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<th>Reliability Standard</th>
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<tr>
<td>MRO2018019527</td>
<td>TOP-001-3</td>
<td>R13</td>
<td>Northern States Power (Xcel Energy) (NSP)</td>
<td>NCR01020</td>
<td>1/15/2018</td>
<td>1/15/2018</td>
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of PSCO. Xcel Energy states that PSCO experienced a loss of its Real Time Assessment (RTA) tool and did not ensure that RTA was being performed during the outage of its tool.

The noncompliance was caused by Xcel Energy failing to implement adequate alarming to alert the operator that the RTA tool was not functioning. Xcel Energy used an alarm that would auto-silence after a period of time and the System Operator did not recognize that the RTA tool was not functioning. Xcel Energy reports that the noncompliance was discovered when an individual investigated the auto-silenced persistent alarm.

The noncompliance began on January 15, 2018, when an RTA was not performed at least once every thirty minutes and ended approximately 30 minutes after the noncompliance began, when PSCO notified its Reliability Coordinator and asked the Reliability Coordinator to run PSCO’s RTA for it.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy states that during the noncompliance, its Reliability Coordinator was performing RTA that included the PSCO system. Additionally, Xcel Energy states that during the noncompliance, the PSCO system did not experience a line or generation trip. No harm is known to have occurred.

**Mitigation**

To mitigate this noncompliance, Xcel Energy:

1) contacted PSCO’s Reliability Coordinator and asked it to run PSCO’s RTA;
2) reconfigured the alarm to change it from a high priority alarm that auto silenced to a critical priority alarm that would produce sound until silenced by an operator;
3) conducted an event review (training) with System Operators on the event.

The mitigation was limited to PSCO.
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<td>IRO-010-1a</td>
<td>R3</td>
<td>Northern States Power (Xcel Energy) (NSP)</td>
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<td>1/24/2018</td>
<td>self-log</td>
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Operator, it was in noncompliance with IRO-010-1a R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of PSCO. Xcel Energy states that upon reviewing PSCO’s Reliability Coordinator’s (RC) data specifications, that it determined that it was not providing all the data from seven required data categories associated with a WECC Transfer Path.

The noncompliance was caused by Xcel Energy failing to define clear ownership for providing this data to the RC. The noncompliance began on October 1, 2011, when the standard became enforceable and ended on January 24, 2018, when it began providing all required data to its RC.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy states that the noncompliance impacted less than 2% of the data points that PSCO was providing to its RC. Further, Xcel Energy stated that the missing data points were not associated with an Interconnection Reliability Operating Limit (IROL), a Remedial Action Scheme (RAS), or a Major WECC Transfer Path. Additionally, Xcel Energy states that the missing data points associated with Blackstart Cranking Paths did not impede PSCO from monitoring the status of those paths. Finally, Xcel Energy reports that the actual MW and Total Transfer Capacity (TTC) were being provided to the RC during the noncompliance and the noncompliance did not prevent either itself or the RC from being able to monitor the actual flows for the impacted WECC Transfer Path. No harm is known to have occurred.

**Mitigation**

To mitigate this noncompliance:

1) PSCO provided the necessary procedures, scheduled MW, and other data points to its RC;
2) PSCO conducted a full evaluation of each obligation in the RC Data Specifications to verify that each was adequately satisfied;
3) NSP and SPS reviewed their RC data specifications and supporting evidence to confirm there were no deficiencies; and
4) PSCO instituted a monthly meeting to review the data specifications with process owners to determine if there were any needed updates.
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<td>MRO2018019531</td>
<td>FAC-008-3</td>
<td>R6</td>
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</table>

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, it was in noncompliance with FAC-008-3 R6. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of SPS and NSP.

Xcel Energy states that it updated its Facility Ratings Methodology (FRM) on July 18, 2016. Pursuant to Xcel Energy’s FRM, it is required to update affected Facility Ratings within 18 months. Xcel Energy failed to review and update 95 of 602 Facilities in the NSP operating system and 24 of 485 Facilities in the SPS operating system within the required 18 months. Xcel Energy was 12 days late in completing all facilities in the NSP operating system and 20 days late in the SPS operating system.

The noncompliance was caused by Xcel Energy failing to adequately consider the time it would take to implement the review and did not have in place a process to ensure that the review was completed within the required timeframe.

The noncompliance began on January 18, 2018, 18 months after Xcel Energy updated its FRM and ended on February 7, 2018, when it reviewed and updated the Facility Ratings for all Facilities.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk to the NSP system was minimal because per Xcel Energy, none of the 95 Facilities were part of a Remedial Action Scheme (RAS) or an Interconnection Reliability Operating Limit (IROL), and the actual loading of the affected Facilities during the period of noncompliance was only 45% of the maximum Facility Rating. Additionally, four of the Facilities were associated with a Blackstart Cranking Path; three of those Facilities saw a slight increase in ratings and the one that saw a decrease had far more MVA actual capacity (279.7 MVA) than the 60 MVA that would be used during System Restoration. The risk to the SPS system was minimal because per Xcel Energy, none of the 24 Facilities were part of a Blackstart Cranking Path, an IROL, or a RAS. No harm is known to have occurred.

**Mitigation**

To mitigate this noncompliance, Xcel Energy:

1) reviewed and updated the Facility Ratings for all Facilities; and
2) implemented a new process to use its compliance tracking tool on future FRM updates.
<table>
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<tr>
<td>MRO2018019965</td>
<td>MOD-026-1 R2</td>
<td></td>
<td>Eastman Cogeneration Limited Partnership (EASTMAN)</td>
<td>NCR01092</td>
<td>7/1/2018</td>
<td>10/17/2018</td>
<td>Self-Report</td>
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</tr>
</tbody>
</table>

**Description of the Noncompliance** (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On July 3, 2018, EASTMAN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. Specifically, EASTMAN was unable to meet the 30% phased-in implementation by July 1, 2018. EASTMAN reports that there was a water leak that threatened the Facility's restarting capability. EASTMAN states that performing the exciter model testing would increase the possibility of a trip. EASTMAN did not want to take any action that could increase the possibility of a trip while the Facility's ability to restart was threatened.

The cause of the noncompliance was that testing could not be performed due to a water leak that impeded the Facility's ability to restart.

This noncompliance started on July 1, 2018, when EASTMAN failed to meet the 30% phased-in implementation plan and ended on October 17, 2018, when it reported the verified model data to its Transmission Planner.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that provides power to an associated industrial operation. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Inherent Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred.

EASTMAN has no relevant history of noncompliance.

**Mitigation**

To mitigate this noncompliance, EASTMAN:

1) repaired the water leak;
2) performed the testing; and
3) reported the verified model to its Transmission Planner.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
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<tr>
<td>MRO2018019966</td>
<td>MOD-027-1 R2</td>
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<td>Eastman Cogeneration Limited Partnership (EASTMAN)</td>
<td>NCR01092</td>
<td>7/1/2018</td>
<td>10/17/2018</td>
<td>Self-Report</td>
<td>Completed</td>
</tr>
</tbody>
</table>

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)**

On July 3, 2018, EASTMAN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. Specifically, EASTMAN was unable to meet the 30% phased-in implementation by July 1, 2018. EASTMAN reports that there was a water leak that threatened the Facility’s restarting capability. EASTMAN states that performing the governor/turbine and load control or active power/frequency control model testing would increase the possibility of a trip. EASTMAN did not want to take any action that could increase the possibility of a trip while the Facility’s ability to restart was threatened.

The cause of the noncompliance was that testing could not be performed due to a water leak that impeded the Facility’s ability to restart.

This noncompliance started on July 1, 2018, when EASTMAN failed to meet the 30% phased-in implementation plan and ended on October 17, 2018, when it reported the verified model data to its Transmission Planner.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that provides power to an associated industrial operation. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Inherent Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred.

EASTMAN has no relevant history of noncompliance.

**Mitigation**

To mitigate this noncompliance, EASTMAN:

1) repaired the water leak;
2) performed the testing; and
3) reported the verified model to its Transmission Planner.
NPCC2018020216  PRC-005-6  R3  Evergreen Gen Lead LLC  NCR11727  04/01/17  11/19/18  Self-Report  Completed

On August 17, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6, R3. During preparation for its audit, the Entity discovered that it did not perform the minimum maintenance activities for its Vented Lead-Acid (VLA) Batteries in accordance with the maximum maintenance intervals prescribed in PRC-005-6 and the Implementation Plan for PRC-005-6.

The Entity owns two wind generation Facilities.

• By the April 1, 2017 deadline, the Entity had not completed all of the aspects of the 18-month interval battery maintenance activities for both Facilities. The battery banks at each Facility were last tested in September 2014 and September 2015. Each battery bank should have been tested under the 18 month criteria by April 1, 2017.
• The Entity also did not conduct the 6-year battery bank performance verification for one of its two Facilities by December 31, 2017 (the expiration of the maintenance interval). The VLA battery bank performance verification last took place in 2011.

The noncompliance started on April 1, 2017, when the Entity was required to have completed the 18-month VLA battery maintenance activities, and ended on November 19, 2018, when the Entity performed all of the required maintenance activities for the VLA batteries and the battery bank. The root cause of this noncompliance was a lack of management oversight around implementing the Protection System Maintenance Program (PSMP) and less than adequate controls for scoping and scheduling PSMP maintenance tasks. A contributing cause was the Entity’s change of ownership leading up to and during the PRC-005 transition.

Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Unmaintained VLA batteries and control circuitry could cause those components to fail when needed and could cause the generator to trip offline, which could potentially exasperate an ongoing real time BES situation. It could expose the generation equipment to damage if the plant fails to trip offline properly when called upon. However, the Entity’s generating facilities consist of two wind sites that total to 142 MW at a common BES point of interconnection. The rated capability of the generation is approximately 7% of the Entity’s Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the output of the site is contingent on these conditions.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.

Mitigation

To mitigate this noncompliance, Evergreen Gen Lead LLC:

1) Completed all of the missing PRC-005 maintenance at both BES facilities
2) Reviewed all PRC-005 maintenance deadlines and added them to its Microsoft Outlook calendar that will alert before the interval due date occurs
3) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness
<table>
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<td>R1</td>
<td>Evergreen Gen Lead LLC</td>
<td>NCR11727</td>
<td>07/01/2016</td>
<td>11/09/2018</td>
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)**

On September 25, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R1. During preparation for an audit, the Entity discovered that it failed to meet the Real Power testing requirements of MOD-025-2, R1 Attachment 1 prior to the effective date of the Standard, which was July 1, 2016 for it’s two BES wind Facilities.

The noncompliance started on July 1, 2016 and ended on November 9, 2018 when the real power testing results for both BES Facilities were provided to the Transmission Planner.

The root cause of this noncompliance was a lack of management oversight around understanding and implementing the MOD-025 testing program and less than adequate controls to track testing due dates.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

The potential risk due to noncompliance with MOD-025-2 R1 is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. The Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generator is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability due to inaccurate information. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the potential real power output of the site is contingent on these conditions and the site is not typically relied upon to operate at a consistent real power output level.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance:

1. Scheduled and performed the real power testing at both BES facilities
2. Provided the test results to the Transmission Planner
3. Added verification of the Real Power capability to its Microsoft Outlook calendar with an interval period of less than 60 calendar months
4. Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness
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<td>Evergreen Gen Lead LLC</td>
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<td>07/01/2016</td>
<td>11/09/2018</td>
<td>Self-Report</td>
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</table>

**Description of the Noncompliance**

On September 25, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R2. During preparation for an audit, the Entity discovered that it failed to meet the Reactive Power testing requirements of MOD-025-2, R2 Attachment 1 prior to the effective date of the Standard, which was July 1, 2016 for its two BES wind Facilities.

The noncompliance started on July 1, 2016 and ended on November 9, 2018 when the reactive power testing results for both BES Facilities were provided to the Transmission Planner.

The root cause of this noncompliance was a lack of management oversight around understanding and implementing the MOD-025 testing program and less than adequate controls to track testing due dates.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

The potential risk due to noncompliance with MOD-025-2 R2 is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. The Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generator is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability due to inaccurate information. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the potential reactive power output of the site is contingent on these conditions and the site is not typically relied upon to operate at a consistent reactive power output level.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance:

1. Scheduled and performed the reactive power testing at both BES facilities
2. Provided the test results to the Transmission Planner
3. Added verification of the Reactive Power capability to its Microsoft Outlook calendar with an interval period of less than 60 calendar months
4. Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness
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<td>R3</td>
<td>Evergreen Gen Lead LLC</td>
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<td>10/14/2016 10/12/2016 06/03/2017</td>
<td>Compliance Audit</td>
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)**

During a Compliance Audit conducted from October 15, 2018 through January 22, 2019, NPCC determined that Evergreen Gen Lead LLC (the Entity), as a Generator Operator, was in noncompliance with COM-002-4, R3. Specifically, between July 2016 and June 2017, there were three instances where operating personnel were placed in an on-shift position where Operating Instructions could have been given or received prior to those operating personnel completing communication training. In all three instances, the Entity could not provide documentation to confirm that the training took place before the operating personnel went on-watch. In all three instances, documentation was provided showing that training was completed approximately one month of assuming the on-shift position. The Entity claimed initial training was performed for the three operating personnel, but that the training records were misplaced during the ownership transition that occurred in 2016.

The noncompliance range of dates for the three Operators were from September 5, 2016 to October 14, 2016, from September 12, 2016 to October 12, 2016, and from May 28, 2017 to June 3, 2017. The root cause of this noncompliance was a lack of organization with respect record retention and specifically to the transfer of training records during a change of Facility ownership.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with COM-002-4 R3 is that incorrect actions could be carried out if incorrect or unclear Operating Instructions are delivered or received. However, the Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generation is approximately 7% of the Entity’s Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. As such, the impact to the BES of the Entity Operator performing an incorrect action due to incorrect communication practices would be minimal. In all three instances, documentation was provided showing that training was completed approximately one month of assuming the on-shift position.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity’s compliance history and determined that there are no prior relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance:

1. The Entity provided documentation that the three Operator’s completed the necessary COM-002 training and provided the documentation.
2. The Entity has transitioned its training responsibilities over to the GE Remote Operations Center training process to enhance training oversight and prevent recurrence of the issue.
3. An enhanced training Curriculum Tracker workbook was developed to track the training for all active operators. A new tab is added when new Operators are hired and COM training is refreshed annually for each Operator.
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<th>Future Expected Mitigation Completion Date</th>
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<td>INT-006-4</td>
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<td>Bonneville Power Administration</td>
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<td>November 30, 2016</td>
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<td>Self Report</td>
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**Description of the Violation**

(For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On March 30, 2017, the entity submitted Self-Reports stating that, as a Balancing Authority (BA) and, it was in noncompliance with INT-006-4 Requirement 1.

Specifically, the entity reported that on November 30, 2016, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 interties with neighboring entities. The entity's vendor monitors the system performance and identified the system performance degradation and notified the entity of the issue. The technical issue prevented the entity from approving or denying four e-tags processed as a BA, of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed within the timelines outlined in the Standard if technical issues occur with its scheduling software. However, the technical issues that occurred on the date above prevented the entity from effectively processing these four e-tags within the timelines despite these multiple backup processes.

The entity failed to approve or deny four on-time Arranged Interchange that it received as a BA, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1.

The root cause of these issues was the scheduling software failing to perform as expected. Specifically, end of month maintenance attributed to significant system activity and ultimately the software performance degradation.

