVR and Voltage Compliance Reporting[1]	VAR-002-3 R2
File 13	Attachment J6- Joliet Station Voltage Monitoring DCS Screen Prints[1]	VAR-002-3 R2
File 14	Attachment J7- Joliet VAR-002 Training Roster[1]	VAR-002-3 R2
File 15	Attachment P1- Unit Switchboard Voltage Response[1]	VAR-002-3 R2
File 16	Attachment P2- FW 2015 Voltage Schedule E-mail to Shift Supervisors and Unit Operators 5-15-2015[1]	VAR-002-3 R2
File 17	Attachment P3- FW U5 6 PJM Control screen and monitoring Bus 2 and 10 kv 4222015[1]	VAR-002-3 R2
File 18	Attachment P4- Powerton PJM Control Screens	VAR-002-3 R2
File 19	Attachment P5- FW Follow up for AVR and Voltage Compliance Reporting[1]	VAR-002-3 R2

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 20	Attachment P6- PO-0-2005-029 First Boiler Unit Startup[1]	VAR-002-3 R2
File 21	Attachment P7- Powerton VAR-002 Training Roster[1]	VAR-002-3 R2
File 22	Attachment P8- ComEd Target Voltage Schedule Range[1]	VAR-002-3 R2
File 23	Attachment WA1-Waukegan VAR-002 Training Roster[1]	VAR-002-3 R2
File 24	Attachment WA2- Unit Voltage Response[1]	VAR-002-3 R2
File 25	Attachment WC1- Logbook Use[1]	VAR-002-3 R2
File 26	Attachment WC2- Yard Voltage Control[1]	VAR-002-3 R2
File 27	Attachment WC3- ComEd Voltage Control[1]	VAR-002-3 R2
File 28	Attachment WC4- U4 Generator Reg's[1]	VAR-002-3 R2
File 29	Attachment WC5- Voltage Regulators[1]	VAR-002-3 R2
File 30	Attachment WC6- Will County VAR-002 Training Roster[1]	VAR-002-3 R2

Verification of Mitigation Plan Completion

Milestone 1: Additional Alarm at Comm Ops Desk for Powerton Station.

File 6, *Attachment A6-Trade Desk Voltage Schedule Display*, contains an e-mail describing the creation of the new voltage displays for the Trader EMS Voltage Performance monitoring system (Comm Ops Desk). It details from where the data is captured and how it is used.

Screen shots of the new voltage displays are contained in the following pdf files:

1. File 3, Attachment A3 - Comm Ops Desk New Voltage Monitoring Screen
2. File 4, Attachment A4 - Comm Ops Desk New Voltage Monitoring Screen
3. File 5, Attachment A5 - Comm Ops Desk New Voltage Monitoring Screen

Milestone #1 completion verified.

Milestone 2: Additional Alarm at Comm Ops Desk for Will County Station.

File 6, Attachm*ent A6-Trade Desk Voltage Schedule Display*, contains an e-mail describing the creation of the new voltage displays for the Trader EMS Voltage Performance monitoring system (Comm Ops Desk). It details from where the data is captured and how it is used.

Screen shots of the new voltage displays are contained in the following pdf files:

1. File 3, Attachment A3 - Comm Ops Desk New Voltage Monitoring Screen
2. File 4, Attachment A4 - Comm Ops Desk New Voltage Monitoring Screen
3. File 5, Attachment A5 - Comm Ops Desk New Voltage Monitoring Screen

Milestone #2 completion verified.

Milestone 3: Additional Alarm at Comm Ops Desk for the Joliet Station.

File 6, *Attachment A6-Trade Desk Voltage Schedule Display*, contains an e-mail describing the creation of the new voltage displays for the Trader EMS Voltage Performance monitoring system (Comm Ops Desk). It details from where the data is captured and how it is used.

Screen shots of the new voltage displays are contained in the following pdf files:

1. File 3, Attachment A3 - Comm Ops Desk New Voltage Monitoring Screen
2. File 4, Attachment A4 - Comm Ops Desk New Voltage Monitoring Screen
3. File 5, Attachment A5 - Comm Ops Desk New Voltage Monitoring Screen

Milestone #3 completion verified.

Milestone 4: Document Storage Verification at the Will County Station.

This simply states they will retain the training records and does not need verification as part of completing the mitigation plan.

Milestone 5: Joliet Station Operator Training on Switchyard Voltage Limits.

File 14, *Attachment J7 - Joliet VAR-002 Training Roster,* contains a training record showing completion of computer based training on Generator Operation for Maintaining Network Voltage Schedules for personnel at the Joliet station.

Milestone #5 completion verified.

Milestone 6: Joliet Station Specific Document for Response to Voltage Excursion.

File 8, *Attachment J1 - Joliet 6 Unit Voltage Response,* contains a procedure for Unit voltage response for Joliet Unit 6.

File 9, *Attachment J2 - Joliet 78 Unit Voltage Response,* contains a procedure for Unit voltage response for Joliet Unit 78.

Milestone #6 completion verified.

Milestone 7: Joliet Station Unit Operating Procedure Revisions.

File 10, *Attachment J3 - Joliet 6 Boiler Turbine Startup*, contains a procedure for startup of Joliet Unit 6. Page 32, Step 10.7, discusses how to set line voltage per the voltage schedule.

File 11, *Attachment J4 - Joliet 78 Unit Startup Rev 4-29-2015[1]*, contains a procedure for startup of Joliet Unit 78. Page 26, Step 24.0, discusses automating the voltage regulators and setting line voltage per the voltage schedule.

Milestone #7 completion verified.

Milestone 8: Joliet Station Voltage Excursion Alarm.

File 8, *Attachment J1 - Joliet 6 Unit Voltage Response*, Page 2, Step 2, details the parameters of the voltage excursion alarms and the proper operator response.

File 9, *Attachment J2 - Joliet 78 Unit Voltage Response*, Page 2, Step 2, details the parameters of the voltage excursion alarms and the proper operator response.

