NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021304	PRC-026-1	R1.	Gainesville Regional Utilities (GRU)	NCR00032	1/1/2019	3/15/2019	Self-Report	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On April 8, 2019, GRU submitted a Self-Report stating that, as a Planning Authority, it was in noncompliance with PRC-026-1 R1. This noncompliance started on January 1, 2019, when GRU failed to include all required BES Elements in its Generator Owner and Transmission Owner notification and ended on March 15, 2019 when an amended notification was made. Specifically, GRU made notifications on December 12, 2018, indicating that no BES Elements met the R1 criteria; however, it was later determined that the content of this notification was not correct. On February 26, 2019, during a planner training session, GRU's Transmission planning engineer discovered an error in the interpretation of the 2017 and 2018 Extreme Event Planning Assessments. There were three (3) scenarios where relay tripping occurred due to a stable or unstable power swing during a simulated disturbance (R1 criteria 4), totaling six (6) BES Elements for all simulations. The cause for this noncompliance was insufficient internal controls to prevent improper interpretation of simulation results.						
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk was reduced because the delay in notifying the Generation Owner and Transmission Owner of applicable BES Elements was minimal (73 days) and the relay tripping in question (criteria 4) involved only simulated extreme events. GRU has a peak load of 483 MWs which represents .94% of the Region and a total generation output of 521 MWs representing 0.96% of the Region. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty. No harm is known to have occurred.						
Mitigation	To mitigate this noncompliance, GRU: 1) perform extent of condition assessment back to 1/1/2018; 2) performed a cause analysis; 3) established procedure for PRC-026-1 assessment, peer review, and notification; and 4) trained all applicable personnel on procedure.						

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021398	TPL-007-1	R5. 5.1.	Tampa Electric Company (TEC or the Entity)	NCR00074	1/1/2019	3/6/2019	Self-Report	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On April 24, 2019, Entity submitted a Self-Report stating that, as a Transmission Planner and Planning Authority, it had an issue of TPL-007-1 R5. This noncompliance started on January 1, 2019, when TEC failed to provide the required Entities with flow information as required and ended on March 6, 2019, when TEC completed the proper notifications. This noncompliance involves an administrative lapse that resulted in a 64-day delay in formally communicating geomagnetically-induced current (GIC) flow information to each Generator Operator (GO) within TEC's planning area. The Entity discovered the deadline to communicate GIC flow information had passed during an internal evidence review of requirement R5 on March 5, 2019. TEC subsequently corrected the problem by communicating the GIC flow information to the GOs on March 6, 2019. TEC's Transmission Planning (TP) department received the GIC flow study results on December 5, 2018. The study results include GIC flow information for the entire FRCC region. The task of extracting GIC flow information for the planning area from the overall study results and communicating that information to the GOs was assigned to a supervisor. The supervisor created a Microsoft Outlook Task to complete this work by December 28, 2018. However, the Outlook tool created to track the compliance of requirement R5 and R5.1 was incorrectly set up and did not alert the employee as the due date approached. An extent of condition was performed, and no additional instances of noncompliance were found related to this issue. The cause for this noncompliance was an incorrect use of the Outlook tool by the supervisor tasked with communicating the GIC flow information to the GOs within the planning area.						
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. The risk of not providing flow information to the required GOs could cause the performance of individual transformer thermal assessments to be incorrect leading to equipment damage should a geomagnetic disturbance occur impacting the BPS. This risk is reduced because the impact of any potential geomagnetic disturbance in the FRCC Region is extremely low. It was further reduced in this instance because although the GOs need GIC flow information to determine whether they are required to perform individual transformer thermal assessment, none of the transformers in TEC's planning area exceeded the 75A/phase threshold that would trigger the requirement for an individual thermal assessment. In fact, the highest GIC level of any transformer in TEC's planning area was 6.097A or only about 8.1 percent of the threshold. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty. No harm is known to have occurred.						
Mitigation	To mitigate this noncompliance, the Entity: 1) sent email to the GOs; 2) determined extent of condition; 3) performed a root cause analysis; 4) updated Transmission Planning Procedures; 5) conducted annual training on revised Transmission Planning Procedures; 6) implemented monthly lookahead on Transmission Planning NERC Deliverables; and 7) reviewed the task feature in Outlook.						

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020122	TOP-002-4	R1	American Transmission Co. LLC (ATC)	NCR00685	2/13/2018	4/27/2018	self-log	6/28/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 13, 2018, ATC submitted a self-log stating that as a Transmission Operator, it was in noncompliance with TOP-002-4 R1. ATC is registered in the ReliabilityFirst (RF) Region under the same name and NCR ID, and both are monitored under the Coordinated Oversight Program. The noncompliance impacted both Regions. Specifically, ATC created a new Division (a geographical area comprised of the Upper Peninsula of Michigan) in the EMS application and relocated all EMS modeled BES Facilities in that geographical area to the new Division. ATC states the creation of the new Division was done to align with changes ATC's Balancing Authority made. However, during this relocation process, ATC failed to include the BES Facilities from the Division in ATC's EMS modeling database that is used to perform Operational Planning Analysis. This Analysis determines if its planned operations would exceed any System Operating Limits (SOLs). The noncompliance affected the BES assets in the new Division (approximately 4% of ATC's BES Facilities) and did not affect ATC's Operational Planning Analysis for the other BES Facilities. The cause of the noncompliance was that ATC did not have sufficient controls (such as procedural documentation or peer review) to ensure that EMS model updates were performed accurately. This noncompliance started on February 13, 2018, when ATC made the error that prevented Operational Planning Analysis from being performed in the Division and ended on April 27, 2018, when the model errors were corrected and Operational Planning Analysis was conducted for the Division.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The BES Assets were located within ATC's Reliability Coordinator's (RC) footprint; ATC states that its RC performed a Real-time Assessment (RTA) of the RC's footprint at least once every 30 minutes during the noncompliance. Further, ATC reports that it has two Remedial Action Schemes (RAS) in the Division, the two RAS were designed to detect abnormal system conditions and take corrective actions, and the noncompliance did not impact that capability. Finally, ATC did not identify a contingency that met the RC's criteria for an Interconnection Reliability Operating Limit (IROL) during the noncompliance and ATC states that a significant event in the Division could only be caused by several forced outages. No harm is known to have occurred. There is little risk of recurrence during the completion of mitigating activities. Modeling changes such as these are infrequent with ATC stating this was the first change completed under its current EMS software. Additionally, this occurrence and the investigation into it, raised awareness in applicable staff.
Mitigation	To mitigate this noncompliance, ATC: 1) corrected the area modeling database errors in the EMS; 2) conducted interviews to determine if there was other similar noncompliance; and 3) completed a third-party assessment of the cause and scope of the events that lead to the noncompliance. To mitigate this noncompliance, ATC will: 1) develop guidance documentation to be used during any EMS modeling changes and other related activities; and 2) provide training to relevant staff on the guidance documentation. The length of the mitigating activities is related to the sequencing of the events and that the development of guidance documentation is a collaborative and deliberative process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020123	TOP-001-3	R13	American Transmission Co. LLC (ATC)	NCR00685	2/13/2018	4/27/2018	self-log	6/28/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 13, 2018, ATC submitted a self-log stating that as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. ATC is registered in the ReliabilityFirst (RF) Region under the same name and NCR ID, and both are monitored under the Coordinated Oversight Program. The noncompliance impacted both Regions. Specifically, ATC created a new Division (a geographical area comprised of the Upper Peninsula of Michigan) in the EMS application and relocated all EMS modeled BES Facilities in that geographical area to the new Division. ATC states the creation of the new Division was done to align with changes ATC's Balancing Authority made. However, during this relocation process, ATC failed to include the BES Facilities in ATC's EMS modeling database that is used to support ATC's Real-time Assessment (RTA). The cause of the noncompliance was that ATC did not have sufficient controls (such as procedural documentation or peer review) to ensure that EMS model updates were performed accurately. This noncompliance started on February 13, 2018, when ATC made the error that prevented a complete RTA from being performed and ended on April 27, 2018, when the model errors were corrected and a complete RTA was performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The BES Assets were located within ATC's Reliability Coordinator's (RC) footprint; ATC states that its RC performed a RTA of the RC's footprint at least once every 30 minutes during the noncompliance. Further, ATC states that its monitoring of stability rating limits was unaffected by the noncompliance. ATC reports that it has two Remedial Action Schemes (RAS) in the Division, the two RAS were designed to detect abnormal system conditions and take corrective actions, and the noncompliance did not impact that capability. Finally, ATC did not identify a contingency that met the RC's criteria for an Interconnection Reliability Operating Limit (IROL) during the noncompliance and ATC states that a significant event in the Division could only be caused by several forced outages. No harm is known to have occurred. There is little risk of recurrence during the completion of mitigating activities. Modeling changes such as these are infrequent with ATC stating this was the first change completed under its current EMS software. Additionally, this occurrence and the investigation into it, raised awareness in applicable staff.
Mitigation	To mitigate this noncompliance, ATC: 1) corrected the area modeling database errors in the EMS; 2) conducted interviews to determine if there was other similar noncompliance; and 3) completed a third-party assessment of the cause and scope of the events that lead to the noncompliance. To mitigate this noncompliance, ATC will: 1) develop guidance documentation to be used during any EMS modeling changes and other related activities; and 2) provide training to relevant staff on the guidance documentation. The length of the mitigating activities is related to the sequencing of the events and that the development of guidance documentation is a collaborative and deliberative process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2017017056	PRC-006-2	R9	Northern States Power (Xcel Energy) (NSP)	NCR01020	10/1/2015	6/28/2016	Self-Certification	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 June 30, 2016, NSP, a Coordinated Oversight Program participant, submitted a Self-Certification to MRO stating that, as a Transmission Owner, it was in noncompliance with PRC-006-2 R9. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating area of NSP. Xcel Energy states that it discovered relays that were not set correctly during sampling for the Self-Certification. A comprehensive review of all NSP UFLS relay settings discovered a total of 73 UFLS relays that were not set according to the documented UFLS Plan. Xcel Energy reports that this caused NSP's load shed for the 59 Hz UFLS step to be 9.7%; this is .3% below the 10% minimum specified by the UFLS program. Xcel Energy states that the 59.3 and 58.7 Hz UFLS steps were not impacted by the noncompliance. The noncompliance was caused by a lack of clarity in the UFLS Program and ineffective controls for the implementation of the UFLS Program. This noncompliance started on October 1, 2015, when the standard became mandatory and ended on June 28, 2016 when the settings were corrected.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The noncompliance translated into a shortfall of .3% of load at one UFLS step; this translates to approximately 30 MW of load. MRO determined that this small fluctuation is consistent with the normal variations in load distribution and broad assumptions used in the development of a UFLS program. No harm is known to have occurred. Xcel Energy has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) investigated all UFLS circuits to verify the frequency to which the relays are set; 2) adjusted the load to be shed to ensure that at least 10% of system load is shed at 59 Hz; and 3) received an updated UFLS Program from its Planning Coordinator that provided improved clarity and established upper and lower UFLS limits. The mitigation was limited to the NSP system.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2018020724	MOD-025-2	R2	Wallingford Energy LLC (Wallingford)	NCR11102	07/01/2018	07/25/2018	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 November 21, 2018, Wallingford Energy LLC ("the Entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R2. The Entity did not complete the verification of its Reactive Power capability of its applicable Facilities in accordance with the MOD-025-2 Implementation Plan. The Entity needed to have verification of Reactive Power capability (testing) completed on 4 out 5 (80%) of its generating units by July 1, 2018. Instead, the Entity verified Reactive Power capability was completed on only 3 units (60%). The Entity completed the verification of Reactive Power capability of a fourth unit on July 25, 2018. The noncompliance was discovered during a review of relevant evidence during audit preparation for Wallingford Energy's 2018 O&P off-site audit. This noncompliance started on July 1, 2018 and ended on July 25, 2018 when testing on the 4th unit was completed and the results provided to the Transmission Planner. The root cause of this noncompliance was lack of management oversight and focus to complete the testing to reach 80% on the existing units. Instead, Wallingford resources were focused on the commissioning of new units 6 and 7 that were coming online in May 2018. Due to the unusual level of activity, resource commitment, and focus on the new unit development and implementation, the testing and verification on at least one more of the existing applicable Facilities was not performed by July 1, 2018. Additionally, the Entity submitted a request to perform testing in February 2018 that was denied by the ISONE because the request did not meet the ISONE scheduling guidelines and the subsequent follow-up to reschedule the test did not occur.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to this noncompliance is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. However, the Entity's applicable facilities consist of five 51MW units had always participated in ISONE historical reactive capability testing before MOD-025-2 came into effect. The plant had a 2017 capacity factor of 6.7 % and a 2016 capacity factor of 10.7%. The rated capability of each of the units is about 2.2 % of the ISONE typical required Operating Reserve (approximately 2,300 MW). The required testing was completed approximately three weeks later than required so the exposure time was relatively short and the unit's reactive capabilities were already well established and documented with their Planning Coordinator and Transmission Planner, ISONE. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Wallingford Energy: 1) Completed the testing on both untested units and provided the results to the Transmission Planner. 2) Implemented a compliance software tool as an internal control that will track all dates and obligations for NERC Standards that will initiate advanced notifications and follow up notices to managers as dates approach and will require maintenance activities to be closed in the system. The notifications in the tool are to the plant and a 3rd party consultant.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2018020870	PRC-019-2	R1	Wallingford Energy LLC (Wallingford)	NCR11102	05/09/2018	08/16/2018	Compliance Audit	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.)	During a Compliance Audit conducted from October 1, 2018 through December 20, 2018, NPCC determined that Wallingford Energy LLC ("the Entity"), as a Generator Owner, was in noncompliance of PRC-019-2, R1. The Entity failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and setting of the applicable Protection System devices and functions for new units 6 and 7 which were both synchronized to the grid on May 9, 2018. The noncompliance started on May 9, 2018, when units 6 and 7 first synchronized to the grid and ended on August 16, 2018 when the verification of the coordination was completed. The root cause of this PRC-019-2 noncompliance was a lack of understanding where it was believed by management that PRC-019-2 Implementation Plan allowed a one year grace period to verify the coordination of new units 6 and 7.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit, which could stress the system further. However, the Entity's applicable Facilities consist of the two 51 MW units. The plant had a 2017 capacity factor of 6.7 % and a 2016 capacity factor of 10.7%. The rated capability of each of the units is about 2.2 % of the ISONE typical required Operating Reserve (approximately 2,300 MW). The combined capability of Units 6 and 7 would be about 4.4 % of the ISO-New England typical operating reserve level. ISO-New England would be able to obtain that amount of replacement operating reserve. The required testing was completed approximately three months after initial synchronization so the exposure time was relatively short. There were no settings changes or adjustments that were discovered to be needed once the entity completed its coordination review. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Wallingford Energy: 1) Completed the necessary coordination of voltage system regulating controls with protection systems for the new units 6 and 7. 2) Implemented a compliance software package as an internal control to include tracking and documentation of dates when testing, equipment setting changes and control settings are made and coordinated to meet NERC standard requirements and milestone dates so that advanced electronic automatic notifications are made to plan for and conduct necessary testing. The notifications in the tool are to the plant and the 3rd party NERC consultant.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2018020871	PRC-024-2	R2	Wallingford Energy LLC (Wallingford)	NCR11102	05/09/2018	08/16/2018	Compliance Audit	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.)	During a Compliance Audit conducted from October 1, 2018 through December 20, 2018, NPCC determined that Wallingford Energy LLC ("the Entity"), as a Generator Owner, was in noncompliance of PRC-024-2, R2. The Entity failed to properly set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. More specifically, the Entity failed to properly set the volts/hz relays on new units 6 and 7 prior to both of them synchronizing to the grid on May 9, 2018. During a review of audit evidence, NPCC discovered that information contained in a generator protection testing report from relay testing that was completed on August 16, 2018 indicated that the Entity unknowingly had the volts/hz relay settings inside the Attachment 2 no trip zone since May 9, 2018. The relay test report reviewed by NPCC during the Compliance Audit was developed as a result of the units tripping off (while online as a test unit and while not participating in the ISONE market) due to volts/hz relay action during July 2018 reactive commissioning testing. The noncompliance started on May 9, 2018 and ended on August 16, 2018 when all of the settings were confirmed to meet the performance characteristics of the Attachment 2 curve. The root cause of this PRC-024-2 noncompliance was a lack of understanding where it was believed by management that PRC-024-2 Implementation Plan allowed a one year grace period to verify and meet the performance characteristics of new units 6 and 7 to Attachment 2..
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. Noncompliance with PRC-024-2 R2 could result in trips that occur when they should not and capacity loss during a system voltage excursion event, which would further stress the system during a contingency. However, the Entity applicable Facilities (new units 6 and 7) consist of two 51MW units. The plant had a 2017 capacity factor of 6.7 % and a 2016 capacity factor of 10.7%. The rated capability of each of the units is about 2.2 % of the ISONE typical required Operating Reserve (approximately 2,300 MW). The combined capability of Units 6 and 7 would be about 4.4 % of the ISO-New England typical operating reserve level. ISONE would be able to obtain that amount of replacement operating reserve. The required testing was completed approximately three months after initial synchronization so the exposure time was relatively short. The entity adjusted the V/Hz settings on both of the redundant microprocessor relays that are associated with unit 6 and unit 7. The undervoltage and overvoltage settings on both of the redundant microprocessor relays were already correct for both unit 6 and unit 7. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Wallingford Energy: 1) Completed a review of all protective relaying associated with units 6 and 7 to ensure that they meet the performance characteristics of Attachment 2. 2) Implemented a compliance software package as an internal control to include tracking and documentation of dates when testing, equipment setting changes and control settings are made and coordinated to meet NERC standard requirements and milestone dates so that advanced electronic automatic notifications are made to plan for and conduct necessary testing. The notifications in the tool are to the plant and the 3rd party NERC consultant.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020404	PRC-001-1.1(ii)	R3	Lakewood Cogeneration, LP	NCR00168	3/9/2017	8/10/2018	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 September 7, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with PRC-001-1.1(ii) R3 because it made relay setting changes prior to notifying, and coordinating with, its Transmission Operator. More specifically, the entity changed the 21G Impedance Relay and 51V Voltage Controlled Overcurrent Relay settings. The changes were implemented in an effort to comply with PRC-025. The root cause of this noncompliance was a lack of effective controls and processes, including ineffective supervision of, and inadequate communications regarding, relay setting changes. This noncompliance implicates the management practices of workforce management and planning. Effective workforce management can minimize the frequency and consequences of events relating to bulk electric system (BES) reliability and resilience and can be achieved, in part, through the development and implementation of clear and executable processes and procedures. And, an entity should strive to avoid unplanned and uncoordinated work, which can produce unintended and undesirable consequences affecting BES reliability and resilience. This noncompliance started on March 9, 2017, when the entity completed the relay setting changes and ended on August 10, 2018, after the entity communicated and coordinated the changes with its Transmission Operator.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. Failing to coordinate protective system changes with a Transmission Operator could result in inadequate protection for interconnected assets, unexpected tripping, misoperation, or a system event. The risk was mitigated by the following facts. First, the changes were implemented in an effort to comply with PRC-025 and were designed to improve the performance of the system under abnormal or emergency conditions and prevent cascading failures. Second, the changes were in place for approximately one-and-one-half years without causing any issues. Third, these types of changes do not occur frequently, and therefore, this issue is unlikely to occur again. 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) developed a change management process to address how facility changes need to be addressed via the NERC standards; 2) reviewed the PRC-001 plant procedure to ensure it properly addresses the required notifications for relay setting changes and, if required, agreed to update the procedure; and 3) retrained staff on what needs to occur prior to changing settings. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019897	EOP-004-2	R3	LSP University Park, LLC	NCR11107	7/1/2016	12/31/2018	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 June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with EOP-004-2 R3. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that it could not locate documentation to verify that the contact information was validated in 2016 and 2017. IPSC conducted interviews with employees who had worked at the plant in 2017. Those individuals confirmed that the validation was completed in 2017, but just not documented properly. The root cause of this noncompliance was the lack of effective internal controls to ensure the validation task was properly completed and documented each year. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to have validated the contact list and ended on February 20, 2018, when the entity validated the contact list for 2018.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk associated with failing to annually validate the contact information in the Operating Plan is that notification to these parties could be delayed due to outdated or inaccurate information. This risk was mitigated in this case by the following factors. First, UPN personnel stated that they validated the contact information in 2017, but that they just failed to document it appropriately. Second, the entity's statement that this is merely a documentation issue is supported by the fact that when IPSC performed the validation in 2018, the contact information was all still valid. ReliabilityFirst also notes that during the time of the noncompliance, no events requiring contact occurred. 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) validated all contact information contained in the Operating Plan pursuant to Requirement 1; and 2) developed a preventive maintenance activity to require completion of the verification annually going forward. This preventive maintenance includes a requirement to store the verification documentation in a SharePoint site to ensure the records will not be lost in the future. The Preventive Maintenance cannot be closed until this activity has been completed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019902	MOD-032-1	R2	LSP University Park, LLC	NCR11107	7/1/2016	6/15/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-032-1 R2. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that the entity failed to transmit the modeling data specified in Requirement 2 to PJM by July 1, 2016, the date specified in the implementation plan. IPSC obtained confirmation from PJM that this modeling data was not submitted until 2017. The root cause of this noncompliance was the lack of effective internal controls to ensure the modeling data was transmitted to PJM on time. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to send the modeling data to PJM and ended on June 15, 2017, when the entity actually sent the modeling data to PJM.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk associated with failing to timely submit modeling data to PJM is that the data used in PJM's models could be incorrect, impacting the accuracy of the models. This risk was mitigated in this case by the following factors. First, the modeling data had not changed from what PJM already had in its possession. Therefore, the late transmittal had no effect on the accuracy of PJM's model. Second, the entity transmitted the modeling data less than a year late, which limits the amount of time that PJM's model could have been inaccurate or out-of-date. 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) reviewed and submitted 2018 MOD-032-1 R2 data to PJM; and 2) created an Annual MOD-032 data submittal Preventive Maintenance Work Order to ensure timely transmittal of the data in the future.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019899	PRC-019-2	R1	LSP University Park, LLC	NCR11107	7/1/2016	8/31/2018	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 June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that, while the entity performed the required coordination study in June 2016, it failed to take action to make necessary changes. Specifically, in regard to PRC-019-2, R1.1.1, the study found that relay limiters were set to operate at values higher than their associated protection relays set points. Therefore, they were not coordinated properly. The errant components included the Volts-to-Hertz relay and the Phase-Undervoltage relay. The root cause of this noncompliance was the lack of effective internal controls to ensure that appropriate action was taken after the PRC-019 study was completed. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on August 31, 2018, when the entity completed work necessary to ensure proper coordination.					
Risk Assessment			This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk posed by failing to properly coordinate these devices is that the relays could operate before the limiters causing an early or unexpected trip. This risk was mitigated in this case by the following factors. First, the units were capable of controlling voltage to the degree permitted by the trip set points of the relays without damage to the facility or the grid. Second, the units are small peaking units, and, typically, only a few are operated at a time. ReliabilityFirst also notes that no early trips occurred due to the limiters not being set to operate prior to the protective relays. 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 modified errant relay setpoints and verified that all PRC-019 requirements are satisfied. The entity developed a Preventive Maintenance work order requiring the completion of the PRC-019-2 on a five-year review cycle.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019900	PRC-024-2	R1	LSP University Park, LLC	NCR11107	7/1/2016	5/29/2018	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 June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that, while the entity performed the required PRC-024 evaluation in 2016, some questions coming out of that evaluation were not resolved completely. Specifically, IPSC could not locate any documentation verifying that the frequency trips for units 2, 3, 4, and 12 were conclusively outside the no trip zone. The root cause of this noncompliance was the lack of effective internal controls to ensure that appropriate action was taken after the PRC-024 evaluation was completed. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on May 29, 2018, when the entity completed its Mitigation Plan.					
Risk Assessment			This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk posed by failing to ensure that the frequency trips are outside of the no trip zone is that the units could be tripped early and not available to provide frequency support when necessary. This risk was mitigated in this case by the fact that the units are small peaking units, and, typically, only a few are operated at a time. ReliabilityFirst also notes that the units have not experienced any early trips due to the present settings of the relays. Furthermore, when running at full load, each of the 12 units contributes approximately 45 MW to the grid and operated at average 12.26% capacity factor for the duration of the noncompliance. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.					