These issues began on November 30, 2016, when the four on-time Arranged Interchange e-tags were not approved or denied within the requirements of the Standard and ended on November 30, 2016, when the e-tags were approved or denied, and the software returned to normal functionality, for a total of 31 minutes.

**Risk Assessment**

These issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to approve or deny four on-time Arranged Interchange that it received as a BA, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day.

The entity had good detective controls in place. Specifically, the entity's vendor was in the process of reviewing the system performance and investigating key system processes active during the slowdown period to find the root cause, system operations returned to normal approximately 30 minutes after the start of the failure. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAAL were impacted, the System Operator would act to ensure that the Interconnection frequency is controlled within defined frequency limits.

**Mitigation**

To mitigate these issues, the entity and the vendor:

a. completed an evaluation of maintenance process schedules and implemented necessary adjustments;

b. completed the software performance improvements for the most impactful maintenance processes and deployed the improvements to the environment. As these processes are background maintenance processes, and do not change any functionality, the changes were incrementally applied to the system over a period of time; and

c. identified software changes to mitigate the impact of such maintenance processes through alternate implementation within its automated scheduling software. These changes will be deployed in its automated scheduling software deployments as the changes are completed following normal processes.
On March 30, 2017, the entity submitted Self-Reports stating that, as a Transmission Service Provider (TSP), it was in noncompliance with INT-006-4 Requirement 2. Specifically, the entity reported that on November 30, 2016, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 interties with neighboring entities. The entity's vendor monitors the system performance and identified the system performance degradation and notified the entity of the issue. The technical issue prevented the entity from approving or denying five e-tags processed as a TSP, of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed within the timelines outlined in the Standard if technical issues occur with its scheduling software. However, the technical issues that occurred on the date above prevented the entity from effectively processing these five e-tags within the timelines despite these multiple backup processes.

The entity failed to approve or deny five on-time Arranged Interchange it received as a TSP, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R2. The root cause of these issues was the scheduling software failing to perform as expected. Specifically, end of month maintenance attributed to significant system activity and ultimately the software performance degradation.

To mitigate these issues, the entity and the vendor:

a. completed an evaluation of maintenance process schedules and implemented necessary adjustments;
b. completed the software performance improvements for the most impactful maintenance processes and deployed the improvements to the environment. As these processes are background maintenance processes, and do not change any functionality, the changes were incrementally applied to the system over a period of time; and
c. identified software changes to mitigate the impact of such maintenance processes through alternate implementation within its automated scheduling software. These changes will be deployed in its automated scheduling software deployments as the changes are completed following normal processes.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
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<th>Violation End Date</th>
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</tr>
</thead>
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**Description of the Violation** (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On October 2, 2017, the entity submitted a Self-Report stating that, as a BA, it was in noncompliance with INT-006-4 R1.

Specifically, the entity reported that on July 27, 2017, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 ties with neighboring entities. The entity’s vendor monitors the system performance and identified the system issue and notified the entity. The technical issue prevented the entity from approving or denying one e-tag processed as of its more than 4,000 per day, on-time Arranged Interchange e-tags, within the Standard’s required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed in the timelines outlined in the Standard if technical issues with its scheduling software occur. However, the technical issues that occurred on the date above prevented the entity from effectively processing one e-tags within the timelines despite these multiple backup processes.

After reviewing all relevant information, WECC Enforcement determined the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a BA, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R1.

The root cause of this issue was the scheduling software having technical issues. Specifically, the vendor incident report stated, "After review by additional technical staff, a correlation was made with the deactivation of the AFC Cleanup Process that was completed just prior to the failover on July 27, 2017. It was found that this process, which shares a connection to the database with other processes, was terminating in an unfinished condition and had caused other processes sharing the same connection to also be disrupted. This caused the data delivery process to be impacted, due to the data sequencing requirements of this interface, and subsequent messages were also blocked."

**Risk Assessment**

WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a BA, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R1. The number of e-tags subject to this instance is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence.

The entity had good detective controls in place. Specifically, the entity’s vendor monitors the system performance and identified the system issue and notified the entity. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the interconnection frequency is controlled within defined frequency limits. Additionally, the software vendor has implemented a safeguard for tickets that are not approved or denied within the defined time requirements and it automatically acted on the e-tag that was not approved or denied and assigned a final status. Because of this safeguard, the entity was only in noncompliance for five minutes. In addition, the vendor has been in use at the entity for over a decade and does have backup processes in place to manage the loss. Lastly, the vendor provides round the clock support to the entity for any system issues that are noticed by the entity’s schedulers.

**Mitigation**

To mitigate these issues, then entity and the vendor:

- a. assigned a final status to the missed e-tag; and
- b. repaired the software's data delivery process that caused the failure of the process for the two missed e-tags

Due to the significant number of e-tags this entity processes, and the time requirements to approve or deny the requested transactions, an automated software tool is needed to maintain compliance with the Standard. Vendor management and support of the automated software includes the potential for technical issues to arise, and without knowing all future possible technical issues, it is unreasonable to ensure that all future potential non-compliance issues will be prevented. Therefore, WECC is satisfied that the mitigation efforts stated above are sufficient.
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**Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)**

On October 2, 2017, the entity submitted a Self-Report stating that, as a TSP, it was in noncompliance with INT-006-4 R2.

Specifically, the entity reported that on July 27, 2017, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 ties with neighboring entities. The entity’s vendor monitors the system performance and identified the system issue and notified the entity. The technical issue prevented the entity from approving or denying one e-tag processed as a TSP of its more than 6400 per day, on-time Arranged interchange e-tags, within the Standard’s required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed in the timelines outlined in the Standard if technical issues with its scheduling software occur. However, the technical issues that occurred on the date above prevented the entity from effectively processing this e-tag within the timelines despite these multiple backup processes.

After reviewing all relevant information, WECC Enforcement determined the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a TSP, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R2. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence.

The root cause of this issue was the scheduling software having technical issues. Specifically, the vendor incident report stated, "After review by additional technical staff, a correlation was made between the deactivation of the AFC Cleanup Process that was completed just prior to the failover on July 27, 2017. It was found that this process, which shares a connection to the database with other processes, was terminating in an unfinished condition and had caused other processes sharing the same connection to also be disrupted. This caused the data delivery process to be impacted, due to the data sequencing requirements of this interface, and subsequent messages were also blocked.”

**Risk Assessment**

WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a TSP, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R2. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence.

The entity had good detective controls in place. Specifically, the entity’s vendor monitors the system performance and identified the system issue and notified the entity. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the interconnection frequency is controlled within defined frequency limits. Additionally, the software vendor has implemented a safeguard for tickets that are not approved or denied within the defined time requirements and it automatically acted on the e-tag that was not approved or denied and assigned a final status. Because of this safeguard, the entity was only in noncompliance for five minutes. In addition, the vendor has been in use at the entity for over a decade and does have backup processes in place to manage the loss. Lastly, the vendor provides round the clock support to the entity for any system issues that are noticed by the entity's schedulers.

**Mitigation**

To mitigate these issues, the entity and the vendor:

- a. assigned a final status to the missed e-tags; and
- b. repaired the software's data delivery process that caused the failure of the process for the missed e-tag.

Due to the significant number of e-tags this entity processes, and the time requirements to approve or deny the requested transactions, an automated software tool is needed to maintain compliance with the Standard. Vendor management and support of the automated software includes the potential for technical issues to arise, and without knowing all future possible technical issues, it is unreasonable to ensure that all future potential non-compliance issues will be prevented. Therefore, WECC is satisfied that the mitigation efforts stated above are sufficient.
Description of the Violation (for purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4.

Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4:

After reviewing all relevant information, WECC determined the entity failed to:

- (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments;
- (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and
- (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively.

The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements.

These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.

Risk Assessment

WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to:

- (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments;
- (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and
- (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively.

As compensation, the entity’s system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.

Mitigation

The entity completed mitigating activities for all the Requirements and WECC verified the entity’s mitigating activities.

To remediate and mitigate this issue, the entity has:

- a. created and implemented its operating procedures;
- b. updated its system operation procedure;
- c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis;
- d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool;
- e. trained each system operator on the procedures that were implemented; and
- f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.
On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4.

After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively.

The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements.

These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days. 

WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively.

As compensation, the entity’s system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4.

After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively.

The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements.

These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.

To remediate and mitigate this issue, the entity has:

a. created and implemented its operating procedures;

b. updated its system operation procedure;
c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis;
d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool;
e. trained each system operator on the procedures that were implemented; and
f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.
During a Compliance Audit conducted December 10, 2018 through December 20, 2018, WECC determined that the entity, as a TOP, had a potential noncompliance with TOP-001-3 R13. On February 17, 2018 at 19:56 PST the entity performed a valid Real-Time assessment (RTA). Per the Requirement of the Standard, the subsequent RTAs were due every 30 minutes, at 20:26 PST and 20:56 PST, etc. The entity utilized the Reliability Coordinator’s Hosted Advanced Application (HAA) for performing Real-Time Contingency Analyses (RTCA). However, the RTCA tool was dysfunctional. As a result, the entity did not perform the next valid RTA until 21:07 PST because the entity’s operators were not trained on handling functionality issues with the HAA.

After reviewing all relevant information, WECC determined that the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13. The root cause of the issue was that the entity has no alert or notification to the operator that the tool used to perform RTCA had failed and that another method must be used. A contributing cause was the lack of operator training as to how to respond to RTCA tool failures.

This issue began on February 17, 2018 at 20:26 PST, 30 minutes after previous valid RTA at 19:56 PST and ended on February 17, 2018 at 21:07 PST when the entity performed a valid RTA, for a total of 41 minutes.

WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13. At the time of the issue, the entity had no preventative or detective controls to prevent or detect the noncompliance. However, the entity’s system is primarily used to serve its own load and is unlikely to have a substantial impact on neighboring entities in the interconnection. Additionally, the entity does not provide generation to neighboring entities or operate elements of a WECC Major Transfer Path.

The entity completed mitigating activities and WECC verified the entity’s mitigating activities.

- added alarms to alert system operators if the RTA monitoring has failed;
- developed a user guide for using the HAA to perform RTCAs;
- issued dispatch standing order providing detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System;
- confirmed that all procedures are in place and that training for each System Operator includes a review of the procedures and monitoring tool;
- completed training for each System Operator for the RC HAA RTCA tool.
<table>
<thead>
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<td>PRC-005-6</td>
<td>R3</td>
<td>Goshen Phase II LLC</td>
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<td>7/1/2017</td>
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**Description of the Violation** (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On August 17, 2017, GPL submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3.

Specifically, GPL discovered that it did not complete specific maintenance activities for two vented lead-acid (VLA) batteries at one substation; including verification of station DC supply voltage, inspection of electrolyte levels, and inspection for unintentional grounds, per the maximum maintenance intervals for the requirements of Table 1-4(a) of the Standard. Due to confusion between the four-month and 18-month testing date intervals, GPL completed the four-month maintenance activities before the March 31, 2017 deadline, on February 17, 2017. The Compliance Task Manager (CTM) incorrectly changed the next four-month maintenance due date to July 31, 2017 instead of the correct date of June 30, 2017. GPL completed the maintenance activities for the two VLA batteries on August 1, 2017 and the maintenance activities reflected no changes or updates to either VLA battery.

After reviewing all relevant information, WECC determined that GPL failed to maintain two VLA batteries at one substation that are included within the time-based maintenance program in accordance with the maximum maintenance intervals prescribed within Table 1-4(a) of the Standard.

The root cause of the issue was an incorrect assumption by the GPL staff that the maintenance and testing dates in the tracking software were accurate.

**Risk Assessment**

WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, GPL failed to maintain two VLA batteries at one substation that are included within the time-based maintenance program in accordance with maximum maintenance intervals prescribed within Table 1-4(a) of the Standard.

GPL had weak preventative controls to prevent this issue. However, as compensation, when the missed maintenance was completed, no deficiencies were identified for the VLA batteries. Furthermore, the short duration of the issue lessens the risk to the BPS.

**Mitigation**

To mitigate this issue, GPL:

a. completed the required maintenance tasks for the two VLA batteries;

b. revised the CTM tasks for batteries to emphasize testing interval at beginning Task Statement;

c. revised the CTM task requiring verification of receipt of batteries to add an additional action to also verify the next CTM due date for the 4-month battery maintenance activities;

d. revised all PRC-005 related CTM tasks to add “Regulatory Required Task” at the beginning of the task statement for awareness;

e. conducted a review of all prior maintenance activities to confirm that no other delays have occurred and verify that all pertinent CTM tasks have the correct due date; and

f. prepared and conducted refresher CTM training for Performance Managers and Deputy Performance Managers for each applicable wind farm.
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<td>WECC2018019007</td>
<td>COM-001-3</td>
<td>R9</td>
<td>Peak Reliability</td>
<td>NCR10289</td>
<td>12/1/2017</td>
<td>12/15/2017</td>
<td>Self-Report</td>
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Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On January 19, 2018, the entity submitted a Self-Report stating, as a Reliability Coordinator (RC), it was in noncompliance with COM-001-3 R9.

Specifically, the entity reported that during the transition from COM-001-2.1 to COM-001-3, a footnote was inadvertently deleted from its Communications Systems Monitoring and Testing document. The footnote cited the requirement to perform monthly calls to test its Alternative Interpersonal Communication (AIC), through its telephone system, with the entities that do not participate in the daily Balancing Authority (BA) and Transmission Operator (TOP) calls. Although the entity completed its daily BA and TOP calls after the transition to COM-001-3, it did not perform the November 2017 calls with one BA and six TOPs due to the deleted footnote.

After reviewing all relevant information, WECC determined the entity failed to test its AIC capability at least once each calendar month, as required by COM-001-3 R9.

The root cause of the issue was an incomplete documented process. The entity had inadvertently removed the monthly calls with certain BAs and TOPs from its Communications Systems Monitoring and Testing document in its transition from one version of the Standard to the next version of the Standard.

This issue began on December 1, 2017, when the entity did not complete a monthly test of its AIC with the required BAs and TOPs and ended on December 15, 2017, when the entity completed the test of its AIC with each required entity, for a total of 16 days.

Risk Assessment

WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to test its AIC capability at least once each calendar month, as required by COM-001-3 R9.

However, the entity has effective compensating measures. Specifically, the entity tests its AIC capability daily with the remaining 35 BAs and 56 TOPs, thus reducing the risk. PEAK also has moderate detective controls in its informal process to review the daily call logs performed by the shift foreman and again by the compliance officer.

Mitigation

To remediate and mitigate this issue, the entity has:

a. completed an adequate test of its AIC capability with the missed BA and six TOPs;

b. revised the Communications Systems Monitoring and Testing process document to return the footnote citing the AIC testing with the entities not participating in the daily BA and TOP calls; and

c. created calendar reminders for departmental staff that test the AIC capability through monthly individual calls with the entities not participating in the daily BA and TOP calls.
Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On October 11, 2017, the entity submitted a Self-Report stating, as a RC, it was in noncompliance with PRC-002-2 R5.

Specifically, the entity reported that in August 2017, it discovered its Dynamic Disturbance Recorder (DDR) list had not been sent to all the owners of identified Bulk Electric System (BES) elements within 90 days of completion of the identification of the BES elements that require DDR. The entity did not include one Control Center owner when it sent the DDR list to the other owners of applicable BES elements on June 30, 2016. The missing Control Center had one Facility that requires DDR. The entity updated and disseminated its DDR list to include the missing Control Center on April 16, 2017.