Milestone #8 completion verified.

Milestone 9: Joliet Station Voltage Regulator Trip to Manual Training.

Provide additional training to the Joliet Control Room Operators as it relates to Voltage Regulator

File 7, *Attachment A7 - NRG AVR reporting 03152015*, contains a training presentation titled *AVR Compliance Reporting for NRG Generating Plants.* Page 7, specifically discusses AVR trips to "manual" and the appropriate response.

File 12, *Attachment J5 -Follow-up for AVR and Voltage Compliance Reporting*, contains an e-mail identifying who attended the training presentation titled *AVR Compliance Reporting for NRG Generating Plants.*

Milestone #9 completion verified.

Milestone 10: Logging and Communication Protocol Training at Joliet Station.

File 8, *Attachment J1 - Joliet 6 Unit Voltage Response*, contains a procedure for Unit voltage response for Joliet Unit 6.

File 9, *Attachment J2 - Joliet 78 Unit Voltage Response*, contains a procedure for Unit voltage response for Joliet Unit 78.

File 10, *Attachment J3 - Joliet 6 Boiler Turbine Startup*, contains a procedure for startup of Joliet Unit 6.

File 11, *Attachment J4 - Joliet 78 Unit Startup Rev 4-29-2015*, contains a procedure for startup of Joliet Unit 78.

The logging and communication protocols to be used during startup and operation of the Joliet units is discussed in detail in the four procedures described above.

Milestone #10 completion verified.

Milestone 11: Logging and Communication Protocol Training at Powerton Station.

File 15, *Attachment P1 - Unit Switchyard Voltage Response*, contains a procedure for Unit voltage response for the Powerton station. The logging and communication protocols to be used during operation of the Powerton units is discussed in detail in Steps 1 through 6 of this procedure.

Milestone #11 completion verified.

Milestone 12: Logging and Communication Protocol Training at Will County.

File 25, *Attachment WC1 – Logbook Use*, contains an e-mail string that discusses operators and Shift Supervisors at Will County using the Logbook for various entries including a NERC category. A screen shot shows part of the entries includes MVAR and Voltage information.

Milestone #12 completion verified.

Milestone 13: Powerton Station Operator Training on Switchyard Voltage Limits.

File 15, *Attachment P1 - Unit Switchyard Voltage Response*, contains a procedure for Unit voltage response for the Powerton station.

File 16, *Attachment P2 - FW_2015 Voltage Schedule E-mail to Shift Supervisors and Unit Operators 5-15-2015*, contains an e-mail dated 5/15/2015 that includes a letter from the TOP about the voltage schedules for Powerton and the proper response to voltage excursions.

File 17, *Attachment P3 - FW_U5_6 PJM Control screen and monitoring Bus 2 and 10 kV 4222015*, contains an e-mail dated 4/22/2015 describing the changes made to the Powerton PJM Control Screen for the Powerton Units.

File 18, *Attachment P4 - Powerton PJM Control Screens*, contains a screenshot and description of voltage alarming and monitoring for the Powerton station.

Milestone 14:

Powerton Station specific Document for Response to Voltage Excursions.

Develop, implement and train station personnel on station specific response procedures to voltage excursions outside of the Voltage Schedule.

File 15, *Attachment P1 - Unit Switchyard Voltage Response*, contains a procedure for Unit voltage response for the Powerton station, with steps for responding to voltage excursions including communications and logging of the event.

File 16, *Attachment P2 - FW_2015 Voltage Schedule E-mail to Shift Supervisors and Unit Operators 5-15-2015*, contains an e-mail dated May 15, 2015 that includes a letter from the TOP about the voltage schedules for Powerton and the proper response to voltage excursions.

Milestone #14 completion verified.

Milestone 15: Powerton Station Voltage Excursion Alarm.

File 18, *Attachment P4 - Powerton PJM Control Screens*, contains a screenshot and description of voltage alarming and monitoring for the Powerton station.

Milestone #15 completion verified.

Milestone 16: Voltage Monitoring at Joliet Station.

File13, *Attachment J6 - Joliet Station Voltage Monitoring DCS Screen Prints*, contains screenshots of the Voltage Monitoring tools available to the operators at the Joliet station.

Milestone #16 completion verified.

Milestone 17: Voltage Monitoring at Powerton Station.

File 18, *Attachment P4 - Powerton PJM Control Screens*, contains a screenshot and description of voltage alarming and monitoring for the Powerton station.

Milestone #17 completion verified.

Milestone 18: Voltage Monitoring at Will County Station.

File 26, *Attachment WC2 - Yard Voltage Control*, contains an e-mail dated February 11, 2015, that describes the voltage alarms for the Will County station. It discusses how the alarms are set up, how they are to be used, and steps to take in response to the alarms.

Milestone #18 completion verified.

Milestone 19: Will County Operator Training on Switchyard Voltage Limits.

File 26, *Attachment WC2 - Yard Voltage Control*, contains an e-mail dated February 11, 2105 that describes the voltage alarms for the Will County station. It discusses how the alarms are set up, how they are to be used, and steps to take in response to the alarms.

File 27, *Attachment WC3 - ComEd Voltage Control*, contains a letter from the TOP dated May 12, 2015 that details the voltage schedules for Will County and the proper response to voltage excursions.

Milestone #19 completion verified.

Milestone 20: Will County Station Specific Document for Response to Voltage Excursions.

File 26, *Attachment WC2 - Yard Voltage Control*, contains an e-mail dated February 11, 2105 that describes the voltage alarms for the Will County station. It discusses how the alarms are set up, how they are to be used, and steps to take in response to the alarms.

File 27, *Attachment WC3 - ComEd Voltage Control*, contains a letter from the TOP dated May 12, 2015 that details the voltage schedules for Will County and the proper response to voltage excursions.

Milestone #20 completion verified.

Milestone 21: Will County Station Unit Operating Procedures Revisions.