Mitigation			To mitigate this noncompliance, the entity evaluated and verified the frequency trips for units 2, 3, 4, and 12 are outside the no trip zone. As an additional mitigating action, the entity reviewed and updated its internal compliance program to ensure that the frequency set points will not be changed without appropriate approvals. ReliabilityFirst has verified the completion of all mitigation activity.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020502	MOD-027-1	R2	Northern Indiana Public Service Company LLC (NIPSCO)	NCR02611	July 1, 2018	July 23, 2018	Self-Report	April 30, 2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 2, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. On April 11, 2018, the entity contracted with General Electric (GE) to perform the required MOD-027 verification testing. MOD-027-1 R2 required that 30% of the entity generation fleet have verification testing completed by July 1, 2018. The entity scheduled GE to conduct the verification testing at Michigan City Unit 12 and Schaffer Unit 15, and to submit a final report to the entity for Schaffer Unit 15. GE designated a GE employee to perform the testing. The GE employee informed the entity that the necessary work would be completed in time to comply with MOD-027-1 R2. On April 13, 2018, GE informed the entity that the GE employee designated to perform the testing had resigned. Approximately a month later on May 16, 2018, a GE supervisor informed the entity that he would perform the test and submit the report to the entity. On May 24, 2018, GE completed the testing at Schaffer Unit 15, and the raw test data was made available at that time. The final analysis and report, however, with verified models sent to the Transmission Planner, were not completed until July 23, 2018. This delay resulted in the entity not completing testing on 30% of its fleet by the due date of July 1, 2018. (31.9% based on Nameplate MVA.) This noncompliance involves the management practices of external interdependencies and verification. External interdependencies is involved because GE did not complete all of its contracted work until after the July 1, 2018 implementation date. The entity did not specify in the contract the actual due date for all work to be completed including submission of the final report and that mistake is a root cause of this noncompliance. Verification is involved because the entity did not verify that the final analysis and report would be completed, with verified models sent to the Transmission Planner, by the July 1, 2018 implementation date. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-027-1 R2 and ended on July 23, 2018, when the entity completed the final analysis and report and sent verified models to the Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance arises from allowing dynamic simulations that assess BPS reliability to inaccurately represent generator unit real power response to system frequency variations. That can lead to planning and operating the BPS with inaccurate information. The risk is minimized because the entity completed verification testing on 30% of the entity generation fleet just 22 days late and no changes were required. Additionally, the entity had contracted with GE to complete all required verification testing in advance of the July 1, 2018 implementation date, but GE did not complete the required verification testing on time. The entity had planned and taken all necessary actions to become compliant with MOD-027-1 R2 as of July 1, 2018 and was only overdue in its compliance due to GE's delays in completing the final analysis and report. 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 will complete the following mitigation activities by April 30, 2019: 1) developed a Power Point slide deck on the MOD-027 requirements to be delivered to the Generator Owner (GO) personnel; 2) delivered MOD-027 training to the relevant GO personnel. This training informed personnel of what their responsibilities are for maintaining compliance with MOD-027; 3) scheduled touchpoints (GO Touchpoint 1) with the entity's Station Engineering and Maintenance Department to track their progress on future MOD-027 milestones; and 4) will schedule touchpoints (GO Touchpoint 2) with the entity's Station Engineering and Maintenance Department to track their progress on future MOD-027 milestones. The entity needs until April 30, 2019 to complete mitigation because of training timing.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019983	PRC-005-2	R3	Talen Generation, LLC (Talen)	NCR11362	4/1/2015	3/9/2018	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 July 2, 2018, Talen submitted a Self-Report on behalf of Nueces Bay WLE LP (NCR04106), Laredo WLE LP (NCR04090), Barney M Davis LP (NCR04009), and Barney M Davis Unit 1 (NCR04010), stating that, as a Generator Owner, it was in noncompliance with PRC-005-2 R3. Talen submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement. The entity owns a variety of plants in Texas that are known as the Topaz Fleet. The Topaz Fleet consists of four plants: Nueces Bay WLE LP (Nueces Bay), Laredo WLE LP (Laredo), Barney M Davis LP (Barney Davis), and Barney M Davis Unit 1 (Barney Davis 1). During an annual review, the entity discovered that historical battery maintenance and testing evidence did not clearly document all PRC-005 related compliance requirements at two of the four plants. After this discovery, the entity further reviewed the battery maintenance and testing evidence and found noncompliances at all four plants. The entity's review discovered that monthly maintenance and testing did not clearly document a total of 47 required maintenance and testing activities across the four plants. More specifically, the following checks on the plants' battery banks were not clearly documented: (a) 8 electro level inspections, (b) 16 unintentional grounds, (c) 9 battery rack inspections, and (d) 14 battery terminal connection resistance reviews. (For battery terminal connection resistance testing, the contractor made measurements using an instrument that produced a standardized printout showing resistance for all straps, but for just one of the two end-connections.) The entity contracts with a third party to perform its PRC-005 battery testing and maintenance. All of the reports that the entity reviewed are automatically produced by the test equipment used by the contractor. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies is involved because the contractor's battery test form templates did not clearly define tasks and did not provide the documentation the entity needed to demonstrate compliance with PRC-005. A root cause is the incorrect test form templates. Verification is also involved because the entity did not verify that the reports generated by the contractor included all of the required information. This noncompliance started on April 1, 2015, when the entity was required to comply with PRC-005-2 R3 and ended on March 9, 2018, when the entity completed its Mitigating Activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is that the generating units are protected by various components, one of which is the battery system. If the battery systems failed, the Protection System may fail and equipment may be damaged if there was a fault. (The four plants involved in this noncompliance combined have a total capacity of ~2400 MVA nameplate.) The risk is minimized because the Topaz facilities exercise good operating practices including twice daily rounds reviewing each battery system (via visual inspections) and Distributed Control System (DCS) alarms for all battery systems. (Barney Davis 1 does not have an alarm system.) These daily rounds increase the likelihood that the entity would discover an issue with any of its batteries. The Topaz facilities also completed all other PRC-005 required maintenance and testing. Lastly, the risk is reduced because the likelihood of generation loss (the potential harm) is low. As an additional note, the entity believes, based off of communications with its contractors and its plant staff, that all of the maintenance activities were being done, but they were not properly documented because the forms being used were either not detailed enough, or lacked specific fields to document all of the mandatory tests. 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) issued new battery form templates that define tasks and clearly document results; and 2) utilized the fleet wide battery test form templates at all four plants (replacing the incorrect contractor form templates) and the plants have provided the final testing reports. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020209	COM-002-4	R4	Wolverine Power Supply Cooperative, Inc. (Wolverine)	NCR00954	7/1/2016	9/10/2018	Compliance Audit	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 2, 2018, during a Compliance Audit conducted from July 17, 2018, through July 18, 2018, ReliabilityFirst determined that the entity, as a Transmission Operator, was in noncompliance with COM-002-4 R4. To assess adherence to its documented communication protocols, the entity listens to tapes of relevant communications and completes evaluation forms that include the criteria that must be met. These criteria include not only the basic three-part communications protocols contained in COM-002-4 R1, but also some additional details, such as using names, etc. The entity provided 12 of these evaluation forms to ReliabilityFirst during the audit. However, issues were present with 11 of these 12 forms. Four of the forms were mismarked, indicating that proper three-part communication had not been performed. However, the entity pulled the tapes and found that proper three-part communication had occurred. (The entity undertook this effort at the request of the audit team.) The other 7 forms noted that other criteria, not related to three-part communication, was missing in the communication. Additionally, the entity indicated that its process was to provide feedback to employees. However, none of the 12 forms contained any feedback. The root cause of this noncompliance was insufficient training in task performance and communication techniques. This root cause involves the management practice of workforce management, which includes providing training, education, and awareness to employees. This noncompliance started on July 1, 2016, when the entity was required to comply with COM-002-4 R4 and ended on September 10, 2018, when the entity completed its Mitigation Plan.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to properly assess adherence to communication protocols is that the responsible entity would not know whether its communication protocols were being properly implemented, resulting in ineffective communications essential to the reliable operation of the BPS. This risk was mitigated in this case by the following factors. First, ReliabilityFirst noted that it reviewed the training records of relevant employees and concluded that they were adequately trained in 3 part communication (and this supported the findings from the tape reviews that proper three-part communication occurred). The evidence to support this finding included signed training class logs and signed test documentation. Second, the entity had designed an internal control (i.e., the evaluation forms), and although the entity did not complete all of the forms correctly, the control was designed to provide feedback on how well its communication protocols were being implemented, thus providing the opportunity to improve performance and ensure alignment with goals and strategies. 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) reviewed protocol for deficiencies, and made preliminary edits; 2) reviewed Power Point training for deficiencies, and made edits. The entity reviewed protocol for deficiencies, understanding of appendix (evaluation), and made edits. (Edits of the communication protocol include (a) a multi-tiered approach to assessing adherence to the protocol to minimize errors; (b) clarified instructions to drive more accurate completion of the assessment forms; and, (c) instructions for electronically storing completed assessments for better record keeping.); 3) approved and distributed the new Power Point via SharePoint-control environment. The entity will review SharePoint annually for updates as needed; 4) approved and distributed the protocol; 5) implemented the internal control for the assessor; 6) completed the internal control tasks; and 7) assessed each System Operator's performance and adequately addressed any corrective action, coaching, training, feedback. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020378	VAR-002-4.1	R3	Wolverine Power Supply Cooperative, Inc. (Wolverine)	NCR00954	8/28/2018	8/31/2018	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 31, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3. During the morning of August 28, 2018, a storm caused a number of lightning driven alarms at the Alpine generation facility. These lightning events caused an exciter to trip, which required it to be reset. This trip/reset cycle on the exciter disabled the power system stabilizer (PSS) on Alpine Unit 1. Approximately 12 hours later, the entity discovered that the PSS was disabled and reengaged it. However, the entity did not notify its Transmission Operator (TOP) of the PSS status change until August 31, 2018, in violation of VAR-002-4.1 R3. The root cause of the noncompliance was an insufficient pre-start check process. Because the PSS becomes automatically disabled after the trip/reset cycle on the exciter, the entity should have included an explicit PSS check step in its pre-start check process. A contributing cause was the fact that the PSS status was not configured for an individual alarm in the operator's software system. The root cause involves the management practice of grid operations, which includes defining operating procedures and performing incident management and control. This noncompliance started on August 28, 2018, when the entity was required to have notified its TOP that the PSS was disabled, and ended on August 31, 2018, when the entity actually notified its TOP.					
Risk Assessment			This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by an entity failing to notify its TOP of a PSS being disabled is that it could make it more difficult for the TOP to maintain system voltage if a power swing occurred on the system. Also, a loss of the generator could occur due to these power fluctuations at the generator. This risk was mitigated in this case by the fact that Unit 1 at the Alpine generation facility runs in parallel with Unit 2. During the period of the noncompliance, Unit 2 was equipped with an automatic voltage regulator and its PSS was engaged, which assisted in voltage control and minimizing the effects of any power swings due to the PSS being disabled on Unit 1. 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) notified its TOP of the PSS being disabled; 2) configured a layered-alarm approach in its software suite for system operators; and 3) updated the generation unit pre-start checklist to include an explicit step requiring a check of the PSS.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017682	PER-005-2	R1	Ameren Services Company (Ameren)	NCR01175	7/1/2016	8/30/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 24, 2017, SERC sent Ameren an audit notification letter notifying it of a compliance audit scheduled for September 11, 2017 through September 15, 2017. On June 2, 2017, Ameren submitted a Self-Report stating that, as a Balancing Authority and Transmission Operator, it was in noncompliance with PER-005-2 R1. Ameren did not have evidence of implementing the systematic approach it used to develop its System Operator training program. On May 5, 2017, during Ameren's internal review of documentation for PER-005-2 R1, Ameren determined that it did not have documentation of the analysis phase of its systematic approach to training process. Ameren's analysis process is to analyze jobs to gain a complete understanding, compile a task inventory of all tasks associated with each job, select tasks that require training, build performance measures for the task training, and choose instructional setting for training. Ameren submitted an attestation stating that it developed the required task list in accordance with its overview process even though Ameren does not have evidence of such. The primary cause of this noncompliance is that Ameren incorrectly believed that it did not need evidence of implementing all requirements of its systematic approach to training process. This noncompliance started on July 1, 2016, when PER-005-2 became mandatory and enforceable, and ended on August 30, 2018, when mitigation was completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Ameren's failure to conduct an analysis of the required job responsibilities could result in the System Operator's inability to perform all duties required. However, Ameren states that it did conduct the interviews but it failed to document that the interviews occurred. Ameren states that its System Operators have demonstrated competence in performing all of the tasks required to maintain the reliability of the BPS and the majority of Ameren's System Operators have an average of 21 years as certified Reliability Coordinators. No harm is known to have occurred. SERC considered Ameren's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Ameren: 1) produced a stand-alone procedure as a supplement to the existing overview document that will govern the development and maintenance of Ameren's Systematic Approach to Training (SAT). The SAT includes: a. a detailed instructions for each step, b. a form or template by which steps of the process can be governed to ensure repeatability and consistency (when such steps lend themselves to such a form/template), c. "sign-off" sheets to produce evidence as appropriate when step 2) isn't warranted and d. sufficient instruction and detail relative to contemporaneous, as well as routine, initiation of the Procedure to assure the Ameren Training Plan is current with respect to new or revised real-time reliability tasks. Because the training personnel responsible for executing the PER-005 procedure will develop and document the procedure, training will not be required; 2) implemented procedure and produced documentation of SAT; and 3) Ameren's corporate NERC Compliance department developed an internal standard for what constitutes evidence of NERC compliance for Standards and Requirements that have the "develop and implement" requirement and provide training or a lessons learned to Ameren personnel across the enterprise who are responsible for ensuring compliance with NERC standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016380	PRC-005-1b	R2	Ameren Missouri (AUE)	NCR10248	1/1/2013	5/25/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 19, 2016, AUE submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-1b R2.1. AUE did not complete testing activities for two Protection System relays within the defined program interval. On January 27, 2012, AUE created a work order to retire two relays at its Sioux Energy Center (SEC), one relay on unit 1 and one relay on unit 2. On August 1, 2016, an engineer reviewing protective relaying work for a SEC September outage found both of these relays still in service. AUE investigated and found that it removed the two relays from the maintenance and testing database with the understanding AUE was retiring the relays. However, field crews failed to remove the relays from service. Neither of these relays had tags or markings on them in the field that indicated they were out of service. These two overvoltage time-delay relays were powered and wired into the trip circuit. Because AUE removed the relays from the maintenance and testing database, AUE did not conduct maintenance and testing activities on both relays within the defined interval of six years. AUE removed the unit 1 relay from service on August 25, 2016 and removed the unit 2 relay from service on August 12, 2016. The cause of noncompliance was a communication and process breakdown. On January 27, 2012, AUE issued a job order to retire the relays. Field crews did not act upon the job order from engineering to remove the relays from service because the field crews thought that engineering would also issue removal schematics. Engineers believed the field crews would complete the work with the retirement job order, including marking up drawings, and did not believe removal schematics were required. Based on a note that the relays were retired, AUE closed the job order, and removed the relays from the maintenance and testing schedule without field verification to confirm that field crews removed the relays from service. AUE completed a review of 100% of its PRC-005 applicable devices as part of its mitigation activities. In addition to the two relays out of 695 (0.29%) that AUE identified in the Self-Report, AUE identified eight lockout relays out of 272 (2.9%), all at the Audrain generating station, that were noncompliant starting in 2013 and tested outside of the defined interval. This noncompliance started on January 1, 2013, when AUE exceeded the maintenance and testing interval for the SEC unit 1 relay, and ended on May 25, 2018, when AUE completed testing on the noncompliant relays.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The relays remaining in service and the lockout relays that were not maintained within interval could have tripped off the SEC plant or Audrain generating station. The SEC consists of two coal-fired units with a net generating capacity of 970 MW and the Audrain generating station consists of eight natural gas turbines with a combined capacity of approximately 800 MW. However, AUE's transmission modeling determined the loss of these units would not cause instability to the Bulk Electric System. In addition, AUE determined that no misoperation occurred. Redundant protection schemes were in place together with the SEC relays. At the Audrain generating station, the lockout relays are redundant to each other, requiring failure of both to render the protection incomplete. If neither lockout relay were functional, generator or backup ground overcurrent relaying on the generator step-up transformer would clear the fault. The failure of a single lockout relay would have no impact. No harm is known to have occurred. AUE had relevant compliance history. However, SERC determined that AUE's PRC-005 compliance history should not serve as a basis for applying a penalty because the root cause of the previous noncompliance and the root cause of the instant noncompliance are unrelated. In addition, the mitigating actions and actions to prevent recurrence in the previous noncompliance did not address the cause of the instant noncompliance.
Mitigation	To mitigate this noncompliance, AUE: 1) Conducted a walk down process for all AUE BES generators, which included: a. Verification of physical components against the current drawings. b. Verification that all GO devices to which PRC-005 is applicable were properly identified. c. Verification that all GO devices were in the appropriate maintenance and testing (M&T) database. d. Verification that all required GO M&T activities under PRC-005-1b/2/6 were in the appropriate database with the correct assigned intervals for the applicable version of PRC-005. e. Verification of accurate GO completion documentation of M&T activities as required by PRC-005-1b/2/6 requirements as appropriate. f. Submitted a report to SERC with the results of the above assessment which included: i. The total count of GO devices reviewed by device type ii. A list of all non-compliant GO devices, basis for non-compliance, and the date that the device became non-compliant iii. Apparent cause of the non-compliance iv. Potential and actual risks of non-compliance

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016380	PRC-005-1b	R2	Ameren Missouri (AUE)	NCR10248	1/1/2013	5/25/2018	Self-Report	Completed
			g. Brought all non-compliant devices identified during the inventory assessment back into compliance and implemented action items to address the associated cause(s) of the non-compliance. 2) Implemented new internal controls to ensure future compliance with PRC-005-2/6 including any new required GO activities, intervals and devices. 3) Added any missing PRC-005-2/6 devices found during walk downs to PowerBase including the 8 missing lockout relays (located in different building from CTGs) found during Audrain EC walk down. Tested any missing PRC-005-2/6 devices added to PowerBase to ensure PRC-005-2/6 M&T interval compliance. 4) Implemented new internal controls to conduct sample audits at three year intervals at selected ECs to ensure all devices are compliant.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020651	PRC-005-6	R3	Broad River Energy, LLC (BroadRiver)	NCR11313	04/01/2017	05/03/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 7, 2018, BroadRiver submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. BroadRiver did not maintain its Protection System batteries in accordance with the minimum maintenance activities and maximum maintenance intervals in Table 1-4a per the NERC implementation plan. On July 1, 2018, during a self-audit, BroadRiver identified that it did not meet the implementation table for battery capacity testing as required under PRC-005-6 Table 1-4a. The NERC implementation plan requires completion of the six-year activity for 30% of batteries by April 1, 2017. Capacity testing is a six calendar year requirement under Table 1-4(a). BroadRiver has a total of five units, with one battery per unit. On May 6, 2016, BroadRiver replaced one battery and completed capacity testing on that battery at that time. As of April 1, 2017, Broad River had only met the six calendar year activity for one of its five batteries, or 20%. Broad River completed the required four calendar month and 18 calendar month activities for the five batteries, but failed to complete the required six calendar year activity for 30% of batteries by April 1, 2017. This noncompliance started on April 1, 2017, when BroadRiver did not meet the 30% implementation plan requirement for battery capacity testing, and ended on May 3, 2017, when BroadRiver completed capacity testing on 40% of its batteries. The root cause of this noncompliance was a lack of an effective transition plan to the requirements of PRC-005-6.
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). BroadRiver's failure to complete the capacity test for a second battery, which would have meet the 30% requirement, by April 1, 2017 could have resulted in the associated Protection System devices not operating as designed and the next level of protection having to respond to the fault. However, BroadRiver was completing maintenance activities as required under PRC-005-1.1 during this transition and BroadRiver was only approximately one month late in meeting the 30% requirement. In addition, plant staff makes rounds daily, which include checking battery rooms and monitoring battery charger alarms. BroadRiver has battery alarms which alert plant control room personnel of any issues. BroadRiver identified no issues when completing the capacity testing; therefore, the batteries should have operated as designed. BroadRiver in an independent power producer facility that operates under purchase power agreements in the Duke Energy Balancing Area. BroadRiver is comprised of five gas-fired units with a total capacity of approximately 1,000 MW with less than a 10% capacity factor. Thus, a loss of BroadRiver would have had minimal impact to the BPS. No harm is known to have occurred. SERC considered BroadRiver's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Broad River: 1) completed battery capacity testing; and 2) developed a PRC-005-6 tracking sheet, which includes the date that the next tests are due.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020269	PRC-005-6	R3	Cube Hydro Carolinas, LLC	NCR01169	08/1/2018	08/27/2018	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 24, 2018, Cube submitted a Self-Report stating that, as a Generator Owner and Transmission Owner, it was in noncompliance with PRC-005-6 R3. Cube did not maintain its Protection System batteries in accordance with the minimum maintenance activities per PRC-005-6 R3. On August 16, 2018, during a maintenance meeting and review of current battery readings, Cube discovered that it had not performed the battery readings for the previous quarter. As a result, Cube failed to perform the required four-calendar month PRC-005-6 verification and inspection for all five batteries. This noncompliance started on August 1, 2018, when Cube failed to perform the required 4-month battery maintenance activities within the interval, and ended on August 27, 2018, when Cube performed the required 4-month battery maintenance activities. The root cause of this noncompliance was a lack of effective internal controls. The Cube quarterly battery reading schedules are in its automated maintenance system, but the supervisors overlooked the required deadlines. In addition, the subject matter expert for PRC-005-6 failed to track the deadline.
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). Cube's failure to conduct the 4-month battery verification and inspection within the defined interval could have impacted the functionality of the Protection System associated with all of Cube's facilities and resulted in downstream Protection System devices having to respond to faults on the system. However, Cube completed the 4-month inspection and verification less than one month late and Cube identified no issues. All of Cube's batteries and battery chargers are alarmed and monitored for loss of AC, DC voltage excursions, no charging current, and grounds. During the weekly routine maintenance rounds, Cube checks and records the battery readings. Cube has 13 units at four dams. The units total 215 MW, range in size from 157 MWs to 8.75 MWs, and operate with a combined capacity factor of about 36%. Thus, the loss of Cube generation would not result in a significant impact to the BPS. No harm is known to have occurred. The Cube has relevant compliance history. However, SERC determined that the Cube's compliance history should not serve as a basis for applying a penalty because the end dates of the prior instances of noncompliance were in February 2012.
Mitigation	To mitigate this noncompliance, Cube: 1) performed the required 4-month battery maintenance activities; 2) retrained the maintenance supervisors as to the importance of meeting the scheduled maintenance activities; and 3) added a recurring appointment on the subject matter expert and Cube's compliance officer's calendars for maintenance deadlines.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018747	MOD-032-1	R2	City of Springfield, IL (CWLP)	NCR01328	11/01/2017	12/05/2017	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 December 8, 2017, CWLP submitted a Self-Report stating that, as a Balancing Authority, Generation Owner, and Transmission Operator, it was in noncompliance with MOD-032-1 R2. CWLP did not provide CWLP did not provide steady-state, dynamics, and short circuit modeling data to its Planning Coordinator (PC), Midcontinent Independent System Operator, Inc. (MISO), within the deadline prescribed in the data requirements and reporting procedures. On December 7, 2017, a CWLP Planning Engineer notified the CWLP Superintendent of Compliance of that CWLP failed to timely respond to a MISO MOD-032-1 Model Validation data request. On June 16, 2017, MISO sent CWLP the Model Validation data request, requiring CWLP to update the Bulk Electric System (BES) model impedance discrepancies identified in the request by October 31, 2017. CWLP submitted the updated BES model data to MISO on November 30, 2017 and December 5, 2017. This noncompliance started on November 1, 2017, when CWLP did not submit the requested data to its PC by the October 31, 2017 due date, and ended on December 5, 2017, when CWLP submitted all requested data to its PC. The root cause of this noncompliance was lack of internal controls to track data requests to ensure timely data submittals.
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. CWLP's failure to provide its PC accurate steady-state, dynamics, and short circuit modeling data could have resulted in the PC incorrectly modeling system behavior. Notwithstanding, the information was submitted approximately one month after the deadline, and the untimely data submittal did not cause any issues in MISO's model build or subsequent studies. No harm is known to have occurred. SERC considered CWLP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CWLP: 1) submitted the requested data to MISO; 2) implemented an internal control requiring specified Planning Engineer personnel to assign a task in the Outlook email to track the data request and submittals; 3) added the CWLP Superintendent of Compliance to the MISO Planning Subcommittee Committee (PSC) email distribution list, increasing the number of CWLP personnel on the distribution list from two to three; and 4) added Planning Engineer attendance to the CWLP compliance meetings for awareness of compliance issues and to help ensure adherence to NERC reliability standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018999	VAR-002-4.1	R1	Duke Energy Progress, LLC (DEP)	NCR01298	10/24/2017	10/25/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 19, 2018, Duke Energy Progress, LLC (DEP) submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R1. DEP had one instance where it failed to operate an automatic voltage regulator (AVR) in automatic controlling voltage. In November 2016, Sharon Harris Nulear Station (HNS) replaced its AVR during a refueling outage. HSN added steps to its operating procedure that it used during the commissioning of the AVR, and trained its operators on the use of the new AVR, but it did not remove those commissioning steps prior to startup and power operation. On October 22, 2017, HNS shutdown to repair a steam leak. During this shutdown, the AVR was moved to manual mode as required. On October 24, 2017, power escalation began and the generator was synchronized to the grid at 10:46 p.m. Per the Voltage Schedule assigned to HNS and HNS's operating procedures, the AVR must be in "Automatic and controlling Voltage" mode during normal operation, and startup procedures require the AVR to be in automatic mode prior to synchronizing the generator to the grid. Later that day, HNS increased power to approximately 29% power and held it there for repairs to the main condenser. At 11:48 a.m. on October 25, 2018, during a system walkdown, an engineer noticed the AVR was still in manual mode and immediately notified Operations. At 11:50 a.m the operator notified the Transmission Operator (TOP). At 12:33 p.m. the operator placed the AVR in automatic controll and notified the TOP of the change of state. The root cause of this noncompliance was a deficient procedure, which was intended to be implemented only during the commissioning of the AVR. The additional steps added to the Operator Procedure were intended to be temporarily and used only for commissioning the AVR, at which time they were supposed to have been removed. This noncompliance started on October 24, 2017, when DEP began operating the generator connected to the grid but without the AVR in automatic mode, and ended on October 25, 2017, when DEP placed the AVR in automatic controlling voltage mode.
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. Failure to maintain the AVR in automatic mode could result in uncontrolled voltage transients. However, Harris maintained its voltage schedule throughout the noncompliance, its TOP did not require or request any corrections or changes, and the transmission system maintained normal operation. DEP did not reach generator operating limits and there were no misoperations or voltage-related events. The operators took corrective action and notified the TOP as soon as the operator noted the discrepancy. The AVR was in manual operation mode for less than 24 hours. No harm is known to have occurred. The DEP has relevant compliance history. However, SERC determined that the DEP's compliance history should not serve as a basis for applying a penalty because of the different causes of the prior noncompliance and the current noncompliance.
Mitigation	To mitigate this noncompliance, DEP: 1) switched the AVR to automatic mode; 2) immediately submitted a Procedure Change Request to remove the added AVR commissioning language from the Operating Procedure; 3) conducted awareness training of this event and NERC requirements to all Harris licensed Operators; 4) shared the event with all applicable Nuclear Site Management and the Operations CFAM (Centralized Function Area Manager) for dissemination to their groups for awareness; and 5) verified proper operation of the new Harris AVR and related requirements of VAR-002 are included in operator training and requalification topics.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016593	TOP-002-2.1b	R11	Duke Energy Progress, LLC (DEP)	NCR01298	10/8/2016	10/8/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 6, 2016, SERC sent DEP an audit detail letter notifying it of a compliance audit scheduled for September 6, 2016 through December 16, 2016. On November 28, 2016, DEP submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-002-2.1b R11. DEP did not update system studies to reflect current system conditions. DEP's real-time contingency analysis tool (RTCA) performs a contingency analysis every five minutes. It also analyzes the operating system to identify islands (limited areas of interconnected load and generation no longer connected to the larger network). The analysis uses data transmitted from the field to establish which lines and generators are in service for the model. When RTCA identifies islands, the tool performs the RTCA on the smallest island and does not perform the analyses on the rest of the model. DEP TOP engineers have an option to preset the minimum number of buses to define an island in RTCA. At the time of this noncompliance, DEP had set the threshold at 5 buses. The RTCA system operates in parallel with a second, similar system that DEP uses for other system studies, Study Contingency Analysis (STCA). However, the base case used for the STCA studies is not determined in real-time and could be up to an hour old. The operator may update the status before running the model. On October 8, 2016, Hurricane Matthew moved through the DEP service territory. By 4:00 p.m. the storm had taken approximately 27 networked transmission lines out of service. At one point, the RTCA presented the System Operator with a non-alarm message that the RTCA "partially solved." The System Operators understood this message to be resulting from the loss of many transmission lines across the DEP footprint during the course of the day. A System Operator attempted to run a study on the STCA to determine the possible effect of a breaker operation and received an "island error" warning. Such warnings are a rare occurrence and are not treated as alarms. The system support staff reviewed the logs for the RTCA and discovered a similar warning occurred on that system at 3:23 p.m. RTCA had been running, but had not been solving contingencies for the entire TOP footprint since it had identified multiple islands in the model at 3:23 p.m. The cause of this noncompliance was the low setting for recognition of islands and the way DEP modeled distributed resources on transmission lines in the RTCA model. The loss of multiple transmission lines with distributed resources, inadequate alarming for multiple island detection and inadequate System Operator knowledge of RTCA impacts due to islands in the model contributed to the duration of this noncompliance. The noncompliance started 10/8/2016 at 3:23 p.m. when the RTCA stopped solving contingencies for the majority of the DEP system and ended on 10/8/2016 at 11:56 p.m. when DEP adjusted the modeling and restored RTCA.
