RFC2018020359  MOD-025-2  R1  
American Municipal Power Inc.  NCR00683  7/1/2016  8/22/2018  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 August 30, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1.

Prior to July 1, 2016, entity personnel tested the reactive and real power output of its Bulk Electric System (BES) facilities. Entity personnel, however, misread the Standard and only tested the Facilities for maximum load. The entity also did not document that it provided its test data to its Transmission Planner for its generation facilities. Therefore, the entity did not have 40% of its generation units tested on or before July 1, 2016 or 60% of its generation units tested on or before July 1, 2017 as required by the implementation schedule for MOD-025-2. The entity discovered these issues while performing an internal review to assure that 80% of its generation facilities had been tested prior to July 1, 2018.

After discovering these issues, the entity engaged in an expedited effort to ensure that it had tested 80% of its generation facilities by July 1, 2018. The entity completed testing on 13 of its 17 BES generation units (77%) by July 1, 2018. The entity completed testing on 16 of its 17 BES generation units (94%) as of August 22, 2018.

This noncompliance involves the management practices of verification and validation. The entity did not verify that it timely and properly completed all of the necessary testing for MOD-025 and met the implementation plan. That failure to verify is a root cause 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 August 22, 2018, when the entity completed testing on 16 of its 17 BES generation units, thereby meeting the 80% requirement.

Risk Assessment

This noncompliance posed a moderate 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 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 not minimal because of the long (approximately 28 month) duration. The risk is lessened because 14 of the entity’s 17 units are less than ten years old. The relative newness of these generating units means that there has been minimal degradation and wear resulting in performance levels at (or very close to) the capability curves determined at the time of commissioning. Another risk mitigating factor is that 15 of the 17 entity generating units are run-of-the-river hydro generators that operate within the limits of their variable resource. Therefore, those hydro units would be able to operate at the maximum real-power output of the unit only under the most ideal of circumstances. 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:

1) scheduled and completed, real and reactive testing at more than 80% of its generators and reported the results of the testing to the applicable Transmission Planners. This action brought the entity back into compliance with the implementation schedule for MOD-025-2; and
2) scheduled recurring maintenance activities for its generators in its MAXIMO system. To assure that future testing occurs, the entity added a reminder in its MAXIMO system for each BES generation unit (except Hamilton JV2 Gas Turbine) to complete MOD-025-2 testing. The reminders are set to alert the operators one year prior to the end of the five-year cycle mandated by MOD-025-2. For Hamilton JV2 Gas Turbine, a peaking unit that does not use the MAXIMO system, the entity added a calendar reminder to the plant operator’s calendar as well as the calendars of the entity’s Generation Operations’ Electrical Engineer and the entity’s Director of Reliability Standards Compliance.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</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>
<tbody>
<tr>
<td>RFC2018020360</td>
<td>MOD-025-2 R2</td>
<td>American Municipal Power Inc.</td>
<td>NCR00683</td>
<td>7/1/2016</td>
<td>8/22/2018</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 noncompliance.)**

On August 30, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2.

Prior to July 1, 2016, entity personnel tested the reactive and real power output of its Bulk Electric System (BES) facilities. Entity personnel, however, misread the Standard and only tested the Facilities for maximum load. The entity also did not document that it provided its test data to its Transmission Planner for its generation facilities. Therefore, the entity did not have 40% of its generation units tested on or before July 1, 2016 or 60% of its generation units tested on or before July 1, 2017 as required by the implementation schedule for MOD-025-2. The entity discovered these issues while performing an internal review to assure that 80% of its generation facilities had been tested prior to July 1, 2018.

After discovering these issues, the entity engaged in an expedited effort to ensure that it had tested 80% of its generation facilities by July 1, 2018. The entity completed testing on 13 of its 17 BES generation units (77%) by July 1, 2018. The entity completed testing on 16 of its 17 BES generation units (94%) as of August 22, 2018.

This noncompliance involves the management practices of verification and validation. The entity did not verify that it timely and properly completed all of the necessary testing for MOD-025 and met the implementation plan. That failure to verify is a root cause 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 August 22, 2018, when the entity completed testing on 16 of its 17 BES generation units thereby meeting the 80% requirement.

**Risk Assessment**

This noncompliance posed a moderate 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 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 not minimal because of the long (approximately 28 month) duration. The risk is lessened because 14 of the entity’s 17 units are less than ten years old. The relative newness of these generating units means that there has been minimal degradation and wear resulting in performance levels at (or very close to) the capability curves determined at the time of commissioning. Another risk mitigating factor is that 15 of the 17 entity generating units are run-of-the-river hydro generators that operate within the limits of their variable resource. Therefore, those hydro units would be able to operate at the maximum real-power output of the unit only under the most ideal of circumstances. 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:

1) scheduled and completed, real and reactive testing at more than 80% of its generators and reported the results of the testing to the applicable Transmission Planners. This action brought the entity back into compliance with the implementation schedule for MOD-025-2; and

2) scheduled recurring maintenance activities for its generators in its MAXIMO system. To assure that future testing occurs, the entity added a reminder in its MAXIMO system for each BES generation unit (except Hamilton JV2 Gas Turbine) to complete MOD-025-2 testing. The reminders are set to alert the operators one year prior to the end of the five-year cycle mandated by MOD-025-2. For Hamilton JV2 Gas Turbine, a peaking unit that does not use the MAXIMO system, the entity added a calendar reminder to the plant operator’s calendar as well as the calendars of the entity’s Generation Operations’ Electrical Engineer and the entity’s Director of Reliability Standards Compliance.

ReliabilityFirst has verified the completion of all mitigation activity.
**NERC Violation ID**: RFC2018020648  
**Reliability Standard**: VAR-002-4  
**Req.**: R2  
**Entity Name**: Invenergy Nelson LLC  
**NCR ID**: NCR11513  
**Noncompliance Start Date**: 8/18/2015  
**Noncompliance End Date**: 4/10/2017  
**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 November 2, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4 R2. Following an audit notification, the entity reviewed voltage activity for the requested sample dates and found no instances where it did not maintain the relevant schedule. However, the entity later conducted a broader review of its entire voltage history and identified 53 instances in which it did not maintain the relevant voltage schedule and failed to properly notify the Transmission Operator or receive an exemption.

More specifically, on August 18, 2015, the entity experienced two voltage deviations that lasted approximately 36 and 38 minutes, respectively. The voltage deviations were less than 1% below the scheduled minimum. Then, throughout 2016, the entity experienced 27 voltage deviations, which lasted approximately between 31 and 232 minutes. The maximum deviation was less than 2% below the scheduled minimum. Also, between January and April 2017, the entity experienced 22 voltage deviations, which lasted approximately between 33 and 177 minutes. The maximum deviation was less than 2% below the scheduled minimum.

The root cause of this noncompliance was the entity's failure to have adequate internal controls in place to quickly detect and correct deviations. Furthermore, the entity's insufficient training of its generation unit operators with respect to notification requirements contributed to the number of occurrences. This root cause involves the management practices of reliability quality management, which includes maintaining a system for deploying internal controls, and workforce management, which includes providing training, education, and awareness to employees.

This noncompliance occurred multiple times over the course of approximately 20 months, from August 18, 2015, when the entity experienced its first voltage deviation, and April 10, 2017, when the entity experienced its last voltage deviation.

**Risk Assessment**

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance was that the entity not adhering to its voltage schedule increased the likelihood that the entity would be unable to respond to changes in voltage caused by reactive power demands and fail to provide voltage support to the BPS. The risk is not minimal in this case based on the number of occurrences (i.e., 53) and the long duration of the noncompliance (i.e., approximately 20 months).

The risk is not serious or substantial in this case based on the following factors. First, the deviations were within a narrow band, between 98.43% of the scheduled voltage at the lower end and 100.65% of the scheduled voltage at the higher end. Second, the average duration of each deviation was approximately one hour, and none exceeded four hours. 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:

1. held internal gap analysis discussions, which identified voltage management as an area of improvement; and
2. implemented improved real-time monitoring practices and system controls: An updated graphic display which shows a rolling 30-minute trend for voltage and reactive power, located on the central control screen, audio and visual alarms, and end of day shift turnover reports.

ReliabilityFirst has verified the completion of all mitigation activity.
On January 12, 2018, the RDW submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with IRO-001-4 R2. At the time of the noncompliance, RDW was part of an MRRE Group monitored under the Coordinated Oversight Program that included Osage Wind, LLC (NCR11534) that was registered in the SERC Reliability Corporation (SERC) Region, Smoky Hills Wind Farm, LLC (NCR11049), Caney River Wind Project, LLC (NCR11230), Rocky Ridge Wind Project, LLC (NCR11234), Chisholm View Wind Project, LLC (NCR11291), Buffalo Dunes Wind Project, LLC (NCR11407), Origin Wind Energy, LLC (NCR11496), Goodwell Wind Project, LLC (NCR11574), Prairie Rose Wind Project, LLC (NCR11293), Cimarron Bend Wind Project, LLC (NCR11693), Drift Sand Wind Project LLC (NCR11670), Lindahl Wind Project, LLC (NCR11699), Rock Creek Wind Project, LLC (NCR11762), Thunder Ranch Wind Project, LLC (NCR11778), and Smoky Hills Wind Project II, LLC (NCR10316) that were located in MRO’s Region. After the noncompliance, the aforementioned entities transferred their assets to Smoky Hills Wind Project II, LLC who changed its name to CHI Power, Inc.; CHI Power, Inc. is registered under the same NCR ID in the ReliabilityFirst (RF), SERC, and MRO Regions and is currently monitored under the Coordinated Oversight Program.