After reviewing all relevant information, WECC determined the entity failed to notify one owner of identified BES element, within 90-calendar days of completion of Part 5.1, that its respective BES Elements require DDR data when requested, as required by PRC-002-2 R5.

The root cause of the issue was to the lack of an adequate process for the creation and dissemination of the entity's DDR list.

This issue began on September 28, 2016, 90 days after the entity notified all but one BES Element owners for which DDR data is required and ended on April 16, 2017, when the entity notified the control center that was missing from the DDR list that its respective BES Elements require DDR data, for a total of 201 days.

Risk Assessment

WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to notify all owners of identified BPS Elements, within 90-calendar days of completion of Part 5.1, that their respective BPS Elements require DDR data when requested, as required by PRC-002-2 R5.

However, the entity had good compensating controls. Specifically, the entity posted the list of BES elements which require DDR data to its external, entity facing website. As further compensation, there were no events during the period of noncompliance that would have required the entity to request DDR, and the Control Center missing from the list is not required to install applicable DDR devices until 2022.

Mitigation

To remediate and mitigate this issue, the entity has:

a. notified the Control Center owner that was missing from the DDR list of the respective BES elements that require DDR data;
b. updated the DDR distribution list to include all applicable owners; and
c. created a process for disturbance monitoring and reporting requirements to address the requirements of the Standard.
WECC2017018755  IRO-010-2  R1
Peak Reliability  NCR10289  1/1/2017  12/8/2017  Self-Report  Completed

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<td>On December 10, 2017, the entity submitted a Self-Report stating, as a RC, it was in noncompliance with IRO-010-2 R1. Specifically, the entity reported that it did not directly address, in the correct format, its current Protection System status or degradation in its documented specification for the data necessary for the entity to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This documented specification is both published on the entity’s public-facing website and distributed to applicable entities, per IRO-010-2 R1. In the transition from the previous version of IRO-010, the entity did not update the documented specification for the data required by the new version of the Standard, by the mandatory and enforceable date of January 1, 2017. The entity incorrectly assumed the previous version of the document would still qualify for compliance with the Standard. After reviewing all relevant information, WECC determined the entity failed to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments; including provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability, as required by IRO-010-2 R1. The root cause of the issue was that the entity did not correctly implement the required updates in the documented specification for the data required by the Standard, when the new version of the Standard, IRO-010-2, became mandatory and enforceable. This issue began on January 1, 2017, when IRO-010-2 became mandatory and enforceable and ended on December 8, 2017, when the entity revised its data specification document to include the correct format for provisions for the notification of current Protection System degradation, for a total of 342 days.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Risk Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>WECC determined this issue posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, the entity failed to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments; including provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability, as required by IRO-010-2 R1. However, the entity implemented effective detective controls in its Compliance Department review of events, which identified this issue. In addition, the entity implemented compensating measures to lessen the risk. Though the entity did not meet the requirements of the Standard, it did communicate with the required entities to provide awareness of Protection System status or degradation that impacts System reliability.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Mitigation</th>
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</thead>
<tbody>
<tr>
<td>To remediate and mitigate this issue, the entity has: a. revised its data specification document to include provisions for notification Protection System degradation that impacts System reliability; and b. implemented a process to notify members regarding updates to the RC data specification.</td>
</tr>
</tbody>
</table>
WECC2017017221  COM-002-4  R1  Seattle City Light  NCR05382  7/1/2016  3/27/2017  Self-Report  Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible or confirmed violation.)

On March 13, 2017, the entity submitted a Self-Report stating, as a Balancing Authority and Transmissions Operator, it was in issue with COM-002-4 R1. Specifically, the entity reported that its internal procedural documents for communication protocols did not include all the required elements of R1. The entity’s procedure neither provided issuance/receipt requirements associated with single-party to multiple-party burst Operating Instructions (R1.4) nor specified instances that require time identification when issuing Operating Instructions (R1.5).

After reviewing all relevant information, WECC determined the entity failed to document communications protocols to require operating personnel that issue a written or oral single-party to multiple-party burst Operating Instructions to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction, as well as specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by COM-002-4 R1.4 and R1.5.

The root cause of the issue was a less than adequate process and procedure. The entity historically had not needed to issue single-party to multiple party burst Operating Instruction or Operating Instructions across time zones and therefore did not believe that these requirements were applicable. This issue began when the Standard and Requirement became mandatory and enforceable and ended when the entity updated its communications protocol procedures, for a total of 256 days.

Risk Assessment

WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to document communications protocols to require operating personnel that issue a written or oral single-party to multiple-party burst Operating Instructions to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction, as well as specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by COM-002-4 R1.4 and R1.5.

The entity conducted a pre-audit review of compliance with the reliability Standards prior to every audit to detect any potential noncompliance. In addition, the entity has never had to issue a single-party to multiple party burst Operating Instruction and the entity’s neighboring TOPs and GOs are in the same time zone as the entity. Hence, the entity would likely not have miscommunication or delayed response due to operation in a different time zone.

Mitigation

The entity submitted a Mitigation Plan to address this issue, WECC accepted the entity's Mitigation Plan.

To remediate and mitigate this issue, the entity has:

a. revised its communication protocol to include procedures for single-party to multiple-party burst Operating Instructions;

b. revised its communications protocol to include procedures to use Pacific Prevailing Time; in 24-hour clock for all communications and when communicating externally across time zones; and

c. conducted training for all System Operators in relation to reading the revised communication protocol procedures before shifts.

The entity submitted a Mitigation Plan Completion Certification, WECC verified the entity’s completion of Mitigation Plan.
**NERC Violation ID** | **Reliability Standard** | **Req.** | **Entity Name** | **NCR ID** | **Noncompliance Start Date** | **Noncompliance End Date** | **Method of Discovery** | **Future Expected Mitigation Completion Date**
---|---|---|---|---|---|---|---|---
FRCC2019020958 | EOP-005-2 | R17. | Tampa Electric Company (TEC) | NCR00074 | 01/01/2018 | 01/07/2019 | Self-Report | Completed

### Description of the Noncompliance

(For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)

On January 22, 2019, TEC submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with EOP-005-2 R17. One (1) out of 37 (2.7%) operators did not receive required two hours training of its Blackstart Resource generation units every two calendar years as required.

This noncompliance started on January 1, 2018, when one operator had not received required Blackstart training and ended on January 7, 2019, when the operator received required training.

In this instance, the operator was absent for four months (July 14, 2017 to November 16, 2017) during which time he missed the 2017 Blackstart Training class. Makeup training for this operator was overlooked when he returned to work.

The issue was discovered by internal review. After the issue was discovered, the operator received training on January 7, 2019, a period of 371 days after it was required.

The cause for this noncompliance was a lack of internal controls to ensure operators scheduled for the required training actually received it.

### Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

The risk of missed training is that the operator would be lacking in required information necessary to perform a Blackstart system restoration when needed.

This risk was reduced as the operator missing the required bi-annual training (i.e., every two calendar years) had received the training in 2013 and 2015, and there have been no substantial changes to the equipment or procedures since his prior training. In addition, there were eight (8) other operators on his crew who had the 2017 training and who were available to perform Blackstart system restoration.

No harm is known to have occurred.

### Mitigation

To mitigate this noncompliance, TEC:

1) trained Operator;
2) performed an extent of condition identifying only one out of 37 operators did not receive training in 2017;
3) completed root cause analysis;
4) created preventative controls to add details to work order such as names of those that require training to ensure everyone receives the appropriate training. Work order won’t close out until everyone receives training. Added a task for Operations Engineer or Operations Manager to review the list of all Operations teams’ personnel to ensure all teams have received this training. Added task to schedule make-up training session as required;
5) created preventative control by updating energy services handbook to include more details; and
6) communicated to personnel the changes to the energy services handbook regarding EOP-005-2 R17.
**NERC Violation ID** | **Reliability Standard** | **Req.** | **Entity Name** | **NCR ID** | **Noncompliance Start Date** | **Noncompliance End Date** | **Method of Discovery** | **Future Expected Mitigation Completion Date**
---|---|---|---|---|---|---|---|---
FRCC2019020949 | VAR-002-4.1 | R3. | Gainesville Regional Utilities (GRU) | NCR00032 | 02/10/2018 | 02/10/2018 | Self-Report | 06/30/2019

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)**

On January 18, 2019, GRU submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3.

This noncompliance started on February 10, 2018, when GRU failed to notify its Transmission Operator of an Automatic Voltage Regulator (AVR) status change greater than 30 minutes, and ended on February 10, 2018, when the proper notification was made.

During an internal audit, GRU discovered the AVR for an 80MW generator had changed from automatic mode to manual mode for a duration of 93 minutes. The change was not communicated to GRU’s system control (GRU is both Generator Operator and Transmission Operator) until 63 minutes after the status change occurred.

An extent of condition review was completed verifying no additional occurrences. Furthermore, GRU verified while the AVR was out of automatic mode the voltage schedule was maintained.

The cause for this noncompliance was inadequate alerting capability of AVR status.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

GRU’s failure to maintain the AVR in automatic mode could result in excursions from the established voltage schedule, preventing the Transmission Operator from effectively managing voltage.

The risk was reduced because of the short duration of the event, and a review of voltage levels during the event revealed no voltage excursions occurred.

No harm is known to have occurred.

**Mitigation**

To mitigate this noncompliance, GRU:

1) completed an extent of condition review;
2) verified that the AVR out of auto event did not result in an excursion from the voltage schedule;
3) corrected AVR alarm for violating plant; and
4) updated generator operator procedures for VAR-002-4.1.

To mitigate this noncompliance, GRU will:

1) create training materials for new system control AVR alarms by March 31, 2019
2) train on generator operator procedures for VAR-002-4.1 by April 30, 2019;
3) train system operators on new AVR alarms by May 30, 2019;
4) create redundant EMS alarm at system control for each unit’s AVR status by June 30, 2019; and
5) investigate and correct AVR alarms for additional plants by June 30, 2019.
On September 13, 2017, COELR submitted a Self-Report, stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R1. Pursuant to MOD-025-2’s phased-in implementation plan, COELR was supposed to have verified the Real Power capability of 40% of its applicable generation units by July 1, 2016. COELR was also unable to achieve MOD-025-2 R1 compliance with 60% of its applicable generation units by July 1, 2017 or with 80% of its applicable generation units by July 1, 2018.

The cause of the noncompliance is that COELR did not understand the scope of its obligations under MOD-025-2 and believed that model testing that occurred prior to the adoption of MOD-025-2 was sufficient to achieve compliance.

The noncompliance began on July 1, 2016, when COELR was required to have verified the Real Power capability of 40% of its applicable generation units, and is expected to end by June 30, 2019, when COELR will have verified the Real Power capability of all of its applicable generation units.

The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. COELR’s 1088 MW generating fleet consists of seven hydro generation stations whose ratings have remained consistent over the years. Per COELR, when changes to Real Power capabilities have occurred, they have been previously provided to its Transmission Planner. Additionally, per the entity, the Real Power capabilities of the units are known to the Transmission Operator as the units are routinely dispatched to their rated outputs. Finally, none of COELR’s hydro generating stations are associated with any Remedial Action Scheme (RAS), any SPP Flowgate, or identified as a Blackstart Resource in any Transmission Operator’s System Restoration Plan. No harm is known to have occurred.

During the ongoing mitigation, COELR will implement a rolling testing and verification schedule and will provide the information to its Transmission Planner as that information becomes available.

COELR has no relevant history of noncompliance.

To mitigate this noncompliance, COELR will complete the following mitigation activities by June 30, 2019:

1) will have contractors perform the verification testing for all applicable generation units, then distribute those results to its Transmission Planner; and
2) will review its compliance with MOD-026-1 and MOD-027-1 and self-report any noncompliance.

The length of time that it will take to complete mitigating activities is related to locating and scheduling an inspection with qualified contractors.
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On September 13, 2017, COELR submitted a Self-Report, stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R2. Pursuant to MOD-025-2’s phased-in implementation plan, COELR was supposed to have verified the Reactive Power capability of 40% of its applicable generation units by July 1, 2016. COELR was also unable to achieve MOD-025-2 R2 compliance with 60% of its applicable generation units by July 1, 2017 or with 80% of its applicable generation units by July 1, 2018.

The cause of the noncompliance is that COELR did not understand the scope of its obligations under MOD-025-2 and believed that model testing that occurred prior to the adoption of MOD-025-2 was sufficient to achieve compliance.

The noncompliance began on July 1, 2016, when COELR was required to have verified the Reactive Power capability of 40% of its applicable generation units, and is expected to end by June 30, 2019, when COELR will have verified the Reactive Power capability of all of its applicable generation units.

Risk Assessment

The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. COELR’s 1088 MW generating fleet consists of seven hydro generating stations whose ratings have remained consistent over the years. COELR states that it has only had one generating station have a change to its excitation system in the last seven years. Per COELR, when changes to Reactive Power capabilities have occurred, they have been previously provided to its Transmission Planner. Additionally, per the entity, the Reactive Power capabilities of the units are known to the Transmission Operator through routine dispatch. Finally, none of COELR’s hydro generating stations are associated with any Remedial Action Scheme (RAS), any SPP Flowgate, or identified as a Blackstart Resource in any Transmission Operator’s System Restoration Plan. No harm is known to have occurred.

During the ongoing mitigation, COELR will implement a rolling testing and verification schedule and will provide the information to its Transmission Planner as that information becomes available.

COELR has no relevant history of noncompliance.

Mitigation

To mitigate this noncompliance, COELR will complete the following mitigation activities by June 30, 2019:

1) have contractors perform the verification testing for all applicable generation units, then distribute those results to its Transmission Planner; and
2) will review its compliance with MOD-026-1 and MOD-027-1 and self-report any noncompliance.

The length of time that it will take to complete mitigating activities is related to locating and scheduling an inspection with qualified contractors.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Noncompliance Start Date</th>
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<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
</tr>
</thead>
</table>

**Description of the Noncompliance**

On July 25, 2016, EASTMAN submitted a Self-Report stating that as a Generator Owner, it was in noncompliance with PRC-005-2(i) R3. EASTMAN also submitted a Self-Report stating that it was in noncompliance with PRC-005-1b R2 (SPP2016015926) on July 21, 2016; both Self-Reports were consolidated into this NERC Violation ID. Under the PRC-005-2(i) R3 implementation plan, EASTMAN was required to be 100% compliant for applicable equipment that has less than a one-year maintenance interval. EASTMAN discovered this noncompliance in preparation for a September 2016 Compliance Audit where PRC-005-2(i) R3 was in scope. EASTMAN identified multiple instances where it failed to perform the four-month maintenance of VLA batteries, verification of communication system functionality, as well as failures to test, inspect, and/or calibrate protection system devices according to EASTMAN's Protection System Maintenance Program (PSMP).

The cause of the noncompliance was that EASTMAN had inadequate internal controls to implement its PSMP and a lack of understanding between internal departments regarding their responsibilities. The noncompliance began on October 1, 2015, when the implementation plan required 100% compliance, and ended on March 31, 2016, when all required maintenance activities were completed.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that was commissioned in 2001 and has not had any PRC-005-2(i) related events or protection system dc supply problems during the life of the plant. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Internal Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred.