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. Failure to perform seasonal, next-day, and current-day Bulk Electric System (BES) studies to determine SOLs could result in inadequate planning and improper operator responses to known and anticipated system configurations. However, in this case the accuracy of system studies was already suspect due to extensive loss of transmission and generation. If System Operators had identified potential SOL exceedances resulting from RTCA it is not likely that DEP would have pro-actively radialized the transmission line and introduced additional possible instabilities to the network. System instrumentation continued to provide indication of BES configuration, and the noncompliance did not jeopardize the Reliability Coordinator's RTCA system. In addition, the DEP System Operators were monitoring the real-time line loading and real-time transformer loading displays on their Energy Management Systems that displays the percentage of line and transformer loadings on each transmission line in service from highest % loading to lowest % loading. DEP maintained Situational Awareness of real-time line and transformer loading through System Operators monitoring these displays throughout the noncompliance. No harm is known to have occurred. SERC considered DEP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEP: 1) took immediate action to manually remove the distributed generators from the RTCA model to restore RTCA operation; 2) modified the network model to convert these resources from generators to (negative) loads alleviating the issue permanently; 3) adjusted the minimum bus setting for the island definition from 5 to 12; 4) enabled an Island Detection Alarm; 5) sent all operators, operations management, and operator training an email detailing the island issue to make them aware of how to manually address/remove small islands if detected; and 6) included training for System Operators during the Fall System Operator Continuing Training.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016592	TOP-004-2	R1	Duke Energy Progress, LLC (DEP)	NCR01298	10/8/2016	10/8/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 16, 2016, SERC sent DEP an audit detail letter notifying it of a compliance audit scheduled for September 6, 2016 through December 16, 2016. On November 28, 2016, DEP submitted a Self-Report stating that, as a Transmission Operator (TOP) it was in noncompliance with TOP-004-2 R1. DEP did not operate within its System Operating Limit (SOL). On October 8, 2016, Hurricane Matthew moved through the DEP service territory. At approximately 4:17 p.m., DEP experienced a SOL exceedance of the Weatherspoon-Fayetteville DuPont 115 kV line as a result of the loss of the Weatherspoon-Fayetteville 230 kV line during storm activity. DEP had approximately 27 networked 115 kV and 230 kV lines outaged due to the hurricane prior to the loss of the Weatherspoon-Fayetteville 230 kV line. That loss of transmission capability resulted in an overload on the Weatherspoon-Fayetteville DuPont 115 kV line. DEP has identified the Facility Rating of 119 MVA as the SOL for the Weatherspoon-Fayetteville DuPont 115 kV line. Data indicates that the line was overloaded by approximately 14% for approximately 7 seconds and then by approximately 8% for 4 minutes, 16 seconds. The system operator evaluated the overload, and mitigated the SOL exceedance by opening the Fayetteville DuPont 115 kV circuit breaker at the Fayetteville 230 kV substation by supervisory control at 4:21 p.m. The operator then notified the Reliability Coordinator (RC) of the SOL exceedance at approximately 4:30 p.m. The RC acknowledged that it had seen the overload and that DEP had corrected the SOL exceedance. The RC issued no Operating Instructions in response to the SOL exceedance. The cause of this noncompliance was hurricane-related outages that resulted in the loss of several lines. This noncompliance started on October 8, 2016 at approximately 4:16 p.m. when the DEP exceeded an SOL and ended on October 8, 2016 at approximately 4:21 p.m. when DEP corrected the SOL exceedance.
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. Exceeding SOLs can result in equipment damage, unanticipated line and generation losses, and voltage or frequency collapse. However, in this case the DEP operators were already operating the system in a degraded state. Despite the loss of 27 transmission lines, DEP operators had indications of the system status, awareness of the system conditions and were well trained in system operations. The operator identified the exceedance quickly and took corrective action in less than five minutes. The RC did not need to issue any Operating Instructions. The exceedance occurred on a 115kV line, and not on higher voltage, and therefore higher risk, lines. When Hurricane Matthew left the region, 58 115kV and 230 kV lines were out of service with no other exceedances identified. No load or generation was lost as a result of the exceedance. No harm is known to have occurred. SERC considered DEP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEP immediately took corrective action to terminate the exceedance. Because storm activity outside of the control of DEP caused the exceedance, no additional actions are necessary to prevent a recurrence.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020365	PRC-019-2	R1	Doswell Limited Partnership (Doswell)	NCR11193	07/01/2016	05/04/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 11, 2018, Doswell submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. Doswell failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions in accordance with the NERC Implementation Plan. At the time of the noncompliance, the Doswell Facility consisted of two combined cycle systems and one additional peaking turbine for a total of seven generating units and 860 MWs. On June 1, 2018, Doswell added two additional generating units. In June 2016, Doswell had a coordination study performed by an outside contractor. On June 30, 2016, the contractor provided the study to Doswell. On July 20, 2016, Doswell met with the contractor to review the results of the study, which showed required relay settings changes for six generating units to meet the requirements of the Standard. Doswell was unsuccessful in finding a contractor that could change the relay settings during the fall 2016 outage. On May 4, 2017, during the spring outage, contractors changed the relay settings on units to achieve the 40% Implementation Plan requirement. On May 15, 2017, contractors completed the required relay setting changes for the six relays that required setting changes to reach 100% implementation. These six relays were associated with six generating units. In all cases, the incorrect setting was on the backup relay. As a result, if the primary relayed failed, the backup would have been slow to respond. The required changes were back-up generator protection loss of excitation from a setting of 1.6898 to 1.8574, and from a setting of 1.98, 2 cycles to 1.9471, 3 cycles. On September 18, 2017, during an internal review initiated after discovering issues with other Reliability Standards with phased implementation plans, Doswell identified that it failed to meet the 40% Implementation Plan requirement. This noncompliance started on July 1, 2016, when Doswell failed to meet the 40% Implementation Plan requirement, and ended on May 4, 2017, when Doswell completed the required relay setting changes to meet the 40% Implementation Plan requirement. The cause of the noncompliance was Doswell's misinterpretation of the percent implementation requirements. The misinterpretation related to what constituted the calculation of percentages complete. Doswell utilized percent of work completed rather than percent of Facilities completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Doswell's failure to verify that the voltage regulating system controls were properly coordinated with its Protection Systems could lead to a generator tripping for a system event that should not have caused the generator to trip or could fail to trip before equipment damage occurred. However, the primary relays were set correctly and the incorrect relay settings were limited to the back-up relays. On May 15, 2017, Doswell made the required relay setting changes for the six relays resulting in Doswell completing the coordination for 100% of its units two years prior to the 100% Implementation Plan requirement. In addition, the units did not trip during the period of noncompliance. The twelve month capacity factors for the two combined cycle Facilities were 53% and 60%. No harm is known to have occurred. SERC considered Doswell's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Doswell: 1) completed the required relay setting changes; 2) created a NERC Preventive Maintenance (PM) task for PRC-019 in its compliance management tool requiring a coordination study and any needed changes identified in that study is implemented within five years of the date of the last coordination study, which is currently in June 2021. This PM will be triggered approximately 6 months prior to the date the coordination study must be completed; 3) provided training for employees involved with the PRC-019-2 NERC Reliability Standard to ensure that this violation is not repeated; and 4) revised the Internal Compliance Program utilized by Doswell to ensure the implementation process for new or revised standards are understood, or that guidance is sought from NERC or the appropriate regional entity to clarify Doswell's responsibility for this action.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020366	PRC-024-2	R1	Doswell Limited Partnership (Doswell)	NCR11193	07/01/2016	05/04/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 11, 2018, Doswell submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. Doswell failed to set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating units within the "no trip zone" of PRC-024 Attachment 1 in accordance with the NERC Implementation Pan. At the time of the noncompliance, the Doswell Facility consisted of two combined cycle systems and one additional peaking turbine for a total of seven generating units and 860 MWs. On June 1, 2018, Doswell added two additional generating units. In June 2016, Doswell had a relay coordination study performed by an outside contractor. On June 30, 2016, the contractor provided the study to Doswell. On July 20, 2016, Doswell met with the contractor to review the results of the study, which showed required relay settings changes for six generating units to meet the requirements of the Standard. Doswell was unsuccessful in finding a contractor that could change the relay settings during the fall 2016 outage. On May 4, 2017, during the spring outage, contractors changed the relay settings on units to achieve the 40% Implementation Plan requirement. On May 7, 2017, contractors completed the required relay setting changes for the six generating units to reach 100% implementation. Over-frequency and under-frequency relay setting changes were required. The required changes ranged from a setting of 60 cycles to 3441 cycles at 61.2 Hz, and from a setting of 1 second to 57.36 at 58.1 Hz seconds. On September 18, 2017, during an internal review initiated after discovering issues with other Reliability Standards with phased implementation plans, Doswell identified that it failed to meet the 40% Implementation Plan requirement. This noncompliance started on July 1, 2016, when Doswell failed to meet the 40% Implementation Plan requirement, and ended on May 4, 2017, when Doswell completed the required relay setting changes to meet the 40% Implementation Plan requirement. The root cause of the noncompliance was Doswell's misinterpretation of the percent implementation requirements. The misinterpretation related to what constituted the calculation of percentages complete. Doswell utilized percent of work completed rather than percent of Facilities completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Doswell's failure to set generator frequency protective relaying so that the relays do not activate and trip the applicable generating units within the "no trip zone" could lead to a generator tripping for a system event that should not have caused the generator to trip. On May 7, 2017, Doswell made the required relay setting changes resulting in Doswell completing the coordination for 100% of its units two years prior to the 100% Implementation Plan requirement. In addition, the units did not trip during the period of noncompliance. The twelve month capacity factors for the two combined cycle Facilities were 53% and 60%. No harm is known to have occurred. SERC considered Doswell's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Doswell: 1) completed the required relay setting changes; 2) created a NERC Preventive Maintenance (PM) task in its compliance management tool requiring a coordination study be performed to ensure the relay settings are maintained in accordance with PRC-024; 3) provided training for employees involved with the PRC-024-2 NERC Reliability Standard to ensure that this violation is not repeated; and 4) revised the Internal Compliance Program utilized by Doswell to ensure the implementation process for new or revised standards are understood or that guidance is sought from NERC or the appropriate regional entity to clarify Doswell's responsibility for this action.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018995	EOP-005-2	R1	Duke Energy Carolinas, LLC (DEC)	NCR01219	09/01/2015	09/26/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 17, 2018, DEC submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with EOP-005-2 R1. DEC reported that it did not properly include a Cranking Path in its restoration plan. On October 19, 2017, during an extent-of-condition review related to a self-reported noncompliance of CIP-002-5 R1, DEC identified the EOP-005-2 R1 noncompliance. In its 2014 restoration plan, DEC included Lee 7C as a Blackstart Resource and described a Cranking Path from Lee to Oconee Nuclear Station. In 2014 and 2015, DEC performed reliability studies and determined that it should substitute a Jocassee-to-Oconee resource for the Lee-to-Oconee resource. DEC revised its 2015 recovery plan to show Jocassee 2 as a Blackstart Resource and Jocassee-to-Oconee as the Cranking Path. However, before receiving approval by its Reliability Coordinator, DEC realized that it had not tested Jocassee 2 as required to declare it as a Blackstart Resource, and decided to restore the original Lee-to-Oconee configuration for the 2015 restoration plan. DEC revised its recovery plan to show Lee 8C as a Blackstart Resource, but failed to change the Cranking Path back to the Lee-to-Oconee configuration. As a result, the restoration plan referred to Jocassee as the starting point for a Cranking Path, but the restoration plan did not show Jocassee as a Blackstart Resource. This noncompliance started on September 1, 2015, when DEC implemented the recovery plan with the incomplete Cranking Path, and ended on September 26, 2016, when DEC implemented the correct recovery plan. The root cause of this noncompliance was inadequate controls, e.g., a checklist, to ensure that Duke considered all sections of the recovery plan while making revisions.
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. Inadequate identification of Blackstart Resources and Cranking Paths will jeopardize the Transmission Operator's access to the generation resources needed for nuclear plant safety and system recovery. However, situations requiring the implementation of the recovery plan are unlikely and if Duke needed to implement the recovery plan, it correctly identified multiple Blackstart Resources and specific switching instructions would have successfully completed Cranking Paths from those resources to the critical loads such as nuclear units. When Duke tested Jocassee 2, it tested satisfactorily as a Blackstart Resource. Duke's recovery plan allows for the use of hydro units such as Jocassee 2 in the event that listed Blackstart Resources are not available. If a System Operator had chosen to use Jocassee 2, the System Operator had access to procedures that would have allowed connection to Oconee. No harm is known to have occurred. SERC considered DEC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEC: 1) revised the 2016 Plan to include the Jocassee 2 Blackstart Resource along with its corresponding Cranking Path; 2) reviewed 2014 and 2017 Plans to confirm the plans listed the Cranking Paths that correctly correspond to the identified Blackstart Resources; 3) developed a checklist of items for the owner of the TOP restoration plan (Plan) that needs to be used when making a change and/or for the annual review of the TOP Plan, which will serve as an internal control when a change or annual review occurs to the TOP Plan; 4) conducted an Apparent Cause Analysis; 5) conducted a meeting with Compliance Coordination, and DEC System Operations Compliance to discuss details of the DEC TOP Plan Checklist; 6) developed a documented onboarding process from the System Operations Owner of the TOP Plan to the succeeding Owner to establish adequate transfer of knowledge; and 7) trained affected personnel on the new onboarding process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019020952	COM-002-4	R3	Effingham County Power, LLC (ECP)	NCR11597	07/01/2016	12/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 14, 2019, ECP submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with COM-002-4 R3. ECP failed to retain documentation that it conducted initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction. On January 10, 2019, during a routine internal audit, ECP discovered that it did not have documentation for the initial training of COM-002-4 R3. On June 29, 2016, ECP sent an email to the operators with the details of the requirement as well as a copy of the plant-specific COM-002 program. The email instructed the operators to read and to reply that the operator understood the training materials. ECP retained a copy of the initial email in the corporate regulatory files. However, ECP did not retain the operator responses in the corporate regulatory files. ECP retained the email replies from the operators in an email folder. Per ECP corporate policy, ECP purges emails older than 18 months unless they are for legal or regulatory purposes. Because the responses from the operators were in an email folder and not the corporate regulatory files, ECP purged the email replies. This noncompliance started on July 1, 2016, when the Requirement became mandatory and enforceable, and ended on December 11, 2017, when the last operator completed training and ECP documented the completion. The root cause of the noncompliance was a lack of an internal control, e.g., a checklist, to ensure that evidence needed to demonstrate compliance is added to the appropriate folder.
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. ECP's failure to provide initial training to its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an Operating Instruction could limit operators' awareness of predefined communications protocols, which could increase the possibility of miscommunication. However, the operators received an email on June 29, 2016 reminding them of this requirement along with the associated documented procedure. ECP failed to retain the emails confirming the operator's read the email and training materials by July 1, 2016. In addition, no operator received an operating instruction during an emergency. No harm is known to have occurred. SERC considered ECP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ECP: 1) trained all applicable compliance personnel on the documentation required for COM-002. All documentation will be retained in the appropriate NERC electronic directories and backed up; 2) will train all operators annually on the COM-002 Standard and document training; 3) will train any new employee on NERC Standard requirements as part of new employee orientation and document training; and 3) implemented a new NERC Compliance Checklist that will require someone at ECP to complete monthly. While completing this spreadsheet, the assigned person will be required to collect the required evidence to show compliance for each applicable Standard and Requirement and add it to the appropriate folder. This will help make sure evidence is not lost or misplaced. The Cogentrix Compliance department will be conducting spot checks to verify that Effingham is completing this task as assigned.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020497	MOD-027-1	R2	East Kentucky Power Cooperative (EKPC)	NCR01225	7/1/2018	9/4/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 4, 2018, EKPC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. EKPC did not provide its Transmission Planner (TP) a verified turbine/governor and load control or active power/frequency control model in accordance with the NERC implementation plan. On June 25, 2018, EKPC submitted the MOD-027-1 model data for EKPC units to PJM Interconnection, LLC (PJM) as its TP. The EKPC data submission included EKPC's Bluegrass units 1 and 2. Also on June 25, 2018, EKPC submitted the MOD-025 data for Bluegrass units 1, 2, and 3 to PJM as the TP. PJM responded to the MOD-025-2 data submission that it was not the TP for Bluegrass unit 3. However, because PJM did not inform EKPC that it was not the TP for Bluegrass units 1 and 2 at the same time PJM informed EKPC that it was not the PC for Bluegrass unit 3, EKPC incorrectly believed that PJM was the TP for Bluegrass units 1 and 2. On September 4, 2018, PJM informed EKPC that it is not the TP for the Bluegrass units 1 and 2 and would not accept the submitted MOD-027-1 modeling data. The Bluegrass units comprised 17% of the 36% unit gross MVA for which EKPC submitted model data to PJM therefore EKPC did not meet the 30% submission requirement by July 1, 2018. The primary cause of the noncompliance was EKPC's incorrect belief that since EKPC is a member of PJM, that PJM is the TP for all EKPC units, including EKPC's Bluegrass units. This noncompliance started on July 1, 2018 when EKPC was required to meet the 30% implementation plan and ended on September 4, 2018, when EKPC submitted the model data to its TP and met the 30% implementation plan requirement.
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. EKPC's failure to provide its TP verified model data for Bluegrass units 1 and 2 could results in inaccurate system models. However, EKPC provided the data for Bluegrass units 1 and 2 only 65 days late for a requirement that has a full implementation requirement of July 1, 2024. No harm is known to have occurred. SERC considered EKPC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EKPC: 1) provided the model data for Bluegrass to LGE and KU; and 2) developed an internal document noting the TP for all individual EKPC generation units and distributed this document to all relevant Standards owners.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020496	MOD-026-1	R2	East Kentucky Power Cooperative (EKPC)	NCR01225	7/1/2018	9/4/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 4, 2018, EKPC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. EKPC did not provide its Transmission Planner (TP) a verified generator excitation control system or plant volt/var control function model in accordance with the NERC implementation plan. On June 25, 2018, EKPC submitted the MOD-026-1 model data for EKPC units to PJM Interconnection, LLC (PJM) as its TP. The EKPC data submission included EKPC's Bluegrass units 1 and 2. Also on June 25, 2018, EKPC submitted the MOD-025 data for Bluegrass units 1, 2, and 3 to PJM as the TP. PJM responded to the MOD-025-2 data submission that it was not the TP for Bluegrass unit 3. However, because PJM did not inform EKPC that it was not the TP for Bluegrass units 1 and 2 at the same time PJM informed EKPC that it was not the PC for Bluegrass unit 3, EKPC incorrectly believed that PJM was the TP for Bluegrass units 1 and 2. On September 4, 2018, PJM informed EKPC that it is not the TP for the Bluegrass units 1 and 2 and would not accept the submitted MOD-026-1 modeling data. The Bluegrass units comprised 17% of the 36% unit gross MVA for which EKPC submitted model data to PJM therefore EKPC did not meet the 30% submission requirement by July 1, 2018. The primary cause of the noncompliance was EKPC's incorrect belief that since EKPC is a member of PJM, that PJM is the TP for all EKPC units, including EKPC's Bluegrass units. This noncompliance started on July 1, 2018 when EKPC was required to meet the 30% implementation plan and ended on September 4, 2018, when EKPC submitted the model data to LGE and KU and met the 30% implementation plan requirement.
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. EKPC's failure to provide its TP verified model data for Bluegrass units 1 and 2 could results in inaccurate system models. However, EKPC provided the data for Bluegrass units 1 and 2 only 65 days late for a requirement that has a full implementation requirement of July 1, 2024. No harm is known to have occurred. SERC considered EKPC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EKPC: 1) provided the model data for Bluegrass to LGE and KU; and 2) developed an internal document noting the TP for all individual EKPC generation units and distributed this document to all relevant Standards owners.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017287	PRC-004-4(i)	R1	Entergy (Entergy)	NCR01234	11/13/2016	12/13/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 28, 2017, Entergy submitted a Self-Report stating that, as a Transmission Owner it was in noncompliance with PRC-004-4(i) R1. Entergy did not determine the cause of a misoperation within 120 days of the operation. On July 15, 2016, a fault occurred on a 115 kV transmission line, tripping breakers on both ends of the line and also tripping an interconnected line at the far end. Following an initial analysis on the same day, Entergy concluded that an incorrect operation had occurred, however there is no record of Entergy issuing a Condition Report (CR) per its procedure to begin a detailed assessment of the Misoperation cause. If Entergy had followed its procedure, then it would have issued a CR to investigate the potential Misoperation and begin a corrective action plan if applicable. On November 17, 2016, in preparation for quarterly reporting of Misoperations to the ERO, Entergy generated a quarterly report used to identify outages that its System Operators recorded with a relay response type of "Incorrect". Entergy also uses that report to verify that it has generated a CR for possible Misoperations. Based on a preliminary third quarter version of this report, Entergy discovered there was no CR for the July 15, 2016 possible Misoperation and Entergy promptly initiated a CR. On December 13, 2016, 151 days after the operation, Entergy completed its assessment, determined a Misoperation had occurred and identified its probable cause. The cause of the noncompliance is that Entergy failed to follow its procedure and thereby failed to submit the CR that would have triggered the Misoperation cause identification. The noncompliance started on November 13, 2016, 121 days after the misoperation and ended on December 13, 2016 when Entergy identified the cause of the misoperation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to properly identify the cause of a relay Misoperation within 120 days delays the correction of the cause and presents the opportunity for additional misoperations. However, in this case, the misoperation was not caused by incorrect Protection System functions, but the fault conditions caused the actuation of only one additional distance relay and the tripping of one additional breaker. Post-trip analysis determined that all relays functioned as designed and adjusted and that the additional relay actuation occurred due to the nature of the fault. Entergy did identify the cause of the Misoperation and was only approximately one month late in doing so. The same type of misoperation has not reoccurred and no other misoperation occurred on this line. No harm is known to have occurred. SERC considered Entergy's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Entergy: 1) identified the correct Protection System component as cause of the Misoperation; 2) performed a Causal Determination in order to determine the cause of the event and actions were taken to prevent recurrence; 3) determined, based on interviews, applicable human performance traps included perceived time pressure to complete relay reviews quickly and avoid the Relay Review "still pending" list; overconfidence in assessing what appeared to be a typical overtrip event; and Off-normal / Infrequent Conditions associated with this being a NERC defined Slow Trip Misoperation. Applicable Human Performance tools not used effectively included Self Checking, Procedure Usage, Questioning Attitude, and Place Keeping; 4) provided refresher training to Grids, with emphasis on the following items: a. The need to create a CR immediately, if not already created, upon COS completed relay review determination of a suspected or confirmed Misoperation; b. NERC's Misoperation definition, in particular "Slow Trip", to ensure future accurate identification of Misoperations; c. Remote Zone 3 trips warrant additional scrutiny and are not always indicative of an overtrip; d. The need to designate relay reviews as completed only after all necessary review activities have been performed, inclusive of supporting documentation. 5) Completed refresher training.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018944	MOD-027-1	R5	Entergy (Entergy)	NCR01234	9/17/2017	10/24/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 4, 2018, Entergy submitted a Self-Report stating that, as a Transmission Planner (TP), it was in noncompliance with MOD-027-1 R5. Entergy reported it did not provide a written response to the Generator Owner (GO) within 90 days of a model verification that the model was usable or not usable. Prior to January 16, 2017, Entergy Power Generation plant personnel (GO) performed communications with Transmission Planning employees concerning MOD-026-1 and MOD-027-1 by using emails directed to the employees. On January 16, 2017, a new Power Generation procedure became effective which directed Entergy Power Generation plant personnel to send model information to a specific email mailbox. Transmission Planning had been involved in the procedure development, but Transmission Planning employees were unaware of the effective date of this procedure or the existence of the new, dedicated mailbox. As a result, Transmission Planning employees had not been monitoring the mailbox. Between January and the beginning in June 2017, Entergy Power Generation plant personnel continued to direct email to individual Transmission Planner employees as well as the new mailbox, but in June 2017, Power Generation employees sent some of the communications exclusively to the dedicated mailbox. Transmission Planning became aware of this in October during a meeting between Power Generation and Transmission Planning to discuss modeling data, and then retrieved the overlooked requests. While most requests were still within the 90 days response requirement, one request dated June 19, 2017 was beyond the 90 day requirement to respond. The cause of the noncompliance is the lack of comprehensive change management communication from Power Generation to Transmission Planning before the effective date of the new Power Generation procedure. This resulted in Transmission Planning failing to regularly check the dedicated mailbox but relied solely on emails directly sent to Transmission Planning personnel. This noncompliance started on September 17, 2017, 90 days after the submission of model verification, and ended 37 days later on October 24, 2017, when Entergy responded to the GO.