File 28, *Attachment WC4 - U4 Generator Reg's*, contains the Technical Instructions for Synchronizing Unit 4 Generators to the system. Page 2, Step 11.0, details the automating of voltage regulators and the need to notify the TOP if they cannot be automated. Page 3, Step 20.0, discusses monitoring and controlling voltage within the schedule.

Milestone #21 completion verified.

Milestone 22: Will County Station Voltage Regulator Trip to Manual.

File 29, *Attachment WC5 - Voltage Regulators*, contains a document titled *Will County Unit 4 Voltage Regular Monitoring Control Room Operator Responsibilities*. This document discusses voltage regulator operation and specifically describes steps to take if the voltage regulator trips to manual.

Milestone #22 completion verified.

Milestone 23: Will County Voltage Excursion Alarm

File 26, *Attachment WC2 - Yard Voltage Control*, contains an e-mail dated February 11, 2015 that describes the voltage alarms for the Will County station. It discusses how the alarms are set up, how they are to be used, and steps to take in response to the alarms.

File 27, *Attachment WC3 - ComEd Voltage Control*, contains a letter from the TOP dated May 12, 2015 that details the voltage schedules for Will County and the proper response to voltage excursions.

Milestone #23 completion verified.

Milestone 24: Document Storage Verification at the Powerton Station.

This simply states that Boston Energy will retain the training records and does not need verification as part of completing the mitigation plan.

Milestone 25: Powerton Station Voltage Regulator Trip to Manual Training.

File 7, *Attachment A7 - NRG AVR reporting 03152015*, contains a training presentation titled *AVR Compliance Reporting for NRG Generating Plants.* Page 7, specifically discusses AVR trips to "manual" and the appropriate response.

File 19, *Attachment P5 - FW _Follow up for AVR and Voltage Compliance Reporting*, contains an e-mail identifying who attended the training presentation titled *AVR Compliance Reporting for NRG Generating Plants* for the Powerton facility.

Milestone #25 completion verified.

Milestone 26: Joliet Station VAR-002 Training

File 14, *Attachment J7 - Joliet VAR-002 Training Roster*, contains a training record showing completion of computer based training on Generator Operation for Maintaining Network Voltage Schedules for personnel at the Joliet station.

Milestone #26 completion verified.

Milestone 27: Powerton Station VAR-002 Training.

File 21, *Attachment P7 - Powerton VAR-002 Training Roster*, contains a training record showing completion of computer based training on Generator Operation for Maintaining Network Voltage Schedules for personnel at the Powerton station.

Milestone #27 completion verified.

Milestone 28: Waukegan Station VAR-002 Training

File 23, *Attachment WA1 - Waukegan VAR-002 Training Roster*, contains a training record showing completion of computer based training on Generator Operation for Maintaining Network Voltage Schedules for personnel at the Waukegan station.

Milestone #28 completion verified.

Milestone 29: Powerton Station Unit Operating Procedure Revisions

File 20, *Attachment P6 - PO-0-2005-029 First Boiler Unit Startup*, contains a technical instruction document that details steps to be taken during startup of the units at the Powerton Station. Pages 32 and 33, Step 205, discuss maintaining station Voltage limits.

Milestone #29 completion verified.

Milestone 30: Document Storage Verification at the Joliet Station.

This simply states that Boston Energy will retain the training records and does not need verified as part of the completion of the mitigation plan.

The Mitigation Plan is hereby verified complete.

Date: January 28, 2016

Tony Purgar
Manager, Risk Analysis & Mitigation
ReliabilityFirst Corporation

Attachment H

Disposition Documents for RFC2015014839 (VAR-002-3 R2)

g.1. GenOn Northeast Management Company’s Self-Report, submitted on March 31, 2015;

g.2. Mitigation Plan RFCMIT011668-2, submitted on June 3, 2016;

g.3. Certification of the Mitigation Plan Completion, dated June 7, 2016; and

g.4. Mitigation Plan Verification for RFCMIT011668-2, dated November 10, 2016.

Self Report

Entity Name: GenOn Northeast Management Company (GNMC)

NERC ID: NCR11137

Standard: VAR-002-3

Requirement: VAR-002-3 R2.

Date Submitted: March 31, 2015

Has this violation previously been reported or discovered?: No

Entity Information:

Joint Registration Organization (JRO) ID:

Coordinated Functional Registration (CFR) ID:

Contact Name: Robert Burkhart

Contact Phone: 7245978553

Contact Email: robert.burkhart@nrg.com

Violation:

Violation Start Date: October 28, 2014

End/Expected End Date: October 28, 2014

Region Initially Determined a Violation On: March 28, 2015

Reliability Functions: Generator Operator (GOP)

Is Possible Violation still occurring?: No

Number of Instances: 1

Has this Possible Violation been reported to other Regions?: No

Which Regions:

Date Reported to Regions:

Detailed Description and Cause of Possible Violation: Per NERC Requirement VAR-002-3 R2, all Generators are directed to participate in maintaining an adequate voltage profile as provided by the Transmission Operator unless exempted by the Transmission Operator or unless the Generator Operator meets the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator (Attachment 2). While reviewing evidence to complete the Self-Certifications for the VAR-002-3 Standard for the last quarter of 2014 in the RF Region, it was discovered that the Keystone Generating Station recorded one (1) instance when the Station was outside the published Voltage Schedule during the 4th Quarter of 2014. Specifically, the highest voltage level achieved on 10/28/2014 was 534.948kV, 0.198% above the scheduled maximum level of 534kV (Attachment 1). In addition, there is no evidence that a phone call was made to the Transmission Operator seeking a change to the Voltage schedule or range. NOTE: the period the station was not within the Voltage Schedule only lasted 31 minutes and 3 seconds.

Mitigating Activities:

Description of Mitigating Activities and Preventative Measure: The station will be reviewing, among other things: the voltage levels that trigger the high and low alarms; logging procedures; and, the schedule for refresher training on this Standard.