On December 7, 2017, RDW's Reliability Coordinator (RC) determined that if the Woodring - Sooner 345 kV line were lost, there could be loading above the emergency rating of a 345/138 kV transformer at the Woodring substation. To mitigate against a post-contingent over loading of the transformer, the RC issued an Operating Instruction to RDW at 2:38 a.m. to limit its generation output to 75 MW. RDW implemented the order by pausing individual turbines. A few minutes later, there was an increase in local wind speeds and RDW’s generation rose, reaching 89.2 MW within five minutes of the implementation of the Operating Instruction. At 05:49 a.m., the RC called and again requested that generation be limited to 75 MW, RDW implemented the Operating Instruction by pausing additional turbines, however due to fluctuating wind speeds, it was not able to keep the output at or below 75 MW. At 7:02 a.m., RDW's vendor called and requested authorization to run tests and RDW granted that request. The vendor raised the generation set point to 300 MW and generation rose to 238 MW by 7:02 a.m. At 7:02 a.m., the RC called RDW and again instructed RDW to comply with the existing Operating Instruction that generation be limited to 75 MW. RDW agreed and reduced the output to under 75 MW by 7:12 a.m.

The cause of the noncompliance is that RDW did not have sufficient controls in place to ensure that its operators could understand and implement Operating Instructions; in this case, there was confusion about implementing an Operating Instruction while the Facility was in commissioning.

This noncompliance started on December 9, 2017, when RDW produced generation in excess of the Operating Instruction, and ended later that day when RDW brought its generation below the maximum allowed by the Operating Instruction.

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The noncompliance was not minimal because RDW’s Control Center controls over 1,000 MVA of nameplate generation. This means that the potential risk of failing to properly respond to an Operating Instructions is not limited to the RDW Facility as the Control Center has the potential to impact the wider BPS. However, the noncompliance was not serious or substantial because the noncompliance did not impact an Interconnection Reliability Operating Limit (IROL). Further, despite RDW’s noncompliance, based on the observed post-contingent loading while the Operating Instruction was in effect, if the 345 kV line had been lost, the transformer would have only exceeded its emergency rating between 6:00 a.m. and 6:10 a.m. Finally, if conditions had warranted, RDW’s RC or Transmission Operator could have removed RDW’s generation from service without significant adverse effects to the BPS. No harm is known to have occurred.

MRO reviewed the compliance history for RDW and all entities that were included in the MRRE Group; the entities have no relevant history of noncompliance.

To mitigate this noncompliance, RDW:

1) complied with the Operating Instruction;
2) reviewed the coordination process for commissioning tests;
3) updated operator procedures including the distribution of a memo prohibiting new site testing while an Operating Instruction is in effect; and
4) retrained control room operators.

A Mitigation Plan for this noncompliance was verified complete on May 25, 2018.
TRE2018020762  
**PRC-024-2**  
R1  
Consolidated Edison Development, Inc. (CED)  
NCR11605  
07/01/2016  
05/03/2019  
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 violation.)

On November 29, 2018, Consolidated Edison Development, Inc. (CED) submitted a Self-Report stating that, as a Generator Owner (GO), it was in no compliance with PRC-024-2 R1. In particular, CED failed to set its frequency protective relays to not trip within the “no trip zone” of PRC-024-2, Attachment 1, for its Alamo 5 and Alamo 7 solar generating Facilities by July 1, 2016.

On June 7, 2016, through consultation with the Original Equipment Manufacturer (OEM), CED discovered that frequency relays at Alamo 5 and Alamo 7 were set to comply with ERCOT Nodal Operating Guide voltage and frequency ride-through requirements, and not with PRC-024-2. CED continued to work with the OEM to determine the precise relay settings at each Facility, but was unable to complete a full review until August 7, 2018. CED was unable to independently verify the relay settings at its Facilities because the OEM relies on a proprietary tool to review and update relay settings. On October 1, 2018, CED developed a baseline settings list and began working with the OEM to update the relay settings at Alamo 5 and Alamo 7. On November 29, 2018, CED Self-Reported the noncompliance. A Compliance Audit, in which PRC-024-2 was in-scope, was conducted by Texas RE March 18, 2019, through March 22, 2019. CED’s Facilities became compliant with PRC-024-2 on May 3, 2019.

The root cause of this noncompliance was that CED failed to establish adequate controls around relay changes made by internal personnel and third-party vendors that impact plant control systems. This noncompliance started on July 1, 2016, when PRC-024-2 became mandatory and enforceable and ended on May 3, 2019, when CED updated relay settings at Alamo 5 and Alamo 7 so they did not trip within the “no trip zone.”

**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 for the following reasons. During the period of the noncompliance with PRC-024-2, Alamo 5 and Alamo 7’s relays were in compliance with ERCOT Nodal Operating Guide frequency ride-through requirements. While not identical to PRC-024-2, this partially mitigated the potential for frequency related trips. Additionally, Alamo 5 and Alamo 7 are intermittent solar photovoltaic facilities, which are online far fewer hours than conventional generation. Frequency trips at these Facilities at night would have zero impact to the bulk power system, and frequency trips during suboptimal production would have minimal impact. Although the maximum peak output of the generating facilities are over 75 MVA, over the past year, the average hourly generation output has been 23.8 MW at Alamo 5 and 29.2 MW at Alamo 7. No harm is known to have occurred.

Texas RE considered CED’s and its affiliates’ PRC-024-2 compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance, CED:

1) implemented relay settings that are compliant with PRC-024; and
2) implemented a Change Management Process to establish controls around any changes made by internal personnel and third party vendors that impact plant control systems. All changes that impact facility control systems must be reviewed and approved by CED’s Engineering and Operations, and Maintenance staff in accordance with the Change Management Process prior to implementation of any proposed modifications.

Texas RE 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>
</tr>
</thead>
<tbody>
<tr>
<td>TRE2019021481</td>
<td>PRC-024-2 R2</td>
<td></td>
<td>Consolidated Edison Development, Inc. (CED)</td>
<td>NCR11605</td>
<td>07/01/2016</td>
<td>05/03/2019</td>
<td>Compliance Audit</td>
<td>Completed</td>
</tr>
</tbody>
</table>

**Description of the Noncompliance**

During a Compliance Audit conducted from March 18, 2019 through March 22, 2019, Texas RE determined that Consolidated Edison Development, Inc. (CED), as a Generator Owner (GO), was in noncompliance with PRC-024-2 R2. In particular, CED failed to set its voltage protective relays to not trip within the "no trip zone" of PRC-024-2, Attachment 2, for its Alamo 5 and Alamo 7 solar generating Facilities by July 1, 2016.

On June 7, 2016, through consultation with the Original Equipment Manufacturer (OEM), CED discovered that voltage relays at Alamo 5 and Alamo 7 were set to comply with ERCOT Nodal Operating Guide voltage and frequency ride-through requirements, and not with PRC-024-2. CED continued to work with the OEM to determine the precise relay settings at each Facility, but was unable to complete a full review until August 7, 2018. CED was unable to independently verify the relay settings at its Facilities because the OEM relies on a proprietary tool to review and update relay settings. On October 1, 2018, CED worked with the OEM and was able to develop a baseline settings list. During the Compliance Audit the audit team reviewed the baseline settings list and the noncompliance was confirmed. CED began working with the OEM to update the relay settings at Alamo 5 and Alamo 7 and its Facilities became compliant with PRC-024-2 on May 3, 2019.

The root cause of this noncompliance was that CED failed to establish adequate controls around relay changes made by internal personnel and third-party vendors that impact plant control systems. This noncompliance started on July 1, 2016, when PRC-024-2 became mandatory and enforceable and ended on May 3, 2019, when CED updated relay settings at Alamo 5 and Alamo 7 so they did not trip within the "no trip zone."

**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 for the following reasons. During the period of the noncompliance with PRC-024-2, Alamo 5 and Alamo 7's relays were in compliance with ERCOT Nodal Operating Guide voltage ride-through requirements. While not identical to PRC-024-2, this partially mitigated the potential for voltage related trips. Additionally, Alamo 5 and Alamo 7 are intermittent solar photovoltaic facilities, which are online far fewer hours than conventional generation. Voltage trips at these Facilities at night would have zero impact to the bulk power system, and voltage trips during suboptimal production would have minimal impact. Although the maximum peak output of the generating facilities are over 75 MVA, over the past year, the average hourly generation output has been 23.8 MW at Alamo 5 and 29.2 MW at Alamo 7. No harm is known to have occurred.

Texas RE considered CED's and its affiliates' PRC-024-2 compliance history and determined there were no relevant instances of noncompliance.

**Mitigation**

To mitigate this noncompliance, CED:

1) implemented relay settings that are compliant with PRC-024-2; and
2) implemented a Change Management Process to establish controls around any changes made by internal personnel and third party vendors that impact plant control systems. All changes that impact facility control systems must be reviewed and approved by CED's Engineering and Operations, and Maintenance staff in accordance with the Change Management Process prior to implementation of any proposed modifications.