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. Failure to acknowledge receipt of a verified model could delay accurate modeling. However, in this case the model was satisfactory and no model changes were necessary. If changes had been necessary, the delay involved one 208 MVA unit and would not have greatly affected model results. Furthermore, the implementation plan for MOD-027-1 allows ten years to reach full compliance. SERC considered Entergy's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Entergy: 1) responded to the GO; 2) set up an Outlook rule to email the Transmission Planning employees every time the dedicated email box received an email; and 3) updated procedure guidance to ensure proper change management occurs and provide training to appropriate individuals.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017816	PRC-005-2(i)	R3	Georgia Transmission Corporation (GTC)	NCR01249	7/9/2015	5/25/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 25, 2017, SERC sent GTC an audit detail letter notifying it of a compliance audit scheduled for April 25, 2017 through August 11, 2017. On June 22, 2017, GTC submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. GTC did not perform the battery testing in accordance with Table 1-4(a) of PRC-005-6 for one battery. SERC later determined that the start date of the noncompliance began under version PRC-005-2(i) of the Standard. On May 24, 2017, during an internal controls review of battery testing data for all of GTC's substations, GTC identified that it did not meet the minimum maintenance requirements of PRC-005-6 for a single battery at the Cuthbert Primary substation. GTC determined that it had not performed the required 18-month maintenance and testing as of July 9, 2015, the date the station became classified as a Bulk Electric System (BES) station. Prior to July 2015, the Cuthbert Primary substation was in-service and classified as an underfrequency only station, and therefore did not require battery testing as per Table 1-4 (a) of PRC-005-2(i). On July 9, 2015, GTC installed a 115 kV capacitor bank, a BES element, which resulted in the battery being a Protection System device required to meet the requirements of PRC-005-2(i) Table 1-4(a). After installation of the capacitor bank, GTC personnel failed to set the flag for battery testing in GTC's maintenance management system to indicate the battery required maintenance and testing as per PRC-005-2(i). As a result, GTC's maintenance management system did not identify the battery as a BES device requiring battery testing. GTC completed all required maintenance activities in Table 1-4(a) prior to the bank being used as a BES Protection System component, including an impedance test. However, GTC performed the last impedance test on December 18, 2013; therefore, the 18-month requirement was out of interval as of July 9, 2015. Although GTC did not correctly designate the battery as a BES device, GTC performed all other Table 1-4(a) activities within the required interval. GTC completed a walk-down of all PRC-005-6 applicable transmission facilities, verified that all other PRC-005-6 elements were correctly identified, verified that all included PRC-005-6 devices were entered into the maintenance management system with the correct tasks and intervals, and verified complete documentation of required maintenance and testing requirements. GTC did not identify any additional issues. The primary cause of the noncompliance was ineffective training, which resulted in a lack of awareness of additional requirements for BES equipment and the importance of correct identification in the maintenance management system. This noncompliance started on July 9, 2015, when Cuthbert Primary substation became a BES station and GTC had not performed the 18-month Table 1-4(a) maintenance and testing, and ended on May 25, 2017, when GTC completed the required maintenance and testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. GTC's failure to conduct the 18-month battery maintenance and testing requirements within the defined interval could have impacted the functionality of the Protection System associated with the Cuthbert Primary substation and resulted in downstream Protection System devices having to respond to faults on the transmission system. However, GTC monitors its battery systems voltages through its Supervisory Control and Data Acquisition system, which should detect battery issues. GTC monitors battery voltages and alarms annunciate when voltages go outside of acceptable ranges. GTC performs a visual inspection, which includes checking electrolyte levels in each cell, corrosion, and overall physical conditions of the batteries on the batteries every month. The battery system showed no degradation and battery testing revealed no problems with the battery system. The battery system is performing as designed. No harm is known to have occurred. SERC considered GTC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GTC: 1) completed the 18-month battery testing at the Cuthbert Primary substation; 2) raised awareness of the compliance concern by having Relay Maintenance share details of the findings and mitigating activities with GTC's Reliability Assurance Sub-Committee (RAC) and ERO Compliance Steering Committee; 3) delivered training developed by Relay Maintenance to applicable GTC employees on integration of new components and/or stations into GTC's Protection System Maintenance Program (PSMP); 4) designed and implemented an automated report in Maximo to identify any time a BES breaker (100 kV or above) is added to a non-BES station to flag the new addition; and 5) implemented a new bi-annual process developed by Relay Maintenance to review all stations within Maximo; the process identifies and flags any new or modified stations that should be integrated into GTC's PSMP, and creates a battery work order when necessary.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019020951	MOD-032-1	R2	LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company (LGE and KU)	NCR01223	04/13/2016	12/27/2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 14, 2019, LGE and KU submitted a Self-Log stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. LGE and KU failed to provide accurate steady-state, dynamics, and short circuit modeling data to its Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its PC and Transmission Planner in Requirement R1. In December 2017, the PC submitted a request for MOD-032 data to LGE and KU. On December 8, 2017, while reviewing the MOD-032 data provided by the PC, an LGE and KU GO employee identified errors with the MOD-032 data LGE and KU previously submitted on April 13, 2016. Specifically, the data previously reported to the PC indicated that the governor was functional for nine units; however, LGE and KU had not enabled governor functionality on the units. LGE and KU also identified errors in the MOD-032 data submitted for the Power System Stabilizer (PSS) for a unit. The data from the PC indicated an active PSS, but LGE and KU tested the unit's PSS when the unit was commissioned then turned the PSS off. In December 2017, to ensure that LGE and KU identified all MOD-032 data errors, LGE and KU GO performed a review of the previously reported MOD-032 data. This included a review of the information related to governor and PSS status, capabilities and parameters for all LGE and KU facilities, and a review of drawings and manuals, and consultations with equipment manufacturers to ensure the accuracy of the information. This noncompliance started on April 13, 2016, when LGE and KU submitted inaccurate unit data for 10 units to its PC, and ended on December 27, 2017, when LGE and KU submitted accurate unit data for 10 units to its PC. The root cause of this noncompliance was lack of a documented process for MOD-032-1 R2 data submissions.
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). LGE and KU's failure to provide accurate data could have resulted in the PC planning models and studies producing inaccurate results that would prevent the PC from adequately conducting analyses of the system to support the reliability of the BPS. However, this issue impacted 10 units and could have resulted in generating unit protection systems isolating any trips to the individual affected unit. The LGE and KU PC conducted a Governor Removal Comparison Study, which found there were no stability issues to the BPS as well as no impacts to TPL standards as a result of LGE and KU not enabling the governor functionality. No harm is known to have occurred. SERC considered LGE and KU's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LGE and KU: 1) submitted accurate MOD-032 data to the PC; 2) implemented a job aid, which provides a process as to how the LGE and KU GO reviews and provides MOD-032 data to the PC; and 3) implemented compliance guidance and training addressing when to notify LGE and KU Generation Compliance in regards to projects/plans to modify generator, excitation system, governor, power system stabilizer.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019639	PRC-006-SERC-01	R2	PJM Interconnection, LLC (PJM)	NCR00879	4/4/2014	3/23/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 4, 2018, PJM submitted a Self-Report stating that, as a Planning Authority (PA), it was in noncompliance with PRC-006-SERC-1 R2. PJM did not identify an Underfrequency Load Shed (UFLS) scheme with time delay Requirements for UFLS entities that are Distribution Providers (DP) registered in SERC. PJM maintains a UFLS program for its Planning Coordinator area that allows for the automatic shedding of load during abnormal frequency, voltage, or power flow conditions. PJM Manual 13: Emergency Operations contains general details of the program. That program is applicable to five registered entities in the SERC region who are members of PJM and is the vehicle for PJM to inform its member TOs and DPs of UFLS requirements. On January 3, 2018, a DP registered in the SERC region that is a member of PJM contacted PJM to request PJM's requirements for UFLS scheme time delay in relation to PRC-006-SERC Requirement R2.6. After reviewing PJM's processes and procedures, PJM determined that it did not select or establish time delay requirements in accordance with the PRC-006-SERC-2. In the past, PJM has utilized a report prepared for SERC by a third party to help specify appropriate UFLS schemes however, while the report details time load shed and time delay requirements for Transmission Owner (TO) zones within the SERC region, the report did not specifically establish time delay requirements for DPs. After learning of this issue, and upon investigation, PJM confirmed it did not specify a time delay requirement for any of its TOs or DPs in the SERC region. SERC determined that the cause of this noncompliance was that PRC-006-SERC-2 retains and specifies design requirements which PJM overlooked when informing SERC entities of their UFLS responsibilities. This noncompliance started on April 4, 2014 when PRC-006-SERC-1 became enforceable, and ended on March 23, 2018 when PJM issued the time delay requirement.
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. By not specifying a UFLS time delay, a low frequency disturbance it could have resulted in an unnecessary load shed. However, during an actual under-frequency event it would result in an anticipatory load shed and could enhance system response to the event. If the load shed were inadvertent, the DP could restore it quickly. In this case, PJM learned that the only load in SERC that did not use the required six-cycle time delay was a single DP that accounted for 301 MW of 7,259 MW of load (4.1%) in the SERC region. All other SERC-based load used the SERC-required time delay. No load was lost as a result of the incorrect time delay. No harm is known to have occurred. SERC considered PJM's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PJM: 1) Reviewed current version of PJM Manual 36 Attachment H to identify the PJM UFLS entities within the SERC region; 2) Worked with the PJM UFLS entities within the SERC region to ensure the UFLS scheme time delay requirement is set to at least six cycles. a. Issued time delay requirement notification to PJM UFLS entities within SERC via email; b. Started the Stakeholder Process for PJM Manual 36 Attachment H revisions to add PJM's time delay Requirement; and c. Completed the Stakeholder Process for PJM Manual 36 Attachment H revisions to add PJM's time delay Requirement.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018921	MOD-026-1	R6	South Carolina Electric & Gas Company (SCEG)	NCR00915	12/12/2016	10/06/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 2, 2018, SCEG submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-026-1 R6. SCEG did not provide a written response to the Generator Owner (GO) within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable or is not usable. On two occasions, SCEG did not provide notification to the GO that the model data received from an independent GO within its Transmission Planning area was usable or not useable. On September 12, 2016, an independent GO sent SCEG model data, via email, to satisfy the MOD-026-1 R2 requirement. SCEG did not provide any notification to the GO after that submission. On May 8, 2017, the same GO referenced the previously submitted MOD-026-1 model data in another email; however, on this occasion, it did so in a SCEG email with the subject line "NERC Reliability Standard MOD-032 Reporting Data." Because of the subject line, SCEG did not immediately identify that the data was MOD-026-1 data and again did not provide any notification to the GO. On July 25, 2017, the GO sent a revised version of the model data to SCEG. On September 5, 2017, the GO contacted SCEG requesting documentation of notification that the MOD-026-1 models were useable. On October 6, 2017, SCEG discovered that it did not confirm the model data was usable or not usable for the September 12, 2016 and May 8, 2017 submissions. On October 6, 2017, SCEG sent an email to the GO confirming that the latest version of the model data submitted on July 25, 2017 was usable. This noncompliance started on December 12, 2016, when SCEG failed to provide the required written notification to the GO within 90 days from receipt of model data from the GO, and ended on October 6, 2017, when SCEG provided notification to the GO that the data was usable. The root cause of this noncompliance was lack of training. The GO made its initial September 2016 submittal to the SCEG Electric Transmission Support Department, which is not the department that responds to such submittals, and thus, was not aware that SCEG needed to respond to the GO's data submittal. Additionally, the GO made its May 2016 submittal responding to an email with a MOD-032 subject line; therefore, SCEG did not immediately recognize the submittal as a MOD-026-1 data submittal. A more careful reading by SCEG of the GO's document would have prevented this oversight.
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. SCEG's failure to respond to the model data submission within the required 90 days could have led to incorrect models resulting in erroneous assessments or an incorrect corrective action plan for the independent GO's combined cycle facility. However, SCEG validated the models via simulation software to demonstrate proper applications of these models. SCEG modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using previously provided modeling data and identified no potential stability issues in the system. SCEG also modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using the updated modeling data and identified no potential stability issues in the system. No harm is known to have occurred. SERC considered SCEG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SCEG: 1) sent a confirmation e-mail back to the GO confirming that the model data was usable; and 2) provided training to the appropriate SCEG Transmission Planning personnel.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018922	MOD-027-1	R5	South Carolina Electric & Gas Company (SCEG)	NCR00915	12/12/2016	10/06/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 2, 2018, SCEG submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-027-1 R5. SCEG did not provide a written response to the Generator Owner (GO) within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is usable or is not usable. On two occasions, SCEG did not provide notification to the GO that the model data received from an independent GO within its Transmission Planning area was usable or not useable. On September 12, 2016, an independent GO sent SCEG model data, via email, to satisfy the MOD-026-1 R2 requirement. SCEG did not provide any notification to the GO after that submission. On May 8, 2017, the same GO referenced the previously submitted MOD-026-1 model data in another email; however, on this occasion, it did so in a SCEG email with the subject line "NERC Reliability Standard MOD-032 Reporting Data." Because of the subject line, SCEG did not immediately identify that the data was MOD-026-1 data and again did not provide any notification to the GO. On July 25, 2017, the GO sent a revised version of the model data to SCEG. On September 5, 2017, the GO contacted SCEG requesting documentation of notification that the MOD-027-1 models were useable. On October 6, 2017, SCEG discovered that it did not confirm the model data was usable or not usable for the September 12, 2016 and May 8, 2017 submissions. On October 6, 2017, SCEG sent an email to the GO confirming that the latest version of the model data submitted on July 25, 2017 was usable. This noncompliance started on December 12, 2016, when SCEG failed to provide the required written notification to the GO within 90 days from receipt of model data from the GO, and ended on October 6, 2017, when SCEG provided notification to the GO that the data was usable. The root cause of this noncompliance was lack of training. The GO made its initial September 2016 submittal to the SCEG Electric Transmission Support Department, which is not the department that responds to such submittals, and thus, was not aware that SCEG needed to respond to the GO's data submittal. Additionally, the GO made its May 2016 submittal responding to an email with a MOD-032 subject line; therefore, SCEG did not immediately recognize the submittal as a MOD-027-1 data submittal. A more careful reading by SCEG of the GO's document would have prevented this oversight.
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. SCEG's failure to respond to the model data submission within the required 90 days could have led to incorrect models resulting in erroneous assessments or an incorrect corrective action plan for the independent GO's combined cycle facility. However, SCEG validated the models via simulation software to demonstrate proper applications of these models. SCEG modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using previously provided modeling data and identified no potential stability issues in the system. SCEG also modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using the updated modeling data and identified no potential stability issues in the system. No harm is known to have occurred. SERC considered SCEG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SCEG: 1) sent a confirmation e-mail back to the GO confirming that the model data was usable; and 2) provided training to the appropriate SCEG Transmission Planning personnel.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019759	COM-002-4	R3	Tilton Energy, LLC (Tilton)	NCR11014	07/01/2016	05/18/2018	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 violation.)	On May 21, 2018, Tilton submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with COM-002-4 R3. Tilton does not have documentation that it conducted initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction. On January 15, 2018, a third party, Cogentrix Energy Power Management, LLC (CEPM), assumed operations and managed support for Tilton. On March 21, 2018, during an internal audit of Tilton, CEPM determined that although Tilton stated that it had conducted COM-002-4 R3 operator training prior to the July 1, 2016 effective date, Tilton was unable to provide training documentation. This noncompliance started on July 1, 2016, when the Standard became enforceable, and ended on May 18, 2018, when Tilton completed the training of its operators. The root cause of the noncompliance was ineffective training record document management.
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. Tilton's failure to provide formal COM-002-4 R3 training to its operating personnel prior to them receiving an Operating Instruction could limit operators' awareness of predefined communications protocols, which could increase the possibility of miscommunication. However, according to Tilton, it trained its generator operators on communication protocols prior to July 1, 2016 but failed to retain training documentation. COM-002-4 R3 is a new Requirement and Tilton operators had been operating the system without issue prior to July 1, 2016. Additionally, Tilton is a small facility that consists of four simple cycle gas turbines rated at 45MW each. Tilton is a peaking facility with capacity factors ranging from 1.48% to 7.27% for each of the past six years. No harm is known to have occurred. SERC considered Tilton's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Tilton: 1) trained operating personnel on COM-002-4 requirements; 2) added COM-002 training to the new hire checklist; and 3) updated the training record retention process and policy to address the documentation for NERC training and how long the records need to be retained.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019799	TPL-001-4	R8	Tennessee Valley Authority (TVA)	NCR01151	9/22/2016	3/8/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 15, 2018, SERC sent TVA an audit notification letter notifying it of a compliance audit scheduled for September 10, 2018 through September 14, 2018. On June 4, 2018, TVA submitted a Self-Report stating that, as a Planning Coordinator (PC) and Transmission Planner (TP), it was in noncompliance with TPL-001-4 R8. TVA did not distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment. On July 12, 2017, TVA completed and signed its 2017 Planning Assessment. On March 6, 2018, 239 days after TVA completed its 2017 Planning Assessment, and while preparing for its 2018 Planning Assessment, TVA determined that it did not distribute its 2017 Planning Assessment results to adjacent PCs and adjacent TPs within 90 days of completing the assessment as required. After identifying the 2017 noncompliance, TVA reviewed the 2016 Planning Assessment distribution. On June 23, 2016, TVA completed and signed its 2016 Planning Assessment. On October 26, 2016, 126 days after the completion of the 2016 Planning Assessment, TVA distributed the 2016 Planning Assessment results to the adjacent PCs and adjacent TPs. The cause of the noncompliance was TVA's lack of an effective internal control. TVA's distribution of its annual Planning Assessment results was dependent on one person remembering to send the TVA Planning Assessment results to all adjacent PCs and TPs. The first instance of noncompliance started on September 22, 2016, 91 days after completion of the 2016 Planning assessment, and ended on October 26, 2016, when TVA distributed its 2016 Planning Assessment results to adjacent PCs and adjacent TPs. The second instance of noncompliance started on October 11, 2017, 91 days after completion of the 2017 Planning assessment, and ended on March 8, 2018, when TVA distributed its 2017 Planning Assessment results to adjacent PCs and adjacent TPs.
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. TVA's failure to distribute its Planning Assessment within 90 days of completion could result in adjacent PCs and TPs lacking awareness of changes planned for the TVA transmission system, and therefore the entities could not properly assess the potential implications of those changes on the adjacent systems. However, as a registered PC and TP, TVA shares information regarding its system, including planned changes, through joint modeling and study activities it participates in with adjacent PCs and TPs. These joint model development and study reports methods of information sharing with neighboring PCs and TPs pre-date the January 1, 2016 enforceable date of TPL-001-4 R8, and continue to serve as an effective means of informing adjacent entities of future plans. No harm is known to have occurred. SERC considered TVA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TVA: 1) distributed the 2017 Planning Assessment to adjacent PCs and TPs; 2) developed a new TPL-001-4 checklist as part of the final approval / signature stage for the annual Planning Assessment. The checklist includes a verification that the Planning Assessment results have been distributed to adjacent PCs and TPs; and 3) revised the coversheet for the TVA annual Planning Assessment documents to incorporate a new checkbox to affirm that personnel completed the TPL-001-4 checklist prior to affixing approval signatures to the Planning Assessment documents; and 4) conducted an evaluation to assess other NERC standards that have similar event-driven notification requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019361	PRC-024-2	R2	Virginia Electric and Power Company – Nuclear (GO, GOP) (VEP-Nuc)	NCR09006	7/1/2016	3/7/2018	Self-Report	Completed
Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 7, 2018, VEP-Nuc submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. VEP-Nuc did not verify that it set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating units as a result of a voltage excursion within the "no trip zone" of PRC-024 Attachment 2 in accordance with the PRC-024-2 implementation plan. VEP-Nuc has four applicable Facilities. During an affiliate's review of its PRC-024 documentation, the affiliate determined that its voltage protective relays did not account for the generator step-up (GSU) transformer turns ratio in the voltage translation calculations. On February 13, 2018, as part of the affiliate's extent of condition evaluation, the affiliate notified VEP-Nuc of this omission. On February 13, 2018, VEP-Nuc reviewed its PRC-024-2 evaluation and determined that it did not consider the GSU turns ratio. VEP-Nuc also determined that it did not consider transformer loading. The evaluations that included the GSU and transformer loadings found that VEP-Nuc's relay and automatic voltage regulator (AVR) settings are outside of the no trip zone and thus required no changes. The cause of the noncompliance was lack of oversight. VEP-Nuc inadvertently overlooked guidance within NERC Reliability Standard PRC-024 regarding the voltage protective relays. This noncompliance started on July 1, 2016, the first date of required compliance with PRC-024-2 R2, and ended on March 7, 2018, when VEP-Nuc completed evaluations with GSU turns ratio and transformer loading.						
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). VEP-Nuc's failure to ensure relaying does not trip within the "no trip zone" could result in generating units unexpectedly disconnecting from the BPS during disturbances. However, the revised evaluations determined that all applicable settings were outside the no-trip zone and thus no setting changes were required. The VEP-Nuc generating units range from 858 MWs to 980 MWs with 2017 annual capacity factors of approximately 90%. VEP-Nuc is not aware of a generating unit disconnecting from the BPS during a voltage excursion as a result of an incorrect relay setting during the evaluation period. No harm is known to have occurred. SERC considered VEP-Nuc's compliance history and determined that there were no relevant instances of noncompliance.						
Mitigation	To mitigate this noncompliance, VEP-Nuc: 1) re-evaluated the voltage protective relays including GSU turns ratio and transformer loading; 2) provided training to applicable staff regarding PRC-024-2 evaluations and lessons learned; and 3) provided training to applicable staff on lessons learned and guidance on reviewing Reliability Standards to ensure compliance.						

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018830	PRC-004-2.1a	R3	Virginia Electric and Power Company – Power Generation (VEP-PG)	NCR09028	6/1/2015	7/1/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 18, 2017, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-004-2.1a R3. VEP-PG, in its 2015 first quarter report, did not provide SERC complete documentation of its Protection System operations in accordance with SERC's Misoperations analyses and Corrective Action Plans procedure. On November 16, 2017, while performing an internal audit, VEP-PG discovered a discrepancy in its 2015 first quarter reporting (Q1). On April 29, 2015, VEP-PG entered its 2015 Q1 data submittal in the SERC Reliability Portal. VEP-PG documented one Protection System Misoperation and one Protection System operation at that time. During the internal audit, VEP-PG identified an additional 230 kV voltage class Protection System operation that occurred in Q1 that it did not report. The SERC procedure required the entity to report the first quarter count of total Protection System operations per voltage level by May 31. On January 24, 2015, the Chesterfield 6 operation occurred. On January 24, 2015, station personnel and the relay department completed an assessment of this operation and determined it was a correct operation. On January 27, 2015, VEP-PG entered the operation into its Power Generation System Operations Event Report database. VEP-PG determined that the primary causes of the noncompliance were human performance due to improper assumptions, indicating the need for retraining, and a gap in its internal processes, indicating the need to revise processes and strengthen internal controls. This noncompliance started on June 1, 2015, the first date after the submission deadline, and ended on July 1, 2016, when PRC-004-4(i) became enforceable and did not require reporting.
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). VEP-PG's failure to report all Protection System operations could have limited SERC's situational awareness of the operations in the SERC footprint and its ability to monitor, analyze and track trends which could hinder the ability to improve BPS reliability. However, this noncompliance was solely a failure to report a correct operation of the Protection System to SERC. In addition, the current version of the Standard no longer requires reporting to SERC or NERC as a compliance obligation. No harm is known to have occurred. SERC considered VEP-PG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) performed an internal review of program documents including, but not limited to, NERC Compliance Procedures, guidance documents, job aids, and process maps; 2) counseled the Power Generation Regulatory Compliance (PGRC) lead; 3) updated program documents to address weaknesses identified during the extent of condition assessment; 4) created an Internal Controls document for use by PGRC to ensure the identification, assessment, submittal and documentation of operations in a consistent manner. This document also outlines a monthly reconciliation process of operations to ensure retention of event review reports from the Power Generation System Operations Event Report database, assessments, root cause analyses, Corrective Action Plans and other supporting documentation; 5) provided training to site personnel and Power Generation Engineering; and 6) notified SERC of 2015 Q1 and Q2 Operations/Misoperations discrepancy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018831	PRC-004-2.1(i)a	R3	Virginia Electric and Power Company – Power Generation (VEP-PG)	NCR09028	9/1/2015	7/1/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 18, 2017, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-004-2.1a R3. VEP-PG, in its 2015 second quarter report, did not provide SERC complete documentation of its Protection System operations in accordance with SERC's Misoperations analyses and Corrective Action Plans procedure. On November 16, 2017, while performing an internal audit, VEP-PG discovered a discrepancy in its 2015 second quarter reporting (Q2). On August 27, 2015, VEP-PG entered its 2015 Q2 data submittal in the SERC Reliability Portal. VEP-PG documented one Protection System Misoperation and one Protection System operation at that time. During the internal audit, VEP-PG identified an additional 500 kV voltage class Protection System operation that occurred in Q2 that it did not report. The SERC procedure requires the entity to report the count of total Protection System operations per voltage level for second quarter by August 31 each year. On June 19, 2015, the Warren County operation occurred. On June 23, 2015, station personnel and the relay department completed an assessment of this operation and determined it was a correct operation. On June 23, 2015, VEP-PG created a Unit Disturbance Report. VEP-PG determined that the primary causes of the noncompliance were human performance due to improper assumptions, indicating the need for retraining, and a gap in its internal processes, indicating the need to revise processes and strengthen internal controls. This noncompliance started on September 1, 2015, the first date after the submission deadline, and ended on July 1, 2016, when PRC-004-4(i) became enforceable and did not require reporting.
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). VEP-PG's failure to report all Protection System operations could have limited SERC's situational awareness of the operations in the SERC footprint and its ability to monitor, analyze, and track trends, which could hinder the ability to improve BPS reliability. However, this noncompliance was solely a failure to report correct operations of the Protection System to SERC. In addition, the current version of the Standard no longer requires reporting to SERC or NERC as a compliance obligation. No harm is known to have occurred. SERC considered VEP-PG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) performed an internal review of program documents including, but not limited to, NERC Compliance Procedures, guidance documents, job aids, and process maps.; 2) counseled the Power Generation Regulatory Compliance (PGRC) lead; 3) updated program documents to address weaknesses identified during the extent of condition assessment;4) created an Internal Controls document for use by PGRC to ensure the identification, assessment, submittal and documentation of operations in a consistent manner. This document also outlines a monthly reconciliation process of operations to ensure retention of event review reports from the Power Generation System Operations Event Report database, assessments, root cause analyses, Corrective Action Plans and other supporting documentation; 5) provided training to site personnel and Power Generation Engineering; and 6) notified SERC of 2015 Q1 and Q2 Operations/Misoperations discrepancy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019331	PRC-024-2	R2	Virginia Electric and Power Company – Power Generation (VEP-PG)	NCR09028	7/1/2016	9/1/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 1, 2018, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. VEP-PG did not set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating units as a result of a voltage excursion within the "no trip zone" of PRC-024 Attachment 2 in accordance with the NERC implementation plan. VEP-PG contracted a third party engineering firm to perform an analysis of generator voltage protective relaying settings for its 107 PRC-024-2 applicable generating units. On December 21, 2017, when the PRC-024 lead was reviewing reports provided by the engineering firm, VEP-PG identified that 92 Volts/Hertz relays, which are required to be included in the voltage protective relay setting analysis, were not included in the engineering analysis. As a result, VEP-PG did not meet the required 40% implementation plan requirement by July 1, 2016, the 60% implementation plan requirement by July 1, 2017, or the 80% implementation plan requirement by July 1, 2018. The analysis identified required relay setting changes for five units. The maximum change was a +12.2% difference where the relay setting changed from 1.08 PU with a 10 second time delay to 1.23 PU with a 5 second time delay. As a result of the incorrect settings, the units would have tripped at 1.08 overvoltage for 10 seconds, outside the 4 second limit shown on the Ride-Through Time Duration Curve, which is 1.8% within the no-trip limit of 1.1 PU requirement over 1 second time duration. The primary cause of the noncompliance is a lack of effective internal controls. During its assessment, VEP-PG discovered that the Power Generation Engineering (PGE) Principal Engineer directed the third party to not include Volts/Hertz protection based on the PGE engineer's interpretation of the "Voltage Ride-Through Curve Clarifications" within NERC Reliability Standard PRC-024-2. VEP-PG determined that Power Generation Regulatory Compliance (PGRC) did not provide a detailed scope of work to PGE prior to the start of the evaluations, nor was a thorough Standard review performed to ensure alignment on compliance requirements. In addition, the PGRC subject matter expert did not evaluate the study results prior to the compliance date. The established process during this time did not specify a review deadline that would provide compliance assurance. This noncompliance started on July 1, 2016, when VEP-PG was required to meet the 40% implementation requirement and ended on September 1, 2018, when VEP-PG completed the required relay setting changes.