Self Report

Date Mitigating Activities Completed:

Impact and Risk Assessment:

Potential Impact to BPS: Severe

Actual Impact to BPS: Minimal

Description of Potential and Actual Impact to BPS: Keystone Units 1 & 2 were not able to maintain the directed values contained in the Voltage Schedule (Attachment 2) for the period in question. There is no evidence of the station making a phone call to the appropriate entities when the station was not able to maintain output voltages (see Attachment 1).

Risk Assessment of Impact to BPS: NRG maintains that this Self Report resulted in a low risk to the reliable operation of the BES.

The highest voltage level achieved was 534.948kV, 0.198% above the scheduled maximum level of 534kV. At no time during this period was undervoltage ever experienced (Attachment 1).

Additional Entity Comments: It is NRG Energy's goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability.

Additional Comments		
From	Comment	User Name
Entity	NRG Energy adheres to a strong culture of compliance with the goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability. The Mitigation Plan that will be submitted will not only strengthen the obligations and actions that must be taken by our plant operations staff, but also reinforce NRG's strong culture of compliance. In addition to reviewing and adjusting Out of Voltage Schedule alarm levels, increasing communication and awareness training will better equip our personnel to identify when a generator is deviating from its schedule. Going forward NRG will have evidence to show that the Voltage or Reactive Power schedule provided by the Transmission Operator has been met (Attachment 2); or, shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule.	Robert Burkhart

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	FE May 2014 Voltage Schedule.pdf	Attachment 2 - 2014 First Energy East Voltage Schedule dated 5/7/2014	959,870
Entity	Keystone Station VAR-002 Voltage Schedule Variances 4Q2014 FINAL.xlsx	Attachment 1 - Keystone VAR-002 Voltage Schedule Out of Range	10,799

Mitigation Plan

Mitigation Plan Summary

Registered Entity: GenOn Northeast Management Company
Mitigation Plan Code:
Mitigation Plan Version: 3

NERC Violation ID	Requirement	Violation Validated On
RFC2015014839	VAR-002-3 R2.	

Mitigation Plan Submitted On: June 03, 2016
Mitigation Plan Accepted On:
Mitigation Plan Proposed Completion Date: December 31, 2015
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by GNMC On:
Mitigation Plan Completion Verified by RF On:
Mitigation Plan Completed? (Yes/No): No

Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Entity Information

Identify your organization:

Entity Name: GenOn Northeast Management Company

NERC Compliance Registry ID: NCR11137

Address: 1000 Main Street
Houston TX 77002

Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Patricia Lynch
Title: Director - Regulatory Compliance
Email: patricia.lynch@nrg.com
Phone: 609-524-5147

Violation(s)

This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
RFC2015014839	10/28/2014	VAR-002-3 R2.
Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility’s capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.		

Brief summary including the cause of the violation(s) and mechanism in which it was identified:

Per NERC Requirement VAR-002-3 R2, which was in effect when the incidents described below occurred, all Generators are directed to participate in maintaining an adequate voltage profile as provided by the Transmission Operator unless exempted by the Transmission Operator; or, unless the Generator Operator meets the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. On March 31, 2015, GenOn Northeast Management self-reported that while reviewing evidence to complete the Self-Certifications for the VAR-002-3 Standard for the last quarter of 2014, Keystone Generating Station experienced 25 separate times where the 500kV line voltage could not be maintained. It was determined during the review of the 25 incidents there was only one (1) instance when the Station output was outside the published Voltage Schedule and the station failed to properly report the 500kv line voltage off schedule for greater than thirty (30) minutes, in accordance with the transmission operator's instructions. This occurred on October 28, 2014. However, this determination was based upon instantaneous readings monitored by the station, not the thirty minute rolling average value, in accordance with the transmission operator's instructions.

Further investigation followed when questions were raised by ReliabilityFirst regarding the real root cause of the incident. It was discovered the 10/28/2014 incident was based on instantaneous voltage level data, not thirty minute rolling average data. Querying the new NRG PJM Voltage Monitoring Trader EMS system, it was determined that the rolling 30 minute average exceedance actually started at 22:54 on 10/28/2014 and didn’t get back into schedule until 06:32 on 10/29/2014 (see Attachment A). First Energy, the TOP, was notified of the voltage excursion for this episode at 23:53 on 10/28/2014 (see Attachment E which is a screenshot of the log entry showing the Real-Time Desk’s notification). However, the call was made 60 minutes after the incident began, not within the required 30 minutes. The Dispatcher on the Real-Time Desk cannot remember what was occurring at that time that would have prevented him from making the call within the 30 minute window. Also, the station control room operators did not have a rolling 30 minute average value displayed on the DCS control system screen(s) to monitor the 30 minute rolling average voltage level. Had this value been added to the screens previously the odds of this particular situation occurring would have been considerably less. The incident is considered a Human Performance Error.

Finally, in preparing for closure of the mitigation plan on 5/24/16, review of various Voltage Schedule excursions that had occurred post self report to present was made as part of due diligence. In all but one case, appropriate voltage schedule requests for exemption were provided to the TOP. The one exception occurred on 8/5/15, still within the active period of the open mitigation plan prior to its completion, but not originally identified in the original self report.

This exception began at 22:56 on 8/5/15, immediately preceding Unit 1’s removal for a maintenance outage while at minimum load. The plant had notified the Real Time Desk of the excursion at 23:08 that the plant was off schedule using the instantaneous voltage signal available at the plant. The Real Time Desk was monitoring the PJM Trader application for the 30 minute rolling average time frame but received response from the plant that the voltage was back in schedule at 23:30 and therefore didn’t make the notification. However, the voltage reverted back to out of schedule until 23:46 when corrections where made by First Energy.(see Attachments G and H). The 30 minute rolling average exceeded the voltage schedule which remained above 534 KV for 50 minutes although the instantaneous signal did not continually exceed the schedule in that time frame. The root cause of this incident was related to an assumption by the Real Time Desk that the voltage schedule had been brought into range and corrected when the plant notified the Real Time Desk (using the instantaneous signal as opposed to a 30 minute rolling average). This was an isolated event that occurred before the 30 minute rolling average display was inserted in the plant Control room for Operations personnel.