Texas RE has verified the completion of all mitigation activity.
## Description of the Noncompliance

During a Compliance Audit conducted from July 25, 2017, through August 30, 2017, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with PRC-005-1.1b R2. Specifically, the Entity failed to provide evidence that its protective relays and DC control circuitry devices were maintained and tested within the defined intervals included in its Protection System Maintenance Program (PSMP). This noncompliance continued during the time when PRC-005-6 R3 was effective. After receiving notice of the Compliance Audit, the Entity identified this issue during an internal review following a change in compliance personnel.

The Entity's PSMP identified a time-based maintenance program for the Entity's protective relay and DC control circuitry devices, with maintenance activities due every 90 months. Maintenance activities were performed for the devices at issue during July 28, 2008, through August 7, 2008. Therefore, the next interval of maintenance activities should have been performed by January 28, 2016, through February 7, 2016. The failure to timely perform maintenance and testing for these devices also caused the Entity to fail to meet the April 1, 2017, milestone for compliance with the implementation plan for PRC-005-6 R3. Thus, this issue resulted in noncompliance regarding both PRC-005-1.1b R2 and PRC-005-6 R3.

The root cause of this issue is that the Entity did not have a sufficient process for compliance with PRC-005-1.1b and PRC-005-6. The Entity stated that it did not devote sufficient resources and personnel to compliance activities regarding PRC-005-1.1b and PRC-005-6. To address this root cause, the Entity revised its PSMP and devoted additional resources to its compliance program.

This noncompliance started on January 29, 2016, when the Entity failed to timely perform the maintenance activities for its protective relays and DC control circuitry devices required by its PSMP, and ended on October 24, 2017, the Entity performed maintenance activities with six-year maximum intervals for the devices at issue pursuant to PRC-005-6 Table 1-1 and Table 1-5.

## 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 risk posed by this issue is that the Entity would not be aware that a Protection System device was not functioning as intended. In addition, the duration of the issue was approximately 21 months, from January 29, 2016, to October 24, 2017.

However, the risk to the reliability of the BPS was reduced by the following factors. First, the Entity's generating facility is relatively small, comprising a single wind generator site with a nameplate rating of 185 MVA. Second, the issue involved only 15 protective relays and 14 DC control circuitry devices, which represents approximately 42% of the 69 devices included in the Entity's PSMP. Third, the Entity did not identify any devices that had failed when it performed the required maintenance activities. Finally, no trips or Misoperations were identified as resulting from the issues identified during the Compliance Audit. No harm is known to have occurred.

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

## Mitigation

To mitigate this noncompliance, the Entity:

1. performed the required maintenance activities for the devices at issue;
2. conducted training for the Entity's employees, including an overview of applicable Reliability Standards;
3. added personnel and consulting services to improve its compliance program; and
4. created an automatic reminder for the next interval of maintenance activities with six-year maximum maintenance intervals for the devices at issue.

Texas RE 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 violation.)

During a Compliance Audit conducted from September 26, 2016 through October 7, 2016, WECC determined that GRMA, as a Balancing Authority (BA), it was in potential noncompliance with EOP-008-1 R1.

Specifically, prior to the registration of GRID to perform the BA functions for GRMA, GRID was already contractually performing the BA functions and the Operating Plan was designed, documented and implemented by GRID on behalf of its clients. WECC found several issues with the Operating Plan GRMA utilized;

a. it defined the backup functionality as being provided by remotely accessing the BA functionality from specified hotel lobbies and using laptops instead of transferring operations to a specific backup facility. GRMA incorporated an incorrect definition of facility, citing the use of laptops in a hotel lobby as implementing backup functionality in addition to an "alternate" Control Center, which did not meet the criteria of backup functionality provided by FERC's directives in Order 693 (R1.1);

b. it listed laptop batteries as the backup power supply to the hotel building power for use from the hotel lobbies (R1.2.4);

c. it did not include physical or cyber security in the hotel lobbies (R1.2.5);

d. it did not include a transition period between the loss of primary control center functionality and the time to transition to the alternate control center in Austin, Texas which was used for low probability high impact events, such as hurricanes requiring evacuation of Houston, Texas. Specifically, the primary Control Center and the alternate Control Center were two and a half hours away from each other by car resulting in a period over the two-hour limit (R1.5);

e. for these reasons, GRMA did not include actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality because GRMA assumed that its operators would be able to gain full operational functionality in under two hours from the hotel lobbies whenever required (R1.6.2).

After reviewing all relevant information, WECC determined that WECC determined that GRMA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. There was a corresponding EOP-008-1 R1 violation for GRID, NERC Violation ID, WECC2016016377.

The root cause of the noncompliance was the incorrect assumptions regarding the criteria for its Operating Plan and not considering the specific sub-requirements of EOP-008-1 R1 nor FERC's directives when it designed and created its Operating Plan.

WECC determined that this issue began on July 1, 2013, when the Standard became mandatory and enforceable and ended on November 23, 2013, when GRID registered to perform BA functions on behalf of GRMA, for a total of 146 days noncompliance.

Risk Assessment

WECC determined that this issue posed a moderate risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, GRMA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. Such failure could result in GRMA not having the system functionality, power sources, nor physical and cyber security controls for backup functionality in place within the required transition period, which could result in a delay or failure in performing its BA obligations and a negative impact the BPS. In addition, personnel tasked with transferring functions to the backup or alternate control center may not understand the time requirement, prolonging the risk of a loss of generation or load. GRMA was responsible for 1,458 MW that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate.

GRMA did not have effective internal controls to detect or prevent this issue. However, as compensation, the Operating Plan was used successfully for backup Control Center functionality on December 14, 2012, due to a bomb threat. In addition, the Operating Plan was used successfully during hurricane evacuation conditions and for routine training and testing of remote functionality verifying all functions could be performed using remote access functionality from 2012 to 2013. Based on this, WECC determined that there was a moderate likelihood of causing intermediate harm to the BPS. No harm is known to have occurred.
<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>
<tbody>
<tr>
<td>WECC2016016576</td>
<td>EOP-008-1</td>
<td>R1</td>
<td>CXA Sundevil Holdco, Inc. (GRMA)</td>
<td>NCR05169</td>
<td>7/1/2013</td>
<td>11/23/2013</td>
<td>Compliance Audit</td>
<td>Completed</td>
</tr>
</tbody>
</table>

**Mitigation**

To mitigate this issue, GRMA:

a. GRID registered to perform the BA functions on behalf of GRMA;
b. engaged a real estate firm to assist with identification of a space that will be managed by the primary BA that is accessible in approximately 90 minutes or less;
c. visited spaces that have been identified by the real estate firm as potential facilities;
d. modified the Operating Plan to include a summary of the risk assessment for power supply needs during a loss of primary control center condition;
e. negotiated the lease and build out requirements;
f. established the new EOP-008 Operating Plan that is inclusive of the primary BA managed designated facility;
g. established new Operating Plan inclusive of the primary BA managed facility; and
h. built out the leased space to meet requirements for backup functionality established in the EOP-008 risk based assessment.

On January 30, 2018, GRMA submitted a Mitigation Plan Completion Certification and on March 7, 2018, WECC verified GRMA's completion of Mitigation Plan.

Upon undertaking the actions outlined in the Mitigation Plan, GRMA took voluntary corrective action to remediate this issue. WECC notes that GRMA does not have any relevant previous violations of this or similar Standards and Requirements. WECC considered these factors in its designation of this remediated issue as an FFT.
### 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 August 6, 2018, ERCOT ISO submitted a Self-Report to Texas RE stating that, as a Reliability Coordinator (RC), it was in noncompliance IRO-008-2 R4. Specifically, ERCOT ISO failed to ensure that a Real-Time Assessment (RTA) was performed at least once every 30 minutes in one instance on June 29, 2018. ERCOT ISO’s process to perform RTAs includes the use of a State Estimator, which creates a save case describing present conditions, and a Real-Time Contingency Analysis (RTCA), which evaluates the save case under various contingencies. On June 29, 2018, ERCOT ISO’s Real-Time Contingency Analysis (RTCA) failed to execute for a 43-minute period between 9:43 p.m. and 10:26 p.m., which prevented ERCOT ISO from performing an RTA during that period. As a result, ERCOT ISO exceeded the 30-minute deadline to perform an RTA pursuant to IRO-008-2 R4 by 13 minutes.

The root cause of the noncompliance was a flaw in the software used by ERCOT ISO to manually create contingencies to be used to create save cases that are evaluated by the RTCA software, as well as an insufficient process to verify a save case before it is saved for use in the RTA process. In this instance, based on the expected unavailability of certain Transmission Elements, ERCOT ISO personnel attempted to revise the save case created by the State Estimator by adding additional manual constraints evaluated by the RTCA software. However, the RTCA software failed to execute after the manual constraints were introduced, which was caused by a flaw in the software used to incorporate manual constraints in the save case. Several months prior to the noncompliance, ERCOT ISO was aware of the software defect and began work on a software update, but, during this time, ERCOT ISO did not implement sufficient controls to prevent personnel from inadvertently creating an invalid save case in the RTCA process. In particular, ERCOT ISO did not disable the ability to incorporate manual constraints until after the noncompliance occurred. In addition, ERCOT ISO has the ability to use its offline Study Contingency Analysis (STCA) process, which is intended to provide a backup to the online RTCA process, but, at that time, the most current save case to be used for the STCA process was already affected by the same software defect that prevented the RTCA software from executing. Subsequently, ERCOT ISO implemented a process to verify a save case before it can be saved for use in the RTCA or STCA processes.