MRO considered EASTMAN's relevant compliance history. EASTMAN's PRC-005-2(i) R3 compliance history includes minimal risk violations of PRC-005-1 R1 (SPP201000297) and PRC-005-1 R2 (SPP201000298). The PRC-005-1 R1 violation involved a failure to have a complete PSMP and include all components within its PSMP; the noncompliance was mitigated on December 15, 2011. The PRC-005-1 R2 violation involved a failure to test four relays within the three-year interval and have testing documentation for the majority of its other components such as battery banks, instrument transformers, and dc control circuits; the noncompliance was mitigated on June 1, 2012. MRO determined that EASTMAN's compliance history should not serve as a basis for applying a penalty. MRO determined that the current noncompliance was not caused by a failure to mitigate the prior instances of noncompliance and there is a substantial duration of time between the current noncompliance and the prior instances of noncompliance.

**Mitigation**

To mitigate this noncompliance, EASTMAN:

1. confirmed the October 2017 shutdown schedule;
2. performed the East/West line differential Protective Relay and Communications Maintenance;
3. performed relay and dc control circuit maintenance;
4. performed six-year interval for dc supply maintenance;
5. purchased a new dc supply;
6. confirmed the maintenance schedule with its contractor; and
7. installed new dc supply line on unit 2.

The associated Mitigation Plan was verified on May 11, 2018.
**NERC Violation ID** | **Reliability Standard** | **Req.** | **Entity Name** | **NCR ID** | **Noncompliance Start Date** | **Noncompliance End Date** | **Method of Discovery** | **Future Expected Mitigation Completion Date**
--- | --- | --- | --- | --- | --- | --- | --- | ---
MRO2018019528 | PRC-005-6 | R3 | Northern States Power (Xcel Energy) (NSP) | NCR01020 | 04/01/2017 | 02/28/2018 | Self-Log | Completed

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of NSP and PSCO.

Xcel Energy states that it discovered that it had missed an 18-month maintenance activity (testing) for a dc supply at one NSP substation. Xcel Energy reports that it conducted an extent of conditions review at all substations subject to dc supply maintenance and verification requirements. The review did not reveal any additional noncompliance with an 18-month maintenance activity, but did identify noncompliance associated with four-month maintenance activities (inspections) at 13 NSP substations and 12 PSCO substations.

The cause of the noncompliance was that Xcel Energy experienced issues in the implementation of a new work order system and Xcel Energy’s Maintenance Program procedure lacked controls and oversight to ensure that testing was completed within the appropriate timeframes.

The noncompliance began on April 1, 2017 when Xcel Energy missed the first four-month maintenance activity and ended on February 28, 2018 when Xcel Energy performed all required maintenance activities.

**Risk Assessment**

The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy reports the dc supplies have alarms for loss of ac or high/low voltage alarms and alarms for grounds; these alarms are designed to alert Xcel Energy prior to a failure. Xcel Energy states that it did not receive any alarms or experience any dc supply failures during the period of noncompliance. Additionally, none of these substations are associated with an IROL, a WECC Major Path, or a Remedial Action Scheme (RAS). No harm is known to have occurred.

**Mitigation**

To mitigate the noncompliance, Xcel Energy:

- 1) completed the required testing;
- 2) updated its Substation Battery Maintenance and Testing Program to include additional controls and oversight;
- 3) added substation dc supply test requirements to its compliance milestones; and
- 4) provided training to Substation O&M staff.

To mitigate the noncompliance related to the four-month maintenance activities, Xcel Energy:

- 1) completed the required inspections;
- 2) implemented auto-generation of work orders of substation dc supply inspections;
- 3) updated substation dc supply inspection work orders to require the inspection of dc supply voltage, electrolyte level, and unintentional grounds;
- 4) setup monthly tasks in its internal corporate task tracking tool for substation O&M managers to review inspection reports; and
- 5) provided training to substation O&M staff on battery testing/inspection requirements.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
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<tr>
<td>MRO2018020440</td>
<td>FAC-008-3</td>
<td>R3</td>
<td>Southern Minnesota Municipal Power Agency (SMMPA)</td>
<td>NCR01030</td>
<td>01/01/2013</td>
<td>06/28/2018</td>
<td>Compliance Audit</td>
<td>Completed</td>
</tr>
</tbody>
</table>

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

During a Compliance Audit conducted on January 24, 2018, MRO determined that SMMPA, as a Transmission Owner, was in noncompliance with FAC-008-3 R3. One or more of SMMPA’s substations contain equipment in bus segments that are not series-connected with adjacent Transmission Lines during normal operations, however the equipment does become series-connected during certain substation configurations (e.g., when any of the circuit breakers on the ring bus are open). MRO originally considered this an Area of Concern, but determined that noncompliance existed once it was confirmed that certain substation configurations had actually occurred in which the equipment had become series-connected.

An extent of condition review determined that since January 1, 2015 abnormal configurations occurred in eight instances at the Byron 345 kV substation where equipment on its ring bus became series connected. MRO determined that during these abnormal configurations, the applicable Facility Rating should have been reduced from 2000 Amps to 1600 Amps, but new ratings were not issued.

SMMPA’s Facility Ratings methodology failed to ensure valid Facility Ratings during these abnormal configurations by either having a requirement that 1) ensured that the Ratings of such equipment be reflected in the Facility Ratings of the adjacent line terminals; or 2) provided temporary Facility Ratings during the substation configuration changes that cause the equipment to become series-connected.

The cause of the noncompliance is that SMMPA’s Facility Ratings methodology did not consider situations where Facility reconfiguration could affect which equipment was series-connected, leading to a modification in the Facility Rating.

The noncompliance began on January 1, 2013, when the Standard became enforceable, and ended on June 28, 2018 when SMMPA updated its Facility Ratings methodology and issued new Facility Ratings.

**Risk Assessment**

The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SMMPA was following ERO guidance in developing its Facility Ratings methodology, the ERO guidance is not clear with respect to non-series equipment that could become the most limiting element during a Facility reconfiguration. Additionally, the Byron substation is SMMPA’s only 345 kV Facility, and is not part of an IROL or Blackstart Cranking Path. Finally, there were no reported outages or equipment damage as a result of the noncompliance. No harm is known to have occurred.

SMMPA has no relevant history of noncompliance.

**Mitigation**

To mitigate this noncompliance, SMMPA:

1) revised its Facility Ratings methodology to include considerations of unique substation configurations; and
2) issued new Facility Ratings for the impacted terminals.
**NERC Violation ID Reliability Standard**

<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
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<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
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<tr>
<td>SPP2018019268</td>
<td>COM-002-4</td>
<td>R4</td>
<td>Southwestern Power Administration (SWPA)</td>
<td>NCR01144</td>
<td>7/1/2017</td>
<td>9/19/2017</td>
<td>Self-Certification</td>
<td>Completed</td>
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</table>

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)**

On February 28, 2018, SWPA submitted a Self-Certification stating that as a Transmission Operator, it was in noncompliance with COM-002-4 R4. During an internal review, SWPA determined that its assessment did not include all the documented communications protocols listed in R1. SWPA states it only reviewed oral communications protocols.

The cause of the noncompliance was that SWPA failed to understand its compliance obligations under the updated Standard and failed to capture the increased scope of the assessment in the updated Standard language.

The noncompliance began on July 1, 2017, when the Standard became enforceable, and ended on September 19, 2017, when a full assessment was completed.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Per SWPA, supervisory staff perform a daily review of Dispatcher E-logs and Special Conditions reports, which use SWPA’s communication protocols. No harm is known to have occurred.

SWPA has no relevant history of noncompliance.

**Mitigation**

To mitigate this noncompliance, SWPA:

1) assessed each component of its Operating Personnel Communications Protocol; its Operating Personnel Communications Protocol;
2) had its Compliance Division and Chief Dispatcher develop a spreadsheet that identifies all Operation Personnel Communications Protocols that must be assess annually;
3) had its Chief Dispatcher develop another spreadsheet to identify which Operation Personnel will be assessed each quarter to ensure that all personnel are fully assessed by the 12-month deadline; and
4) had its Chief Dispatcher set calendar reminders to conduct the quarterly assessments.
<table>
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<tr>
<td>SPP2018019399</td>
<td>VAR-002-4.1</td>
<td>R2</td>
<td>Thunder Ranch Wind Project, LLC (TRW)</td>
<td>NCR11778</td>
<td>1/15/2018</td>
<td>1/16/2018</td>
<td>Self-Report</td>
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**Description of the Noncompliance** (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On March 19, 2018, TRW submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. TRW reported that it failed to follow the voltage control schedule provided by its Transmission Operator from January 15 to January 16, 2018. Per TRW, this occurred when the voltage controller inadvertently switched into voltage control mode. This occurred while contractors were working on the SCADA system; during that work the SCADA system defaulted to its normal mode of operations, which included the voltage controller being set to voltage control mode. TRW states that the contractors did not inform the control room of the change and that no alarm was triggered by the change. Because of the change, TRW was no longer maintaining a 0 MVar target as required by its Transmission Operator.

The noncompliance was caused by inadequate alarming for a voltage control status and that TRW did not have a process to ensure that contractors notified the control room of changes to the SCADA system.

The noncompliance began at approximately 9:00 p.m. on January 15, 2018, when the voltage controller switched modes and TRW no longer maintained the target set by its Transmission Operator, and ended on January 16, 2018 at approximately 5:00 p.m. when TRW returned the voltage controller back to the correct mode and achieved the target set by its Transmission Operator.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The generation Facility could only have a minor impact on the bulk power system as it has a nameplate rating of 300 MW. Additionally, the generation Facility is not part of a Remedial Action Scheme (RAS) and is not associated with any Interconnection Reliability Operating Limit (IROL). No harm is known to have occurred.

TRW has no relevant history of noncompliance.

**Mitigation**

To mitigate this noncompliance, TRW:

1) set the voltage controller back to the correct mode;
2) created a "Return to normal Voltage Controller Alarm" that identifies deviations from the mode of operation required by the Transmission Operator, this alarm must be acknowledged by the operator;
3) updated its "Wind Control System User Administration Policy" and implemented a procedure for all contractors to follow, this procedure will place controls on how contractors access the SCADA system and ensure that the control room is notified of changes to the system; and
4) conducted training with applicable staff on the updated policy.
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Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2, R1. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have 40% of their applicable Facilities tested, the NRG corporate methodology was to calculate the MOD-025-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% deadline on July 1, 2016 for its applicable facilities.

At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it’s methodology in an attempt to meet the upcoming 60% testing threshold for the July 1, 2017 deadline for MOD-025-2. By July 1, 2018, GenConn had 100% of their applicable facilities tested.

The violation start date is July 1, 2016 and ended on June 29, 2018 when the MOD-025-2 R1 real power capability was verified via testing.

The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the MOD-025-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.

Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS).

Noncompliance with MOD-025-2 R1 has the potential to affect the reliability of the BPS by allowing for the TP to have inaccurate information about the capabilities of the generating units in planning models used to assess BPS reliability. In the ISO-NE market, real and reactive power testing on the GenConn units that closely matches MOD-025-2 has been regularly verified, reported, communicated, and approved by the ISOs/Transmission Planners to validate generator capability. Although the original documentation provided to ISO-NE may not meet full compliance with the requirement, the potential and actual risks to the BES are low as much of the relevant data needed by the TP was verified, valid, tested, and provided on a consistent basis in previous years. The Net Capacity Factors (NCF) of the 8 GenConn units (480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. Additionally, the result of the verification made in accordance with R1 required no adjustments to the units.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.

Mitigation

To mitigate this noncompliance, GenConn:
1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations
2) Completed the necessary MOD-025-2 R1 testing and then provided the results to the TP.
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</tr>
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</table>

**Description of the Noncompliance**

On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2, R2. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have 40% of their applicable facilities tested, the NRG corporate methodology was to calculate the MOD-025-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% deadline on July 1, 2016 for its applicable facilities.

At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it’s methodology in an attempt to meet the upcoming 60% testing threshold for the July 1, 2017 deadline for MOD-025-2. By July 1, 2018, GenConn had 100% of their applicable facilities tested.

The violation started on July 1, 2016 and ended on June 29, 2018 when the MOD-025-2 R2 reactive power capability was verified via testing.

The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the MOD-025-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS).

Noncompliance with MOD-025-2 R2 has the potential to affect the reliability of the BPS by allowing for the TP to have inaccurate information about the capabilities of the generating units in planning models used to assess BPS reliability. In the ISO-NE market, real and reactive power testing on the GenConn units that closely matches MOD-025-2 has been regularly verified, reported, communicated, and approved by the ISOs/Transmission Planners to validate generator capability. Although the original documentation provided to ISO-NE may not meet full compliance with the requirements, the potential and actual risks to the BES are low as much of the relevant data needed by the TP was verified, valid, tested, and provided on a consistent basis in previous years. The Net Capacity Factors (NCF) of the 8 GenConn units (480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. Additionally, the result of the verification made in accordance with R2 required no adjustments to the units.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity’s compliance history and determined that there are no prior relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance, GenConn:
1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations
2) Completed the necessary MOD-025-2 R2 testing and then provided the results to the TP.
On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2, R1. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have the protection system and voltage regulating control system verified on 40% of their applicable Facilities, the NRG corporate methodology was to calculate the PRC-019-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LLC NCR11710 and neither NCR met the 40% verification deadline on July 1, 2016 for its applicable facilities.

At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early 2017, NRG adjusted its methodology in an attempt to meet the upcoming 60% verification threshold for the July 1, 2017 deadline for PRC-019-2. By July 1, 2017, GenConn had 100% of their applicable facilities verified. The violation started on July 1, 2016 and ended on June 30, 2017 when the PRC-019-2 R1 verification that brought GenConn into compliance was completed.

The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the PRC-019-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS).

The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit. However, the result of the June 2017 verification made in accordance with R1 required no adjustments to the units. The Net Capacity Factors (NCF) of the eight GenConn units (8 * 60 MW = 480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. The BA (ISO-NE) carries operating reserves of approximately 2,300 MW of which a GenConn unit is less than 2%. Therefore, if this instance of noncompliance had caused any of the affected generators to trip unnecessarily, the BA would have been able to replace the lost capacity.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.

To mitigate this noncompliance, GenConn:
1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations
2) Completed the necessary PRC-019-2 verification.
### Description of the Noncompliance

On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2, R2. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have the protection system and voltage regulating control system verified on 40% of their applicable Facilities, the NRG corporate methodology was to calculate the PRC-024-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LLC NCR11710 and neither NCR met the 40% verification deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early 2017, NRG adjusted its methodology in an attempt to meet the upcoming 60% verification threshold for the July 1, 2017 deadline for PRC-024-2. By July 1, 2017, GenConn had 100% of their applicable facilities verified. The violation started on July 1, 2016 and ended on June 30, 2017 when the PRC-024-2 R2 verification that brought GenConn into compliance was completed.

The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the PRC-019-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.

### Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS).

The failure to verify the relay settings to the voltage curve could cause the unit to trip at a time when it could exasperate a system event further. However, the result of the June 2017 verification made in accordance with R2 required no adjustments to the units. The Net Capacity Factors (NCF) of each of the eight GenConn units (8 * 60 MW = 480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. The BA (ISO-NE) carries operating reserves of approximately 2,300 MW of which a GenConn unit is less than 2%. Therefore, if this instance of noncompliance had caused any of the affected generators to trip unnecessarily during a system voltage event, the BA would have been able to replace the lost capacity.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.