Relevant information regarding the identification of the violation(s):

NRG receives both the actual voltage and the requested schedule points via its ICCP link with PJM. These are the points NRG should be controlling voltage to and were used in PJM's Generation Performance Monitoring (GPM) system. PJM's GPM system compared the rolling 30 minute average to the designated voltage schedule and flagged performance outside that threshold. NRG initially used PJM's GPM, but as its PJM fleet grew and NRG had a growing need for historical data NRG ended up building its own voltage monitoring application using the actual voltage and the requested schedule points to emulate PJM's GPM system. PJM retired their GPM on 6/1/2015 and now expects the GO/GOPs to monitor their unit's performance using a comparable methodology. The NRG PJM Voltage Monitoring Trader EMS application was built using the same 30 minute average.

In May of 2014 Keystone received direction from First Energy revising the 500kV voltage schedule tolerance values to 1.5% and an updated voltage schedule. This updated voltage schedule required the revision of the existing alarm limits, which were reviewed with the Control Room Operators during daily job briefings at the beginning of each shift. In addition, training on the revised schedule was provided in April, 2015.

Plan Details

Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

The specific tasks and actions taken include: a review of the importance of maintaining and reporting deviations from the established Voltage Schedule; a review of alarm response procedures; upgrades of existing alarms; refresher training of both the Plant Operators and Real Time Traders; the implementation of additional alarms to the station Digital Control Systems; and, the addition of the 30 minute rolling voltage average value to the control room DCS screens.

Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: December 31, 2015

Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
Maintain Voltage Schedule	Keystone normal voltage schedule should be maintained at 526kV unless a "Heavy Schedule" is in effect and is required by system conditions. It is very important that we are always making every effort to maintain the target 526kV schedule.	04/10/2015	04/13/2015	The first training session provided a review of the importance of maintaining and reporting the generator voltage schedule; and, review of alarm response procedures. See Attachment B.	No
518kV Low "Off Schedule" HIGH Priority Alarm After 15 Minutes	The 518kV Low "Off Schedule" HIGH Priority Alarm after 15 minutes will go away when the acknowledge button is pressed. Operator to adjust the 500kV voltage while maintaining station electrical system operating parameters. The operators are required to notify the	04/17/2015	04/15/2015	The "High Priority" Alarm After 15 minutes Off Schedule has been added (complete - see Attachment C). Operator & Supervisor training has been completed. (See Attachment C)	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	load dispatcher, acknowledge a control system prompt and make a log book entry of the alarm and reporting information.				
518kV Low "Off Schedule" HIGH Priority Alarm After 5 Minutes	518kV Low "Off Schedule" High Priority Alarm After 5 Minutes stays on until the 500kV voltage is back on schedule. Operator to adjust the 500kV voltage while maintaining station electrical system operating parameters.	04/17/2015	04/15/2015	The alarm priority has been upgraded to "High Priority" (complete - see Attachment C). Operator & Supervisor training completed (see Attachment C).	No
518kV Low "Off Schedule" URGENT Priority Alarm After 25 Minutes	518kV Low "Off Schedule" URGENT Priority Alarm after 25 minutes stays on until the 500kv voltage is back on schedule. Operator to adjust 500kV voltage while maintaining station electrical system operating parameters. The operators are required to notify the load dispatcher and make a log book entry of the alarm and reporting information.	04/17/2015	04/15/2015	The alarm priority has been upgraded to "Urgent Priority" (complete - see Attachment C). Operator & Supervisor training has been completed. See Attachment C.	No
534kV High "Off Schedule" HIGH Priority Alarm After 15 Minutes	The 534kV High "Off Schedule" HIGH Priority Alarm after 15 minutes will go away when the acknowledge button	04/17/2015	04/15/2015	The "High Priority" Alarm After 15 minutes Off Schedule has been added (complete - see Attachment C).	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	is pressed. Operator to adjust the 500kV voltage while maintaining station electrical system operating parameters. The operators are required to notify the load dispatcher, acknowledge a control system prompt and make a log book entry of the alarm and reporting information.			Operator & Supervisor training has been completed. (See Attachment C)	
534kV High "Off Schedule" HIGH Priority Alarm After 5 Minutes	534kV High "Off Schedule" HIGH Priority Alarm after 5-minutes stays on until the 500kV voltage is back on schedule. Operator to adjust the 500kV voltage while maintaining station electrical system operating parameters.	04/17/2015	04/15/2015	The alarm priority has been upgraded to "High Priority" (complete - see Attachment C). Operator & Supervisor training completed (see Attachment C).	No
534kV High "Off Schedule" URGENT Priority Alarm After 25 Minutes	534kV High "Off Schedule" URGENT Priority Alarm after 25 minutes stays on until the 500kv voltage is back on schedule. Operator to adjust 500kV voltage while maintaining station electrical system operating parameters. The operators are required to notify the load dispatcher and make a log book	04/17/2015	04/15/2015	The alarm priority has been upgraded to "Urgent Priority"(complete - see Attachment C). Operator & Supervisor training has been completed. See Attachment C.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	entry of the alarm and reporting information.				
Back On Schedule	Keystone Voltage Schedule High 534kV condition clears. The operator will receive an URGENT Priority Alarm (500kV Voltage "On Schedule"). This alarm will go away when the acknowledge button is pressed. Both the high voltage condition "High Priority and URGENT" alarms will clear automatically. The operators are required to: notify the load dispatcher as soon as they are back within the Voltage Schedule; acknowledge a control system prompt; and, make a log book entry of the alarm and reporting information.	04/17/2015	04/15/2015	The alarm priority has been upgraded to "Urgent Priority"(complete - see Attachment C). Operator & Supervisor training completed. See Attachment C.	No
Back On Schedule Keystone Voltage Schedule Low 518kV condition clears.	The operator will receive an URGENT Priority Alarm (500kV Voltage "On Schedule"). This alarm will go away when the acknowledge button is pressed. Both the high voltage condition "High Priority" and "URGENT" alarms	04/17/2015	04/15/2015	The alarm priority has been upgraded to "Urgent Priority" (complete - see Attachment C). Operator & Supervisor training completed. See Attachment C.	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
	will clear automatically. The operators are required to: notify the load dispatcher as soon as they are back within the Voltage Schedule; acknowledge a control system prompt; and, make a log book entry of the alarm and reporting information.				
Maintain Voltage Schedule	Keystone normal voltage schedule should be maintained at 526kV unless a "Heavy Schedule" is in effect and is required by system conditions. It is very important that we are always making every effort to maintain the target 526kV schedule.	04/17/2015	04/15/2015	The second training session provided training on the alarm response revisions associated with maintaining and reporting generator voltage. See Attachment C.	No
Station 500kV Voltage Off Schedule Alarm Response Procedure	Develop a more formal station specific 500kV Voltage Off Schedule Alarm Response Procedure.	06/25/2015	06/25/2015	See Attachment D. This document is an official station alarm response procedure based on predecessor document, Attachment C.	No
Placeholder Milestone for 30 Minute Rolling Average Display and Refresher Training of Real Time Traders	Add a 30 minute rolling average display in the Control Room for Ops Personnel and Real Time Trader refresher training on OCC- VAR-002 Compliance procedure for reinforcement of notification requirements	09/25/2015	12/30/2015	This display provides the Control Room Operators a method to monitor station voltage output levels. See Attachment F. Refresher Training of Real Time Traders on procedure will provide reinforcement of notification requirements. See Attachments I and J NOTE: These activities were completed by 12/31/2015. As additional	No