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). VEP-PG's failure to set the generator voltage protective relaying outside of the "no trip zone" could have resulted in up to five units prematurely tripping. However, these five units, which ranged from 83 MW with a 16% capacity factor to 153 MW with a 10% capacity factor, were only a total of 691 MWs of VEP-PG's 20,220 MWs of generation. The analysis determined that only five of the 107 units required relay setting changes. A premature trip of these five units would not have significant impact to the reliability of the BPS. No units tripped as a result of the incorrect relay settings. No harm is known to have occurred. SERC considered VEP-PG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) completed the required PRC-024-2 analysis; 2) changed the incorrect relay settings; 3) performed an internal review of program documents to determine how personnel overlooked specific guidance, and if program documents include sufficient guidance with regard to roles, responsibilities, and requirement deliverables. Updated program documents to address identified weaknesses; 4) reviewed scope of work for third party engineering firm to ensure correct methodology. 5) created an Internal Controls document for use by PGRC that identifies roles and responsibilities with regard to PRC-024 program management. This document provides details to ensure the identification, assessment, submittal and documentation of protective relays for compliance with PRC-024; and 6) provided training to PGE and PGRC staff regarding the Internal Controls document and lessons learned.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018329	FAC-009-1	R1	Virginia Electric and Power Company (DP, TO) (VEP-Trans)	NCR01214	12/6/2010	7/20/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 8, 2017, VEP-Trans submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with FAC-009-1 R1. VEP-Trans did not establish Facility Ratings for its Facilities that are consistent with the associated Facility Ratings Methodology. SERC determined that this noncompliance continued into version FAC-008-3 R6 of the Standard and Requirement. In 2010, VEP-Trans completed a project to add a new 230kV transmission line between the Chickahominy and Lanexa substations. To add the new line, VEP-Trans relocated some existing lines to facilitate the use of existing spans of idle conductor. At Chickahominy, line 2024 was one of the existing lines VEP-Trans relocated. The Facility Ratings Database (FRD) identified the limiting element of existing line 2024 as 2-636 aluminum-conductor steel-reinforced (ACSR) cable with a rating of 2,628 amps. During construction, VEP-Trans was unable to install a temporary pole for reconfiguring line 2024 as designed which resulted in field changes to line 2024 that differed from the original design. On November 18, 2010, VEP-Trans took an outage on line 2024 and cut in line 2024 jumpers in two locations between spans of 2-636 ACSR conductor. VEP-Trans installed new jumpers for line 2024 reconnecting line 2024 to a section of existing idle conductor, making that once idle conductor part of line 2024. This is the field change that differed from the original design. VEP-Trans later determined that the formerly idle conductor, now part of line 2024, was 2-721 aluminum-conductor alloy-reinforced (ACAR) cable. On December 6, 2010, VEP-Trans re-energized line 2024 with 2-721 ACAR. Bundled 721 ACAR has an ampacity of 1,812 amps, which is less than the 2-636 ACSR rating of 2,628 amps. On June 22, 2017, during an unrelated field visit to the Lanexa substation, an engineer recognized that VEP-Trans did not update the transmission lines construction one-line after completion of the 2010 project. Therefore, it did not record the field changes for re-configuration of line 2024 in the FRD. Updating the transmission lines construction one-line would have prompted an update to the FRD that the most limiting element of line 2024 was the configuration of 2-721 ACAR with a rating of 1,812 amps. The cause of this noncompliance was the result of failure in human performance and ineffective internal controls. Personnel did not communicate changes made in the field 'as built' and therefore personnel did not record the changes on the construction one-line. The construction one-line is the document of record for ratings of facilities to be recorded (if new), or updated (if changed) from prior existing facilities as recorded in the FRD. As a result, the line rating in the FRD as of December 6, 2010 was incorrect. This noncompliance started on December 6, 2010, when VEP-Trans re-energized line 2024 with 2-721 ACAR, and ended on July 20, 2017, when VEP-Trans entered the correct ratings in the FRD and submitted them to PJM.
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). Failure to establish correct Facility Ratings may result in improper operational planning and operation of equipment causing damage or reduced lifetime of BPS Facilities. However, the actual capacity of line 2024 is 1,812 amps (summer rating at 100 degrees F). The highest load recorded during the noncompliance was 1,441 amps and occurred for approximately 2.5 hours on March 4, 2011, when the temperature for the day ranged from a low in the 20s degrees F to a high of mid 50s degrees F. Thus, line 2024 would have an even higher ampacity rating due to cooler weather conditions. In addition, VEP-Trans runs numerous studies on a continual basis using real time data and/or projected system configurations, including real time or projected ambient temperatures. No harm is known to have occurred. VEP-Trans had relevant compliance history. However, SERC determined that VEP-Trans's FAC-009-1 R1 compliance history should not serve as a basis for applying a penalty because the primary cause and associated mitigating activities for the prior noncompliances and the instant noncompliance are unrelated or the relevant mitigating activities occurred after this instance of noncompliance began, making it impossible for VEP-Trans to use the mitigation from an older noncompliance in order to prevent the instant noncompliance. Therefore, the causes and mitigating activities for the prior noncompliances could not prevent the instant noncompliance from occurring. In addition, those prior mitigation activities should prevent a noncompliance similar to the instant noncompliance from reoccurring.
Mitigation	To mitigate this noncompliance, VEP-Trans: 1) re-issued the corrected line 2024 Operating One-Line drawing. This correctly identified 2-721 ACAR as the most limiting element; 2) received and validated the ratings in the FRD for Transmission Line 2024 Operating One-Line; 3) issued correct ratings for line 2024 recording them in the FRD; 4) called and emailed ET System Operations Engineering notifying them of the line ratings change resulting in a de-rate of line 2024; 5) submitted to PJM eDART TERM ticket # 695963 decreasing the line 2024 rating to reflect the 2-721 ACAR conductor as the most limiting element; and 6) implemented a new Project Management internal control for a prior noncompliance that would prevent the instance noncompliance from recurring.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017960	TOP-001-3	R13	Public Utility District No. 1 of Chelan County (CHPD)	NCR05338	April 30, 2017	April 30, 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 July 17, 2017, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-001-3 R13. Specifically, on April 30, 2017, at 2:11 PM, the entity's internal Energy Management System (EMS) generated an alarm indicating that 12 minutes had elapsed since the last Real Time Assessment (RTA) was performed at 1:59 PM. However, the entity's System Operators on shift mistakenly believed that they had 30 minutes to complete a RTA from the time of this alarm, rather than the 18 minutes that the alarm indicated. At 2:40 PM, the entity's System Operator logged a manual RTA using the hosted advanced application (HAA) real-time contingency analysis (RTCA); however, they should have been performed the RTA at 2:29 PM, not at 2:40 PM, 11 minutes past the 30-minute requirement of the Standard After reviewing all relevant information, WECC determined the entity failed to ensure that a RTA was performed at least once every thirty minutes, as required by TOP-001-3 R13. The root cause of the noncompliance was the System Operator's incorrect interpretation of the EMS alarm which indicated that he had thirty minutes to perform a RTA, rather than the 18 minutes that the EMS alarm indicated. The noncompliance began on April 30, 2017, at 2:29 PM when the entity failed to ensure that an RTA was performed 30 minutes after the last successful RTA and ended on April 30, 2017, at 2:40 PM when the entity performed an RTA using the Reliability Coordinator's HAA, for a total of 11 minutes.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to ensure that a RTA was performed at least once every thirty minutes The entity implemented good preventive controls to prevent the above noncompliance from occurring. Specifically, the entity implemented an alarm that notified the System Operator that twelve minutes had elapsed since the last valid RTA solution was recorded. This control was designed to be a reminder that time was elapsing and the System Operator needed to prepare for the RTA. Additionally, the entity uses the Reliability Coordinator's RTCA tool to assist in conducting its RTA, which is normally recorded every five minutes, and completes a manual process for the RTA if the tool is unavailable. Further as detective control, every morning the System Operations Manager reviewed all logs from the previous twenty-five hours and discovered the above issue. In addition to the other controls, the entity has implemented good compensating controls. The entity's RC performed a valid RTA of its area and would have notified the entity if the RTA identified a real-time or contingent condition that required actions to prevent an adverse impact the reliability of the western interconnection
Mitigation	1. The entity completed mitigating activities to address its noncompliance and WECC verified the completion of the mitigating activities. 2. To remediate and mitigate this noncompliance, the entity has: a. completed a valid RTA; b. added a visual timer to its EMS displays showing the amount of time that has elapsed since the previous valid solution was recorded; c. updated the alarm language to specify the duration since the valid solution was recorded; and d. added a supplementary alarm to indicate the failure to record a valid RTA after twenty minutes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019968	MOD-027-1	R2; R2.1; R2.2; R2.3; R2.4; R2.5	Cabrillo Power I LLC (the "Encina Generating Station") (CPI)	NCR05040	7/1/2018	12/11/18	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 July 3, 2018, the entity submitted a Self-Report stating, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. Specifically, the entity discovered that it did not provide a verified active power frequency control model for 30% of the total MVA for its applicable units to its Transmission Planner by July 1, 2018, as required by the Standard. The entity mistakenly understood the retirement schedule for its generating units to be a rolling retirement with individual units being retired as new generating units would come on-line. The entity expected its generating units to be fully retired by the end of 2017. The entity owns four generating units, two of which are exempt from the scope of the issue because they have capacity factors less than 5%, per the Standard. The other two generating units are subject to this instance because they have capacity factors greater than 5%, per the Standard. In December 2017, the Balancing Authority (BA) issued a Capacity Procurement Mechanism (CPM) designation for the two generating units in scope to cover capacity needs in the area for a period of 12 months before the adjacent generating facility was to be commissioned in October 2018. Subsequently, the two generating units in scope would not fully retire until October 2018. Due to the age of the generating units, the entity was unable to use its internal modeling resources. Further, given the limited timeline, the entity was unable to contract a third-party to complete the modeling before the generating units retired in October 2018. After reviewing all relevant information, WECC determined the entity failed to provide for two units, an active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. The root cause of the issue was that the entity misunderstood the timeline for retiring its generating units, as such, insufficient time was allotted to complete the modeling and verification by the required date. This issue began on July 1, 2018, when the Standard became mandatory and enforceable and ended on December 11, 2018, when the entity's generating units were decommissioned, for a total of 164 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The entity had good compensating controls. Specifically, the entity had submitted previous active power/frequency control models to the Transmission Planner (TP) before the new version of the Standard came into effect, but they were not verified per the Standard. In addition, the two generating units in scope have had less than 11% operational hours in 2018 thus reducing the potential for harm and the likelihood of harm occurring. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, CPI: 1) decommissioned the generating units; and 2) submitted its formal deregistration request to WECC. CPI has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019527	TOP-001-3	R13	Northern States Power (Xcel Energy) (NSP)	NCR01020	1/15/2018	1/15/2018	self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of PSCO. Xcel Energy states that PSCO experienced a loss of its Real Time Assessment (RTA) tool and did not ensure that RTA was being performed during the outage of its tool. The noncompliance was caused by Xcel Energy failing to implement adequate alarming to alert the operator that the RTA tool was not functioning. Xcel Energy used an alarm that would auto-silence after a period of time and the System Operator did not recognize that the RTA tool was not functioning. Xcel Energy reports that the noncompliance was discovered when an individual investigated the auto-silenced persistent alarm. The noncompliance began on January 15, 2018, when an RTA was not performed at least once every thirty minutes and ended approximately 30 minutes after the noncompliance began, when PSCO notified its Reliability Coordinator and asked the Reliability Coordinator to run PSCO's RTA for it.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy states that during the noncompliance, its Reliability Coordinator was performing RTA that included the PSCO system. Additionally, Xcel Energy states that during the noncompliance, the PSCO system did not experience a line or generation trip. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) contacted PSCO's Reliability Coordinator and asked it to run PSCO's RTA; 2) reconfigured the alarm to change it from a high priority alarm that auto silenced to a critical priority alarm that would produce sound until silenced by an operator; 3) conducted an event review (training) with System Operators on the event. The mitigation was limited to PSCO.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019530	IRO-010-1a	R3	Northern States Power (Xcel Energy) (NSP)	NCR01020	10/1/2011	1/24/2018	self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Operator, it was in noncompliance with IRO-010-1a R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of PSCO. Xcel Energy states that upon reviewing PSCO's Reliability Coordinator's (RC) data specifications, that it determined that it was not providing all the data from seven required data categories associated with a WECC Transfer Path. The noncompliance was caused by Xcel Energy failing to define clear ownership for providing this data to the RC. The noncompliance began on October 1, 2011, when the standard became enforceable and ended on January 24, 2018, when it began providing all required data to its RC.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy states that the noncompliance impacted less than 2% of the data points that PSCO was providing to its RC. Further, Xcel Energy stated that the missing data points were not associated with an Interconnection Reliability Operating Limit (IROL), a Remedial Action Scheme (RAS), or a Major WECC Transfer Path. Additionally, Xcel Energy states that the missing data points associated with Blackstart Cranking Paths did not impede PSCO from monitoring the status of those paths. Finally, Xcel Energy reports that the actual MW and Total Transfer Capacity (TTC) were being provided to the RC during the noncompliance and the noncompliance did not prevent either itself or the RC from being able to monitor the actual flows for the impacted WECC Transfer Path. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance: 1) PSCO provided the necessary procedures, scheduled MW, and other data points to its RC; 2) PSCO conducted a full evaluation of each obligation in the RC Data Specifications to verify that each was adequately satisfied; 3) NSP and SPS reviewed their RC data specifications and supporting evidence to confirm there were no deficiencies; and 4) PSCO instituted a monthly meeting to review the data specifications with process owners to determine if there were any needed updates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019531	FAC-008-3	R6	Northern States Power (Xcel Energy) (NSP)	NCR01020	1/18/2018	2/7/2018	self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, it was in noncompliance with FAC-008-3 R6. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of SPS and NSP. Xcel Energy states that it updated its Facility Ratings Methodology (FRM) on July 18, 2016. Pursuant to Xcel Energy's FRM, it is required to update affected Facility Ratings within 18 months. Xcel Energy failed to review and update 95 of 602 Facilities in the NSP operating system and 24 of 485 Facilities in the SPS operating system within the required 18 months. Xcel Energy was 12 days late in completing all facilities in the NSP operating system and 20 days late in the SPS operating system. The noncompliance was caused by Xcel Energy failing to adequately consider the time it would take to implement the review and did not have in place a process to ensure that the review was completed within the required timeframe. The noncompliance began on January 18, 2018, 18 months after Xcel Energy updated its FRM and ended on February 7, 2018, when it reviewed and updated the Facility Ratings for all Facilities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk to the NSP system was minimal because per Xcel Energy, none of the 95 Facilities were part of a Remedial Action Scheme (RAS) or an Interconnection Reliability Operating Limit (IROL), and the actual loading of the affected Facilities during the period of noncompliance was only 45% of the maximum Facility Rating. Additionally, four of the Facilities were associated with a Blackstart Cranking Path; three of those Facilities saw a slight increase in ratings and the one that saw a decrease had far more MVA actual capacity (279.7 MVA) than the 60 MVA that would be used during System Restoration. The risk to the SPS system was minimal because per Xcel Energy, none of the 24 Facilities were part of a Blackstart Cranking Path, an IROL, or a RAS. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) reviewed and updated the Facility Ratings for all Facilities; and 2) implemented a new process to use its compliance tracking tool on future FRM updates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019965	MOD-026-1	R2	Eastman Cogeneration Limited Partnership (EASTMAN)	NCR01092	7/1/2018	10/17/2018	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 violation.)	On July 3, 2018, EASTMAN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. Specifically, EASTMAN was unable to meet the 30% phased-in implementation by July 1, 2018. EASTMAN reports that there was a water leak that threatened the Facility's restarting capability. EASTMAN states that performing the exciter model testing would increase the possibility of a trip. EASTMAN did not want to take any action that could increase the possibility of a trip while the Facility's ability to restart was threatened. The cause of the noncompliance was that testing could not be performed due to a water leak that impeded the Facility's ability to restart. This noncompliance started on July 1, 2018, when EASTMAN failed to meet the 30% phased-in implementation plan and ended on October 17, 2018, when it reported the verified model data to its Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that provides power to an associated industrial operation. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Inherent Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred. EASTMAN has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, EASTMAN: 1) repaired the water leak; 2) performed the testing; and 3) reported the verified model to its Transmission Planner.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019966	MOD-027-1	R2	Eastman Cogeneration Limited Partnership (EASTMAN)	NCR01092	7/1/2018	10/17/2018	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 violation.)	On July 3, 2018, EASTMAN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. Specifically, EASTMAN was unable to meet the 30% phased-in implementation by July 1, 2018. EASTMAN reports that there was a water leak that threatened the Facility's restarting capability. EASTMAN states that performing the governor/turbine and load control or active power/frequency control model testing would increase the possibility of a trip. EASTMAN did not want to take any action that could increase the possibility of a trip while the Facility's ability to restart was threatened. The cause of the noncompliance was that testing could not be performed due to a water leak that impeded the Facility's ability to restart. This noncompliance started on July 1, 2018, when EASTMAN failed to meet the 30% phased-in implementation plan and ended on October 17, 2018, when it reported the verified model data to its Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that provides power to an associated industrial operation. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Inherent Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred. EASTMAN has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, EASTMAN: 1) repaired the water leak; 2) performed the testing; and 3) reported the verified model to its Transmission Planner.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020216	PRC-005-6	R3	Evergreen Gen Lead LLC	NCR11727	04/01/17	11/19/18	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 August 17, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6, R3. During preparation for its audit, the Entity discovered that it did not perform the minimum maintenance activities for its Vented Lead-Acid (VLA) Batteries in accordance with the maximum maintenance intervals prescribed in PRC-005-6 and the Implementation Plan for PRC-005-6. The Entity owns two wind generation Facilities. • By the April 1, 2017 deadline, the Entity had not completed all of the aspects of the 18-month interval battery maintenance activities for both Facilities. The battery banks at each Facility were last tested in September 2014 and September 2015. Each battery bank should have been tested under the 18 month criteria by April 1, 2017. • The Entity also did not conduct the 6-year battery bank performance verification for one of its two Facilities by December 31, 2017 (the expiration of the maintenance interval). The VLA battery bank performance verification last took place in 2011. The noncompliance started on April 1, 2017, when the Entity was required to have completed the 18-month VLA battery maintenance activities, and ended on November 19, 2018, when the Entity performed all of the required maintenance activities for the VLA batteries and the battery bank. The root cause of this noncompliance was a lack of management oversight around implementing the Protection System Maintenance Program (PSMP) and less than adequate controls for scoping and scheduling PSMP maintenance tasks. A contributing cause was the Entity's change of ownership leading up to and during the PRC-005 transition.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Unmaintained VLA batteries and control circuitry could cause those components to fail when needed and could cause the generator to trip offline, which could potentially exasperate an ongoing real time BES situation. It could expose the generation equipment to damage if the plant fails to trip offline properly when called upon. However, the Entity's generating facilities consist of two wind sites that total to 142 MW at a common BES point of interconnection. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the output of the site is contingent on these conditions. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Evergreen Gen Lead LLC: 1) Completed all of the missing PRC-005 maintenance at both BES facilities 2) Reviewed all PRC-005 maintenance deadlines and added them to its Microsoft Outlook calendar that will alert before the interval due date occurs 3) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020452	MOD-025-2	R1	Evergreen Gen Lead LLC	NCR11727	07/01/2016	11/09/2018	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 violation.)	On September 25, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R1. During preparation for an audit, the Entity discovered that it failed to meet the Real Power testing requirements of MOD-025-2, R1 Attachment 1 prior to the effective date of the Standard, which was July 1, 2016 for it's two BES wind Facilities. The noncompliance started on July 1, 2016 and ended on November 9, 2018 when the real power testing results for both BES Facilities were provided to the Transmission Planner. The root cause of this noncompliance was a lack of management oversight around understanding and implementing the MOD-025 testing program and less than adequate controls to track testing due dates.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with MOD-025-2 R1 is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. The Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generator is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability due to inaccurate information. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the potential real power output of the site is contingent on these conditions and the site is not typically relied upon to operate at a consistent real power output level. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance: 1) Scheduled and performed the real power testing at both BES facilities 2) Provided the test results to the Transmission Planner 3) Added verification of the Real Power capability to its Microsoft Outlook calendar with an interval period of less than 60 calendar months 4) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020453	MOD-025-2	R2	Evergreen Gen Lead LLC	NCR11727	07/01/2016	11/09/2018	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 violation.)	On September 25, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R2. During preparation for an audit, the Entity discovered that it failed to meet the Reactive Power testing requirements of MOD-025-2, R2 Attachment 1 prior to the effective date of the Standard, which was July 1, 2016 for it's two BES wind Facilities. The noncompliance started on July 1, 2016 and ended on November 9, 2018 when the reactive power testing results for both BES Facilities were provided to the Transmission Planner. The root cause of this noncompliance was a lack of management oversight around understanding and implementing the MOD-025 testing program and less than adequate controls to track testing due dates.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with MOD-025-2 R2 is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. The Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generator is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 a 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability due to inaccurate information. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the potential reactive power output of the site is contingent on these conditions and the site is not typically relied upon to operate at a consistent reactive power output level. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance: 1) Scheduled and performed the reactive power testing at both BES facilities 2) Provided the test results to the Transmission Planner 3) Added verification of the Reactive Power capability to its Microsoft Outlook calendar with an interval period of less than 60 calendar months 4) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020956	COM-002-4	R3	Evergreen Gen Lead LLC	NCR11727	09/05/2016 09/12/2016 05/28/2017	10/14/2016 10/12/2016 06/03/2017	Compliance Audit	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.)	During a Compliance Audit conducted from October 15, 2018 through January 22, 2019, NPCC determined that Evergreen Gen Lead LLC (the Entity), as a Generator Operator, was in noncompliance with COM-002-4, R3. Specifically, between July 2016 and June 2017, there were three instances where operating personnel were placed in an on-shift position where Operating Instructions could have been given or received prior to those operating personnel completing communication training In all three instances, the Entity could not provide documentation to confirm that the training took place before the operating personnel went on-watch. In all three instances, documentation was provided showing that training was completed approximately one month of assuming the on-shift position. The Entity claimed initial training was performed for the three operating personnel, but that the training records were misplaced during the ownership transition that occurred in 2016. The noncompliance range of dates for the three Operators were from September 5, 2016 to October 14, 2016, from September 12, 2016 to October 12, 2016, and from May 28, 2017 to June 3, 2017. The root cause of this noncompliance was a lack of organization with respect record retention and specifically to the transfer of training records during a change of Facility ownership.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with COM-002-4 R3 is that incorrect actions could be carried out if incorrect or unclear Operating Instructions are delivered or received. However, the Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. As such, the impact to the BES of the Entity Operator performing an incorrect action due to incorrect communication practices would be minimal. In all three instances, documentation was provided showing that training was completed approximately one month of assuming the on-shift position No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance: 1) The Entity provided documentation that the three Operator's completed the necessary COM-002 training and provided the documentation. 2) The Entity has transitioned its training responsibilities over to the GE Remote Operations Center training process to enhance training oversight and prevent recurrence of the issue. 3) An enhanced training Curriculum Tracker workbook was developed to track the training for all active operators. A new tab is added when new Operators are hired and COM training is refreshed annually for each Operator.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017311	INT-006-4	1	Bonneville Power Administration	NCR05032	November 30, 2016	November 30, 2016	Self Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 30, 2017, the entity submitted Self-Reports stating that, as a Balancing Authority (BA) and, it was in noncompliance with INT-006-4 Requirement 1. Specifically, the entity reported that on November 30, 2016, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 interties with neighboring entities. The entity's vendor monitors the system performance and identified the system performance degradation and notified the entity of the issue. The technical issue prevented the entity from approving or denying four e-tags processed as a BA, of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed within the timelines outlined in the Standard if technical issues occur with its scheduling software. However, the technical issues that occurred on the date above prevented the entity from effectively processing these four e-tags within the timelines despite these multiple backup processes. The entity failed to approve or deny four on-time Arranged Interchange that it received as a BA, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1. The root cause of these issues was the scheduling software failing to perform as expected. Specifically, end of month maintenance attributed to significant system activity and ultimately the software performance degradation. These issues began on November 30, 2016, when the four on-time Arranged Interchange e-tags were not approved or denied within the requirements of the Standard and ended on November 30, 2016, when the e-tags were approved or denied, and the software returned to normal functionality, for a total of 31 minutes.
Risk Assessment	These issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to approve or deny four on-time Arranged Interchange that it received as a BA, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day. The entity had good detective controls in place. Specifically, the entity's vendor was in the process of reviewing the system performance and investigating key system processes active during the slowdown period to find the root cause, system operations returned to normal approximately 30 minutes after the start of the failure. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the Interconnection frequency is controlled within defined frequency limits.
Mitigation	To mitigate these issues, the entity and the vendor: a. completed an evaluation of maintenance process schedules and implemented necessary adjustments; b. completed the software performance improvements for the most impactful maintenance processes and deployed the improvements to the environment. As these processes are background maintenance processes, and do not change any functionality, the changes were incrementally applied to the system over a period of time; and c. identified software changes to mitigate the impact of such maintenance processes through alternate implementation within its automated scheduling software. These changes will be deployed in its automated scheduling software deployments as the changes are completed following normal processes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017313	INT-006-4	2	Bonneville Power Administration	NCR05032	November 30, 2016	November 30, 2016	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 30, 2017, the entity submitted Self-Reports stating that, as a Transmission Service Provider (TSP), it was in noncompliance with INT-006-4 Requirement 2. Specifically, the entity reported that on November 30, 2016, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 interties with neighboring entities. The entity's vendor monitors the system performance and identified the system performance degradation and notified the entity of the issue. The technical issue prevented the entity from approving or denying five e-tags processed as a TSP, of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed within the timelines outlined in the Standard if technical issues occur with its scheduling software. However, the technical issues that occurred on the date above prevented the entity from effectively processing these five e-tags within the timelines despite these multiple backup processes. The entity failed to approve or deny five on-time Arranged Interchange it received as a TSP, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R2. The root cause of these issues was the scheduling software failing to perform as expected. Specifically, end of month maintenance attributed to significant system activity and ultimately the software performance degradation.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to approve or deny five on-time Arranged Interchange it received as a TSP, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R2. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day. The entity had good detective controls in place. Specifically, the entity's vendor was in the process of reviewing the system performance and investigating key system processes active during the slowdown period to find the root cause, system operations returned to normal approximately 30 minutes after the start of the failure. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the Interconnection frequency is controlled within defined frequency limits.
Mitigation	To mitigate these issues, the entity and the vendor: a. completed an evaluation of maintenance process schedules and implemented necessary adjustments; b. completed the software performance improvements for the most impactful maintenance processes and deployed the improvements to the environment. As these processes are background maintenance processes, and do not change any functionality, the changes were incrementally applied to the system over a period of time; and c. identified software changes to mitigate the impact of such maintenance processes through alternate implementation within its automated scheduling software. These changes will be deployed in its automated scheduling software deployments as the changes are completed following normal processes

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018401	INT-006-4	1	Bonneville Power Administration	NCR05032	July 27, 2017	July 27, 2017	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 2, 2017, the entity submitted a Self-Report stating that, as a BA, it was in noncompliance with INT-006-4 R1. Specifically, the entity reported that on July 27, 2017, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 ties with neighboring entities. The entity's vendor monitors the system performance and identified the system issue and notified the entity. The technical issue prevented the entity from approving or denying one e-tag processed as a of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed in the timelines outlined in the Standard if technical issues with its scheduling software occur. However, the technical issues that occurred on the date above prevented the entity from effectively processing this one e-tags within the timelines despite these multiple backup processes. After reviewing all relevant information, WECC Enforcement determined the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a BA, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R1. The root cause of this issue was the scheduling software having technical issues. Specifically, the vendor incident report stated, "After review by additional technical staff, a correlation was made with the deactivation of the AFC Cleanup Process that was completed just prior to the failover on July 27, 2017. It was found that this process, which shares a connection to the database with other processes, was terminating in an unfinished condition and had caused other processes sharing the same connection to also be disrupted. This caused the data delivery process to be impacted, due to the data sequencing requirements of this interface, and subsequent messages were also blocked."
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a BA, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R1. The number of e-tags subject to this instance is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence. The entity had good detective controls in place. Specifically, the entity's vendor monitors the system performance and identified the system issue and notified the entity. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the interconnection frequency is controlled within defined frequency limits. Additionally, the software vendor has implemented a safeguard for tickets that are not approved or denied within the defined time requirements and it automatically acted on the e-tag that was not approved or denied and assigned a final status. Because of this safeguard, the entity was only in noncompliance for five minutes. In addition, the vendor has been in use at the entity for over a decade and does have backup processes in place to manage the loss. Lastly, the vendor provides round the clock support to the entity for any system issues that are noticed by the entity's schedulers.