During the noncompliance, ERCOT ISO’s State Estimator continued to execute, but ERCOT ISO’s Voltage Security Assessment Tool (VSAT), which calculates certain reliability limits, failed to execute, allowing ERCOT ISO to continue to perform the pre-Contingency portion of the RTA. ERCOT ISO was also able to observe any outages using the Forced Outage Detection Tool. Second, during the noncompliance, ERCOT ISO directed Transmission Operators (TOPs) to monitor their respective service areas, and no TOPs notified ERCOT ISO of any issues. Third, although VSAT failed to execute during the noncompliance, the existing voltage limits calculated by ERCOT ISO’s VSAT remained valid because no forced outages occurred that would have invalidated the previous calculated limits. ERCOT ISO continued to monitor actual flows relative to those limits. No harm is known to have occurred.

A Settlement Agreement covering IRO-002-2 R7 (TRE2016016699), IRO-003-2 R1 (TRE2016016700), IRO-003-2 R2 (TRE2016016701), IRO-005-3.1a R1 (TRE2016016702), IRO-008-2 R4 (TRE2017017719), and TOP-001-3 R13 (TRE2017017720) was filed with FERC under NP18-10-000 on April 30, 2018. On May 30, 2018, FERC issued an order stating it would not engage in further review of the Notice of Penalty.

Texas RE considered this compliance history in determining that this issue is appropriate for Find, Fix, and Track (FFT) treatment. While the instances were of the same or similar Reliability Standards and Requirements and involved a failure to timely perform an RTA, the underlying conduct of the instances was different. One prior instance was caused by a lack of detailed instructions during the system troubleshooting process to begin manually performing an RTA, and the other prior instance was the result of an insufficient process to prevent test data from being inadvertently loaded into an active production environment.

### Risk Assessment

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ERCOT ISO’s failure to perform an RTA for 13 minutes could have potentially reduced ERCOT ISO’s situational awareness. However, the risk posed by this issue was reduced by the following factors. First, during the noncompliance the State Estimator continued to execute, allowing ERCOT ISO to continue to perform the pre-Contingency portion of the RTA. ERCOT ISO was also able to observe any outages using the Forced Outage Detection Tool. Second, during the noncompliance, ERCOT ISO directed Transmission Operators (TOPs) to monitor their respective service areas, and no TOPs notified ERCOT ISO of any issues. Third, although VSAT failed to execute during the noncompliance, the existing voltage limits calculated by ERCOT ISO’s VSAT remained valid because no forced outages occurred that would have invalidated the previous calculated limits. ERCOT ISO continued to monitor actual flows relative to those limits. No harm is known to have occurred.

### Mitigation

To mitigate this noncompliance, ERCOT ISO:

1. implemented software updates to allow the creation of an RTA save case only after RTCA has successfully executed and to disable the ability to create a manual constraint for a group of generators;
2. implemented a software update to fix the software flaw that caused the RTCA execution failure; and
3. created an additional offline backup to the existing RTA process, which automatically stores offline cases and performs RTAs using the last valid State Estimator and RTCA save cases.

Texas RE has verified the completion of all mitigation activity.

### NERC Violation ID

<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>
<tbody>
<tr>
<td>TRE20180201B4</td>
<td>IRO-008-2</td>
<td>R4</td>
<td>Electric Reliability Council of Texas, Inc. (ERCOT ISO)</td>
<td>NCR04056</td>
<td>06/29/2018</td>
<td>06/29/2018</td>
<td>Self-Report</td>
<td>Completed</td>
</tr>
</tbody>
</table>

### Future Expected Mitigation Completion Date

The violation started on June 29, 2018, at 10:14 p.m., which is 31 minutes after an RTA was performed, and ended on June 29, 2018, at 10:26 p.m., when an RTA was performed.
<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>
<tbody>
<tr>
<td>TRE20180201B5</td>
<td>TOP-001-3</td>
<td>R13</td>
<td>Electric Reliability Council of Tex, Inc. (ERCOT ISO)</td>
<td>NCR00456</td>
<td>06/29/2018</td>
<td>06/29/2018</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 August 6, 2018, ERCOT ISO submitted a Self-Report to Texas RE stating that, as a Transmission Operator (TOP), it was in noncompliance TOP-001-3 R13. Specifically, ERCOT ISO failed to ensure that a Real-time Assessment (RTA) was performed at least once every 30 minutes in one instance on June 29, 2018. ERCOT ISO’s process to perform RTAs includes the use of a State Estimator, which creates a save case describing present conditions, and a Real-Time Contingency Analysis (RTCA), which evaluates the save case under various contingencies. On June 29, 2018, ERCOT ISO’s Real-Time Contingency Analysis (RTCA) failed to execute for a 43-minute period between 9:43 p.m. and 10:26 p.m., which prevented ERCOT ISO from performing an RTA during that period. As a result, ERCOT ISO exceeded the 30-minute deadline to perform an RTA pursuant to TOP-001-3 R13 by 13 minutes.

The root cause of the noncompliance was a flaw in the software used by ERCOT ISO to manually create contingencies to be used to create save cases that are evaluated by the RTCA software, as well as an insufficient process to verify a save case before it is saved for use in the RTA process. In this instance, based on the expected unavailability of certain Transmission Elements, ERCOT ISO personnel attempted to revise the save case created by the State Estimator by adding additional manual constraints evaluated by the RTCA software. However, the RTCA software failed to execute after the manual constraints were introduced, which was caused by a flaw in the software used to incorporate manual constraints in the save case. Several months prior to the noncompliance, ERCOT ISO was aware of the software defect and began work on a software update, but, during this time, ERCOT ISO did not implement sufficient controls to prevent personnel from inadvertently creating an invalid save case in the RTCA process. In particular, ERCOT ISO did not disable the ability to incorporate manual constraints until after the noncompliance occurred. In addition, ERCOT ISO has the ability to use its offline Study Contingency Analysis (STCA) process, which is intended to provide a backup to the online RTCA process, but, at that time, the most current save case to be used for the STCA process was already affected by the same software defect that prevented the RTCA software from executing. Subsequently, ERCOT ISO implemented a process to verify a save case before it can be saved for use in the RTA or STCA processes.

During the noncompliance, ERCOT ISO’s State Estimator continued to execute, but ERCOT ISO’s Voltage Security Assessment Tool (VSAT), which calculates certain reliability limits, failed to execute between 9:42 p.m. and 10:28 p.m.

The violation started on June 29, 2018, at 10:14 p.m., which is 31 minutes after an RTA was performed, and ended on June 29, 2018, at 10:26 p.m., when an RTA was performed.

**Risk Assessment**

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ERCOT ISO’s failure to perform an RTA for 13 minutes could have potentially reduced ERCOT ISO’s situational awareness. However, the risk posed by this issue was reduced by the following factors. First, during the noncompliance the State Estimator continued to execute, allowing ERCOT ISO to continue to perform the pre-Contingency portion of the RTA. ERCOT ISO was also able to observe any outages using the Forced Outage Detection Tool. Second, during the noncompliance, ERCOT ISO directed TOPs to monitor their respective service areas, and no TOPs notified ERCOT ISO of any issues. Third, although VSAT failed to execute during the noncompliance, the existing voltage limits calculated by ERCOT ISO’s VSAT remained valid because no forced outages occurred that would have invalidated the previous calculated limits. ERCOT ISO continued to monitor actual flows relative to those limits. No harm is known to have occurred.

A Settlement Agreement covering IRO-002-2 R7 (TRE2016016699), IRO-003-2 R1 (TRE2016016700), IRO-003-2 R2 (TRE2016016701), IRO-005-3.1a R1 (TRE2016016702), IRO-008-2 R4 (TRE2017017719), and TOP-001-3 R13 (TRE2017017720) was filed with FERC under NP18-10-000 on April 30, 2018. On May 30, 2018, FERC issued an order stating it would not engage in further review of the Notice of Penalty.

Texas RE considered this compliance history in determining that this issue is appropriate for Find, Fix, and Track (FFT) treatment. While the instances were of the same or similar Reliability Standards and Requirements and involved a failure to timely perform an RTA, the underlying conduct of the instances was different. One prior instance was caused by a lack of detailed instructions during the system troubleshooting process to begin manually performing an RTA, and the other prior instance was the result of an insufficient process to prevent test data from being inadvertently loaded in to an active production environment.

**Mitigation**

To mitigate this noncompliance, ERCOT ISO:

1. implemented software updates to allow the creation of an RTA save case only after RTCA has successfully executed and to disable the ability to create a manual constraint for a group of generators;
2. implemented a software update to fix the software flaw that caused the RTCA execution failure; and
3. created an additional offline backup to the existing RTA process, which automatically stores offline cases and performs RTAs using the last valid State Estimator and RTCA save cases.

Texas RE has verified the completion of all mitigation activity.
Risk Assessment

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ERCOT ISO’s failure to monitor certain Facilities to identify SOL exceedances under post-Contingency conditions for 947 contingencies for one week reduced ERCOT ISO’s situational awareness. Of the disabled contingencies, five contingencies were associated with post-Contingency SOL exceedances during the noncompliance. For these six disabled contingencies, Texas RE identified 41 instances of post-Contingency SOL exceedances that occurred during the noncompliance.