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date	Entity Comment on Milestone Completion	Extension Request Pending
				activities were identified post original mitigation plan submittal, a placeholder milestone has been added.	
Placeholder milestone for 30 Minute Rolling Average Display and Completion of Refresher Training of Real Time Traders	Add a 30 minute rolling average display in the Control Room for Ops Personnel. Real Time Trader refresher training on OCC- VAR-002 Compliance procedure for reinforcement of notification requirements.	12/25/2015	12/30/2015	This display provides the Control Room Operators a method to monitor station voltage output levels. See Attachment F. Refresher Training of Real Time Traders on procedure will provide reinforcement of notification requirements. See Attachments I and J for training completion by 11/29/15 NOTE: These activities were completed by 12/31/2015. As additional activities were identified post original mitigation plan submittal, a placeholder milestone has been added.	No
30 Minute Rolling Average Display	Add a 30 minute rolling average display in the Control Room for Ops Personnel	12/31/2015	12/30/2015	This display provides the Control Room Operators a method to monitor station voltage output levels. See Attachment F. NOTE: This activity was projected and completed by 12/31/2015. As this activity was identified post original mitigation plan submittal, a placeholder milestone was added.	No

Additional Relevant Information

The details contained herein can differ considerably from those presented in the Self Report. This is a result of the deeper investigations conducted that uncovered details which were not obvious at the time of submission of the Self Report.

Reliability Risk

Reliability Risk

While the Mitigation Plan is being implemented, the reliability of the bulk Power System may remain at higher Risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are known or anticipated : (i) Identify any such risks or impacts, and; (ii) discuss any actions planned or proposed to address these risks or impacts.

NRG originally maintained that this PV resulted in a low risk to the reliable operation of the BES. The highest voltage level achieved was 538.630kV, 0.867% above the scheduled maximum level of 534kV. Further review by the Real Time Desk was conducted to determine why it took 7 hours to bring the voltage back on schedule. During the time period involved, PJM was in a High Voltage Limit Condition under low load conditions. Equipment constraints at the plants, typically a lower limit of operating voltage on the 4160V switchgear, prevents them from being able to lower local voltages to bring the system voltage down. A single plant cannot improve the voltage levels, nor can all of the plants collectively under a High Voltage Limit Condition. Only more load can bring the voltage down to expected levels. FYI - PJM’s high limit on the 500kV system is 550kV. The 7 hour period covered the early morning hours. Conditions didn’t start to improve until 06:32 on 10/29/14 when everyone was getting ready to start their day.
With regard to the 8/5/15 over voltage condition, the risk to the grid was very low as PJM and the TO had been informed of the upcoming maintenance outage and the unit was expected to be removed from service momentarily.
NOTE: At no time during these periods were under voltage ever experienced.

Prevention

Describe how successful completion of this plan will prevent or minimize the probability further violations of the same or similar reliability standards requirements will occur

Having already implemented all of the Milestone Activities described in this Plan, the Keystone Station has raised the level of existing alarm priorities; added additional high priority and urgent alarms at 15 and 25 minutes, and, reinforced the requirement of the operators and Real Time Traders reporting the off schedule condition, using the 30 Minute rolling average, all of which will enhance continued compliance with the NERC standard.

Describe any action that may be taken or planned beyond that listed in the mitigation plan, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements

NRG Energy adheres to a strong culture of compliance with the goal to conduct business activities in a manner that supports the reliable operation of the BES and foster a culture of reliability. This Mitigation Plan will not only strengthen the obligations and actions that must be taken by our plant operations staff and Real Time Desk, but also reinforce NRG's strong culture of compliance. In addition to reviewing and adjusting Out of Voltage Schedule alarm levels, increasing communication and awareness training will better equip our personnel to identify when a generator is deviating from its schedule. Going forward NRG will have evidence to show that the Voltage or Reactive Power schedule provided by the Transmission Operator has been met; or, shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator has been met; or, shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule.

Refresher training will be implemented according to NRG Company policies to minimize the probability of further violations.

Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

* Submits the Mitigation Plan, as presented, to the regional entity for acceptance and approval by NERC, and

* if applicable, certifies that the Mitigation Plan, as presented, was completed as specified.

Acknowledges:

1. I am qualified to sign this mitigation plan on behalf of my organization.

2. I have read and understand the obligations to comply with the mitigation plan requirements and ERO remedial action directives as well as ERO documents, including but not limited to, the NERC rules of procedure and the application NERC CMEP.