Mitigation	To mitigate these issues, then entity and the vendor: a. assigned a final status to the missed e-tag; and b. repaired the software's data delivery process that caused the failure of the process for the two missed e-tags Due to the significant number of e-tags this entity processes, and the time requirements to approve or deny the requested transactions, an automated software tool is needed to maintain compliance with the Standard. Vendor management and support of the automated software includes the potential for technical issues to arise, and without knowing all future possible technical issues, it is unreasonable to ensure that all future potential non-compliance issues will be prevented. Therefore, WECC is satisfied that the mitigation efforts stated above are sufficient.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018402	INT-002-4	2	Bonneville Power Administration	NCR05032	July 27, 2016	July 27, 2016	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 2, 2017, the entity submitted a Self-Report stating that, as a TSP, it was in noncompliance with INT-006-4 2. Specifically, the entity reported that on July 27, 2017, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 ties with neighboring entities. The entity's vendor monitors the system performance and identified the system issue and notified the entity. The technical issue prevented the entity from approving or denying one e-tag processed as a TSP of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed in the timelines outlined in the Standard if technical issues with its scheduling software occur. However, the technical issues that occurred on the date above prevented the entity from effectively processing this e-tag within the timelines despite these multiple backup processes. After reviewing all relevant information, WECC Enforcement determined the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a TSP, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R2. The root cause of this issue was the scheduling software having technical issues. Specifically, the vendor incident report stated, "After review by additional technical staff, a correlation was made with the deactivation of the AFC Cleanup Process that was completed just prior to the failover on July 27, 2017. It was found that this process, which shares a connection to the database with other processes, was terminating in an unfinished condition and had caused other processes sharing the same connection to also be disrupted. This caused the data delivery process to be impacted, due to the data sequencing requirements of this interface, and subsequent messages were also blocked."
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a TSP, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R2. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence. The entity had good detective controls in place. Specifically, the entity's vendor monitors the system performance and identified the system issue and notified the entity. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the interconnection frequency is controlled within defined frequency limits. Additionally, the software vendor has implemented a safeguard for tickets that are not approved or denied within the defined time requirements and it automatically acted on the e-tag that was not approved or denied and assigned a final status. Because of this safeguard, the entity was only in noncompliance for five minutes. In addition, the vendor has been in use at the entity for over a decade and does have backup processes in place to manage the loss. Lastly, the vendor provides round the clock support to the entity for any system issues that are noticed by the entity's schedulers.
Mitigation	To mitigate these issues, then entity and the vendor: a. assigned a final status to the missed e-tags; and b. repaired the software's data delivery process that caused the failure of the process for the missed e-tag. Due to the significant number of e-tags this entity processes, and the time requirements to approve or deny the requested transactions, an automated software tool is needed to maintain compliance with the Standard. Vendor management and support of the automated software includes the potential for technical issues to arise, and without knowing all future possible technical issues, it is unreasonable to ensure that all future potential non-compliance issues will be prevented. Therefore, WECC is satisfied that the mitigation efforts stated above are sufficient.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020036	TOP-010-1(i)	R1	Eugene Water & Electric Board	NCR05153	4/1/2018	6/13/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4: After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements. These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, , as required by TOP-010-1(i) R1, R3, and R4 respectively. As compensation, the entity's system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
Mitigation	The entity completed mitigating activities for all the Requirements and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. created and implemented its operating procedures; b. updated its system operation procedure; c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis; d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool; e. trained each system operator on the procedures that were implemented; and f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020037	TOP-010-1(i)	R3	Eugene Water & Electric Board	NCR05153	4/1/2018	6/13/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4. After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements. These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, , as required by TOP-010-1(i) R1, R3, and R4 respectively. As compensation, the entity's system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
Mitigation	The entity completed mitigating activities for all the Requirements and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. created and implemented its operating procedures; b. updated its system operation procedure; c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis; d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool; e. trained each system operator on the procedures that were implemented; and f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020038	TOP-010-1(i)	R4	Eugene Water & Electric Board	NCR05153	4/1/2018	6/13/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4. After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements. These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. As compensation, the entity's system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
Mitigation	The entity completed mitigating activities for all the Requirements and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. created and implemented its operating procedures; b. updated its system operation procedure; c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis; d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool; e. trained each system operator on the procedures that were implemented; and f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019020891	TOP-001-3	R13	Eugene Water & Electric Board	NCR05153	2/17/2018	2/17/2018	Audit	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted December 10, 2018 through December 20, 2018, WECC determined that the entity, as a TOP, had a potential noncompliance with TOP-001-3 R13. On February 17, 2018 at 19:56 PST the entity performed a valid Real-Time assessment (RTA). Per the Requirement of the Standard, the subsequent RTAs were due every 30 minutes, at 20:26 PST and 20:56 PST, etc. The entity utilized the Reliability Coordinator's Hosted Advanced Application (HAA) for performing Real-Time Contingency Analyses (RTCA). However, the RTCA tool was dysfunctional. As a result, the entity did not perform the next valid RTA until 21:07 PST because the entity's operators were not trained on handling functionality issues with the HAA. After reviewing all relevant information, WECC determined that the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13. The root cause of the issue was that the entity has no alert or notification to the operator that the tool used to perform RTCA had failed and that another method must be used. A contributing cause was the lack of operator training as to how to respond to RTCA tool failures. This issue began on February 17, 2018 at 20:26 PST, 30 minutes after previous valid RTA at 19:56 PST and ended on February 17, 2018 at 21:07 PST when the entity performed a valid RTA, for a total of 41 minutes
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13. At the time of the issue, the entity had no preventative or detective controls to prevent or detect the noncompliance. However, the entity's system is primarily used to serve its own load and is unlikely to have a substantial impact on neighboring entities in the interconnection. Additionally, the entity does not provide generation to neighboring entities or operate elements of a WECC Major Transfer Path.
Mitigation	The entity completed mitigating activities and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. added alarms to alert system operators if the RTA monitoring has failed; b. developed a user guide for using the HAA to perform RTCAs; c. issued dispatch standing order providing detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System; d. confirmed that all procedures are in place and that training for each System Operator includes a review of the procedures and monitoring tool; e. completed training for each System Operator for the RC HAA RTCA tool.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018227	PRC-005-6	R3	Goshen Phase II LLC	NCR11089	7/1/2017	8/1/2017	SR	Completed
Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 17, 2017, GPL submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. Specifically, GPL discovered that it did not complete specific maintenance activities for two vented lead-acid (VLA) batteries at one substation; including verification of station DC supply voltage, inspection of electrolyte levels, and inspection for unintentional grounds, per the maximum maintenance intervals for the requirements of Table 1-4(a) of the Standard. Due to confusion between the four-month and 18-month testing date intervals, GPL completed the four-month maintenance activities before the March 31, 2017 deadline, on February 17, 2017. The Compliance Task Manager (CTM) incorrectly changed the next four-month maintenance due date to July 31, 2017 instead of the correct date of June 30, 2017. GPL completed the maintenance activities for the two VLA batteries on August 1, 2017 and the maintenance activities reflected no changes or updates to either VLA battery. After reviewing all relevant information, WECC determined that GPL failed to maintain two VLA batteries at one substation that are included within the time-based maintenance program in accordance with the maximum maintenance intervals prescribed within Table 1-4(a) of the Standard. The root cause of the issue was an incorrect assumption by the GPL staff that the maintenance and testing dates in the tracking software were accurate.						
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, GPL failed to maintain two VLA batteries at one substation that are included within the time-based maintenance program in accordance with maximum maintenance intervals prescribed within Table 1-4(a) of the Standard. GPL had weak preventative controls to prevent this issue. However, as compensation, when the missed maintenance was completed, no deficiencies were identified for the VLA batteries. Furthermore, the short duration of the issue lessens the risk to the BPS.							
Mitigation	To mitigate this issue, GPL: a. completed the required maintenance tasks for the two VLA batteries; b. revised the CTM tasks for batteries to emphasize testing interval at beginning Task Statement; c. revised the CTM task requiring verification of receipt of batteries to add an additional action to also verify the next CTM due date for the 4-month battery maintenance activities; d. revised all PRC-005 related CTM tasks to add "Regulatory Required Task" at the beginning of the task statement for awareness; e. conducted a review of all prior maintenance activities to confirm that no other delays have occurred and verify that all pertinent CTM tasks have the correct due date; and f. prepared and conducted refresher CTM training for Performance Managers and Deputy Performance Managers for each applicable wind farm.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date
WECC2018019007	COM-001-3	R9	Peak Reliability	NCR10289	12/1/2017	12/15/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 19, 2018, the entity submitted a Self-Report stating, as a Reliability Coordinator (RC), it was in noncompliance with COM-001-3 R9. Specifically, the entity reported that during the transition from COM-001-2.1 to COM-001-3, a footnote was inadvertently deleted from its Communications Systems Monitoring and Testing document. The footnote cited the requirement to perform monthly calls to test its Alternative Interpersonal Communication (AIC), through its telephone system, with the entities that do not participate in the daily Balancing Authority (BA) and Transmission Operator (TOP) calls. Although the entity completed its daily BA and TOP calls after the transition to COM-001-3, it did not perform the November 2017 calls with one BA and six TOPs due to the deleted footnote. After reviewing all relevant information, WECC determined the entity failed to test its AIC capability at least once each calendar month, as required by COM-001-3 R9. The root cause of the issue was an incomplete documented process. The entity had inadvertently removed the monthly calls with certain BAs and TOPs from its Communications Systems Monitoring and Testing document in its transition from one version of the Standard to the next version of the Standard. This issue began on December 1, 2017, when the entity did not complete a monthly test of its AIC with the required BAs and TOPs and ended on December 15, 2017, when the entity completed the test of its AIC with each required entity, for a total of 16 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to test its AIC capability at least once each calendar month, as required by COM-001-3 R9. However, the entity has effective compensating measures. Specifically, the entity tests its AIC capability daily with the remaining 35 BAs and 56 TOPs, thus reducing the risk. PEAK also has moderate detective controls in its informal process to review the daily call logs performed by the shift foreman and again by the compliance officer.
Mitigation	To remediate and mitigate this issue, the entity has: a. completed an adequate test of its AIC capability with the missed BA and six TOPs; b. revised the Communications Systems Monitoring and Testing process document to return the footnote citing the AIC testing with the entities not participating in the daily BA and TOP calls; and c. created calendar reminders for departmental staff that test the AIC capability through monthly individual calls with the entities not participating in the daily BA and TOP calls.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date
WECC2017018483	PRC-002-2	R5	Peak Reliability	NCR10289	9/28/2016	4/16/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 11, 2017, the entity submitted a Self-Report stating, as a RC, it was in noncompliance with PRC-002-2 R5. Specifically, the entity reported that in August 2017, it discovered its Dynamic Disturbance Recorder (DDR) list had not been sent to all the owners of identified Bulk Electric System (BES) elements within 90 days of completion of the identification of the BES elements that require DDR. The entity did not include one Control Center owner when it sent the DDR list to the other owners of applicable BES elements on June 30, 2016. The missing Control Center had one Facility that requires DDR. The entity updated and disseminated its DDR list to include the missing Control Center on April 16, 2017. After reviewing all relevant information, WECC determined the entity failed to notify one owner of identified BES element, within 90-calendar days of completion of Part 5.1, that its respective BES Elements require DDR data when requested, as required by PRC-002-2 R5. The root cause of the issue was to the lack of an adequate process for the creation and dissemination of the entity's DDR list. This issue began on September 28, 2016, 90 days after the entity notified all but one BES Element owners for which DDR data is required and ended on April 16, 2017, when the entity notified the control center that was missing from the DDR list that its respective BES Elements require DDR data, for a total of 201 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to notify all owners of identified BPS Elements, within 90-calendar days of completion of Part 5.1, that their respective BPS Elements require DDR data when requested, as required by PRC-002-2 R5. However, the entity had good compensating controls. Specifically, the entity posted the list of BES elements which require DDR data to its external, entity facing website. As further compensation, there were no events during the period of noncompliance that would have required the entity to request DDR, and the Control Center missing from the list is not required to install applicable DDR devices until 2022.
Mitigation	To remediate and mitigate this issue, the entity has: a. notified the Control Center owner that was missing from the DDR list of the respective BES elements that require DDR data; b. updated the DDR distribution list to include all applicable owners; and c. created a process for disturbance monitoring and reporting requirements to address the requirements of the Standard.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018755	IRO-010-2	R1	Peak Reliability	NCR10289	1/1/2017	12/8/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 10, 2017, the entity submitted a Self-Report stating, as a RC, it was in noncompliance with IRO-010-2 R1. Specifically, the entity reported that it did not directly address, in the correct format, its current Protection System status or degradation in its documented specification for the data necessary for the entity to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This documented specification is both published on the entity's public-facing website and distributed to applicable entities, per IRO-010-2 R1. In the transition from the previous version of IRO-010, the entity did not update the documented specification for the data required by the new version of the Standard, by the mandatory and enforceable date of January 1, 2017. The entity incorrectly assumed the previous version of the document would still qualify for compliance with the Standard. After reviewing all relevant information, WECC determined the entity failed to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments; including provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability, as required by IRO-010-2 R1. The root cause of the issue was that the entity did not correctly implement the required updates in the documented specification for the data required by the Standard, when the new version of the Standard, IRO-010-2, became mandatory and enforceable. This issue began on January 1, 2017, when IRO-010-2 became mandatory and enforceable and ended on December 8, 2017, when the entity revised its data specification document to include the correct format for provisions for the notification of current Protection System degradation, for a total of 342 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, the entity failed to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments; including provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability, as required by IRO-010-2 R1. However, the entity implemented effective detective controls in its Compliance Department review of events, which identified this issue. In addition, the entity implemented compensating measures to lessen the risk. Though the entity did not meet the requirements of the Standard, it did communicate with the required entities to provide awareness of Protection System status or degradation that impacts System reliability.
Mitigation	To remediate and mitigate this issue, the entity has: a. revised its data specification document to include provisions for notification Protection System degradation that impacts System reliability; and b. implemented a process to notify members regarding updates to the RC data specification.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017221	COM-002-4	R1	Seattle City Light	NCR05382	7/1/2016	3/27/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 13, 2017, the entity submitted a Self-Report stating, as a Balancing Authority and Transmissions Operator, it was in issue with COM-002-4 R1. Specifically, the entity reported that its internal procedural documents for communication protocols did not include all the required elements of R1. The entity's procedure neither provided issuance/receipt requirements associated with single-party to multiple-party burst Operating Instructions (R1.4) nor specified instances that require time identification when issuing Operating Instructions (R1.5). After reviewing all relevant information, WECC determined the entity failed to document communications protocols to require operating personnel that issue a written or oral single-party to multiple-party burst Operating Instructions to confirm or verify that the Operating Instruction was received by at least one receive of the Operating Instruction, as well as specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by COM-002-4 R1.4 and R1.5. The root cause of the issue was a less that adequate process and procedure. The entity historically had not needed to issue single-party to multiple party burst Operating Instruction or Operating Instructions across time zones and therefore did not believe that these requirements were applicable. This issue began when the Standard and Requirement became mandatory and enforceable and ended when the entity updated its communications protocol procedures, for a total of 256 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to document communications protocols to require operating personnel that issue a written or oral single-party to multiple-party burst Operating Instructions to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction, , as well as specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by COM-002-4 R1.4 and R1.5. The entity conducted a pre-audit review of compliance with the reliability Standards prior to every audit to detect any potential noncompliance. In addition, the entity has never had to issue a single-party to multiple party burst Operating Instruction and the entity's neighboring TOPs and GOs are in the same time zone as the entity. Hence, the entity would likely not have miscommunication or delayed response due to operation in a different time zone.
Mitigation	The entity submitted a Mitigation Plan to address this issue, WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: a. revised its communication protocol to include procedures for single-party to multiple-party burst Operating Instructions; b. revised its communications protocol to include procedures to use Pacific Prevailing Time; in 24-hour clock for all communications and when communicating externally across time zones; and c. conducted training for all System Operators in relation to reading the revised communication protocol procedures before shifts. The entity submitted a Mitigation Plan Completion Certification, WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019020958	EOP-005-2	R17.	Tampa Electric Company (TEC)	NCR00074	01/01/2018	01/07/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On January 22, 2019, TEC submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with EOP-005-2 R17. One (1) out of 37 (2.7%) operators did not receive required two hours training of its Blackstart Resource generation units every two calendar years as required. This noncompliance started on January 1, 2018, when one operator had not received required Blackstart training and ended on January 7, 2019, when the operator received required training. In this instance, the operator was absent for four months (July 14, 2017 to November 16, 2017) during which time he missed the 2017 Blackstart Training class. Makeup training for this operator was overlooked when he returned to work. The issue was discovered by internal review. After the issue was discovered, the operator received training on January 7, 2019, a period of 371 days after it was required. The cause for this noncompliance was a lack of internal controls to ensure operators scheduled for the required training actually received it.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk of missed training is that the operator would be lacking in required information necessary to perform a Blackstart system restoration when needed. This risk was reduced as the operator missing the required bi-annual training (i.e., every two calendar years) had received the training in 2013 and 2015, and there have been no substantial changes to the equipment or procedures since his prior training. In addition, there were eight (8) other operators on his crew who had the 2017 training and who were available to perform Blackstart system restoration. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, TEC: 1) trained Operator; 2) performed an extent of condition identifying only one out of 37 operators did not receive training in 2017; 3) completed root cause analysis; 4) created preventative controls to add details to work order such as names of those that require training to ensure everyone receives the appropriate training. Work order won't close out until everyone receives training. Added a task for Operations Engineer or Operations Manager to review the list of all Operations teams' personnel to ensure all teams have received this training. Added task to schedule make-up training session as required; 5) created preventative control by updating energy services handbook to include more details; and 6) communicated to personnel the changes to the energy services handbook regarding EOP-005-2 R17.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019020949	VAR-002-4.1	R3.	Gainesville Regional Utilities (GRU)	NCR00032	02/10/2018	02/10/2018	Self-Report	06/30/2019
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On January 18, 2019, GRU submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3. This noncompliance started on February 10, 2018, when GRU failed to notify its Transmission Operator of an Automatic Voltage Regulator (AVR) status change greater than 30 minutes, and ended on February 10, 2018, when the proper notification was made. During an internal audit, GRU discovered the AVR for an 80MW generator had changed from automatic mode to manual mode for a duration of 93 minutes. The change was not communicated to GRU's system control (GRU is both Generator Operator and Transmission Operator) until 63 minutes after the status change occurred. An extent of condition review was completed verifying no additional occurrences. Furthermore, GRU verified while the AVR was out of automatic mode the voltage schedule was maintained. The cause for this noncompliance was inadequate alerting capability of AVR status.						
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. GRU's failure to maintain the AVR in automatic mode could result in excursions from the established voltage schedule, preventing the Transmission Operator from effectively managing voltage. The risk was reduced because of the short duration of the event, and a review of voltage levels during the event revealed no voltage excursions occurred. No harm is known to have occurred.						
Mitigation	To mitigate this noncompliance, GRU: 1) completed an extent of condition review; 2) verified that the AVR out of auto event did not result in an excursion from the voltage schedule; 3) corrected AVR alarm for violating plant; and 4) updated generator operator procedures for VAR-002-4.1. To mitigate this noncompliance, GRU will: 1) create training materials for new system control AVR alarms by March 31, 2019 2) train on generator operator procedures for VAR-002-4.1 by April 30, 2019; 3) train system operators on new AVR alarms by May 30, 2019; 4) create redundant EMS alarm at system control for each unit's AVR status by June 30, 2019; and 5) investigate and correcte AVR alarms for additional plants by June 30, 2019.						

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2017018322	MOD-025-2	R1	USACE - Little Rock District (COELR)	NCR06037	07/01/2016	Present	Self-Report	Expected Completion 06/30/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 13, 2017, COELR submitted a Self-Report, stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R1. Pursuant to MOD-025-2's phased-in implementation plan, COELR was supposed to have verified the Real Power capability of 40% of its applicable generation units by July 1, 2016. COELR was also unable to achieve MOD-025-2 R1 compliance with 60% of its applicable generation units by July 1, 2017 or with 80% of its applicable generation units by July 1, 2018. The cause of the noncompliance is that COELR did not understand the scope of its obligations under MOD-025-2 and believed that model testing that occurred prior to the adoption of MOD-025-2 was sufficient to achieve compliance. The noncompliance began on July 1, 2016, when COELR was required to have verified the Real Power capability of 40% of its applicable generation units, and is expected to end by June 30, 2019, when COELR will have verified the Real Power capability of all of its applicable generation units.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. COELR's 1088 MW generating fleet consists of seven hydro generation stations whose ratings have remained consistent over the years. Per COELR, when changes to Real Power capabilities have occurred, they have been previously provided to its Transmission Planner. Additionally, per the entity, the Real Power capabilities of the units are known to the Transmission Operator as the units are routinely dispatched to their rated outputs. Finally, none of COELR's hydro generating stations are associated with any Remedial Action Scheme (RAS), any SPP Flowgate, or identified as a Blackstart Resource in any Transmission Operator's System Restoration Plan. No harm is known to have occurred. During the ongoing mitigation, COELR will implement a rolling testing and verification schedule and will provide the information to its Transmission Planner as that information becomes available. COELR has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, COELR will complete the following mitigation activities by June 30, 2019: 1) will have contractors perform the verification testing for all applicable generation units, then distribute those results to its Transmission Planner; and 2) will review its compliance with MOD-026-1 and MOD-027-1 and self-report any noncompliance. The length of time that it will take to complete mitigating activities is related to locating and scheduling an inspection with qualified contractors.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2017018323	MOD-025-2	R2	USACE - Little Rock District (COELR)	NCR06037	07/01/2016	Present	Self-Report	Expected Completion 06/30/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 13, 2017, COELR submitted a Self-Report, stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R2. Pursuant to MOD-025-2's phased-in implementation plan, COELR was supposed to have verified the Reactive Power capability of 40% of its applicable generation units by July 1, 2016. COELR was also unable to achieve MOD-025-2 R2 compliance with 60% of its applicable generation units by July 1, 2017 or with 80% of its applicable generation units by July 1, 2018. The cause of the noncompliance is that COELR did not understand the scope of its obligations under MOD-025-2 and believed that model testing that occurred prior to the adoption of MOD-025-2 was sufficient to achieve compliance. The noncompliance began on July 1, 2016, when COELR was required to have verified the Reactive Power capability of 40% of its applicable generation units, and is expected to end by June 30, 2019, when COELR will have verified the Reactive Power capability of all of its applicable generation units.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net Real and Reactive Power capability is available for planning models used to assess BES reliability. COELR's 1088 MW generating fleet consists of seven hydro generating stations whose ratings have remained consistent over the years. COELR states that it has only had one generating station have a change to its excitation system in the last seven years. Per COELR, when changes to Reactive Power capabilities have occurred, they have been previously provided to its Transmission Planner. Additionally, per the entity, the Reactive Power capabilities of the units are known to the Transmission Operator through routine dispatch. Finally, none of COELR'S hydro generating stations are associated with any Remedial Action Scheme (RAS), any SPP Flowgate, or identified as a Blackstart Resource in any Transmission Operator's System Restoration Plan. No harm is known to have occurred. During the ongoing mitigation, COELR will implement a rolling testing and verification schedule and will provide the information to its Transmission Planner as that information becomes available. COELR has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, COELR will complete the following mitigation activities by June 30, 2019: 1) will have contractors perform the verification testing for all applicable generation units, then distribute those results to its Transmission Planner; and 2) will review its compliance with MOD-026-1 and MOD-027-1 and self-report any noncompliance. The length of time that it will take to complete mitigating activities is related to locating and scheduling an inspection with qualified contractors.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2016015951	PRC-005-2(i)	R3	Eastman Cogeneration Limited Partnership (EASTMAN)	NCR01092	10/1/2015	3/31/2016	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 July 25, 2016, EASTMAN submitted a Self-Report stating that as a Generator Owner, it was in noncompliance with PRC-005-2(i) R3. EASTMAN also submitted a Self-Report stating that it was in noncompliance with PRC-005-1b R2 (SPP2016015926) on July 21, 2016; both Self-Reports were consolidated into this NERC Violation ID. Under the PRC-005-2(i) R3 implementation plan, EASTMAN was required to be 100% compliant for applicable equipment that has less than a one-year maintenance interval. EASTMAN discovered this noncompliance in preparation for a September 2016 Compliance Audit where PRC-005-2(i) R3 was in scope. EASTMAN identified multiple instances where it failed to perform the four-month maintenance of VLA batteries, verification of communication system functionality, as well as failures to test, inspect, and/or calibrate protection system devices according to EASTMAN's Protection System Maintenance Program (PSMP). The cause of the noncompliance was that EASTMAN had inadequate internal controls to implement its PSMP and a lack of understanding between internal departments regarding their responsibilities. The noncompliance began on October 1, 2015, when the implementation plan required 100% compliance, and ended on March 31, 2016, when all required maintenance activities were completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that was commissioned in 2001 and has not had any PRC-005-2(i) related events or protection system dc supply problems during the life of the plant. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Internal Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred. MRO considered EASTMAN's relevant compliance history. EASTMAN's PRC-005-2(i) R3 compliance history includes minimal risk violations of PRC-005-1 R1 (SPP201000297) and PRC-005-1 R2 (SPP201000298). The PRC-005-1 R1 violation involved a failure to have a complete PSMP and include all components within its PSMP; the noncompliance was mitigated on December 15, 2011. The PRC-005-1 R2 violation involved a failure to test four relays within the three-year interval and have testing documentation for the majority of its other components such as battery banks, instrument transformers, and dc control circuits; the noncompliance was mitigated on June 1, 2012. MRO determined that EASTMAN's compliance history should not serve as a basis for applying a penalty. MRO determined that the current noncompliance was not caused by a failure to mitigate the prior instances of noncompliance and there is a substantial duration of time between the current noncompliance and the prior instances of noncompliance.
Mitigation	To mitigate this noncompliance, EASTMAN: 1) confirmed the October 2017 shutdown schedule; 2) performed the East/West line differential Protective Relay and Communications Maintenance; 3) performed relay and dc control circuit maintenance; 4) performed six-year interval for dc supply maintenance; 5) purchased a new dc supply; 6) confirmed the maintenance schedule with its contractor; and 7) installed new dc supply line on unit 2. The associated Mitigation Plan was verified on May 11, 2018.