However, the risk posed by this issue was reduced by the following factors. First, during the noncompliance, the State Estimator continued to execute, allowing ERCOT ISO to monitor real-time conditions for the affected Facilities and would have been able to respond to SOL exceedances that occurred in the pre-Contingency time period. Second, the number and number of the disabled contingencies also reduced the risk posed by this issue. The number of disabled contingencies was only 947 out of approximately 7,300 total contingencies evaluated by ERCOT ISO, which is approximately 13% of the total number of contingencies. None of the disabled contingencies impacted the assessment of the voltage stability limits for the Rio Grande Valley or Houston-area Import areas. ERCOT ISO also noted that all of the disabled contingencies were single-circuit contingencies involving 69 kV or 138 kV Facilities. Finally, many of the disabled contingencies are associated with Transmission Operators (TOPs) that have the ability to perform monitoring of post-Contingency conditions for their own systems. Of the five disabled contingencies that were associated with post-Contingency SOL exceedances, four are associated with TOPs that have post-Contingency analysis capabilities, and of the total of 947 disabled contingencies, 762 are associated with TOPs that have post-Contingency analysis capabilities. Further, all associated TOPs have pre-Contingency monitoring capabilities. No harm is known to have occurred.

A Settlement Agreement covering IRO-002-2 R7 (TRE2016016699), IRO-003-2 R1 (TRE2016016700), IRO-003-2 R2 (TRE2016016701), IRO-003-3.1a R1 (TRE2016016702), IRO-008-2 R4 (TRE2017017719), and TOP-001-3 R13 (TRE2017017720) was filed with FERC under NP18-10-000 on April 30, 2018. On May 30, 2018, FERC issued an order stating it would not engage in further review of the Notice of Penalty.

Texas RE considered this compliance history in determining that this issue is appropriate for Find, Fix, and Track (FFT) treatment. While the instances were of the same or similar Reliability Standards and Requirements, the underlying conduct of the instances was different. The compliance history described above involved a failure to ensure that an RTA was timely performed, which is not an issue in this case. Further, this compliance history was caused by a lack of detailed instructions during the system troubleshooting process to begin manually performing an RTA and by an insufficient process to prevent test data from being inadvertently loaded in to an active production environment, which were also not issues in this case.

Mitigation

To mitigate this noncompliance, ERCOT ISO:

1) resumed monitoring the contingencies at issue;
2) revised the weekly model loading and review process to add notifications to ERCOT ISO personnel showing the number of disabled contingencies and to add a review of disabled contingencies to the agenda for weekly meetings;
3) revised the documented process for model-loading procedures to include verifying the number of disabled contingencies when loading new model information;
4) revised the documented process for the Advanced Network Applications group’s database-loading procedures to include verifying the number of active and inactive contingencies;
5) implemented a software update to prevent the unintentional disabling of contingencies when importing new contingency sets;
6) created an automatic notification system to alert ERCOT ISO personnel of significant changes to the number of disabled contingencies; and
7) modified the “Contingency Solution Results” display to include the total number of inactive contingencies.

Texas RE has verified the completion of all mitigation activity.
On November 2, 2018, the entity submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3 (The entity initially submitted the Self-Report under PRC-005-6 R1. After discussions with the entity, ReliabilityFirst determined that the instance of noncompliance was not a violation of PRC-005-6 R1, but, rather, was a violation of PRC-005-6 R3.)

The noncompliance occurred on the entity’s 500 kV tie line 5016, which runs from the entity’s Branchburg Switching Station to the PPL Alburtis Station. The power line carrier communication system on this line met the attributes associated with a monitored communication system described in Table 1-2. This communication system performed periodic automated testing for the presence of the channel function, and alarming for loss of function. A part of the communication system for tie line 5016 is the RFL 9785 carrier transceiver unit. A carrier check-back card had been installed into the existing RFL 9785 carrier transceiver unit to perform automatic check-back tests.

On October 23, 2017, an unsuccessful carrier check on tie line 5016 triggered a carrier check-back failure alarm. A Relay Technician was notified of the alarm and investigated the problem, but incorrectly assumed the alarm was caused by a PLC on the line that was previously retired in place and tagged as “out of service.” As a result, the Technician erroneously disconnected the alarm without further investigating the issue. The Relay Technician was unaware of the installation of the carrier check-back card on the RFL 9785, which caused the alarm.

A year later, on September 14, 2018, during the NS&C Group internal controls review of the entity's Branchburg Switching Station, an NS&C Relay Test Engineer observed that the line tie 5016 RFL 9785 carrier transceiver unit was in "Carrier Check Back Failure" alarm state, but that no alarm was posted on the panel. Following this, the entity conducted an internal investigation and determined that the relay technician admitted to making an incorrect assumption which led to the mistake (disconnecting the alarm) described above.

This noncompliance involves the management practices of workforce management, validation, and verification. The root cause of this noncompliance is the entity’s failure to verify a communication system as functional per the PRC-005-6 table 1-2 specified requirements because of ineffective training. The relay technician was not effectively trained and did not verify that his understanding of what he was required to do was correct.

This noncompliance started on October 23, 2017, when the relay technician incorrectly disconnected the alarm and ended on October 5, 2018, when the entity repaired the automatic check-back system, enabled the alarms, and returned it to service.

This noncompliance posed a moderate 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 disconnecting the alarm is undetected failure of the communication system could lead to a misoperation and loss of the 500 kV tie line. The risk is not minimal because the line operates at 500 kV and is connected to two other 500 kV lines that are part of the Eastern Reactive Transfer Interface and because of the approximately one year duration. This risk is lessened by the following factors. First, the primary and backup protection systems were fully functional throughout the noncompliance. Only the communication systems monitoring experienced an issue. This means that the systems were in place and operating to protect the BPS. Second, the blocking carrier system was fully functional and would have operated to help prevent a line trip outside the relay’s designated zone of protection. Third, the board failure would have prevented the line protection from operating to clear a fault within its designated zones and the relay protection would have functioned as designed. The line protection consists of a primary and completely redundant back-up protection scheme with breaker failure and high speed remote tripping. (During the time this equipment remained out of service, there were no misoperations on this line.) No harm is known to have occurred.

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

To mitigate this noncompliance, the entity completed the following mitigation activities:

1) performed a manual check on the communication system;
2) placed the Line 5016 Blocking Carrier System on the list of communication systems which are tested manually every three months at a maximum;
3) repaired the Line 5016 Automatic Check-back System, enabled the alarms and returned it to service;
4) placed all monitored power line carrier systems onto the list of communication systems which are tested manually every three months at a maximum, with the exception of Hope Creek Generating Station (PSEG Nuclear);
5) communicated these findings to all applicable Division personnel as lessons learned. Electric Division Managers were included in the communications;
6) provided an update to ReliabilityFirst on the status;
<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>

7) created a procedure which will allow for the Hope Creek monitored power line carrier systems to be tested every three months and will add the Hope Creek monitored power line carrier systems to the manual testing schedule of every three months (maximum); and 8) performed an Internal Assessment and Focused Compliance Review of the entire PRC-005-6 standard.
<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>

**Description of the Noncompliance**

On February 22, 2018, the entity submitted a Self-Report stating that, as a Distribution Provider and Generator Owner, it was in noncompliance with PRC-004-5(i) R6. The entity failed to implement or update a Corrective Action Plan (CAP) designed to address the cause of a misoperation. The misoperation occurred on August 31, 2017, when Unit 7 at the St. Clair Power Plant cleared from the system after synchronizing and increasing output. The misoperation was caused by a Current Transformer (CT) shorting switch that was in the wrong position.

An after action review was conducted on September 29, 2017, and the entity developed a CAP, which included tasks and corresponding deadlines. However, the entity subsequently failed to implement or update the CAP before the target completion date of December 31, 2017. The entity discovered the issue on February 9, 2018, while collecting 2017 Q4 relay data.

The root cause of this noncompliance was an inadequate process to track and verify the performance and completion of tasks identified in the CAP. This noncompliance implicates the management practice of workforce management. An entity can minimize this type of violation by implementing adequate processes, procedures, and controls.

This noncompliance started on December 31, 2017, when the entity failed to implement or update the CAP prior to its scheduled completion date and ended on February 16, 2018, when the entity updated the CAP.

**Risk Assessment**

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. If an entity fails to implement or update a CAP regarding a protection system misoperation, then there is an increased likelihood of future misoperations of a similar nature. The risk was not minimal in this case because of the size of the generating unit (605 MVA) involved in the noncompliance. And, two separate relay protection schemes were impacted (i.e., a bus differential and a generator differential). The risk was not serious or substantial because the underlying issues were only present at a single location (i.e., this was not a fleet-wide issue). Although the entity did not implement the CAP before the initial target completion date, it took steps to investigate the misoperation, identify cause(s), and develop a plan to prevent recurrence in a timely manner, thus further reducing the risk in this case. 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:

1. performed St. Clair Power Plant operator refresher training on the use and purpose of shorting switches;
2. reviewed the protective tagging restoration procedure for the St. Clair Power Plant Unit 7;
3. reviewed protective tagging for all units at the St. Clair Power Plant;
4. revised labeling on shorting switches for all units at the St. Clair Power Plant; and
5. shared the results of the event review with the rest of the fleet. In addition, to address the root cause of this noncompliance, the entity improved its process for tracking and verifying the completion of tasks identified in CAPs.