3. I have read and am familiar with the contents of the foregoing Mitigation Plan.

GenOn Northeast Management Company Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authority.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Patricia Lynch

Title: Director - Regulatory Compliance

Authorized On: June 03, 2016

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name:	GenOn Northeast Management Company
NERC Registry ID:	NCR11137
NERC Violation ID(s):	RFC2015014839
Mitigated Standard Requirement(s):	VAR-002-3 R2.
Scheduled Completion as per Accepted Mitigation Plan:	December 31, 2015
Date Mitigation Plan completed:	December 30, 2015
RF Notified of Completion on Date:	June 06, 2016
Entity Comment:	Updated the mitigation plan to correct errata concerning attachment references and added an additional event with mitigating activities during the open mitigation plan interval.

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT D[1].pdf	ATTACHMENT D - 500kV Voltage Off Schedule Alarm Response Procedure # 400	1,068,670
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 4Q 2014_ATT B Final.pdf	ATTACHMENT B-First session training material	2,428,506
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 4Q 2014 Att F-30 min Rolling Average.msg	Attachment F- New 30 minute rolling average alarm installation	165,376
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 4Q 2014 ATTC Final.pdf	Attachment C- Second session training material on modified alarm response procedure	1,318,503
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 4Q 2014_Att A.pdf	Attachment A- Keystone Voltage for 10/28-10/29/14	622,175
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 4Q 2014 ATT E.pdf	Attachment E-Log Entry of communication to PJM and First Energy-10/28/14	986,674
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 ATT I.pdf	Attachment I- Real Time Desk training dates for OCC-VAR-002 Compliance Procedure	19,325
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 4Q 2014 AttJ.pdf	Attachment J- OCC-VAR-002 Compliance Procedure	193,973
Entity	CDMS_MitPLan_Keystone	Attachment H- Keystone Actual (Instantaneous and	244,241

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	VAR-002-3 R2 ATT H.pdf	30 Minute rolling average) vs Schedule Voltage- 8/5/15	244,241
Entity	CDMS_MitPlan_Keystone VAR-002-3 R2 AttG.xlsx	Attachment G- Keystone Actual vs Schedule Voltage (by minute) on 8/5/15	20,137

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Patricia Lynch

Title: Director - Regulatory Compliance

Email: patricia.lynch@nrg.com

Phone: (609) 524-5147

Authorized Signature ______________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

RELIABILITY FIRST

Mitigation Plan Verification for RFC2015014839

GenOn Northeast Management Company

Standard/Requirement: VAR-002-3 R2

NERC Mitigation Plan ID: RFCMIT011668-2

Method of Disposition: Not yet determined

Relevant Dates					
Initiating Document	**Mitigation Plan Submittal**	**RF Acceptance**	**NERC Approval**	**Certification Submittal**	**Date of Completion**
Self-Report 03/31/15	06/03/16	06/06/16	06/30/16	06/06/16	12/30/15

Description of Issue

On March 31, 2015, GenOn Northeast Management self-reported that while reviewing evidence to complete the Self-Certifications for the VAR-002-3 Standard for the last quarter of 2014, Keystone Generating Station experienced 25 separate times where the 500kV line voltage could not be maintained. It was determined during the review of the 25 incidents there was only one (1) instance when the Station output was outside the published Voltage Schedule and the station failed to properly report the 500kv line voltage off schedule for greater than thirty (30) minutes, in accordance with the transmission operator's instructions. This occurred on October 28, 2014. However, this determination was based upon instantaneous readings monitored by the station, not the thirty minute rolling average value, in accordance with the transmission operator's instructions.

Further investigation followed when questions were raised by ReliabilityFirst regarding the real root cause of the incident. It was discovered the 10/28/2014 incident was based on instantaneous voltage level data, not thirty minute rolling average data. Querying the new NRG PJM Voltage Monitoring Trader EMS system, it was determined that the rolling 30 minute average exceedance actually started at 22:54 on 10/28/2014 and didn't get back into schedule until 06:32 on 10/29/2014 (see Attachment A). First Energy, the TOP, was notified of the voltage excursion for this episode at 23:53 on 10/28/2014 (see Attachment E which is a screenshot of the log entry showing the Real-Time Desk's notification). However, the call was made 60 minutes after the incident began, not within the required 30 minutes. The Dispatcher on the Real-Time Desk cannot remember what was occurring at that time that would have prevented him from making the call within the 30 minute window. Also, the station control room operators did not have a rolling 30 minute average value displayed on the DCS control system screen(s) to monitor the 30 minute rolling average voltage level. Had this value been added to the screens previously the odds of this particular situation occurring would have been considerably less. The incident is considered a Human Performance Error.

Finally, in preparing for closure of the mitigation plan on 5/24/16, review of various Voltage Schedule excursions that had occurred post self report to present was made as part of due diligence. In all but one case, appropriate voltage schedule requests for exemption were provided to the TOP. The one exception occurred on 8/5/15, still within the active period of the open mitigation plan prior to its completion, but not originally identified in the original self report.

This exception began at 22:56 on 8/5/15, immediately preceding Unit 1's removal for a maintenance outage while at minimum load. The plant had notified the Real Time Desk of the excursion at 23:08 that the plant was off schedule using the instantaneous voltage signal available at the plant. The Real Time Desk was monitoring the PJM Trader application for the 30 minute rolling average time frame but received response from the plant that the voltage was back in schedule at 23:30 and therefore didn't make the notification. However, the voltage reverted back to out of schedule until 23:46 when corrections where made by First Energy.(see Attachments G and H).

The 30 minute rolling average exceeded the voltage schedule which remained above 534 KV for 50 minutes although the instantaneous signal did not continually exceed the schedule in that time frame. The root cause of this incident was related to an assumption by the Real Time Desk that the voltage schedule had been brought into range and corrected when the plant notified the Real Time Desk (using the instantaneous signal as opposed to a 30 minute rolling average). This was an isolated event that occurred before the 30 minute rolling average display was inserted in the plant Control room for Operations personnel.