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

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of NSP and PSCO. Xcel Energy states that it discovered that it had missed an 18-month maintenance activity (testing) for a dc supply at one NSP substation. Xcel Energy reports that it conducted an extent of conditions review at all substations subject to dc supply maintenance and verification requirements. The review did not reveal any additional noncompliance with an 18-month maintenance activity, but did identify noncompliance associated with four-month maintenance activities (inspections) at 13 NSP substations and 12 PSCO substations. The cause of the noncompliance was that Xcel Energy experienced issues in the implementation of a new work order system and Xcel Energy's Maintenance Program procedure lacked controls and oversight to ensure that testing was completed within the appropriate timeframes. The noncompliance began on April 1, 2017 when Xcel Energy missed the first four-month maintenance activity and ended on February 28, 2018 when Xcel Energy performed all required maintenance activities.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy reports the dc supplies have alarms for loss of ac or high/low voltage alarms and alarms for grounds; these alarms are designed to alert Xcel Energy prior to a failure. Xcel Energy states that it did not receive any alarms or experience any dc supply failures during the period of noncompliance. Additionally, none of these substations are associated with an IROL, a WECC Major Path, or a Remedial Action Scheme (RAS). No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, Xcel Energy: To mitigate the noncompliance to the 18-month maintenance activities, Xcel Energy: 1) completed the required testing; 2) updated its Substation Battery Maintenance and Testing Program to include additional controls and oversight; 3) added substation dc supply test requirements to its compliance milestones; and 4) provided training to Substation O&M staff. To mitigate the noncompliance related to the four-month maintenance activities, Xcel Energy: 1) completed the required inspections; 2) implemented auto-generation of work orders of substation dc supply inspections; 3) updated substation dc supply inspection work orders to require the inspection of dc supply voltage, electrolyte level, and unintentional grounds; 4) setup monthly tasks in its internal corporate task tracking tool for substation O&M managers to review inspection reports; and 5) provided training to substation O&M staff on battery testing/inspection requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020440	FAC-008-3	R3	Southern Minnesota Municipal Power Agency (SMMPA)	NCR01030	01/01/2013	06/28/2018	Compliance Audit	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.)	During a Compliance Audit conducted on January 24, 2018, MRO determined that SMMPA, as a Transmission Owner, was in noncompliance with FAC-008-3 R3. One or more of SMMPA's substations contain equipment in bus segments that are not series-connected with adjacent Transmission Lines during normal operations, however the equipment does become series-connected during certain substation configurations (e.g., when any of the circuit breakers on the ring bus are open). MRO originally considered this an Area of Concern, but determined that noncompliance existed once it was confirmed that certain substation configurations had actually occurred in which the equipment had become series-connected. An extent of condition review determined that since January 1, 2015 abnormal configurations occurred in eight instances at the Byron 345 kV substation where equipment on its ring bus became series connected. MRO determined that during these abnormal configurations, the applicable Facility Rating should have been reduced from 2000 Amps to 1600 Amps, but new ratings were not issued. SMMPA's Facility Ratings methodology failed to ensure valid Facility Ratings during these abnormal configurations by either having a requirement that 1) ensured that the Ratings of such equipment be reflected in the Facility Ratings of the adjacent line terminals; or 2) provided temporary Facility Ratings during the substation configuration changes that cause the equipment to become series-connected. The cause of the noncompliance is that SMPPA's Facility Ratings methodology did not consider situations where Facility reconfiguration could affect which equipment was series-connected, leading to a modification in the Facility Rating. The noncompliance began on January 1, 2013, when the Standard became enforceable, and ended on June 28, 2018 when SMMPA updated its Facility Ratings methodology and issued new Facility Ratings.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SMMPA was following ERO guidance in developing its Facility Ratings methodology, the ERO guidance is not clear with respect to non-series equipment that could become the most limiting element during a Facility reconfiguration. Additionally, the Byron substation is SMMPA's only 345 kV Facility, and is not part of an IROL or Blackstart Cranking Path. Finally, there were no reported outages or equipment damage as a result of the noncompliance. No harm is known to have occurred. SMMPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, SMMPA: 1) revised its Facility Ratings methodology to include considerations of unique substation configurations; and 2) issued new Facility Ratings for the impacted terminals.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019268	COM-002-4	R4	Southwestern Power Administration (SWPA)	NCR01144	7/1/2017	9/19/2017	Self-Certification	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 February 28, 2018, SWPA submitted a Self-Certification stating that as a Transmission Operator, it was in noncompliance with COM-002-4 R4. During an internal review, SWPA determined that its assessment did not include all the documented communications protocols listed in R1. SWPA states it only reviewed oral communications protocols. The cause of the noncompliance was that SWPA failed to understand its compliance obligations under the updated Standard and failed to capture the increased scope of the assessment in the updated Standard language. The noncompliance began on July 1, 2017, when the Standard became enforceable, and ended on September 19, 2017, when a full assessment was completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Per SWPA, supervisory staff perform a daily review of Dispatcher E-logs and Special Conditions reports, which use SWPA's communication protocols. No harm is known to have occurred. SWPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, SWPA: 1) assessed each component of its Operating Personnel Communications Protocol; its Operating Personnel Communications Protocol; 2) had its Compliance Division and Chief Dispatcher develop a spreadsheet that identifies all Operation Personnel Communications Protocols that must be assess annually; 3) had its Chief Dispatcher develop another spreadsheet to identify which Operation Personnel will be assessed each quarter to ensure that all personnel are fully assessed by the 12-month deadline; and 4) had its Chief Dispatcher set calendar reminders to conduct the quarterly assessments.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019399	VAR-002-4.1	R2	Thunder Ranch Wind Project, LLC (TRW)	NCR11778	1/15/2018	1/16/2018	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 violation.)	On March 19, 2018, TRW submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. TRW reported that it failed to follow the voltage control schedule provided by its Transmission Operator from January 15 to January 16, 2018. Per TRW, this occurred when the voltage controller inadvertently switched into voltage control mode. This occurred while contractors were working on the SCADA system; during that work the SCADA system defaulted to its normal mode of operations, which included the voltage controller being set to voltage control mode. TRW states that the contractors did not inform the control room of the change and that no alarm was triggered by the change. Because of the change, TRW was no longer maintaining a 0 MVar target as required by its Transmission Operator. The noncompliance was caused by inadequate alarming for a voltage control status and that TRW did not have a process to ensure that contractors notified the control room of changes to the SCADA system. The noncompliance began at approximately 9:00 p.m. on January 15, 2018, when the voltage controller switched modes and TRW no longer maintained the target set by its Transmission Operator, and ended on January 16, 2018 at approximately 5:00 p.m. when TRW returned the voltage controller back to the correct mode and achieved the target set by its Transmission Operator.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The generation Facility could only have a minor impact on the bulk power system as it has a nameplate rating of 300 MW. Additionally, the generation Facility is not part of a Remedial Action Scheme (RAS) and is not associated with any Interconnection Reliability Operating Limit (IROL). No harm is known to have occurred. TRW has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, TRW: 1) set the voltage controller back to the correct mode; 2) created a "Return to normal Voltage Controller Alarm" that identifies deviations from the mode of operation required by the Transmission Operator, this alarm must be acknowledged by the operator; 3) updated its "Wind Control System User Administration Policy" and implemented a procedure for all contractors to follow, this procedure will place controls on how contractors access the SCADA system and ensure that the control room is notified of changes to the system; and 4) conducted training with applicable staff on the updated policy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020920	MOD-025-2	R1	GenConn Energy LLC	NCR11710	7/1/2016	6/29/2018	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 violation.)	On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2, R1. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have 40% of their applicable Facilities tested, the NRG corporate methodology was to calculate the MOD-025-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% testing threshold for the July 1, 2017 deadline for MOD-025-2. By July 1, 2018, GenConn had 100% of their applicable facilities tested. The violation start date is July 1, 2016 and ended on June 29, 2018 when the MOD-025-2 R1 real power capability was verified via testing. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the MOD-025-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Noncompliance with MOD-025-2 R1 has the potential to affect the reliability of the BPS by allowing for the TP to have inaccurate information about the capabilities of the generating units in planning models used to assess BPS reliability. In the ISO-NE market, real and reactive power testing on the GenConn units that closely matches MOD-025-2 has been regularly verified, reported, communicated, and approved by the ISOs/Transmission Planners to validate generator capability. Although the original documentation provided to ISO-NE may not meet full compliance with the requirement, the potential and actual risks to the BES are low as much of the relevant data needed by the TP was verified, valid, tested, and provided on a consistent basis in previous years. The Net Capacity Factors (NCF) of the 8 GenConn units (480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. Additionally, the result of the verification made in accordance with R1 required no adjustments to the units. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary MOD-025-2 R1 testing and then provided the results to the TP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020919	MOD-025-2	R2	GenConn Energy LLC	NCR11710	7/1/2016	6/29/2018	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 January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2, R2. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have 40% of their applicable Facilities tested, the NRG corporate methodology was to calculate the MOD-025-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% testing threshold for the July 1, 2017 deadline for MOD-025-2. By July 1, 2018, GenConn had 100% of their applicable facilities tested. The violation started on July 1, 2016 and ended on June 29, 2018 when the MOD-025-2 R2 reactive power capability was verified via testing. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the MOD-025-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Noncompliance with MOD-025-2 R2 has the potential to affect the reliability of the BPS by allowing for the TP to have inaccurate information about the capabilities of the generating units in planning models used to assess BPS reliability. In the ISO-NE market, real and reactive power testing on the GenConn units that closely matches MOD-025-2 has been regularly verified, reported, communicated, and approved by the ISOs/Transmission Planners to validate generator capability. Although the original documentation provided to ISO-NE may not meet full compliance with the requirements, the potential and actual risks to the BES are low as much of the relevant data needed by the TP was verified, valid, tested, and provided on a consistent basis in previous years. The Net Capacity Factors (NCF) of the 8 GenConn units (480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. Additionally, the result of the verification made in accordance with R2 required no adjustments to the units. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary MOD-025-2 R2 testing and then provided the results to the TP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020918	PRC-019-2	R1	GenConn Energy LLC	NCR11710	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2, R1. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have the protection system and voltage regulating control system verified on 40% of their applicable Facilities, the NRG corporate methodology was to calculate the PRC-019-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% verification deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% verification threshold for the July 1, 2017 deadline for PRC-019-2. By July 1, 2017, GenConn had 100% of their applicable facilities verified. The violation started on July 1, 2016 and ended on June 30, 2017 when the PRC-019-2 R1 verification that brought GenConn into compliance was completed. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the PRC-019-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit. However, the result of the June 2017 verification made in accordance with R1 required no adjustments to the units. The Net Capacity Factors (NCF) of the eight GenConn units (8 * 60 MW = 480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. The BA (ISO-NE) carries operating reserves of approximately 2,300 MW of which a GenConn unit is less than 2%. Therefore, if this instance of noncompliance had caused any of the affected generators to trip unnecessarily, the BA would have been able to replace the lost capacity. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary PRC-019-2 verification.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020917	PRC-024-2	R2	GenConn Energy LLC	NCR11710	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 11 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2, R2. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have the protection system and voltage regulating control system verified on 40% of their applicable Facilities, the NRG corporate methodology was to calculate the PRC-024-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% verification deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% verification threshold for the July 1, 2017 deadline for PRC-024-2. By July 1, 2017, GenConn had 100% of their applicable facilities verified. The violation started on July 1, 2016 and ended on June 30, 2017 when the PRC-024-2 R2 verification that brought GenConn into compliance was completed. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the PRC-019-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to verify the relay settings to the voltage curve could cause the unit to trip at a time when it could exasperate a system event further. However, the result of the June 2017 verification made in accordance with R2 required no adjustments to the units. The Net Capacity Factors (NCF) of each of the eight GenConn units (8 * 60 MW = 480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. The BA (ISO-NE) carries operating reserves of approximately 2,300 MW of which a GenConn unit is less than 2%. Therefore, if this instance of noncompliance had caused any of the affected generators to trip unnecessarily during a system voltage event, the BA would have been able to replace the lost capacity. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary PRC-024-2 verification on all of the applicable facilities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021075	PRC-019-2	R2	Taunton Municipal Lighting Plant	NCR07214	12/03/2018	12/10/2018	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 violation.)	On February 20, 2019, Taunton Municipal Lighting Plant ("Taunton" or "the entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2, R2. Specifically, the entity discovered on December 6, 2018 that it did not re-coordinate within 90 days it's voltage regulating system controls as a result of generator exciter limiter setting changes that were made on September 4, 2018. The noncompliance associated with the needed re-coordination started on December 3, 2018 and ended on December 10, 2018, when the re-coordination was completed by a third party engineering firm. Although the entity had a documented Protection System Maintenance Plan (PSMP), the root cause of this noncompliance was a lack of the development of proper controls around the expected actions and communications for limiter, AVR, and protection system re-coordination when such adjustments are made.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. A lack of coordination amongst the Protection System and the in-service limiters could cause an unnecessary trip of the affected Generating Station. However, the entity's generating facilities total to 130 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 8% in 2017 and 11% in 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Finally, the results of the December 10, 2018 coordination study showed there were no settings changes needed. No harm is known to have occurred as a result of this of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) Completed the re-coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection System. 2) Created a tracking spreadsheet for all applicable Reliability Standards with recurring compliance due dates. 3) Entered compliance due dates into the Primary Compliance Contact and immediate supervisor's Microsoft Outlook calendars to ensure future due dates are met. 4) Instituted six-month meetings where the Primary Compliance Contact and subject matter experts from Engineering and Operations will meet to review the compliance obligations of applicable Reliability Standards which include technical requirements. 5) Instituted monthly communication reviews (in-person or conference call) to discuss changes to entity generating unit or plant capabilities, voltage regulating controls, and protection system. Compliance, Engineering, and Operations participate in these reviews that will allow for ample time to properly coordinate these settings, if needed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021076	PRC-005-6	R3	Taunton Municipal Lighting Plant	NCR07214	09/01/2018	01/28/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On February 20, 2019, Taunton Municipal Lighting Plant ("Taunton" or "the entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6, R3. Specifically, the entity missed an 18-month VLA battery inspection. On January 4, 2019, it was discovered upon internal review that 18-month battery testing activity that had last been completed on February 27, 2017 and had not been completed again by September 1, 2018. Upon discovery, the entity coordinated to have the missed battery maintenance completed on January 28, 2019. The noncompliance associated with the 18-month battery testing intervals started on September 1, 2018 and ended on January 28, 2019 when the maintenance was completed. Although the entity had a documented PSMP, the root cause of this noncompliance was a lack of the development of proper controls around employing a reminder or notification system to ensure that this task was completed within 18 calendar months after the February 27, 2017 testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to uncompleted PRC-005-6 R3 maintenance is that the entity generation could possibly trip offline prematurely which could exasperate an ongoing real time BES situation. It could also expose the plant equipment to damage if the plant fails to trip offline properly when called upon. However, the entity generating facilities total to 130 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 8% in 2017 and 11% in 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Although the 18-month battery testing was performed approximately 4 months late, the entity had no known issues with any of their battery systems and or indication that a battery system failure was imminent. No harm is known to have occurred as a result of this of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) Completed the required 18-month interval battery testing per PRC-005-6, Attachment A, Table 1-4(a). 2) Created a tracking spreadsheet for all applicable Reliability Standards with recurring compliance due dates. 3) Entered compliance due dates into the Primary Compliance Contact and immediate supervisor's Microsoft Outlook calendars to ensure future due dates are met. 4) Instituted six-month meetings where the Primary Compliance Contact and subject matter experts from Engineering and Operations will meet to review the compliance obligations of applicable Reliability Standards which include technical requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019908	PRC-019-2	R1	American Electric Power Service Corporation as agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Ohio Transmission Company, AEP Appalachian Transmission Company, AEP West Virginia Transmission Company, AEP Indiana Michigan Transmission Company and AEP Kentucky Transmission Company, Inc. (AEPSC)	NCR00682	7/1/2017	4/5/2018	Self-Report	Complete
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)			On June 11, 2018, AEPSC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. ACPSC submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement on behalf of AEP as Agent for AEP OK Transco., PSCO, and SWEPCO (AEP West) (NCR01056). The phased implementation plan for PRC-019-2 R1 requires that each Generator Owner verify at least 40% of its applicable Facilities by July 1, 2016; 60% of its applicable Facilities by July 1, 2017; 80% of its applicable Facilities by July 1, 2018; and 100% of its applicable Facilities by July 1, 2019. Because of AEP West's efforts to meet the 80% milestone due by July 1, 2018, AEP West completed a fleet-wide compliance assurance evaluation of all facilities including the already completed facilities that were documented to meet prior implementation deadlines. From this review, AEP West determined that its Northeastern Unit 3 did not meet the intent of PRC-019-2 R1.1 (AEP West determined that the applicable loss of field protective function enabled within the overall differential and generator protection microprocessor relays for Northeastern Unit 3 did not meet the intent of PRC-019-2 Requirement R1.1.1. Specifically, the loss of field protective relays were set to operate before the voltage regulator minimum excitation limiter settings. AEP West completed this evaluation on June 25, 2017 and that resulted in a lack of time for AEP Generation to conduct the comprehensive quality assurance review and technical evaluation of the coordination study following field data collection.) and could not be considered as part of AEP Generation's percentage of completed facilities utilized to meet the 60% milestone due by July 1, 2017. Due to the exclusion of Northeastern Unit 3, the resulting percentage of completed PRC-019-2 applicable facilities within the SPP (now MRO) footprint fell below 60% to 59.1% and resulted in this noncompliance. This noncompliance involves the management practices of planning and verification. AEP West determined the cause of this noncompliance to be that it allowed itself insufficient time to conduct a quality assurance review and technical evaluation of the coordination study following field data collection, issue the settings to correct the discoordination issue, and implement changes within a scheduled outage of sufficient duration prior to the milestone due date. This failure to adequately plan and to verify that AEP West had completed 60% of its applicable Facilities are both root causes of this noncompliance. This noncompliance started on July 1, 2017, when AEP West was required to have verified at least 60% of its applicable Facilities and ended on April 5, 2018, when AEP West finished its verification at Northeastern Unit 3.					
Risk Assessment			This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because AEP West conducted an evaluation of unit operating conditions over the duration of this noncompliance. That evaluation indicated that operation was solely in the over-excited region and would not impact the set points associated with the loss of excitation protective relaying. PRC-019-2 R1 required AEP West to complete verification of 60% of its applicable facilities by July 1, 2017 and AEP West completed 59.1% by July 1, 2017. Missing this one applicable facility only slightly reduced AEP West below the 60% threshold, which minimizes the risk. No harm is known to have occurred. As of July 1, 2018, AEP West had 81.8% of applicable facilities verified in the SPP/MRO footprint which helps reduce the risk while mitigation is ongoing. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because of the different causes of the prior noncompliance and the current noncompliance.					
Mitigation			To mitigate this noncompliance, AEP West:					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019908	PRC-019-2	R1	American Electric Power Service Corporation as agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Ohio Transmission Company, AEP Appalachian Transmission Company, AEP West Virginia Transmission Company, AEP Indiana Michigan Transmission Company and AEP Kentucky Transmission Company, Inc. (AEPSC)	NCR00682	7/1/2017	4/5/2018	Self-Report	Complete
			1) performed the coordination study following revision and implementation of the Northeastern unit 3 relay settings and this serves as the initial corrective action to allow AEP West to maintain the schedule adherence of the implementation milestones; 2) performed an extent of condition review to ensure the coordination is in compliance on the remaining facilities completed for 60% and 80% milestones. As well as an extent of condition review on the upcoming 100% milestone plan for the remaining applicable facilities to ensure the adequate time for the settings retrieval, coordination, and implementation of settings changes as required per Requirement R1; 3) adjusted the existing plan to allocate additional time to retrieve and analyze the protective relay and automatic voltage regulator limiter settings, and implement changes during the scheduled unit outage to prevent recurrence; and 4) identifed the remaining PRC-019 applicable relays, evaluate associated settings, and updates within the Asset Management Database to aid the future coordination planning. This will allow future planning to save time in identifying applicable relays and obtaining the necessary field settings. In turn, this will reduce the time needed for the PRC-019 coordination.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017017732	MOD-025-2	R1	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	7/24/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 2, 2017, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with MOD-025-2 R1 identified during a Compliance Audit conducted from May 8, 2017 through May 19, 2017. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity did not perform the Real Power verifications by staged test as required for the first verification. The entity incorrectly performed the verifications using historical operational data. MOD-025-2 R1.1 requires that the first verification be performed via a staged test. As a result, the entity had verified none of its generating Facilities by July 1, 2016, thereby missing the 40% requirement detailed in the implementation plan for MOD-025-2 R1. Additionally, the entity did not submit the data using the MOD-025-2 Attachment 2 (or a similar form containing the same information). Instead, the entity submitted the data using the PJM (Transmission Planner) processes that were in place at the time—the entity submitted data via eGads, email, etc. which did not include all information that is required by MOD-025-2. The entity also submitted these forms late (i.e. after the 90 day deadline in MOD-025-2 R1.2). The entity did provide some data to PJM. The data the entity provided, however, did not meet the MOD-025 requirements. The entity provided the test data that PJM requested using a PJM form, but what PJM requests is different than what MOD-025-2 requires. The PJM forms were very similar to, but not as inclusive as, MOD-025 Attachment 2, which required more data. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to develop and implement an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One root cause was that entity staff was ineffectively trained on how to comply with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly (failing to perform the first verification using a staged test) by relying on what PJM required for its own purposes rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all contributing causes of this noncompliance. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on July 24, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity performed and submitted to its Transmission Planner (PJM) some of the MOD-025 required testing elements before the initial enforcement date of July 1, 2016. (The entity performed the verification using historical data rather than via staged verifications. Had the entity performed the verifications via a staged verification, the results would have likely been identical.) The information that the entity failed to provide was not required or needed to validate net capability for the Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) prescheduled and conducted Real Power verification testing in accordance with MOD-025 R1 at Keystone and Conemaugh Generating Facilities; 2) completed MOD-025 Attachment 2 and submitted it to PJM within 90 days in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and 3) developed and implemented an internal process for review of MOD-025 test information and submission of dates. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018634	MOD-025-2	R1	GenOn REMA 1 (GR1)	NCR11141	7/1/2016	10/23/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 compliance date, the entity had performed real power testing and submitted data for 8 of the 10 units. The entity submitted these tests using the PJM Test form. The testing the entity performed was invalid because the entity performed the testing using the PJM Test form which did not include all of the data fields per MOD-025 Attachment 2. Therefore, none of the ten units in the entity registration met the 2016 reactive testing deadline. The entity met the July 1, 2017 compliance date requirements of 60% by correctly completing the MOD-025 real and reactive power verification for 9 of its 10 units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 23, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. Lastly, the entity contributes approximately 662 MW to the grid and operated at approximately a 1% capacity factor during the noncompliance. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018635	MOD-025-2	R2	GenOn REMA 1 (GR1)	NCR11141	7/1/2016	10/23/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 compliance date, the entity had performed real power testing and submitted data for 8 of the 10 units. The entity submitted these tests using the PJM Test form. The testing the entity performed was invalid because the PJM Test form did not include all of the data fields per MOD-025 Attachment 2. Therefore, none of the ten units in the entity registration met the 2016 reactive testing deadline. The entity met the July 1, 2017 compliance date requirements of 60% by correctly completing the real and reactive power verification for 9 of its 10 units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that the entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on October 23, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. Lastly, the entity contributes approximately 662 MW to the grid and operated at approximately a 1% capacity factor during the noncompliance. No harm is known to have occurred. ReliabilityFirst considered the entity's MOD-025 R2 compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017017847	PRC-019-2	R1	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	2/28/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 2, 2017, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-019-2 R1 identified during a Compliance Audit conducted from May 8, 2017 through May 19, 2017. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. During the May 2017 Compliance Audit of the entity, the Audit Team identified a noncompliance with PRC-019-2 R1. The entity failed to verify 40% of its generating Facilities by the required July 1, 2016 date. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on February 28, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because when the entity performed the verification and coordination, no changes were required. There were no deficiencies in the coordination at any of the entity units. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity completed the required PRC-019 R1 analysis for units at the Generating facilities and is now executing its implementation plan consistent with NERC guidance concerning phased implementation on a registration basis and revised its processes and procedures accordingly. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018630	PRC-024-2	R1	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	2/28/2017	Self-Report	Completion

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity completed the required verification for 4 of 4 applicable units (100%). NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on February 28, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018632	PRC-024-2	R1	GenOn Power Midwest (GPM)	NCR11136	7/1/2016	5/27/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 5, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on three of eight its units (38%). As of the July 1, 2017 implementation date, however, the entity had completed the required verification for seven of its eight applicable units (88%). NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 1,837 MW to the grid and operated at approximately a 15% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on May 27, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. The risk is further reduced because the entity had completed its verification on 33% of its applicable units (instead of the required 40%) by the July 1, 2016 implementation date. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018631	PRC-024-2	R2	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	2/28/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its applicable units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all four of its applicable units. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on February 28, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018633	PRC-024-2	R2	GenOn Power Midwest (GPM)	NCR11136	7/1/2016	5/27/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 5, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on three of its eight (33%) applicable units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification on seven of its eight (88%) applicable units. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 1,837 MW to the grid and operated at approximately a 15% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on May 27, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. The risk is further reduced because the entity had completed its verification on 33% of its applicable units (instead of the required 40%) by the July 1, 2016 implementation date. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018763	MOD-025-2	R1	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	10/3/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 and July 1, 2017 compliance dates, the entity had tested and submitted data for only one of three units, completing the real power and reactive power verification for only 33% of its applicable units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to develop an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason for this failure is that entity staff was ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. The entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 3, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG Energy, Inc. corporate project approach to perform targeted testing on the entity Generation registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed and NERC MOD-025 Attachment 2 was completed for each of the entity units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1; 3) submitted NERC MOD-025 Attachment 2 to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and 4) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018765	MOD-025-2	R2	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	9/8/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 and July 1, 2017 compliance dates, the entity had tested and submitted data for only one of three units, completing the real power and reactive power verification for only 33% of its applicable units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on September 8, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG Energy, Inc. corporate project approach to perform targeted testing on the entity Generation registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed and NERC MOD-025 Attachment 2 was completed for each of the four reactive test verifications for each of the entity units to meet the phased-in implementation requirements per MOD-025-2 Requirement 2; 3) submitted NERC MOD-025 Attachment 2 to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and 4) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018766	PRC-019-2	R1	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	4/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. The entity failed to verify 40% of its generating Facilities by the required July 1, 2016 date. As of July 1, 2016, the entity had verified none of its units. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on April 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the corporate project approach to perform targeted coordination analyses of applicable NRG Energy, Inc. units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-019-2 R1; and 2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-019-2 Requirement 1. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018767	PRC-024-2	R1	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	4/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all three of its units. The entity completed the verifications on April 30, 2017. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on April 30, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted its corporate project approach to perform targeted coordination analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1; and 2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-024-2 Requirement 1. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018842	PRC-024-2	R2	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	4/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all three of its units. The entity completed the verifications on April 30, 2017. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on April 30, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted its corporate project approach to perform targeted coordination analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R2; and 2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-024-2 Requirement 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019843	PRC-019-2	R1	Indianapolis Power & Light Company (IPL)	NCR00798	7/1/2016	8/30/2017	Self-Report	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)			On June 5, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. During an internal program review, the entity discovered that, due to a lack of effective processes and procedures to track the work, it failed to coordinate the voltage regulating system controls for its generation facilities by the required deadline. Subsequently, the entity completed the study and coordination of 100% of its generation facilities by August 30, 2017. The root cause of this noncompliance was the entity's lack of effective processes and procedures to track the work. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, the first implementation deadline that the entity missed and ended on August 30, 2017, when the entity completed the coordination work.					
Risk Assessment			This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to coordinate voltage regulating system controls is that it could result in unnecessary tripping of a generator or damage to the equipment. This risk was mitigated in this case by the following factors. First, when the entity completed the study, it found that in all cases, the excitation system limiters always operated before the excitation system protection, which prevents an unnecessary disconnection of the generator. Second, the entity was only required to make minor adjustments to two gas turbine loss of field relays, which would not adversely affect the protection for the unit. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.					