### Mitigation

To mitigate this noncompliance, GenConn:

1. Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations
2. Completed the necessary PRC-024-2 verification on all of the applicable facilities.
On February 20, 2019, Taunton Municipal Lighting Plant ("Taunton" or "the entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2, R2. Specifically, the entity discovered on December 6, 2018 that it did not re-coordinate within 90 days its voltage regulating system controls as a result of generator exciter limiter setting changes that were made on September 4, 2018.

The noncompliance associated with the needed re-coordination started on December 3, 2018 and ended on December 10, 2018, when the re-coordination was completed by a third party engineering firm.

Although the entity had a documented Protection System Maintenance Plan (PSMP), the root cause of this noncompliance was a lack of the development of proper controls around the expected actions and communications for limiter, AVR, and protection system re-coordination when such adjustments are made.

Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

A lack of coordination amongst the Protection System and the in-service limiters could cause an unnecessary trip of the affected Generating Station. However, the entity’s generating facilities total to 130 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 8% in 2017 and 11% in 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Finally, the results of the December 10, 2018 coordination study showed there were no settings changes needed.

No harm is known to have occurred as a result of this noncompliance.

NPCC considered the Entity’s compliance history and determined there are no prior relevant instances of noncompliance.

Mitigation

To mitigate this noncompliance, the entity:

1) Completed the re-coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection System.
2) Created a tracking spreadsheet for all applicable Reliability Standards with recurring compliance due dates.
3) Entered compliance due dates into the Primary Compliance Contact and immediate supervisor’s Microsoft Outlook calendars to ensure future due dates are met.
4) Instituted six-month meetings where the Primary Compliance Contact and subject matter experts from Engineering and Operations will meet to review the compliance obligations of applicable Reliability Standards which include technical requirements.
5) Instituted monthly communication reviews (in-person or conference call) to discuss changes to entity generating unit or plant capabilities, voltage regulating controls, and protection system. Compliance, Engineering, and Operations participate in these reviews that will allow for ample time to properly coordinate these settings, if needed.
NPCC2019021076  PRC-005-6  R3  Taunton Municipal Lighting Plant  NCR07214  09/01/2018  01/28/2019  Self-Report  Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On February 20, 2019, Taunton Municipal Lighting Plant ("Taunton" or "the entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6, R3. Specifically, the entity missed an 18-month VLA battery inspection. On January 4, 2019, it was discovered upon internal review that 18-month battery testing activity that had last been completed on February 27, 2017 and had not been completed again by September 1, 2018. Upon discovery, the entity coordinated to have the missed battery maintenance completed on January 28, 2019.

The noncompliance associated with the 18-month battery testing intervals started on September 1, 2018 and ended on January 28, 2019 when the maintenance was completed.

Although the entity had a documented PSMP, the root cause of this noncompliance was a lack of the development of proper controls around employing a reminder or notification system to ensure that this task was completed within 18 calendar months after the February 27, 2017 testing.

Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

The potential risk due to uncompleted PRC-005-6 R3 maintenance is that the entity generation could possibly trip offline prematurely which could exasperate an ongoing real time BES situation. It could also expose the plant equipment to damage if the plant fails to trip offline properly when called upon. However, the entity generating facilities total to 130 MW. The rated capability of the generation is approximately 7% of the Entity’s Balancing Authority (ISONIE) required Operating Reserve. In addition, the generator operated at capacity factors of 8% in 2017 and 11% in 2018. Therefore, the capacity of this unit can be replaced by the ISONIE in the event of an unnecessary trip or loss of generating capability. Although the 18-month battery testing was performed approximately 4 months late, the entity had no known issues with any of their battery systems and or indication that a battery system failure was imminent.

No harm is known to have occurred as a result of this of noncompliance.

NPCC considered the Entity’s compliance history and determined there are no prior relevant instances of noncompliance.

Mitigation

To mitigate this noncompliance, the entity:

1) Completed the required 18-month interval battery testing per PRC-005-6, Attachment A, Table 1-4(a).
2) Created a tracking spreadsheet for all applicable Reliability Standards with recurring compliance due dates.
3) Entered compliance due dates into the Primary Compliance Contact and immediate supervisor’s Microsoft Outlook calendars to ensure future due dates are met.
4) Instituted six-month meetings where the Primary Compliance Contact and subject matter experts from Engineering and Operations will meet to review the compliance obligations of applicable Reliability Standards which include technical requirements.
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On June 11, 2018, AEPSC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. ACPSC submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement on behalf of AEP as Agent for AEP OK Transco., PSCO, and SWPCO (AEP West) (NCR01056).

The phased implementation plan for PRC-019-2 R1 requires that each Generator Owner verify at least 40% of its applicable Facilities by July 1, 2016; 60% of its applicable Facilities by July 1, 2017; 80% of its applicable Facilities by July 1, 2018; and 100% of its applicable Facilities by July 1, 2019. Because of AEP West’s efforts to meet the 80% milestone due by July 1, 2018, AEP West completed a fleet-wide compliance assurance evaluation of all facilities including the already completed facilities that were documented to meet prior implementation deadlines.

From this review, AEP West determined that its Northeastern Unit 3 did not meet the intent of PRC-019-2 R1.1 (AEP West determined that the applicable loss of field protective function enabled within the overall differential and generator protection microprocessor relays for Northeastern Unit 3 did not meet the intent of PRC-019-2 Requirement R1.1.1. Specifically, the loss of field protective relays were set to operate before the voltage regulator minimum excitation limiter settings. AEP West completed this evaluation on June 25, 2017 and that resulted in a lack of time for AEP Generation to conduct the comprehensive quality assurance review and technical evaluation of the coordination study following field data collection.) and could not be considered as part of AEP Generation’s percentage of completed facilities utilized to meet the 60% milestone due by July 1, 2017. Due to the inclusion of Northeastern Unit 3, the resulting percentage of completed PRC-019-2 applicable facilities within the SPP (now MRO) footprint fell below 60% to 59.1% and resulted in this noncompliance.

This noncompliance involves the management practices of planning and verification. AEP West determined the cause of this noncompliance to be that it allowed itself insufficient time to conduct a quality assurance review and technical evaluation of the coordination study following field data collection, issue the settings to correct the discoordination issue, and implement changes within a scheduled outage of sufficient duration prior to the milestone due date. This failure to adequately plan to verify that AEP West had completed 60% of its applicable Facilities are both root causes of this noncompliance.

This noncompliance started on July 1, 2017, when AEP West was required to have verified at least 60% of its applicable Facilities and ended on April 5, 2018, when AEP West finished its verification at Northeastern Unit 3.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because AEP West conducted an evaluation of unit operating conditions over the duration of this noncompliance. That evaluation indicated that operation was solely in the over-excited region and would not impact the set points associated with the loss of excitation protective relaying. PRC-019-2 R1 required AEP West to complete verification of 60% of its applicable facilities by July 1, 2017 and AEP West completed 59.1% by July 1, 2017. Missing this one applicable facility only slightly reduced AEP West below the 60% threshold, which minimizes the risk.

No harm is known to have occurred.

As of July 1, 2018, AEP West had 81.8% of applicable facilities verified in the SPP/MRO footprint which helps reduce the risk while mitigation is ongoing.

The entity has relevant compliance history. However, ReliabilityFirst determined that the entity’s compliance history should not serve as a basis for applying a penalty because of the different causes of the prior noncompliance and the current noncompliance.

**Mitigation**

To mitigate this noncompliance, AEP West:
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1) performed the coordination study following revision and implementation of the Northeastern unit 3 relay settings and this serves as the initial corrective action to allow AEP West to maintain the schedule adherence of the implementation milestones;
2) performed an extent of condition review to ensure the coordination is in compliance on the remaining facilities completed for 60% and 80% milestones. As well as an extent of condition review on the upcoming 100% milestone plan for the remaining applicable facilities to ensure the adequate time for the settings retrieval, coordination, and implementation of settings changes as required per Requirement R1;
3) adjusted the existing plan to allocate additional time to retrieve and analyze the protective relay and automatic voltage regulator limiter settings, and implement changes during the scheduled unit outage to prevent recurrence; and
4) identified the remaining PRC-019 applicable relays, evaluate associated settings, and updates within the Asset Management Database to aid the future coordination planning. This will allow future planning to save time in identifying applicable relays and obtaining the necessary field settings. In turn, this will reduce the time needed for the PRC-019 coordination.
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<td>RFC2017017732</td>
<td>MOD-025-2</td>
<td>R1</td>
<td>GenOn Northeast Management Company (GNMC)</td>
<td>NCR11137</td>
<td>7/1/2016</td>
<td>7/24/2017</td>
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On June 2, 2017, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with MOD-025-2 R1 identified during a Compliance Audit conducted from May 8, 2017 through May 19, 2017.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The entity did not perform the Real Power verifications by staged test as required for the first verification. The entity incorrectly performed the verifications using historical operational data. MOD-025-2 R1.1 requires that the first verification be performed via a staged test. As a result, the entity had verified none of its generating Facilities by July 1, 2016, thereby missing the 40% requirement detailed in the implementation plan for MOD-025-2 R1.

Additionally, the entity did not submit the data using the MOD-025-2 Attachment 2 (or a similar form containing the same information). Instead, the entity submitted the data using the PJM (Transmission Planner) processes that were in place at the time—the entity submitted data via eGads, email, etc. which did not include all information that is required by MOD-025-2. The entity also submitted these forms late (i.e. after the 90 day deadline in MOD-025-2 R1.2).

The entity did provide some data to PJM. The data the entity provided, however, did not meet the MOD-025 requirements. The entity provided the test data that PJM requested using a PJM form, but what PJM requests is different than what MOD-025-2 requires. The PJM forms were very similar to, but not as inclusive as, MOD-025 Attachment 2, which required more data.

This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to develop and implement an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One root cause was that entity staff was ineffectively trained on how to comply with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly (failing to perform the first verification using a staged test) by relying on what PJM required for its own purposes rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all contributing causes of this noncompliance.

The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on July 24, 2017, when the entity completed its Mitigation Plan.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity performed and submitted to its Transmission Planner (PJM) some of the MOD-025 required testing elements before the initial enforcement date of July 1, 2016. (The entity performed the verification using historical data rather than via staged verifications. Had the entity performed the verifications via a staged verification, the results would have likely been identical.) The information that the entity failed to provide was not required or needed to validate net capability for the Transmission Planner.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) prescheduled and conducted Real Power verification testing in accordance with MOD-025 R1 at Keystone and Conemaugh Generating Facilities;
2) completed MOD-025 Attachment 2 and submitted it to PJM within 90 days in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and
3) developed and implemented an internal process for review of MOD-025 test information and submission of dates.

ReliabilityFirst has verified the completion of all mitigation activity.
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<td>MOD-025-2</td>
<td>R1</td>
<td>GenOn REMA 1 (GR1)</td>
<td>NCR11141</td>
<td>7/1/2016</td>
<td>10/23/2017</td>
<td>Self-Report</td>
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On November 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The entity is implementing NRG’s corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 compliance date, the entity had performed real power testing and submitted data for 8 of the 10 units. The entity submitted these tests using the PJM Test form. The testing the entity performed was invalid because the entity performed the testing using the PJM Test form which did not include all of the data fields per MOD-025 Attachment 2. Therefore, none of the ten units in the entity registration met the 2016 reactive testing deadline. The entity met the July 1, 2017 compliance date requirements of 60% by correctly completing the MOD-025 real and reactive power verification for 9 of its 10 units.

NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG’s “fleet-wide” compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement.

This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM’s requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 23, 2017, when the entity completed its Mitigating Activities.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. Lastly, the entity contributes approximately 662 MW to the grid and operated at approximately a 1% capacity factor during the noncompliance.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1;
2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2;
3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability;
4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and
5) developed and implemented a process for the internal review of test data by NRG’s Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected.

ReliabilityFirst has verified the completion of all mitigation activity.
On November 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The entity is implementing NRG’s corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 compliance date, the entity had performed real power testing and submitted data for 8 of the 10 units. The entity submitted these tests using the PJM Test form. The testing the entity performed was invalid because the PJM Test form did not include all of the data fields per MOD-025 Attachment 2. Therefore, none of the ten units in the entity registration met the 2016 reactive testing deadline. The entity met the July 1, 2017 compliance date requirements of 60% by correctly completing the real and reactive power verification for 9 of its 10 units.

NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG’s “fleet-wide” compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement.

This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that the entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM’s requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on October 23, 2017, when the entity completed its Mitigating Activities.

Risk Assessment
This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is mitigated by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. Lastly, the entity contributes approximately 662 MW to the grid and operated at approximately a 1% capacity factor during the noncompliance.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s MOD-025 R2 compliance history and determined there were no relevant instances of noncompliance.

Mitigation
To mitigate this issue, the entity:
1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1;
2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2;
3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability;
4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and
5) developed and implemented a process for the internal review of test data by NRG’s Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected.

ReliabilityFirst has verified the completion of all mitigation activity.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Noncompliance Start Date</th>
<th>Noncompliance End Date</th>
<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
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<tr>
<td>RFC2017017847</td>
<td>PRC-019-2 R1</td>
<td>R1</td>
<td>GenOn Northeast Management Company (GNMC)</td>
<td>NCR11137</td>
<td>7/1/2016</td>
<td>2/28/2017</td>
<td>Compliance Audit</td>
<td>Completed</td>
</tr>
</tbody>
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**Description of the Noncompliance:** On June 2, 2017, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-019-2 R1 identified during a Compliance Audit conducted from May 8, 2017 through May 19, 2017.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. During the May 2017 Compliance Audit of the entity, the Audit Team identified a noncompliance with PRC-019-2 R1. The entity failed to verify 40% of its generating Facilities by the required July 1, 2016 date.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct.

The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on February 28, 2017, when the entity completed its Mitigation Plan.

**Risk Assessment:** This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because when the entity performed the verification and coordination, no changes were required. There were no deficiencies in the coordination at any of the entity units. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation:** To mitigate this issue, the entity completed the required PRC-019 R1 analysis for units at the Generating facilities and is now executing its implementation plan consistent with NERC guidance concerning phased implementation on a registration basis and revised its processes and procedures accordingly.

ReliabilityFirst has verified the completion of all mitigation activity.
<table>
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</tr>
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</table>

**Description of the Noncompliance**: On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of the entity’s applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the “no trip zone” of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity completed the required verification for 4 of 4 applicable units (100%).

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on February 28, 2017, when the entity completed its Mitigating Activities.

**Risk Assessment**: This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the “no trip zone,” a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**: To mitigate this issue, the entity:

1) adjusted NRG’s fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and
2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2.

ReliabilityFirst has verified the completion of all mitigation activity.
On November 5, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directly directs NERC compliance activities for the entity at the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on three of eight its units (38%). As of the July 1, 2017 implementation date, however, the entity had completed the required verification for seven of its eight applicable units (88%).

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

The entity contributes approximately 1,837 MW to the grid and operated at approximately a 15% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on May 27, 2017, when the entity completed its Mitigating Activities.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. The risk is further reduced because the entity had completed its verification on 33% of its applicable units (instead of the required 40%) by the July 1, 2016 implementation date. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted NRG’s fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and

2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2.

ReliabilityFirst has verified the completion of all mitigation activity.
On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard’s implementation plan, requires 40% of the entity’s applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the “no trip zone” of PRC-024 Attachments 1 and 2 by July 1, 2016.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its applicable units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all four of its applicable units.

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on February 28, 2017, when the entity completed its Mitigating Activities.

Risk Assessment
This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the “no trip zone,” a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

Mitigation
To mitigate this issue, the entity:

1) adjusted NRG’s fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and
2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2.