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 1	CDMS MitPlan Keystone VAR-002-3 R2 Q4 2014 Att A	VAR-002-3 R2
File 2	CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT B	VAR-002-3 R2
File 3	CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C[1]	VAR-002-3 R2

Evidence Reviewed		
File Name	**Description of Evidence**	**Standard/Req.**
File 4	CDMS MitPlan Keystone VAR-002-3 R2 $Q 2014 ATT D[1]	VAR-002-3 R2
File 5	CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT E[1]	VAR-002-3 R2
File 6	CDMS MitPlan Keystone VAR-002-3 R2 4Q 20104 Att F-30 Min Rolling Average	VAR-002-3 R2
File 7	CDMS MitPlan Keystone VAR-002-3 R2 AttG	VAR-002-3 R2
File 8	CDMS MitPlan Keystone VAR-002-3 R2 Att H	VAR-002-3 R2
File 9	CDMS MitPlan Keystone VAR-002-3 R2 ATT I	VAR-002-3 R2
File 10	CDMS Mit Plan Keystone VAR-002-3 R2 4Q 2014 AttJ	VAR-002-3 R2
File 11	Keystone signed 500kv voltage off schedule alarm response	VAR-002-3 R2
File 12	30 minute rolling average voltage schedule display	VAR-002-3 R2

Verification of Mitigation Plan Completion

Milestone 1: Maintain Voltage Schedule.

File 2, *CDMS MitPlan Keystone VAR-002-R2 4Q 2014 ATT B*, is an internal email dated May 25, 2014 which explains that the 500 kV voltage schedule alarm limits have been changed and to use the new operating parameters listed and described in the email.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C,* is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015 which specifies the 526 kV voltage schedule that must be maintained.

Milestone #1 completion verified.

Milestone 2: 518kv Low "Off Schedule" HIGH Priority Alarm After 15 Minutes.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C,* is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule Low, Page 2, Item 3, describes the alarm functionality and operator actions for this condition.

Milestone #2 completion verified.

Milestone 3: 518kv Low "Off Schedule" HIGH Priority Alarm After 5 Minutes.

File 3, CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C, is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule Low, Page 2, Item 2, describes the alarm functionality and operator actions for this condition.

Milestone #3 completion verified.

Milestone 4: 518kv Low "Off Schedule" URGENT Priority Alarm After 25 Minutes.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C,* is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule Low, Page 3, Item 4, describes the alarm functionality and operator actions for this condition.

Milestone #4 completion verified.

Milestone 5: 534kv High "Off Schedule" HIGH Priority Alarm After 15 Minutes.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C,* is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule High, Page 1, Item 3, describes the alarm functionality and operator actions for this condition.

Milestone #5 completion verified.

Milestone 6: 534kv High "Off Schedule" HIGH Priority Alarm After 5 Minutes.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C,* is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule High, Page 1, Item 2, describes the alarm functionality and operator actions for this condition.

Milestone #6 completion verified.

Milestone 7: 534kv High "Off Schedule" URGENT Priority Alarm After 25 Minutes.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C,* is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule High, Pages 1 and 2, Item 4, describes the alarm functionality and operator actions for this condition.

Milestone #7 completion verified.

Milestone 8: Back on Schedule

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C*, is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule High, Page 1, Item 3, describes the alarm functionality and operator actions for this condition.

Milestone #8 completion verified.

Milestone 9: Back on Schedule Keystone Voltage schedule Low 518kv condition clears.

File 3, CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C, is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015, Keystone 500 kV Voltage off schedule High, Page 1, Item 5, describes the alarm functionality and operator actions for this condition. Keystone 500 kV Voltage off schedule Low, Pages 3 and 4, Item 5, describes the alarm functionality and operator actions for this condition.

Milestone #9 completion verified.

Milestone 10: Maintain Voltage Schedule

File 2, *CDMS MitPlan Keystone VAR-002-R2 4Q 2014 ATT B*, is an internal email dated May 25, 2014, which explains that the 500 kV voltage schedule alarm limits have been changed and to use the new operating parameters listed and described in the email.

File 3, *CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT C*, is the 500 kV Voltage Reporting Compliance Revision dated April 10, 2015 which specifies the 526 kV voltage schedule that must be maintained unless a "Heavy Schedule" is in effect, Page 1, Item 1 and Page 2, Item 1.

Milestone #10 completion verified.

Milestone 11: Station 500kv Voltage Off Schedule Alarm Response Procedure.

File 4, CDMS MitPlan Keystone VAR-002-3 R2 4Q 2014 ATT D[1], is the revised alarm response procedure, Revision 0, Effective June 25, 2015. Procedure has not been approved by the Supervisor, Station Operations.

File 11, *Keystone signed 500kv voltage off schedule alarm response*, provided to ReliabilityFirst on June 10, 2016, includes the approval by the Supervisor, Station Operations and demonstrates completion of this milestone.

Milestone #11 completion verified.

Milestone 12: Placeholder Milestone for 30 Minute Rolling Average Display and Refresher Training of Real Time Traders.

Milestone #12 verified complete.

Milestone 13: Placeholder milestone for 30 Minute Rolling Average Display and Completion of Refresher Training of Real Time Traders.

Milestone #13 verified complete.

Milestone 14: 30 Minute Rolling Average Display

File 6, *CDMS MitPlan Keystone VAR-002-3 R2 QS 2014 Att F - 30 min Rolling Average,* consists of an internal email which is intended to indicate the design of this alarm but no data is displayed.

File 12, *30 Minute rolling average voltage schedule display*, provided to RF on June 10, 2016, is a screenshot of the Operator Group which includes the 30 Min Rolling Average voltage data and demonstrates completion of this milestone.

Milestone #14 completion verified.

The Mitigation Plan is hereby verified complete.

Tony Purgar

Date: November 10, 2016

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