ReliabilityFirst has verified the completion of all mitigation activity.
On September 13, 2018, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-005-6 R3. The noncompliance was identified during a Compliance Audit conducted from August 9, 2018 through September 13, 2018.

Specifically, the entity failed to maintain/test the following components within required time periods: (a) unmonitored protective relays [Table 1-1]; and (b) control circuity [Table 1-5]. Pursuant to the implementation plan for PRC-005-6, thirty percent (30%) of the unmonitored protective relays should have been tested by April 1, 2017, but none were tested by that date. They were last tested in 2014 and were not scheduled to be tested again until 2020. Thirty percent (30%) of the control circuity components also should have been tested by April 1, 2017, but none were tested by that date. They were last tested in 2013 and were not scheduled to be tested again until 2025.

The root cause of this noncompliance was inadequate planning, which resulted in confusion regarding the implementation of changes relating to required maintenance and testing under PRC-005-6. This noncompliance implicates the management practice of planning, which includes the need to effectively identify and understand changing requirements and establish safeguards to avoid an unintentional adverse effect on Bulk Electric System reliability and resilience.

This noncompliance started on April 1, 2017, which was the date on or before which certain testing should have been completed, and will end on May 28, 2019, after maintenance and testing is completed and in alignment with the PRC-005-6 implementation plan.

Risk Assessment
This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. Neglecting to maintain and test protection system, automatic reclosing, and sudden pressure relaying components could lead to device malfunction, premature or undetected device failure, or misoperation. Such issues could have significant consequences related to equipment damage and power system performance (e.g., generating or system instability, unacceptable loss of load or generation, cascading, or uncontrolled system separation). The risk was not minimal because the entity was unaware of the issue until it was identified during an audit, and based upon the existing maintenance schedule, the issue likely would have persisted for multiple years. However, the risk was not serious or substantial in this case because of the following mitigating factors. First, in the unlikely event that the components failed, only two units with a total generating output of 340 MW were at risk of being lost. Second, testing was performed on the subject relays and control circuity in 2014 and 2013, respectively, and testing was scheduled to occur again in the future. Restated, the affected components were subject to an existing maintenance plan, which would have helped the entity identify any issues with the components and allowed for corrective actions to be performed. No harm is known to have occurred. In exercising its discretion to treat this issue as an FFT, ReliabilityFirst underscored to the entity the importance of staying abreast of maximum maintenance and testing intervals and new and updated standards and requirements.

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

Mitigation
To mitigate this noncompliance, the entity:
1) reviewed, and edited if required, the entity’s PRC-005 procedure;
2) conducted a review of its Protective System component attributes;
3) will complete all required testing to get the entity on track with the PRC-005-6 implementation plan, including testing sixty percent (60%) of the entity’s relays and control circuity and thirty percent (30%) of entity’s CT/PT’s, communication systems, and microprocessor relays on or before May 28, 2019; and
4) will develop a plan for completing the remainder of the testing prior to January 1, 2021. Then, the entity will continue maintenance and testing activities in accordance with the PRC-005-6 implementation plan and PRC-005-6.

Mitigation is ongoing as the entity needs additional time to complete required maintenance and testing to get on track with the PRC-005-6 implementation 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
--- | --- | --- | --- | --- | --- | --- | --- | ---

**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 20, 2018, GRU submitted a Self-Report stating that, as a Distribution Provider, Generation Owner, and Transmission Owner, it was in violation of PRC-005-6 R3. This violation started on November 24, 2017, when the Entity did not complete one (1) component of the 18-month battery maintenance activities required for one (1) Vented Lead-Acid (VLA) battery bank of twenty-four (24) banks, and ended on September 26, 2018, when all maintenance activities were complete.

During an internal review of battery maintenance records, it was discovered that the intercell/intracell testing for one (1) VLA battery bank had not been performed within the 18-month interval, as required by PRC-005-6 Table 1-4(a). The last recorded intercell/intracell test was conducted on May 23, 2016, making the next required test to be completed no later than November 23, 2017 (18 months). Prior to this discovery, the Entity had performed a complete test on September 26, 2018, or 28 months from the previous test (10 months beyond the maximum maintenance interval).

An extent of condition review was conducted verifying there were no additional occurrences.

The cause for this noncompliance was a lack of a uniform preventive maintenance (PM) schedule for the generating site batteries, which comprise eight (8) of the twenty-four (24) total PRC-005-6 batteries.

**Risk Assessment**

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

The risk is reduced because the Entity completed the monthly maintenance activities which included visual inspection of battery for cleanliness and corrosion, fluid level checks, measurement of cell specific gravities, electrolyte temperature, and terminal voltage. The Entity’s failure to take intercell/intracell readings on the battery could result in a lack of awareness of battery deterioration, which could lead to battery failure. A battery failure could result in a misoperation of a BES system device, a local service interruption, and/or loss of ability to provide peaking support of up to 72.5 MW.

Additionally, the Entity’s total generation of 630 MWs is 1.25% of the Region.

The Region determined that the Entity’s compliance history (FRCC200900166, FRCC200900174, FRCC201000402) should not serve as a basis for applying a penalty due to different facts and circumstances. No harm is known to have occurred. The instant noncompliance is a repeat of FRCC2011008750 resulting in FFT treatment; however, FRCC2011008750 should not serve as an aggravating factor in applying a penalty.

**Mitigation**

To mitigate this violation, the Entity:
1) performed extent of condition review;
2) conducted root cause analysis;
3) established common battery PM schedules for all generation batteries;
4) revised the Protection System Maintenance Program to reflect changes in generation battery PMs;
5) created training materials; and
6) trained all applicable personnel on changes.
On December 20, 2017, the entity submitted a Self-Report stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R9. On September 21, 2017, the entity’s Real-Time Assessment (RTA) did not converge for a timeframe greater than 30 minutes. (Specifically, the RTA was not converging for 8 hours and 10 minutes on September 21, 2017.) The entity examined the issue and learned that potential (post-contingency) operating conditions were the only item not being met by the entity regarding the RTAs being performed. Operators in the Transmission Operations Control Center (TOCC) were monitoring the entity transmission system during this time. However, the entity did not notify MISO or its impacted interconnected utilities. (MISO did not notify the entity of any issues resulting from the Real-Time Contingency Analysis during the period of time that the entity was having issues with its RTAs.) Furthermore, after identifying the noncompliance, ReliabilityFirst and the entity verified that MISO’s RTA and Contingency Analysis was fully functional on the date in question.

The root cause of this noncompliance was the fact that the alarms operators received for non-converging State Estimator solutions did not provide enough information to the operators to easily determine when the 30 minute threshold was reached. This major contributing factor involves the management practice of grid operations, which includes maintaining situational awareness of operations and validating operations tools.

This noncompliance started on September 21, 2017, when the entity’s operators failed to make the requisite notification to MISO and ended on January 4, 2018, when ReliabilityFirst confirmed that the entity had actually made the requisite notification to MISO.

**Risk Assessment**

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk involved in this noncompliance is a reduction in visibility of potential post-contingencies on the BPS. If these are not addressed and communicated properly, they could result in wider spread adverse impact on the BPS. This risk was mitigated in this case by the following factors. First, it was confirmed that MISO’s RTA and Contingency Analysis was fully functional and operational on the date in question. Therefore, if an issue had occurred, MISO would have been aware of it independently from the entity’s notification. Second, RTA is only one of many methods used to monitor the BPS and would not necessarily be the only indicator of a potential risk. For example, the entity’s TOCC Operators were constantly monitoring the transmission system during the time of non-convergence. Other examples include Supervisory Control and Data Acquisition displays and energy management system alarms. ReliabilityFirst also notes that both the entity and MISO observed no BPS issues during the time of non-convergence. 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:

1. created and tested the alarm functionality. The entity implemented a new alarm notification;
2. created training based on the new alarm notification; and
3. provided training to the Transmission Operations Control Center Operators.

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>
</tr>
</thead>
<tbody>
<tr>
<td>NERC Violation ID</td>
<td>Reliability Standard</td>
<td>Req.</td>
<td>Entity Name</td>
<td>NCR ID</td>
<td>Noncompliance Start Date</td>
<td>Noncompliance End Date</td>
<td>Method of Discovery</td>
<td>Future Expected Mitigation Completion Date</td>
</tr>
<tr>
<td>------------------</td>
<td>----------------------</td>
<td>------</td>
<td>-------------</td>
<td>--------</td>
<td>--------------------------</td>
<td>-----------------------</td>
<td>---------------------</td>
<td>------------------------------------------</td>
</tr>
<tr>
<td>RFC2017018693</td>
<td>VAR-002-4</td>
<td>R2</td>
<td>NRG Energy Services LLC - Morgantown (NRG Morgantown)</td>
<td>NCR11581</td>
<td>1/31/2016</td>
<td>9/7/2017</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 November 12, 2017, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4 R2. During an internal compliance review, the entity discovered several failures to notify PJM, the Transmission Operator (TOP), through First Energy (FE), when the 30 minute voltage exceeded the assigned high voltage schedule, during select dates in 2016 and 2017. In total, the entity identified a total of 87 instances of noncompliance where it failed to notify its TOP. However, the majority of the voltage exceedances were only slightly higher than the high voltage limit. In fact, the average exceedance was 21% above the threshold, with the single highest exceedance being 1.12% above the threshold. Furthermore, FE informed the entity that there is a difference of minus .3 kV voltage at the substation, which, when taken into account, would reduce the number of exceedances by almost half. Additionally, the entity discovered that voltage monitoring and control is maintained at the generator step-up (GSU) transformer output with no visibility at the Interconnection point in violation of VAR-002-4 R2.3. Consequently, the entity had no methodology to convert the voltage measurement at the GSU transformer output to the voltage measurement at the point of Interconnection.