ReliabilityFirst has verified the completion of all mitigation activity.
**NERC Violation ID** | **Reliability Standard** | **Req.** | **Entity Name** | **NCR ID** | **Noncompliance Start Date** | **Noncompliance End Date** | **Method of Discovery** | **Future Expected Mitigation Completion Date**
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On November 5, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard’s implementation plan, requires 40% of the entity’s applicable units to have performed analyses to verify the generator frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on three of its eight (33%) applicable units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification on seven of its eight (88%) applicable units.

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

The entity contributes approximately 1,837 MW to the grid and operated at approximately a 15% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on May 27, 2017, when the entity completed its Mitigating Activities.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. The risk is further reduced because the entity had completed its verification on 33% of its applicable units (instead of the required 40%) by the July 1, 2016 implementation date. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted NRG’s fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and
2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2.

ReliabilityFirst has verified the completion of all mitigation activity.
**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG’s corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 and July 1, 2017 compliance dates, the entity had tested and submitted data for only one of three units, completing the real power and reactive power verification for only 33% of its applicable units.

NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG’s “fleet-wide” compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to develop an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason for this failure is that entity staff was ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM’s requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance.

The entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 3, 2017, when the entity completed its Mitigation Plan.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted the NRG Energy, Inc. corporate project approach to perform targeted testing on the entity Generation registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1;
2) ensured all required testing was performed and NERC MOD-025 Attachment 2 was completed for each of the entity units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1;
3) submitted NERC MOD-025 Attachment 2 to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and
4) developed and implemented a process for the internal review of test data by NRG’s Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected.

ReliabilityFirst has verified the completion of all mitigation activity.
### Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The entity is implementing NRG’s corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 and July 1, 2017 compliance dates, the entity had tested and submitted data for only one of three units, completing the real power and reactive power verification for only 33% of its applicable units.

NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG’s “fleet-wide” compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement.

This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM’s requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance.

Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on September 8, 2017, when the entity completed its Mitigation Plan.

### Risk Assessment

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

### Mitigation

To mitigate this issue, the entity:

1. adjusted the NRG Energy, Inc. corporate project approach to perform targeted testing on the entity Generation registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1;
2. ensured all required testing was performed and NERC MOD-025 Attachment 2 was completed for each of the four reactive test verifications for each of the entity units to meet the phased-in implementation requirements per MOD-025-2 Requirement 2;
3. submitted NERC MOD-025 Attachment 2 to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and
4. developed and implemented a process for the internal review of test data by NRG’s Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected.

ReliabilityFirst has verified the completion of all mitigation activity.

<table>
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<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Noncompliance Start Date</th>
<th>Noncompliance End Date</th>
<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
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</table>

Last Updated 03/28/2019
On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. The entity failed to verify 40% of its generating Facilities by the required July 1, 2016 date. As of July 1, 2016, the entity had verified none of its units.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct.

Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on April 30, 2017, when the entity completed its Mitigating Activities.

Risk Assessment

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

Mitigation

To mitigate this issue, the entity:

1) adjusted the corporate project approach to perform targeted coordination analyses of applicable NRG Energy, Inc. units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-019-2 R1; and
2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-019-2 Requirement 1.

ReliabilityFirst has verified the completion of all mitigation activity.
<table>
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<tr>
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<tr>
<td>RFC2017018767</td>
<td>PRC-024-2</td>
<td>R1</td>
<td>Homer City Generation, L.P. (Homer)</td>
<td>NCR11297</td>
<td>7/1/2016</td>
<td>4/30/2017</td>
<td>Self-Report</td>
<td>Completed</td>
</tr>
</tbody>
</table>

**Description of the Noncompliance** (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all three of its units. The entity completed the verifications on April 30, 2017.

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on April 30, 2017, when the entity completed its Mitigation Plan.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted its corporate project approach to perform targeted coordination analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1; and
2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-024-2 Requirement 1.

ReliabilityFirst has verified the completion of all mitigation activity.
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On December 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity’s applicable units to have performed analyses to verify the generator frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all three of its units. The entity completed the verifications on April 30, 2017.

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on April 30, 2017, when the entity completed its Mitigation Plan.

Risk Assessment

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016.

No harm is known to have occurred.

ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.

Mitigation

To mitigate this issue, the entity:

1) adjusted its corporate project approach to perform targeted coordination analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R2; and
2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-024-2 Requirement 2.

ReliabilityFirst has verified the completion of all mitigation activity.
**NERC Violation ID**: RFC2018019843  
**Reliability Standard**: PRC-019-2  
**Req.**: R1  
**Entity Name**: Indianapolis Power & Light Company (IPL)  
**NCR ID**: NCR00798  
**Noncompliance Start Date**: 7/1/2016  
**Noncompliance End Date**: 8/30/2017  
**Method of Discovery**: Self-Report  
**Future Expected Mitigation Completion Date**: Completed

### Description of the Noncompliance

(For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On June 5, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. During an internal program review, the entity discovered that, due to a lack of effective processes and procedures to track the work, it failed to coordinate the voltage regulating system controls for its generation facilities by the required deadline. Subsequently, the entity completed the study and coordination of 100% of its generation facilities by August 30, 2017.

The root cause of this noncompliance was the entity's lack of effective processes and procedures to track the work. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls.

This noncompliance started on July 1, 2016, the first implementation deadline that the entity missed and ended on August 30, 2017, when the entity completed the coordination work.

### Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to coordinate voltage regulating system controls is that it could result in unnecessary tripping of a generator or damage to the equipment. This risk was mitigated in this case by the following factors. First, when the entity completed the study, it found that in all cases, the excitation system limiters always operated before the excitation system protection, which prevents an unnecessary disconnection of the generator. Second, the entity was only required to make minor adjustments to two gas turbine loss of field relays, which would not adversely affect the protection for the unit. No harm is known to have occurred.

ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.

### Mitigation

To mitigate this noncompliance, the entity completed the study and coordination of 80% of the entity's generating locations to meet the implementation date of July 1, 2018. As an additional mitigating action, the entity implemented an automated tracking tool that provides reminders for upcoming required activities to multiple responsible people and their supervisors.

ReliabilityFirst has verified the completion of all mitigation activity.
NRG Violation ID | Reliability Standard | Req. | Entity Name | NCR ID | Noncompliance Start Date | Noncompliance End Date | Method of Discovery | Future Expected Mitigation Completion Date
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RFC2017018639 | MOD-025-2 | R1 | NRG East | NCR11715 | 7/1/2016 | 10/11/2017 | Self-Report | Completed

**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The entity is implementing NRG’s corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration.

NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG’s “fleet-wide” compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement.

As of the July 1, 2016 implementation date, the legacy Registered Entities under the entity had not verified 40% of its applicable units. At that time, only a total of 11 units (20% of applicable units) had been properly tested with adequate documentation and submittals.

This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that the entity staff was ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM’s requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance.

The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 11, 2017, when the entity completed its Mitigating Activities.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E, 2 - E3 Requirements and PJM Manual 21 Rev 12 12/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1;
2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2;
3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability;
4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and
5) developed and implemented a process for the internal review of test data by NRG’s Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected.

ReliabilityFirst has verified the completion of all mitigation activity.
NRG Violation ID | Reliability Standard | Req. | Entity Name | NCR ID | Noncompliance Start Date | Noncompliance End Date | Method of Discovery | Future Expected Mitigation Completion Date
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**Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)**

On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2.

NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The entity is implementing NRG’s corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard’s implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration.

As of the July 1, 2016 implementation date, the legacy Registered Entities under the entity had not verified 40% of its applicable units. At that time, only a total of 11 units (20% of applicable units) had been properly tested with adequate documentation and submittals.

NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG’s “fleet-wide” compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. That incorrect interpretation and implementation led to this noncompliance.

This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM’s requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance.

The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on October 11, 2017, when the entity completed its Mitigating Activities.

**Risk Assessment**

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E, 2 - E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this issue, the entity:

1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1;
2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2;
3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability;
4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and
5) developed and implemented a process for the internal review of test data by NRG’s Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected.

ReliabilityFirst has verified the completion of all mitigation activity.
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration.

As of the implementation plans’ July 1, 2017 milestone, the entity, completed the required analyses for 47 of the 55 applicable units (85%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-019-2 R1. Specifically, three legacy Registered Entities did not complete the required analyses to meet the required percentages for these individual legacy registrations.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct.

The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on June 30, 2017, when the entity completed its Mitigating Activities.

Risk Assessment

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because when the entity performed the verification and coordination, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings and excitation controls. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred.

Mitigation

To mitigate this issue, the entity:

1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-019-2 R1; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity units using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-019-2 Requirement 1.

ReliabilityFirst has verified the completion of all mitigation activity.
On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016.

The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration.

As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 53 of the 55 applicable units (96%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-024-2 R1. The entity only verified five of its 23 generating units (22%) within the legacy entity registration by July 1, 2016 as required by PRC-024-2 R1. The entity’s failure to verify 40% of its generating units by its registration date of December 16, 2016 is a cause of this noncompliance.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on June 30, 2017, when the entity completed its Mitigating Activities.

Risk Assessment

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the “no trip zone,” a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred.

ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.

Mitigation

To mitigate this issue, the entity:

1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and
2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2.

ReliabilityFirst has verified the completion of all mitigation activity.
On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level.

The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity’s applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone” of PRC-024 Attachments 1 and 2 by July 1, 2016.

The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration.

As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 53 of the 55 applicable units (96%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-024-2 R1. The entity only verified five of its 23 generating units (22%) within the legacy registration by July 1, 2016 as required by PRC-024-2 R1. The entity's failure to verify 40% of its generating units by its registration date of December 16, 2016 is the root of this noncompliance.

NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity.

NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct.

The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance.

This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on June 30, 2017, when the entity completed its Mitigating Activities.

Risk Assessment

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the “no trip zone,” a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred.

ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.

Mitigation

To mitigate this issue, the entity:

1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and
2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2.

ReliabilityFirst has verified the completion of all mitigation activity.
On July 13, 2018 and on October 26, 2018, the entity submitted Self-Reports stating that, as a Distribution Provider and Generator Owner, it was in noncompliance with PRC-005-6 R3. ReliabilityFirst consolidated the second Self-Report into the first Self-Report because the second was discovered while the entity completed mitigating activities for the first Self-Report.

In May 2018, while preparing for the entity’s upcoming 2019 NERC audit, the entity undertook a review of its last three years of PRC-005-6 battery activities. In this review, the entity discovered that a 2016 maintenance activity for two 125-volt station batteries was not completed within the maximum interval of 18 months. More specifically, the two battery bank’s annual tests were not reviewed against the battery baseline for a period of 25 and 28 months, respectively. The entity, however, did perform annual and quarterly testing on the battery banks during the period of noncompliance that indicated the batteries were functioning properly. (The entity had established a practice of performing the 18 month maintenance activities on the NERC batteries on an annual basis. The baseline review for these batteries was completed in 2015 and 2017, but was not completed in 2016.)

As a result of subsequent review and discussion with its Transmission Operator (TOP), American Transmission Company (ATC), the entity determined that 11 additional battery banks, which supply control power to ATC Bulk Electric System breakers, were also not reviewed within the maximum interval of 18 months; making a total of 13 battery banks that were not timely reviewed. At the affected substations that had battery banks that were not timely reviewed, the 125VDC batteries provide trip and close control power to ATC’s 138kV breakers. None of the substations or associated battery banks support or rely on Remedial Actions Schemes (RAS). Two of these substations are on Blackstar Resource Unit cranking paths.

The entity had established a practice of performing the 18-month maintenance activities for all of its NERC batteries and battery banks (including the 13 at issue in this noncompliance) on an annual basis. However, the entity failed to complete the review for all 13 of these battery banks at different times in 2016 and 2017.

Regarding the root cause, when the entity tests a battery or a battery bank on its annual schedule, the results are manually uploaded into the entity’s Cascade system (a tracking database), and an automatic notification is sent to a prescribed list of individuals to review this test result. The engineer is then responsible to review the results against the baseline results, document their review, identify any anomalies, and then close out the work order in Cascade to complete this activity.

These noncompliances involve the management practices of work management and workforce management. The alert emails were sent to the appropriate individuals, but the Cascade work orders issued for these activities were not completed within the prescribed interval of 18 calendar months. The work orders were not completed due to ineffective work management as the current work process had no additional automated tracking or follow-up notification to the engineer to complete the review of the work orders within the compliance interval. That ineffective work management design (lacking a follow-up and automated tracking) is a root cause of this noncompliance. Workforce management through ineffective training is also a contributing cause as the individuals responsible for completing the work orders were not effectively trained on the importance of timely completing the work orders.

This noncompliance started on November 1, 2016, when the entity missed the 18 month maintenance interval on the first battery bank and ended on September 12, 2018, when the entity completed the overdue maintenance activities on all of the relevant battery banks.

Risk Assessment

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by these noncompliances is that unattended and untested battery banks could fail, and that failure could lead to local loss of load or transmission equipment at the substation. The risk is minimized because during the noncompliance, the entity successfully performed quarterly inspections and those inspections revealed no performance issues with the battery banks. The entity also monitors the battery chargers that normally carry the station DC load and the voltage on battery banks that provide backup power remotely. That monitoring revealed no significant conditions with the battery banks. Lastly, when the entity performed the overdue tests, the tests revealed that the battery banks were functioning properly.

No harm is known to have occurred.

The entity has relevant compliance history. However, ReliabilityFirst determined that the entity’s compliance history should not serve as a basis for applying a penalty because the prior noncompliance was an isolated issue that was promptly identified, assessed, and corrected and both the prior noncompliance and the current noncompliances were promptly self-reported and mitigated. The prior noncompliance and the current noncompliances also have different root causes, which further makes the prior noncompliance distinguishable.

Mitigation

To mitigate this noncompliance, the entity:

1) created an Engineering Review tracking report that identifies all reviews required for NERC batteries. The report identifies the non-compliance date for the review (18 months from previous review) and the key milestone dates to manage responsible parties to stay within compliance. This is to be reviewed on a monthly basis;

2) created a monthly control activity in the entity’s FERC Compliance Database to review the Engineering Review completion status; and
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Noncompliance Start Date</th>
<th>Noncompliance End Date</th>
<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
</tr>
</thead>
</table>

3) developed a training module to explain the compliance tasks required for VLA and VRLA batteries, including the roles and responsibilities of all stakeholders from field personnel through program administrators.

ReliabilityFirst has verified the completion of all mitigation activity.
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<thead>
<tr>
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**Description of the Noncompliance** (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)

On November 21, 2018, the Entity submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-006-2 R9. This noncompliance started on February 9, 2016, when the Entity failed to properly set the time delay of their Under-Frequency Load Shedding (UFLS) relays to provide automatic tripping of Load in accordance with the UFLS program as determined by its Planning Coordinator (PC), and ended on November 16, 2018, when BES adjusted the time delay for the UFLS relays to meet the Planning Coordinator parameters.

Specifically, the Entity's relay test records indicate that 12 of the Entity's 15 UFLS relays had a total time delay greater than 0.28 seconds and were outside of tripping parameter limits as required by PRC-006 R9 and the limits set by the FRCC UFLS program of less than 0.28 seconds (where the total time delay = intentional delay + relay delay + breaker delay).

The cause for this noncompliance was insufficient training on the FRCC UFLS program and the associated settings.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system.

The risk was reduced because if a UFLS event had occurred, the Entity's UFLS relays would have operated; however, the operation would have been slower than required. The maximum time delay would have been .07 seconds greater than the .28 seconds specified by the FRCC UFLS program.

There were no UFLS events during the period of noncompliance. The Entity's UFLS Load Shed represents 0.51% of the Regional UFLS Load Shed. No harm is known to have occurred.

The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty.

**Mitigation**

To mitigate this noncompliance, the Entity:

1) performed an extent of condition review;
2) performed a root cause analysis;
3) corrected the settings on the UFLS relays to be within the allowable range of the FRCC UFLS Regional Program;
4) tested to confirm the correct settings were entered;
5) created workflow with three levels of review and approval to ensure the devices have the correct settings; and
6) created an annual training program for all BES employees involved with the UFLS program which will be provided by an outside entity based on the FRCC UFLS program.
NPCC2018020744  PRC-005-6  R3  National Grid USA  NCR11171  9/1/2017  04/02/2018  Self-Log  Completed

On November 29, 2018, National Grid USA (“the Entity”) submitted a Self-Log stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005-6 R3. The Entity discovered that it had failed to perform certain diagnostic tests on one battery bank, of the type Vented Lead Acid (VLA), at one of its 345kV substations. The battery bank had been last tested on February 16, 2016. Therefore, per the time-based maximum interval of eighteen calendar months, as specified in PRC-005-6 Table 1-4(a), maintenance on this device was required by August 31, 2017.

This noncompliance started on September 1, 2017, the day after the date when the periodic maintenance for the battery bank was required by, and ended on April 2, 2018, when the Entity completed required diagnostic tests for a new VLA battery bank that it had installed to replace the existing aging unit.

The root cause of this instance of noncompliance was that the diagnostic test Work Orders for the VLA batteries had been inadvertently, and prematurely, closed out in Cascade by the Substation Supervisor on January 30th, 2017 before verifying whether any actual testing work had been performed.

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS).

Lack of proper DC voltage at a substation could cause protection systems to misoperate or not operate when called upon. However, the substation at issue is equipped with a redundant battery bank (fully tested in accordance with required intervals) that operates the primary protection system. Additionally, the non-compliant battery bank, which operates the substation’s back-up protection system, was subject to bi-monthly Visual and Operational Inspections and was found to be in good working order from the time the required diagnostic tests were missed until the Entity replaced it with a new VLA bank. The Entity’s Reliability Coordinator (the NYISO) carries required summer Operating Reserve of approximately 1965 MW and could have compensated for the loss of transmission facilities caused by a potential misoperation of the substation protection system by appropriately dispatching generating facilities in its Control Area.

No harm is known to have occurred as a result of this noncompliance.

To mitigate this noncompliance, the Entity:
1) completed required diagnostic tests for a new VLA battery bank that was installed to replace the existing aging unit;
2) evaluated the incident with its Substation Operations/Maintenance & Construction (M&C) personnel and provided detailed information to responsible staff located throughout its facilities regarding the reasons that led to the noncompliance as well as detailed instructions that must be followed to ensure the timely completion of future maintenance items; and
3) enhanced its existing compliance software tool (“Cascade”) by adding a “Work Completed Date” field that needs to be populated before any work order can be closed.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Violation Start Date</th>
<th>Violation End Date</th>
<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
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<td>Los Vientos Windpower III, LLC (LVWPIII)</td>
<td>NCR11538</td>
<td>1/30/2017</td>
<td>2/26/2017</td>
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**Description of the Violation** (for purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On May 4, 2017, LVWPIII submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-004-4(i) R3. Specifically, LVWPIII failed to identify whether its Protection System component caused a Misoperation within the later of 60 calendar days of notification or 120 calendar days of the Bulk Electric System (BES) interrupting device operation.

While conducting a review of its Protection Systems operation reporting, LVWPIII discovered that it received notice of an interrupting device operation by a shared Composite Protection System on November 2, 2016. LVWPIII identified that its Protection System component did not cause a misoperation, but did not complete this analysis until February 26, 2017, 27 calendar days after the PRC-004-4(i) R3 deadline.

The root cause of this noncompliance was that LVWPIII had an inadequate process to ensure compliance with all newly applicable NERC Reliability Standards. In particular, LVWPIII did not have a written process to evaluate and implement changes in compliance obligations for new or revised NERC Reliability Standards. As a result, LVWPIII personnel utilized an outdated procedure that did not contain the requirements and deadlines for the current version of PRC-004.

This noncompliance started on January 30, 2017, the day after the identification was due, and ended on February 26, 2017, when LVWPIII determined that its Protection System component did not cause a Misoperation.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. First, while not timely, LVWPIII did provide evidence that it performed an analysis of the device operation at issue. Second, after conducting an analysis, LVWPIII did not identify any Protection System component Misoperation for this issue. Third, the other Composite Protection System owner indicated that it was aware of the interrupting device operation. Fourth, the duration of the noncompliance was relatively short, lasting less than one month. No harm is known to have occurred.

Texas RE considered LVWPIII’s and its affiliates’ compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance, LVWPIII:

1. completed the required PRC-004-4(i) R3 misoperation determination;
2. developed an email alert for BES interrupting device operation by a Composite Protection System. The email alert directs operators to archive evidence needed for PRC-004 evaluation and reporting, and to forward evidence to the responsible analysis personnel;
3. updated its PRC-004 compliance process document and, as part of an annual review of NERC compliance procedures, implemented an automated task to review the process document;
4. conducted NERC training for site managers and technicians on the reporting process and the updated requirements of PRC-004;
5. implemented a process to track and implement compliance obligations for new or revised NERC Reliability Standards.

Texas RE verified the completion of all mitigation activity.
**NERC Violation ID**  | **Reliability Standard** | **Req.** | **Entity Name** | **NCR ID** | **Violation Start Date** | **Violation End Date** | **Method of Discovery** | **Future Expected Mitigation Completion Date**  
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TRE2018019448 | PRC-005-6 | R3 | Rattlesnake Wind I LLC (RSWILLC) | NCR11547 | 12/1/2016 | 3/23/2017 | Compliance Audit | Completed  

**Description of the Violation** (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

During a Compliance Audit conducted from February 6, 2018 through February 8, 2018, Texas RE determined that RSWILLC, as a Generator Owner (GO), was in noncompliance with PRC-005-6 R3. Specifically, RSWILLC did not timely perform all 18-month maintenance activities for two Vented-Lead Acid (VLA) batteries as required by PRC-005-6, Table 1-4(a).

On April 18, 2015, two VLA battery banks were installed and commission testing was conducted on May 10, 2015. As a result RSWILLC was required to complete the maintenance activities for the two VLA batteries, with a maximum maintenance interval of 18-calendar-months, by November 30, 2016. However, RSWILLC did not complete the testing for the two VLA batteries until March 23, 2017.

The root cause of the noncompliance was that RSWILLC did not correctly determine the 18-calendar-month maintenance interval start date. RSWILLC mistakenly believed that the 18-calendar-month interval started from the Facility’s commercial operation date rather than from the date testing was performed. Additionally, RSWILLC misinterpreted the Implementation Plan for PRC-005-6.

This noncompliance started on December 1, 2016, the day after the 18-calendar-month maintenance activities were due for its VLA batteries. The noncompliance ended on March 23, 2017, when the required maintenance activities were performed.

**Risk Assessment**

This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). This risk posed by this issue is that the VLA batteries at issue would not function as intended. However, the risk posed by this issue is reduced by several factors. First, the VLA batteries at issue comprise only 2% (2/89) of the total Protection System devices in RSWILLC’s PSMP. Second, RSWILLC did not identify any issues with the two VLA batteries when it performed the required 18-month testing. Third, RSWILLC regularly performed monthly maintenance on the two VLA batteries at issue, reducing the scope for missed testing. Finally, during the Compliance Audit it was determined that this issue was limited to only one type of device and that RSWILLC timely tested all other devices in the PSMP.

No harm is known to have occurred.

Texas RE considered RSWILLC’s compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance, RSWILLC:

1) performed the required maintenance activities on the VLA batteries;
2) contracted with a vendor to provide compliance program services and monthly compliance training;
3) conducted trainings to specifically address the PRC-005-6 implementation plan; and
4) implemented a spreadsheet to track the maximum maintenance intervals for Protection System maintenance and confirm that RSWILLC correctly recorded the required PRC-005-6 maintenance intervals for Protection System devices.

Texas RE has verified the completion of all mitigation activity.
Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

On October 5, 2016, GRMA submitted a Self-Report stating that, as a Balancing Authority (BA), it was in violation with INT-006-4 R1. Specifically, GRMA reported that on July 5, 2016 at 1:40 PM, its scheduling software automatically approved a downward modification to a Confirmed Interchange (CI) even though it was not capable of supporting the magnitude including ramping throughout the duration of the Arranged Interchange (AI). The request for the AI should have been denied or curtailed. The downward modification or curtailment resulted in an AI that was below the low operating limit of GRMA. At 1:50 PM, the modified CI resulted in an over generation condition in which the primary BA was producing more than the expected magnitude of Interchange and ramp because of the minimum generation levels at GRMA. The primary BA then directed GRMA to reconfigure its generation blocks to achieve the magnitude of the interchange. The interchange value remained constant into the next hour. In the absence of being directed off line, at 2:56 PM, the output of GRMA matched the magnitude of the AI.

After reviewing all relevant information, WECC determined that GRMA failed to deny an AI or curtail CI for which it did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the AI, as required by INT-006-4 R1, R1.1.

The root cause of the violation was a lack of controls around the protocol and configuration of GRMA’s electronic tagging system, which automatically accepted an AI, even though GRMA could not support the magnitude of the Interchange.

Risk Assessment

WECC determined that this noncompliance posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, GRMA failed to deny an AI or curtail CI for which it did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the AI as required by INT-006-4 R1, R1.1. Such failure could result in inadvertent energy, an out-of-balance condition on the system, and incorrect NSI information to the Interconnection and BAAL deviations which affected another Requirement. The amount of over-generation relative to the Western Interconnection was small, ACE + 100 MW, during the event. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible.

However, this over-frequency (outside of BAAL limits) lasted a total of 66 minutes and GRMA was in communication with its RC during the entire event. Based on this, WECC determined that there was a low likelihood of causing negligible harm to the BPS. No harm is known to have occurred.

Mitigation

To mitigate this issue, GRMA:
- performed an investigation of the BAAL exceedance issue and provided a summary of the event to appropriate parties;
- conducted a conference call with the member BA, power marketer to review timeline of events associated with the issue and discuss future mitigation;
- developed procedures identifying coordination in the Day Ahead and Real-Time time frames and shared with the appropriate parties;
- created communication guidelines for shut-down to identify the conditions for a shut-down as well as the appropriate communications between parties for a shut-down;
- developed lessons learned training; and
- delivered training to GRMA system operators based on the procedures and communications guidelines developed.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Violation Start Date</th>
<th>Violation End Date</th>
<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
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**Description of the Violation**

(For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

UNWP discovered on January 11, 2017 that it failed to provide its Transmission Planner verification of Real Power and Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R1. UNWP had 68 hydro-generating units applicable to this standard and requirements that it failed to verify its Real Power capabilities of at least 40% of as it assumed the incorrect effective date of the Standard. UNWP misunderstood the one-hour soak requirement for maximum Real Power capacities as required by Attachment 1, section 2.1.1. Because of this oversight, UNWP was unable schedule testing in accordance with the effective date of the Standard.

The root cause of the issue was UNWP’s misunderstanding of the testing specifications for the Requirement. Specifically, UNWP overlooked the one-hour soak time of the maximum Real Power and lagging Reactive Power capacity as required in Attachment 1 section 2.1.1. Subsequently, the testing was not scheduled in accordance with the accurate implementation schedule.

**Risk Assessment**

These issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, UNWP failed to provide its Transmission Planner verification of Real Power and Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R1. Such failures could potentially result in inaccurate information of generator gross and net Real Power capabilities used in planning models which are used to assess BES Reliability. Inaccurate information would result in inaccurate models; therefore, the BES could be planned with the expectation that a generator has the capability to mitigate a modeled system contingency, whereas it may not completely mitigate the contingency. UNWP owns and/or operates 68 applicable units location at eight facilities with a total capacity of 6,378 MW, of which 36 units were applicable to these issues. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor.

However, UNWP implemented the WECC Generating Unit Model Validation testing for all its generating units in the past; therefore, if a real-time contingency that required the generating unit to respond were to occur, the current data would be satisfactory for mitigating the contingency. Additionally, the information obtained through the verification process is merely used for system modeling to develop contingencies and operating limits and not depended upon for real-time operating limits. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.

**Mitigation**

To mitigate these issues, UNWP:

a. developed a procedure to perform the required testing of MOD-025-2 R1 and 2;
b. coordinated with all 8 facilities’ Maintenance and Operation departments to determine when each Facilities testing could be performed;
c. completed testing on 43% of applicable units;
d. completed testing on 54% of applicable units;
e. complete the testing on 57% of applicable units;
f. completed testing on 72% of applicable units;
g. completed testing on 93% of applicable units; and
h. four generating units are out of commission for long term service and are unable to be tested. Testing will be complete once these units are ready for commercial service.
NERC Violation ID | Reliability Standard | Req. | Entity Name | NCR ID | Violation Start Date | Violation End Date | Method of Discovery | Future Expected Mitigation Completion Date
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WECC2017016779 | MOD-025-2 | 2 | USACE - Portland District | NCR05538 | 7/1/2016 | 6/30/2017 | Self-report | Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)

UNWP discovered on January 11, 2017 that it failed to provide its Transmission Planner verification of Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R2. UNWP had 68 hydro-generating units applicable to this standard and requirements that it failed to verify its Reactive Power capabilities of at least 40% of as it assumed the incorrect effective date of the Standard. UNWP misunderstood the one-hour soak requirement for lagging Reactive Power capacities as required by Attachment 1, section 2.1.1. Because of this oversight, UNWP was unable schedule testing in accordance with the effective date of the Standard.

The root cause of the issue was UNWP’s misunderstanding of the testing specifications for the Requirement. Specifically, UNWP overlooked the one-hour soak time of the maximum Real Power and lagging Reactive Power capacity as required in Attachment 1 section 2.1.1. Subsequently, the testing was not scheduled in accordance with the accurate implementation schedule.

Risk Assessment

These issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, UNWP failed to provide its Transmission Planner verification of Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R2. Such failures could potentially result in inaccurate information of generator gross and net Reactive Power capabilities used in planning models which are used to assess BES Reliability. Inaccurate information would result in inaccurate models; therefore, the BES could be planned with the expectation that a generator has the capability to mitigate a modeled system contingency, whereas it may not completely mitigate the contingency. UNWP owns and/or operates 68 applicable units location at eight facilities with a total capacity of 6,378 MW, of which 36 units were applicable to these issues. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor.

However, UNWP implemented the WECC Generating Unit Model Validation testing for all its generating units in the past; therefore, if a real-time contingency that required the generating unit to respond were to occur, the current data would be satisfactory for mitigating the contingency. Additionally, the information obtained through the verification process is merely used for system modeling to develop contingencies and operating limits and not depended upon for real-time operating limits. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.