The root cause of this noncompliance were (a) inadequate detective controls to notify operators to respond when nearing the voltage limit; and, (b) the fact that the entity did not have a methodology in place to convert the voltage at the GSU transformer output to the voltage level at the point of Interconnection.

This noncompliance started on January 31, 2016, when the first voltage exceedance occurred, and ended on September 7, 2017, when the last voltage exceedance ended.

**Risk Assessment**

This noncompliance posed a moderate 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 a Generator Operator failing to inform the TOP of a voltage or reactive power exceedance is that it could cause the TOP to be uncertain of what generator was creating or contributing to an abnormal voltage condition on the BPS. This uncertainty could impede the TOP’s ability to take appropriate action. The risk posed by failing to accurately monitor and control the voltage at the point of Interconnection is that it could impede the generator’s ability to automatically regulate the voltage to maintain the proper voltage. These risks are not minimal in this case because of the number of exceedances (i.e., 87) and the length of time over which they occurred. However, these risks are not serious in this case based on the following factors. First, the generating unit does not have enough reactive capability, due to its size (50 MWs), to make a significant change in the voltage level at the point of Interconnection. Second, the majority of the voltage exceedances were found only slightly higher than the high voltage limit (i.e., an average of 140.3 kV or .21% above the voltage threshold) with the single largest exception at 141.580 which is 1.12 % above the scheduled maximum level of 140kV. 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:

1) instituted voltage data report from the distributed control system (DCS) at this site for exception reporting to be used as Catsweb quarterly control evidence;  
2) changed entries in electronic log book to capture alarm limits and required response by operators;  
3) created an advanced alarm for high voltage schedule set to initiate at 130.5 with a high-high alarm at 140 KV to provide adequate notification for operators to respond to when nearing the voltage limit;  
4) created an advanced alarm for low voltage schedule set to initiate at 136.5 with a low-low alarm at 136 KV to provide adequate notification for operators to respond to when nearing the voltage limit;  
5) instituted an alarm response procedure to include the new alarm limits and response requirements for the operators when this occurs;  
6) monitored adherence to voltage schedule weekly until an automated or batch process of exception reported is developed;  
7) trained all control board operators and Operations supervision on updated procedure and NRG OCC-VAR-002 Compliance procedure;  
8) compared DCS voltage output with FE’s voltage readings at Interconnection to determine correlation in voltage readings over load range and determine feasibility of retrieving PJUM and FE real time voltage profile for monitoring purposes; and  
9) determined and implemented a means for definitive measurement or methodology of voltage monitoring at the Interconnection can be established.

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>
</tr>
</thead>
<tbody>
<tr>
<td>SERC2018019780</td>
<td>VAR-002-2b</td>
<td>R2</td>
<td>Carville Energy LLC (Carville)</td>
<td>NCR11479</td>
<td>7/3/2014</td>
<td>05/07/2017</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 violation.)

On May 29, 2018, Carville submitted a Self-Report indicating that, as a Generator Operator, it was in noncompliance with VAR-002-3 R2. During an internal compliance review performed in August 2017, Carville determine that it had failed to meet the conditions of notification for deviations from the Voltage schedule provided by its TOP, Entergy Corporation.

Entergy’s Voltage Schedule Policy for Generating Facilities Interconnected to the Entergy Transmission System (Entergy Voltage Schedule) provides that during all times of the year, Carville is to maintain 232.3 kV with a tolerance band of +3 kV / -2 kV at its interconnection. Further Entergy’s Voltage Schedule provides:

1. Each plant should contact Entergy’s operations control center immediately (within 30 minutes) upon meeting both of the following conditions:
   a. The discovery of a deviation from the prescribed schedule tolerance band.
   b. The plant has exhausted all means of controlling voltage or reactive power.

Carville indicated that it has historically had difficulty maintaining the voltage schedule with all generators in automatic voltage control producing the respective reactive power during the summer months due to the increased system load demand during the summers. Further, Carville stated that until the internal compliance review, it believed it was in compliance with VAR-002-3 by following the terms of its January 2000 Interconnection and Operating Agreement (Operating Agreement) with Entergy. The Operating Agreement provides that “in the event that the voltage schedule is not being maintained, the facility shall be operated (within the design limitations of the equipment in service at the time) to produce the maximum reactive power (MVAR) output available in an attempt to achieve the prescribed voltage schedule, provided that Entergy has requested other generators in the affective area (including but not limited to Entergy’s generators) to produce maximum reactive power (MVAR) in an attempt to achieve the prescribed voltage.”

Carville estimated that during the months of June, July and August for the years 2015, 2016 and 2017, it deviated from the voltage schedule for 201 hours or 9% of the time in 2015, 429 hours or 19% of the time in 2016, and 884 hours or 40% of the time in 2017. The maximum Voltage schedule deviation experienced during these times was + 1.8 kV (.76%) / - 7.7 kV (3.3%). Carville indicated that it was not always operating at its maximum reactive power capability during the aforementioned times and did not always notify its TOP of the deviation from the Voltage schedule.

The root cause of this noncompliance was Carville’s incorrect assumption that complying with the terms of its Operating Agreement with Entergy was sufficient to achieve compliance with VAR-002-2b R2.

This noncompliance started on July 3, 2014, the date of the first instance that Carville did not meet the conditions of notification for deviations from the Voltage schedule provided by its TOP, and ended on May 7, 2017, the last date Carville failed to meet the conditions of notification for deviations from the Voltage schedule provided by its TOP.

**Risk Assessment**

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Specifically, Carville is a 555 MW, 2x1 combined cycle generating facility that is interconnected to the BPS at 230 kV. Additionally, the noncompliance occurred over an extended period of time (two years and seven months) and during the summer months, a time the BPS is heavily loaded. Nevertheless, Carville indicated that it is rarely called upon by the TOP for voltage support and has always responded by providing the maximum reactive power available. No harm is known to have occurred.

SERC determined that Carville's compliance history should not serve as a basis for applying a penalty. Carville has no relevant prior violations of VAR-002-3 R2 or any other standards that are similar in nature.

**Mitigation**

To mitigate this noncompliance, Carville:

1) trained operations personnel on the requirements of VAR-002-4;
2) requested and received a modification to the TOP’s voltage schedule, providing for a more sustainable voltage schedule;
3) trained operations personnel and management on the new voltage schedule; and
4) implemented an alarm system to notify plant operators when plant voltage deviates from the voltage schedule.
On December 15, 2016, GPC submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-023-1 R1. On April 27, 2016, during quarterly monitoring of internal controls by GPC Transmission Compliance, a GPC Control Center Support Engineer discovered an error with a relay setting for the Fortson – Tenaska 500 kV transmission line. Following the replacement of a 500 kV switch in 2015, which resulted in an increase in the line rating for the Fortson – Tenaska transmission line, GPC failed to adjust the protective relay setting to greater than 150% of the transmission line Facility Rating. As a result of the line rating increase, the protective relay limited the loadability of the Fortson – Tenaska transmission line to 147% of its highest seasonal Facility Rating (R1.1).

Subsequent to the Self-Report submitted on December 15, 2016, GPC identified two additional instances of noncompliance with PRC-023-1 R1. In the first instance, as part of its mitigation plan for the December 15, 2016 self-reported instance, GPC reviewed all of its protective relays to ensure the protection relays were set above 150% of the highest seasonal Facility Rating of the associated transmission facility. The protective relays for the Big Shanty Bank A, Big Shanty Bank B, and Bowen Bank 10 autotransformer facilities were set to limit the loadability of the autotransformer facilities to 149.85%, 149.85% and 149.91% of their respective highest seasonal Facility Rating (R1.11).

In the second instance, on March 23, 2017, GPC identified a disparity between the Facility Rating information in its PRC-023 spreadsheet and the GPC Operations’ Facility Ratings. Upon correcting the Facility Rating disparity, GPC discovered the protective relay for the McIntosh CC-1 - West McIntosh 230 kV transmission line limited the loadability of the transmission line to 140.4 % of its highest seasonal Facility Rating (R1.1).

The root cause of this noncompliance was lack of a formal process for changing Facility Ratings and lack of managerial oversight. By not having a formal process for changing Facility Ratings, GPC utilized inexact hand calculations for the Low Side Back-up Over-Current relays in the autotransformer spreadsheet to calculate relay settings, which resulted in Facility Rating errors. Proper managerial oversight should have identified the undocumented process for changing Facility Ratings.

This noncompliance started on July 1, 2010, the date PRC-023-1 became mandatory and enforceable and GPC failed to ensure the relay settings were set to limit the loadability, and ended on May 18, 2017, the date GPC corrected the relay settings for the relays that were not set to limit the loadability of the respective transmission facilities to greater than 150% of the highest seasonal Facility Rating.