Mitigation

To mitigate these issues, UNWP:

a. developed a procedure to perform the required testing of MOD-025-2 R1 and 2;
b. coordinated with all 8 facilities’ Maintenance and Operation departments to determine when each Facilities testing could be performed;
c. completed testing on 43% of applicable units;
d. completed testing on 54% of applicable units;
e. complete the testing on 57% of applicable units;
f. completed testing on 72% of applicable units;
g. completed testing on 93% of applicable units; and
h. four generating units are out of commission for long term service and are unable to be tested. Testing will be complete once these units are ready for commercial service.
**NERC Violation ID**: WECC2017017148

**Reliability Standard**: MOD-032-1

**Req.**: R2

**Entity Name**: Judith Gap Energy LLC (JUGE)

**NCR ID**: NCR05503

**Violation Start Date**: 7/1/2016

**Violation End Date**: 7/27/2017

**Method of Discovery**: Self-Certification

**Future Expected Mitigation Completion Date**: Completed

### Description of the Violation

For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.

On February 28, 2017, JUGE submitted a Self-Certification stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. In preparation for its upcoming self-certification, JUGE discovered that it had not provided steady-state, dynamics, and short circuit modeling data for its 180 MW of wind generation to its Transmission Planner (TP) and Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its TP and PC in Requirement 1. Furthermore, the required data had not been gathered or prepared for distribution prior to the identification of the noncompliance.

The root cause of the issue was an administrative oversight causing JUGE to fail to gather and provide the required data to its TP and PC. Specifically, JUGE did not have adequate compliance tracking mechanisms in place to ensure that the required data was collected and provided to the TP and PC.

This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on July 27, 2017, when JUGE provided its modeling data for a total of 392 days of noncompliance.

### Risk Assessment

WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, JUGE failed to provide steady-state, dynamics, and short circuit modeling data to its TP and PC according to the data requirements and reporting procedures developed by its TP and PC in Requirement 1, as required by MOD-032-1 R2. Such failure could result in inaccurate data modeling in planning for meeting system operating conditions and addressing contingencies to be created by the TP and PC. Inaccurate modeling could have led to an unexpected loss of the 180 MW of wind generation that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible.

However, the data missing was applicable to 180 MW of wind generation and contributes only 135 MW to the grid while operating and operates at an average 38% capacity factor. Based on this, WECC determined that there was a low likelihood of causing negligible harm to the BPS. No harm is known to have occurred.

### Mitigation

To mitigate this issue, JUGE:

- submitted to MOD-032 data model to its TP and PC;
- created an automated task notification in its internal task management system to remind SMEs 60 days prior to the end of the 12-month review period;
- created a new policy to escalate incomplete compliance tasks to the compliance team if the tasks are not complete within 30 days of receiving the task notification; and
- entity’s new Compliance Manager reviewed the model guidelines and discussed the annual future model update expectations with team.
**Description of the Violation**

On June 29, 2018, AGCS submitted a Self-Report stating that, as a Generator Operator, it was in violation with PRC-024-2 R1.

Specifically, AGCS reported that it did not set the protective relaying settings correctly on its solar generating Facility per the requirements of PRC-024-2 R1, Attachments 1 by July 1, 2016. AGCSs parent corporation, reported that it implemented a plan in 2015 that included its entire fleet of generating Facilities within the Western Interconnection for a single compliance approach. However, in March 2017, AGCSs parent corporation changed this incorrect approach based upon NERC guidance to demonstrate compliance with the Standard on a Registered Entity basis rather than its entire fleet of generating Facilities. As a result of this guidance, AGCS then completed the required analyses and required adjustments of its inverter frequency and voltage trip settings for its applicable Facility; one solar generating unit which generates 320 MWA, on July 25, 2017.

After reviewing all relevant information, WECC determined that AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip zone," as required by PRC-024-2 R1 and 2, Attachments 1.

The root cause of these issues was due to the incorrect interpretation of the implementation of PRC-024-2 R1, by AGCS and by its parent company. Specifically, that the implementation plan applied to the entire fleet of solar generating Facilities owned by AGCSs parent company, instead of the implementation plan applying to individual entities that AGCSs parent company owned separately. This incorrect interpretation resulted in AGCS missing the compliance deadline specified in the implementation plan.

WECC determined that the issues began on July 1, 2016, when AGCS failed to change its generating unit’s inverter settings and ended on July 25, 2017, when AGCS changed the inverters to not trip within the "no trip zone," for a total of 390 days of noncompliance.

**Risk Assessment**

WECC determined that these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip zone," as required by PRC-024-2 R1. Such failure could potentially result in the premature tripping of the generating Facility due to voltage excursions within the "no trip zone." AGCS owns and operates 242 MVA solar generating Facility that was applicable to this issue. Its previous setting for under-frequency would have operated between 57 - 59.3 Hz for 0.16 seconds before tripping within the "no trip zone." If the Facility had experienced a voltage excursion, its previous setting for under-voltage would have operated at 0.5 pu voltage for 0.16 seconds before tripping within the "no trip zone." Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor.

AGCS implemented weak preventative controls to prevent the above issue from occurring. Specifically, AGCSs parent corporation provided compliance support to AGCS through its corporate regulatory compliance program that contributed to this issue. However, the 242 MVA is an intermittent resource and there was no substation frequency and voltage ride through trips equipped at this Facility. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred. WECC determined that AGCS has no relevant compliance history for this noncompliance.

**Mitigation**

AGCS completed mitigating activities to address its issues with the Standards and WECC verified AGCSs mitigating activities.

To remediate and mitigate these issues, AGCS:
- completed analysis for frequency and voltage trips for the Facility and adjusted the inverter settings as required by the Standard; and
- instituted an internal quarterly control measures form to identify any changes in its frequency and voltage settings to ensure compliance with the Standard. This form states that the plant personnel are required to document proposed inverter frequency and voltage setting changes and notify the engineering group prior to making any changes. The plant personnel must select an appropriate statement from a list of scenarios including whether or not changes have been made to the inverter frequency and voltage settings and whether they were communicated to the engineering and consultants to verify compliance.
**Description of the Violation**

On June 29, 2018, AGCS submitted a Self-Report stating that, as a Generator Operator, it was in violation with PRC-024-2 R2.

Specifically, AGCS reported that it did not set the protective relaying settings correctly on its solar generating Facility per the requirements of PRC-024-2 R2, Attachments 2 by July 1, 2016. AGCS’s parent corporation, reported that it implemented a plan in 2015 that included its entire fleet of generating Facilities within the Western Interconnection for a single compliance approach. However, in March 2017, AGCS’s parent corporation changed this incorrect approach based upon NERC guidance to demonstrate compliance with the Standard on a Registered Entity basis rather than its entire fleet of generating Facilities. As a result of this guidance, AGCS then completed the required analyses and required adjustments of its inverter frequency and voltage trip settings for its applicable Facility; one solar generating unit which generates 320 MWA, on July 25, 2017.

After reviewing all relevant information, WECC determined that AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the “no trip one,” as required by PRC-024-2 R2, Attachments 2.

The root cause of these issues was due to the incorrect interpretation of the implementation of PRC-024-2 R2, by AGCS and by its parent company. Specifically, that the implementation plan applied to the entire fleet of solar generating Facilities owned by AGCS’s parent company, instead of the implementation plan applying to individual entities that AGCS’s parent company owned separately. This incorrect interpretation resulted in AGCS missing the compliance deadline specified in the implementation plan.

WECC determined that the issues began on July 1, 2016, when AGCS failed to change its generating unit’s inverter settings and ended on July 25, 2017, when AGCS changed the inverters to not trip within the “no trip zone,” for a total of 390 days of noncompliance.

**Risk Assessment**

WECC determined that these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the “no trip one,” as required by PRC-024-2 R2. Such failure could potentially result in the premature tripping of the generating Facility due to voltage excursions within the “no trip zone.” AGCS owns and operates 242 MVA solar generating Facility that was applicable to this issue. Its previous setting for under-frequency would have operated between 57 - 59.3 Hz for 0.16 seconds before tripping within the “no trip zone.” If the Facility had experienced a voltage excursion, its previous setting for under-voltage would have operated at 0.5 pu voltage for 0.16 seconds before tripping within the “no trip zone.” Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor.

AGCS implemented weak preventative controls to prevent the above issue from occurring. Specifically, AGCS’s parent corporation provided compliance support to AGCS through its corporate regulatory compliance program that contributed to this issue. However, the 242 MVA is an intermittent resource and there was no substation frequency and voltage ride through trips equipped at this Facility. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred. WECC determined that AGCS has no relevant compliance history for this noncompliance.

**Mitigation**

AGCS completed mitigating activities to address its issues with the Standards and WECC verified AGCS’s mitigating activities.

To remediate and mitigate these issues, AGCS:

a. completed analysis for frequency and voltage trips for the Facility and adjusted the inverter settings as required by the Standard; and
b. instituted an internal quarterly control measures form to identify any changes in its frequency and voltage settings to ensure compliance with the Standard. This form states that the plant personnel are required to document proposed inverter frequency and voltage setting changes and notify the engineering group prior to making any changes. The plant personnel must select an appropriate statement from a list of scenarios including whether or not changes have been made to the inverter frequency and voltage settings and whether they were communicated to the engineering and consultants to verify compliance.
### Risk Assessment

**WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS).** In these instances, PSE failed to provide data and information, as specified, to its RC, as required by IRO-010-1a R3, to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area. Such failure could cause the RC to use inaccurate generating capacities in the development of its Operating Plan. Inaccurate capabilities in the Operating Plan may affect real-time or contingent conditions leading to unexpected load shedding and delayed system restoration after an event. PSE owns and/or operates 3711 MW of generation that was applicable to this issue. However, the RC had indicated that the four data items were used primarily for forecasting studies and not daily operations studies. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor.

Additionally, PSE is a member of a reserves sharing group which made additional generation available if PSE was unable to meet the generation requirements of the Operating Plan. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred.

### Mitigation

To mitigate this issue, PSE:

a. permanently changed the MCG calculation methodology to report on calendar days and not business days. The spreadsheet shows that the schedule for submitting the generation forecast was changed from the current day plus four to the current day plus seven. This modification corrected a logic error in the MCG's methodology for populating unit commitment schedules so that it would provide seven full calendar days of data; and

b. Establish process to update the Pmax and Pmin values manually in MCG when generation availability changes. The document indicates that the entity established a daily calendar reminder to have the outage coordination personnel in its load office update the minimum and maximum values manually in the application when there is a generation availability change. Page 2 of the document demonstrates that a report is pulled from RC's coordinated outage system to determine if any new outages are scheduled to occur or if any unscheduled generation outages happened as indicated from the COS. This information is then entered into the MCG application which is submitted directly to the RC.

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<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Entity Name</th>
<th>NCR ID</th>
<th>Violation Start Date</th>
<th>Violation End Date</th>
<th>Method of Discovery</th>
<th>Future Expected Mitigation Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>WECC2017017040</td>
<td>IRO-010-1a</td>
<td>R3</td>
<td>Puget Sound Energy, Inc.</td>
<td>NCR05344</td>
<td>4/1/2016</td>
<td>1/24/2017</td>
<td>Self-Report</td>
<td>Completed</td>
</tr>
</tbody>
</table>

**Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)**

PSE discovered February 16, 2017 that it inadvertently supplied inaccurate or incomplete information in response to an ongoing data request from its Reliability Coordinator (RC). PSE’s four data items that were not accurately and completely provided to the RC were:

a. PSE’s hourly Unit Commitment for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities. This information is required to be submitted daily; by 10 a.m. Pacific Prevailing Time, for the current day through the next four business days;

b. PSE’s hourly Unit Commitment for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities 10 minutes prior to the hour, every hour, plus the next four hours;

c. PSE’s Hourly Operational Minimum MW for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities. This information is required to be submitted daily; by 10 a.m. Pacific Prevailing Time, for the current day through the next four business days; and

d. PSE’s Hourly Operational Minimum MW for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities 10 minutes prior to the hour, every hour, plus the next four hours.

When the data request was issued, PSE staff created the reporting formulas in the MCG Energy Solutions software (MCG), which reports the data to the RC. However, the data that was generated by MCG was not verified to be accurate prior to sending the information to the RC. Specifically, when MCG made its calculation, it was using business days instead of calendar days, causing the transmitted data to be inaccurate. Additionally, MCG was reporting inaccurate data due to Pmax and Pmin values being calculated inaccurately during outages.

The root cause of the issue was PSE’s lack of internal controls. Specifically, PSE did not verify the calculations and resulting data generated in its MCG for accuracy prior to starting the automated data transmission.

WECC determined that this issue began on April 1, 2016, when the first inaccurate dataset was sent to the RC and ended on January 24, 2017, when PSE provided complete and accurate data to the RC for a total of 298 days of noncompliance.
On March 27, 2017, WALC submitted a Self-Report stating that, as a Balancing Authority (BA), it was in noncompliance with BAL-001-2 R2.

On September 6, 2016, the WALC SCADA system was failing to update its information between it and the Bureau of Reclamation (Bureau), which is essential for generation control of 1539 MW from the Hoover power plant. The WALC System Operator called the Hoover Operator inquiring about the values they were seeing and the Hoover control status confirmed WALC’s data was not updating. The WALC System Operator requested the Hoover Operator switch their communication channel from “A” to “B”, then back to “A” again, to which he observed no resolution. The WALC System Operator then called SCADA Support who suggested that the WALC System Operator log into the ECC Server to check for better visibility, however, the ECC server was not updating either. In the interim, the WALC System Operator called the Hoover Operator to verify generation output levels, on-line capacity, and control status. SCADA support then rebooted the servers and the Data Link appeared to be restored. The WALC System Operator verified with the Hoover Operator that the plant was receiving data and generating to the correct value, but the Data Link data remained non-updating. In the interim, WALC’s SCADA Support rebooted the WALC servers again and successfully restored the Data Link. The WALC System Operator observed WAPA data updating again and called the Hoover Operator to validate the generation data. Finally, the WALC Operator logged the BAAL exceedance of 39 minutes and reported the exceedance and the Data Link status to the Desk Supervisor (Start BAAL exceedance minute count at 21:02; End BAAL exceedance minute count at 21:40 (39 minutes)).

The root cause of the issue was WALC’s System Operator failed to follow the established procedure by taking manual control of the communication system when the Data Link failed to transmit accurate data between WALC and the Bureau.

This issue began on September 6, 2016, when WALC’s clock minute average of reporting ACE exceeded the clock-minute Balancing Authority ACE Limit for the 31st minute and ended on September 6, 2016, when its Data Link servers were rebooted, for a total of 9 minutes of noncompliance.

This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WALC failed to operate such that its clock-minute average of reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit for more than 30 consecutive clock-minutes calculated in accordance with Attachment 2, as required by BAL-001-2 R2. Such failure could have caused an interconnection frequency excursion outside of defined limits. WALC balances 3066 MW of generation, of which, 1539 MW were applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate.

However, WALC was still able to monitor the interconnection from its Reliability Messaging Tool to verify that there was no loss of generation, load or transmission. The generator was aware of the situation, still receiving data and was able to monitor in real-time. Lastly, if the frequency excursions had been detected, WALC would likely have corrected the condition as the entity has implemented strong corrective controls. WALC is part of a reserve sharing group that could have provided more generation if necessary. Based on this, WECC determined that there was a low likelihood of causing intermediate harm to the BPS. No harm is known to have occurred.

To mitigate this issue, WALC:

a. Returned to operate such that the BAAL limit does not exceed 30 minutes;

b. Notified and trained System Operators of the existing procedure to be followed for Data Link failures.