### Risk Assessment

This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). GPC’s failure to set protective relays so they did not operate at or below 150% of the highest seasonal Facility Rating of a transmission facility increased the risk that relays would unnecessary trip transmission facilities during system events that otherwise would not have caused a transmission facility outage. Notwithstanding, SERC determined that the risk to the BPS was mitigated because the incorrect 500 kV line relay settings would support at least 147% of the highest seasonal Facility Rating of the circuit. GPC operates its transmission system to withstand the loss of any single transmission facility without adversely affecting the continued operation of its transmission system. The actual load on the 500 kV line during the period of non-compliance did not exceed 1084 amps, which is well below the original setting of 2,675 amps. Additionally, the improperly set protective relay errors were small – the largest error occurred for the McIntosh CC-1 – West McIntosh 230 kV transmission line where loadability of the transmission line was limited to 140.4 % of its highest seasonal rating. No harm is known to have occurred due to the incorrect relay settings.

A Spreadsheet Notice of Penalty covering violation of PRC-023-1 R1 (SERC2011007157) for GPC was filed with FERC under NP12-27-000 on May 30, 2012. On June 29, 2012, FERC issued an order stating it would not engage in further review of the Notice of Penalty. GPC identified seven protection relays that were not set to operate above 150% of the highest seasonal Facility Rating of the associated transmission facilities.

SERC determined that GPC’s compliance history should not serve as a basis for applying a penalty. The current issue does not involve recurring conduct that was the same or similar to the conduct in the prior noncompliance. Whereas the prior violation resulted from omissions and a failure to follow approved change procedures, the instant violation is the result of incorrect relay settings due to mathematical errors. SERC determined that the repeat violation of PRC-023-1 does not represent a systemic problem with GPC’s internal compliance program but is illustrative of lack of a formalized process and managerial oversight.

### Mitigation

To mitigate this noncompliance, GPC:

1. changed the incorrect protective relay settings to comply with PRC-023-1;
2. implemented a formal process for changing Facility Ratings for GPC Operations;
3. created an informational user interface module in the GPC lines rating database to identify transmission line Facilities with pending changes in Ratings;
4. incorporated the calculations for Low Side Back-Up Over-Current (LSBUOC) load responsive relays into the autotransformer spreadsheet used to calculate relay settings;
5. removed the McIntosh circuit from service;
6. trained personnel in the use of the formal process for changing Facility Ratings for GPC Operations; 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>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>SERC2016016658</td>
<td>PRC-023-1</td>
<td>R1</td>
<td>Georgia Power Company (GPC)</td>
<td>NCR01247</td>
<td>7/1/2010</td>
<td>May 18, 2017</td>
<td>Self-Report</td>
<td>Completed</td>
</tr>
</tbody>
</table>

7) completed a 100% review of PRC-023 relays.
**NERC Violation ID** | **Reliability Standard** | **Req.** | **Entity Name** | **NCR ID** | **Noncompliance Start Date** | **Noncompliance End Date** | **Method of Discovery** | **Future Expected Mitigation Completion Date**
---|---|---|---|---|---|---|---|---
SERC2017018600 | TOP-001-3 | R13 | Duke Energy Progress, LLC (DEP) | NCR01298 | 07/21/2017 | 07/21/2017 | 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 violation.)**

On November 7, 2017, Duke Energy Progress, LLC (DEP) submitted a Self-Report on behalf of Duke Energy Florida, LLC (DEF) stating that, as a Transmission Operator, DEF was noncompliant with TOP-001-3 R13. DEF did not perform a Real-time Assessment at least once every 30 minutes. DEF submitted the Self-Report under an existing Multi-regional Registered Entity Agreement.

On July 21, 2017, the DEF Energy Control Center (ECC) performed a Backup Control Center (BUCC) functionality test. At 6:10 a.m., prior to initiating transfer of operations to the BUCC, DEF completed a Real-time Contingency Analysis (RTCA) assessment, i.e., Real-time Assessment. No contingencies were identified on DEF’s transmission system by the RTCA assessment. Thereafter, DEF Energy Management System (EMS) Support Engineering initiated the EMS function at the primary ECC server to failover to the BUCC server.

At 6:19 a.m., an RTCA assessment utilizing the BUCC EMS identified an unsupported number of contingencies. Notwithstanding the perceived problem with the BUCC EMS RTCA results, System Operators determined the DEF BUCC EMS was operational and providing valid real-time flows, generator output, frequency, and other EMS data. DEF System Operators subsequently determined that although the RTCA was solving, the results of the RTCA were not valid.

At 6:47 a.m., System Operators attempted a manual RTCA assessment per DEF Standing Order TS115 using a parallel Study Contingency Analysis (STCA) program. System Operators determined the STCA assessment was also invalid. At 7:25 a.m., System Operators contacted EMS Support Engineering who began troubleshooting the RTCA application problem at 7:41 a.m. At 8:14 a.m., DEF completed a second STCA assessment utilizing modified 5:45 a.m. EMS data. Although, the STCA assessment did not utilize the most current EMS data, no contingencies were identified on DEF’s transmission system.

At 8:28 a.m., DEF informed its Reliability Coordinator (RC), Florida Reliability Coordinating Council that the DEF RTCA application was providing invalid solutions. The RC agreed to monitor its Real-time assessments to identify DEF contingencies until the DEF RTCA issue was resolved.

At 8:30 a.m., DEF performed a third STCA utilizing modified EMS data from 8:14 a.m. No contingencies were identified on DEF’s transmission system.

At 8:45 a.m., DEF EMS Support Engineering restored normal operation of the BUCC RTCA application. It was determined that the RTCA application failure occurred because the EMS database at the BUCC was updated with incorrect generating unit data during the failover of the primary ECC server to the BUCC server.

DEF’s failure to ensure the performance of a Real-time Assessment within 30 minutes was attributed to: failure to stop and restart all process on all EMS servers following an EMS database update to ensure a relink of generating unit indexes in the EMS Transfer Manager; inadequate controls to verify that a Real-time Assessment occurred every 30 minutes; the RTCA application failure occurring concurrent with the BUCC functionality test; System Operator failure to implement protocols to mitigate the loss of the RTCA function; System Operator involvement in the investigation of the cause of the RTCA application failure; and System Operator confusion regarding the continued operation of the BUCC EMS, i.e., notwithstanding the erroneous contingencies generated by the RTCA application, the BUCC EMS continued to provide valid real-time flows, generator output, frequency, and other EMS data.

This noncompliance started on July 21, 2017, at 6:40 a.m., the time by which DEF should have performed a Real-time Assessment following the, successful 6:10 a.m. Real-time Assessment, and ended on July 21, 2017, at 8:28 a.m., when the DEF RC began monitoring its Real-time Assessment for DEF contingencies.
### Risk Assessment

This noncompliance posed a moderate risk to the reliability of the bulk power system (BPS). The failure to ensure the performance of a Real-time Assessment of the transmission system every 30 minutes increases the risk that System Operators could be unaware of system conditions that would impact the reliability of the BPS. This lack of system awareness increases the risk that System Operators would not proactively mitigate system conditions that could result in instability, uncontrolled separation, or cascading outages. Here, DEF failed to perform a Real-time Assessment of its transmission system for one hour and forty-eight minutes. Additionally, DEF failed to timely report its inability to perform a Real-time Assessment to its RC and seek the RC’s assistance in monitoring for contingencies on the DEF transmission system. SERC determined that this issue is appropriate for FFT disposition because: the failure to perform a Real-time Assessment occurred during morning hours when system conditions typically change, but change in a predictable manner; DEF continued to have Real-time EMS data available to monitor system status; the RC’s Real-time Assessment capabilities were unaffected by the DEF RTCA failure; DEF employed the STCA process to provide near Real-time assessments; and neither DEF nor its RC identified pre-contingency or post-contingency conditions that required mitigating actions during the noncompliance. No harm is known to have occurred.

SERC considered DEF’s compliance history and determined that there were no relevant instances of noncompliance.

### Mitigation

To mitigate this noncompliance, DEF:

1. ECC system operators implemented DEF Standing Order TS115 to run manual real-time assessments using STCA;
2. EMS support engineering troubleshooted and then restarted the transfer manager application to relink the real-time EMS applications;
3. updated DEF Standing Order TS115 to include:
   a. actions to be taken when RTCA solves but results are invalid;
   b. notifying the FRCC RC; and
   c. pulling the last valid real-time savecase into EMS applications;
4. EMS support engineering updated failover procedures to include:
   a. pre-job brief with system operations prior to commencing;
   b. critical steps to notify system operations prior to performing;
   c. process to stop/start all servers after all database updates;
   d. EMS support engineering will be in a fixed location prior to any predetermined failovers; and
   e. opening a bridge line to be used for constant communication during failovers between system operations and EMS support engineering;
5. EMS support engineering provided a copy of the revised failover procedures to system operations;
6. updated EMS checklist for system operations to include RTCA contingency list after the failover coincides with the RTCA contingency list prior to the failover; and
7. provided system operations training on the following:
   a. the new failover procedures and EMS checklist;
   b. hands on demonstration using the DTS creating a save case and performing a manual real-time assessment; and
   c. communications protocols.