Mitigation			To mitigate this noncompliance, the entity completed the study and coordination of 80% of the entity's generating locations to meet the implementation date of July 1, 2018. As an additional mitigating action, the entity implemented an automated tracking tool that provides reminders for upcoming required activities to multiple responsible people and their supervisors. ReliabilityFirst has verified the completion of all mitigation activity.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018639	MOD-025-2	R1	NRG East	NCR11715	7/1/2016	10/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. As of the July 1, 2016 implementation date, the legacy Registered Entities under the entity had not verified 40% of its applicable units. At that time, only a total of 11 units (20% of applicable units) had been properly tested with adequate documentation and submittals. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that the entity staff was ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 11, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018640	MOD-025-2	R2	NRG East	NCR11715	7/1/2016	10/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the July 1, 2016 implementation date, the legacy Registered Entities under the entity had not verified 40% of its applicable units. At that time, only a total of 11 units (20% of applicable units) had been properly tested with adequate documentation and submittals. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. That incorrect interpretation and implementation led to this noncompliance. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on October 11, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018636	PRC-019-2	R1	NRG East	NCR11715	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 47 of the 55 applicable units (85%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-019-2 R1. Specifically, three legacy Registered Entities did not complete the required analyses to meet the required percentages for these individual legacy registrations. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on June 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because when the entity performed the verification and coordination, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings and excitation controls. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-019-2 R1; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity units using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-019-2 Requirement 1. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018637	PRC-024-2	R1	NRG East	NCR11715	7/1/2016	6/30/2017	Self-Report	Completion

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 53 of the 55 applicable units (96%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-024-2 R1. The entity only verified five of its 23 generating units (22%) within the legacy entity registration by July 1, 2016 as required by PRC-024-2 R1. The entity's failure to verify 40% of its generating units by its registration date of December 16, 2016 is a cause of this noncompliance. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on June 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018638	PRC-024-2	R2	NRG East	NCR11715	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 53 of the 55 applicable units (96%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-024-2 R1. The entity only verified five of its 23 generating units (22%) within the legacy registration by July 1, 2016 as required by PRC-024-2 R1. The entity's failure to verify 40% of its generating units by its registration date of December 16, 2016 is the root of this noncompliance. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on June 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020083	PRC-005-6	R3	Wisconsin Electric Power Company (WEPCO)	NCR00951	11/1/2016	9/12/2018	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 July 13, 2018 and on October 26, 2018, the entity submitted Self-Reports stating that, as a Distribution Provider and Generator Owner, it was in noncompliance with PRC-005-6 R3. ReliabilityFirst consolidated the second Self-Report into the first Self-Report because the second was discovered while the entity completed mitigating activities for the first Self-Report. In May 2018, while preparing for the entity's upcoming 2019 NERC audit, the entity undertook a review of its last three years of PRC-005-6 battery activities. In this review, the entity discovered that a 2016 maintenance activity for two 125-volt station batteries was not completed within the maximum interval of 18 months. More specifically, the two battery bank's annual tests were not reviewed against the battery baseline for a period of 25 and 28 months, respectively. The entity, however, did perform annual and quarterly testing on the battery banks during the period of noncompliance that indicated the batteries were functioning properly. (The entity had established a practice of performing the 18 month maintenance activities on the NERC batteries on an annual basis. The baseline review for these batteries was completed in 2015 and 2017, but was not completed in 2016.) As a result of subsequent review and discussion with its Transmission Operator (TOP), American Transmission Company (ATC), the entity determined that 11 additional battery banks, which supply control power to ATC Bulk Electric System breakers, were also not reviewed within the maximum interval of 18 months; making a total of 13 battery banks that were not timely reviewed. At the affected substations that had battery banks that were not timely reviewed, the 125VDC batteries provide trip and close control power to ATC's 138kV breakers. None of the substations or associated battery banks support or rely on Remedial Actions Schemes (RAS). Two of these substations are on Blackstart Resource Unit cranking paths. The entity had established a practice of performing the 18-month maintenance activities for all of its NERC batteries and battery banks (including the 13 at issue in this noncompliance) on an annual basis. However, the entity failed to complete the review for all 13 of these battery banks at different times in 2016 and 2017. Regarding the root cause, when the entity tests a battery or a battery bank on its annual schedule, the results are manually uploaded into the entity's Cascade system (a tracking database), and an automatic notification is sent to a prescribed list of individuals to review this test result. The engineer is then responsible to review the results against the baseline results, document their review, identify any anomalies, and then close out the work order in Cascade to complete this activity. These noncompliances involve the management practices of work management and workforce management. The alert emails were sent to the appropriate individuals, but the Cascade work orders issued for these activities were not completed within the prescribed interval of 18 calendar months. The work orders were not completed due to ineffective work management as the current work process had no additional automated tracking or follow-up notification to the engineer to complete the review of the work orders within the compliance interval. That ineffective work management design (lacking a follow-up and automated tracking) is a root cause of this noncompliance. Workforce management through ineffective training is also a contributing cause as the individuals responsible for completing the work orders were not effectively trained on the importance of timely completing the work orders. This noncompliance started on November 1, 2016, when the entity missed the 18 month maintenance interval on the first battery bank and ended on September 12, 2018, when the entity completed the overdue maintenance activities on all of the relevant battery banks.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by these noncompliances is that unmaintained and untested battery banks could fail and that failure could lead to local loss of load or transmission equipment at the substation. The risk is minimized because during the noncompliance, the entity successfully performed quarterly inspections and those inspections revealed no performance issues with the battery banks. The entity also monitors the battery chargers that normally carry the station DC load and the voltage on battery banks that provide backup power remotely. That monitoring revealed no significant conditions with the battery banks. Lastly, when the entity performed the overdue tests, the tests revealed that the battery banks were functioning properly. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because the prior noncompliance was an isolated issue that was promptly identified, assessed, and corrected and both the prior noncompliance and the current noncompliances were promptly self-reported and mitigated. The prior noncompliance and the current noncompliances also have different root causes, which further makes the prior noncompliance distinguishable.
Mitigation	To mitigate this noncompliance, the entity: 1) created an Engineering Review tracking report that identifies all reviews required for NERC batteries. The report identifies the non-compliance date for the review (18 months from previous review) and the key milestone dates to manage responsible parties to stay within compliance. This is to be reviewed on a monthly basis; 2) created a monthly control activity in the entity's FERC Compliance Database to review the Engineering Review completion status; and

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020083	PRC-005-6	R3	Wisconsin Electric Power Company (WEPCO)	NCR00951	11/1/2016	9/12/2018	Self-Report	Completed
			3) developed a training module to explain the compliance tasks required for VLA and VRLA batteries, including the roles and responsibilities of all stakeholders from field personnel through program administrators. ReliabilityFirst has verified the completion of all mitigation activity.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2018020722	PRC-006-2	R9.	Beaches Energy Services of Jacksonville Beach ("the Entity")	NCR00004	2/9/2016	11/16/2018	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 November 21, 2018, the Entity submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-006-2 R9. This noncompliance started on February 9, 2016, when the Entity failed to properly set the time delay of their Under-Frequency Load Shedding (UFLS) relays to provide automatic tripping of Load in accordance with the UFLS program as determined by its Planning Coordinator (PC), and ended on November 16, 2018, when BES adjusted the time delay for the UFLS relays to meet the Planning Coordinator parameters. Specifically, the Entity's relay test records indicate that 12 of the Entity's 15 UFLS relays had a total time delay greater than 0.28 seconds and were outside of tripping parameter limits as required by PRC-006 R9 and the limits set by the FRCC UFLS program of less than 0.28 seconds (where the total time delay = intentional delay + relay delay + breaker delay). The cause for this noncompliance was insufficient training on the FRCC UFLS program and the associated settings.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk was reduced because if a UFLS event had occurred, the Entity's UFLS relays would have operated; however, the operation would have been slower than required. The maximum time delay would have been .07 seconds greater than the .28 seconds specified by the FRCC UFLS program. There were no UFLS events during the period of noncompliance. The Entity's UFLS Load Shed represents 0.51% of the Regional UFLS Load Shed. No harm is known to have occurred. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed an extent of condition review; 2) performed a root cause analysis; 3) corrected the settings on the UFLS relays to be within the allowable range of the FRCC UFLS Regional Program; 4) tested to confirm the correct settings were entered; 5) created workflow with three levels of review and approval to ensure the devices have the correct settings; and 6) created an annual training program for all BES employees involved with the UFLS program which will be provided by an outside entity based on the FRCC UFLS program.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020744	PRC-005-6	R3	National Grid USA	NCR11171	9/1/2017	04/02/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 29, 2018, National Grid USA ("the Entity") submitted a Self-Log stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005-6 R3. The Entity discovered that it had failed to perform certain diagnostic tests on one battery bank, of the type Vented Lead Acid (VLA), at one of its 345kV substations. The battery bank had been last tested on February 16, 2016. Therefore, per the time-based maximum interval of eighteen calendar months, as specified in PRC-005-6 Table 1-4(a), maintenance on this device was required by August 31, 2017. This noncompliance started on September 1, 2017, the day after the date when the periodic maintenance for the battery bank was required by, and ended on April 2, 2018, when the Entity completed required diagnostic tests for a new VLA battery bank that it had installed to replace the existing aging unit. The root cause of this instance of noncompliance was that the diagnostic test Work Orders for the VLA batteries had been inadvertently, and prematurely, closed out in Cascade by the Substation Supervisor on January 30th, 2017 before verifying whether any actual testing work had been performed.
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). Lack of proper DC voltage at a substation could cause protection systems to misoperate or not operate when called upon. However, the substation at issue is equipped with a redundant battery bank (fully tested in accordance with required intervals) that operates the primary protection system. Additionally, the non-compliant battery bank, which operates the substation's back-up protection system, was subject to bi-monthly Visual and Operational Inspections and was found to be in good working order from the time the required diagnostic tests were missed until the Entity replaced it with a new VLA bank. The Entity's Reliability Coordinator (the NYISO) carries required summer Operating Reserve of approximately 1965 MW and could have compensated for the loss of transmission facilities caused by a potential misoperation of the substation protection system by appropriately dispatching generating facilities in its Control Area. No harm is known to have occurred as a result of this noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) completed required diagnostic tests for a new VLA battery bank that was installed to replace the existing aging unit; 2) evaluated the incident with its Substation Operations/Maintenance & Construction (M&C) personnel and provided detailed information to responsible staff located throughout its facilities regarding the reasons that led to the noncompliance as well as detailed instructions that must be followed to ensure the timely completion of future maintenance items; and 3) enhanced its existing compliance software tool ("Cascade") by adding a "Work Completed Date" field that needs to be populated before any work order can be closed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017523	PRC-004-4(i)	R3	Los Vientos Windpower III, LLC (LVWPIII)	NCR11538	1/30/2017	2/26/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 4, 2017, LVWPIII submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-004-4(i) R3. Specifically, LVWPIII failed to identify whether its Protection System component caused a Misoperation within the later of 60 calendar days of notification or 120 calendar days of the Bulk Electric System (BES) interrupting device operation. While conducting a review of its Protection Systems operation reporting, LVWPIII discovered that it received notice of an interrupting device operation by a shared Composite Protection System on November 2, 2016. LVWPIII identified that its Protection System component did not cause a misoperation, but did not complete this analysis until February 26, 2017, 27 calendar days after the PRC-004-4(i) R3 deadline. The root cause of this noncompliance was that LVWPIII had an inadequate process to ensure compliance with all newly applicable NERC Reliability Standards. In particular, LVWPIII did not have a written process to evaluate and implement changes in compliance obligations for new or revised NERC Reliability Standards. As a result, LVWPIII personnel utilized an outdated procedure that did not contain the requirements and deadlines for the current version of PRC-004. This noncompliance started on January 30, 2017, the day after the identification was due, and ended on February 26, 2017, when LVWPIII determined that its Protection System component did not cause a Misoperation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. First, while not timely, LVWPIII did provide evidence that it performed an analysis of the device operation at issue. Second, after conducting an analysis, LVWPIII did not identify any Protection System component Misoperation for this issue. Third, the other Composite Protection System owner indicated that it was aware of the interrupting device operation. Fourth, the duration of the noncompliance was relatively short, lasting less than one month. No harm is known to have occurred. Texas RE considered LVWPIII's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVWPIII: 1) completed the required PRC-004-4(i) R3 misoperation determination; 2) developed an email alert for BES interrupting device operation by a Composite Protection System. The email alert directs operators to archive evidence needed for PRC-004 evaluation and reporting, and to forward evidence to the responsible analysis personnel; 3) updated its PRC-004 compliance process document and, as part of an annual review of NERC compliance procedures, implemented an automated task to review the process document; 4) conducted NERC training for site managers and technicians on the reporting process and the updated requirements of PRC-004; 5) implemented a process to track and implement compliance obligations for new or revised NERC Reliability Standards. Texas RE verified the completion of all mitigation activity.

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

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 6, 2018 through February 8, 2018, Texas RE determined that RSWILLC, as a Generator Owner (GO), was in noncompliance with PRC-005-6 R3. Specifically, RSWILLC did not timely perform all 18-month maintenance activities for two Vented-Lead Acid (VLA) batteries as required by PRC-005-6, Table 1-4(a). On April 18, 2015, two VLA battery banks were installed and commission testing was conducted on May 10, 2015. As a result RSWILLC was required to complete the maintenance activities for the two VLA batteries, with a maximum maintenance interval of 18-calendar-months, by November 30, 2016. However, RSWILLC did not complete the testing for the two VLA batteries until March 23, 2017. The root cause of the noncompliance was that RSWILLC did not correctly determine the 18-calendar-month maintenance interval start date. RSWILLC mistakenly believed that the 18-calendar-month interval started from the Facility's commercial operation date rather than from the date testing was performed. Additionally, RSWILLC misinterpreted the Implementation Plan for PRC-005-6. This noncompliance started on December 1, 2016, the day after the 18-calendar-month maintenance activities were due for its VLA batteries. The noncompliance ended on March 23, 2017, when the required maintenance activities were performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). This risk posed by this issue is that the VLA batteries at issue would not function as intended. However, the risk posed by this issue is reduced by several factors. First, the VLA batteries at issue comprise only 2% (2/89) of the total Protection System devices in RSWILLC's PSMP. Second, RSWILLC did not identify any issues with the two VLA batteries when it performed the required 18-month testing. Third, RSWILLC regularly performed monthly maintenance on the two VLA batteries at issue, reducing the scope for missed testing. Finally, during the Compliance Audit it was determined that this issue was limited to only one type of device and that RSWILLC timely tested all other devices in the PSMP. No harm is known to have occurred. Texas RE considered RSWILLC's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, RSWILLC: 1) performed the required maintenance activities on the VLA batteries; 2) contracted with a vendor to provide compliance program services and monthly compliance training; 3) conducted trainings to specifically address the PRC-005-6 implementation plan; and 4) implemented a spreadsheet to track the maximum maintenance intervals for Protection System maintenance and confirm that RSWILLC correctly recorded the required PRC-005-6 maintenance intervals for Protection System devices. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2016016322	INT-006-4	1	CXA Sundevil Holdco, Inc. (GRMA)	NCR05169	7/5/2016	7/5/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 5, 2016, GRMA submitted a Self-Report stating that, as a Balancing Authority (BA), it was in violation with INT-006-4 R1. Specifically, GRMA reported that on July 5, 2016 at 1:40 PM, its scheduling software automatically approved a downward modification to a Confirmed Interchange (CI) even though it was not capable of supporting the magnitude including ramping throughout the duration of the Arranged Interchange (AI). The request for the AI should have been denied or curtailed. The downward modification or curtailment resulted in an AI that was below the low operating limit of GRMA. At 1:50 PM, the modified CI resulted in an over generation condition in which the primary BA was producing more than the expected magnitude of Interchange and ramp because of the minimum generation levels at GRMA. The primary BA then directed GRMA to reconfigure its generation blocks to achieve the magnitude of the interchange. The interchange value remained constant into the next hour. In the absence of being directed off line, at 2:56 PM, the output of GRMA matched the magnitude of the AI. After reviewing all relevant information, WECC determined that GRMA failed to deny an AI or curtail CI for which it did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the AI, as required by INT-006-4 R1, R1.1. The root cause of the violation was a lack of controls around the protocol and configuration of GRMA's electronic tagging system, which automatically accepted an AI, even though GRMA could not support the magnitude of the Interchange.
Risk Assessment	WECC determined that this noncompliance posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, GRMA failed to deny an AI or curtail CI for which it did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the AI as required by INT-006-4 R1, R1.1. Such failure could result in inadvertent energy, an out-of-balance condition on the system, and incorrect NSI information to the Interconnection and BAAL deviations which affected another Requirement. The amount of over-generation relative to the Western Interconnection was small, ACE + 100 MW, during the event. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible. However, this over-frequency (outside of BAAL limits) lasted a total of 66 minutes and GRMA was in communication with its RC during the entire event. Based on this, WECC determined that there was a low likelihood of causing negligible harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, GRMA: a. performed an investigation of the BAAL exceedance issue and provided a summary of the event to appropriate parties; b. conducted a conference call with the member BA, power marketer to review timeline of events associated with the issue and discuss future mitigation; c. developed procedures identifying coordination in the Day Ahead and Real-Time time frames and shared with the appropriate parties; d. created communication guidelines for shut-down to identify the conditions for a shut-down as well as the appropriate communications between parties for a shut-down; e. developed lessons learned training; and f. delivered training to GRMA system operators based on the procedures and communications guidelines developed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017016778	MOD-025-2	1	USACE - Portland District	NCR05538	7/1/2016	6/30/2017	Self-report	Completed
Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)			UNWP discovered on January 11, 2017 that it failed to provide its Transmission Planner verification of Real Power and Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R1. UNWP had 68 hydro-generating units applicable to this standard and requirements that it failed to verify its Real Power capabilities of at least 40% of as it assumed the incorrect effective date of the Standard. UNWP misunderstood the one-hour soak requirement for maximum Real Power capacities as required by Attachment 1, section 2.1.1. Because of this oversight, UNWP was unable schedule testing in accordance with the effective date of the Standard. The root cause of the issue was UNWP's misunderstanding of the testing specifications for the Requirement. Specifically, UNWP overlooked the one-hour soak time of the maximum Real Power and lagging Reactive Power capacity as required in Attachment 1 section 2.1.1. Subsequently, the testing was not scheduled in accordance with the accurate implementation schedule.					
Risk Assessment			These issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, UNWP failed to provide its Transmission Planner verification of Real Power and Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R1. Such failures could potentially result in inaccurate information of generator gross and net Real Power capabilities used in planning models which are used to assess BES Reliability. Inaccurate information would result in inaccurate models; therefore, the BES could be planned with the expectation that a generator has the capability to mitigate a modeled system contingency, whereas it may not completely mitigate the contingency. UNWP owns and/or operates 68 applicable units location at eight facilities with a total capacity of 6,378 MW, of which 36 units were applicable to these issues. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. However, UNWP implemented the WECC Generating Unit Model Validation testing for all its generating units in the past; therefore, if a real-time contingency that required the generating unit to respond were to occur, the current data would be satisfactory for mitigating the contingency. Additionally, the information obtained through the verification process is merely used for system modeling to develop contingencies and operating limits and not depended upon for real-time operating limits. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.					
Mitigation			To mitigate these issues, UNWP: a. developed a procedure to perform the required testing of MOD-025-2 R1 and 2; b. coordinated with all 8 facilities' Maintenance and Operation departments to determine when each Facilities testing could be performed; c. completed testing on 43% of applicable units; d. completed testing on 54% of applicable units; e. complete the testing on 57% of applicable units; f. completed testing on 72% of applicable units; g. completed testing on 93% of applicable units; and h. four generating units are out of commission for long term service and are unable to be tested. Testing will be complete once these units are ready for commercial service.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017016779	MOD-025-2	2	USACE - Portland District	NCR05538	7/1/2016	6/30/2017	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	UNWP discovered on January 11, 2017 that it failed to provide its Transmission Planner verification of Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R2. UNWP had 68 hydro-generating units applicable to this standard and requirements that it failed to verify its Reactive Power capabilities of at least 40% of as it assumed the incorrect effective date of the Standard. UNWP misunderstood the one-hour soak requirement for lagging Reactive Power capacities as required by Attachment 1, section 2.1.1. Because of this oversight, UNWP was unable schedule testing in accordance with the effective date of the Standard. The root cause of the issue was UNWP's misunderstanding of the testing specifications for the Requirement. Specifically, UNWP overlooked the one-hour soak time of the maximum Real Power and lagging Reactive Power capacity as required in Attachment 1 section 2.1.1. Subsequently, the testing was not scheduled in accordance with the accurate implementation schedule.
Risk Assessment	These issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, UNWP failed to provide its Transmission Planner verification of Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R2. Such failures could potentially result in inaccurate information of generator gross and net Reactive Power capabilities used in planning models which are used to assess BES Reliability. Inaccurate information would result in inaccurate models; therefore, the BES could be planned with the expectation that a generator has the capability to mitigate a modeled system contingency, whereas it may not completely mitigate the contingency. UNWP owns and/or operates 68 applicable units location at eight facilities with a total capacity of 6,378 MW, of which 36 units were applicable to these issues. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. However, UNWP implemented the WECC Generating Unit Model Validation testing for all its generating units in the past; therefore, if a real-time contingency that required the generating unit to respond were to occur, the current data would be satisfactory for mitigating the contingency. Additionally, the information obtained through the verification process is merely used for system modeling to develop contingencies and operating limits and not depended upon for real-time operating limits. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate these issues, UNWP: a. developed a procedure to perform the required testing of MOD-025-2 R1 and 2; b. coordinated with all 8 facilities' Maintenance and Operation departments to determine when each Facilities testing could be performed; c. completed testing on 43% of applicable units; d. completed testing on 54% of applicable units; e. complete the testing on 57% of applicable units; f. completed testing on 72% of applicable units; g. completed testing on 93% of applicable units; and h. four generating units are out of commission for long term service and are unable to be tested. Testing will be complete once these units are ready for commercial service.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017148	MOD-032-1	R2	Judith Gap Energy LLC (JUGE)	NCR05503	7/1/2016	7/27/2017	Self-Certification	Completed
Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 28, 2017, JUGE submitted a Self-Certification stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. In preparation for its upcoming self-certification, JUGE discovered that it had not provided steady-state, dynamics, and short circuit modeling data for its 180 MW of wind generation to its Transmission Planner (TP) and Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its TP and PC in Requirement 1. Furthermore, the required data had not been gathered or prepared for distribution prior to the identification of the noncompliance The root cause of the issue was an administrative oversight causing JUGE to fail to gather and provide the required data to its TP and PC. Specifically, JUGE did not have adequate compliance tracking mechanisms in place to ensure that the required data was collected and provided to the TP and PC. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on July 27, 2017, when JUGE provided its modeling data for a total of 392 days of noncompliance.						
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, JUGE failed to provide steady-state, dynamics, and short circuit modeling data to its TP and PC according to the data requirements and reporting procedures developed by its TP and PC in Requirement 1, as required by MOD-032-1 R2. Such failure could result in inaccurate data modeling in planning for meeting system operating conditions and addressing contingencies to be created by the TP and PC. Inaccurate modeling could have led to an unexpected loss of the 180 MW of wind generation that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible. However, the data missing was applicable to 180 MW of wind generation and contributes only 135 MW to the grid while operating and operates at an average 38% capacity factor. Based on this, WECC determined that there was a low likelihood of causing negligible harm to the BPS. No harm is known to have occurred.						
Mitigation	To mitigate this issue, JUGE: a. submitted to MOD-032 data model to its TP and PC; b. created an automated task notification in its internal task management system to remind SMEs 60 days prior to the end of the 12-month review period; c. created a new policy to escalate incomplete compliance tasks to the compliance team if the tasks are not complete within 30 days of receiving the task notification; and d. entity's new Compliance Manager reviewed the model guidelines and discussed the annual future model update expectations with team.						

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019956	PRC-024-2	R1	Agua Caliente Solar LLC (AGCS)	NCR11209	7/1/2016	7/25/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 29, 2018, AGCS submitted a Self-Report stating that, as a Generator Operator, it was in violation with PRC-024-2 R1. Specifically, AGCS reported that it did not set the protective relaying settings correctly on its solar generating Facility per the requirements of PRC-024-2 R1, Attachments 1 by July 1, 2016. AGCS's parent corporation, reported that it implemented a plan in 2015 that included its entire fleet of generating Facilities within the Western Interconnection for a single compliance approach. However, in March 2017, AGCS's parent corporation changed this incorrect approach based upon NERC guidance to demonstrate compliance with the Standard on a Registered Entity basis rather than its entire fleet of generating Facilities. As a result of this guidance, AGCS then completed the required analyses and required adjustments of its inverter frequency and voltage trip settings for its applicable Facility; one solar generating unit which generates 320 MWA, on July 25, 2017. After reviewing all relevant information, WECC determined that AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R1 and R2, Attachments 1. The root cause of these issues was due to the incorrect interpretation of the implementation of PRC-024-2 R1, by AGCS and by its parent company. Specifically, that the implementation plan applied to the entire fleet of solar generating Facilities owned by AGCS's parent company, instead of the implementation plan applying to individual entities that AGCS's parent company owned separately. This incorrect interpretation resulted in AGCS missing the compliance deadline specified in the implementation plan. WECC determined that the issues began on July 1, 2016, when AGCS failed to change its generating unit's inverter settings and ended on July 25, 2017, when AGCS changed the inverters to not trip within the "no trip zone," for a total of 390 days of noncompliance.
Risk Assessment	WECC determined that these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R1. Such failure could potentially result in the premature tripping of the generating Facility due to voltage excursions within the "no trip zone." AGCS owns and operates 242 MVA solar generating Facility that was applicable to this issue. Its previous setting for under-frequency would have operated between 57 - 59.3 Hz for 0.16 seconds before tripping within the "no trip zone." If the Facility had experienced a voltage excursion, its previous setting for under-voltage would have operated at 0.5 pu voltage for 0.16 seconds before tripping within the "no trip zone." Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. AGCS implemented weak preventative controls to prevent the above issue from occurring. Specifically, AGCS's parent corporation provided compliance support to AGCS through its corporate regulatory compliance program that contributed to this issue. However, the 242 MVA is an intermittent resource and there was no substation frequency and voltage ride through trips equipped at this Facility. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred. WECC determined that AGCS has no relevant compliance history for this noncompliance.
Mitigation	AGCS completed mitigating activities to address its issues with the Standards and WECC verified AGCS's mitigating activities. To remediate and mitigate these issues, AGCS: a. completed analysis for frequency and voltage trips for the Facility and adjusted the inverter settings as required by the Standard; and b. instituted an internal quarterly control measures form to identify any changes in its frequency and voltage settings to ensure compliance with the Standard. This form states that the plant personnel are required to document proposed inverter frequency and voltage setting changes and notify the engineering group prior to making any changes. The plant personnel must select an appropriate statement from a list of scenarios including whether or not changes have been made to the inverter frequency and voltage settings and whether they were communicated to the engineering and consultants to verify compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019957	PRC-024-2	R2	Agua Caliente Solar LLC (AGCS)	NCR11209	7/1/2016	7/25/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 29, 2018, AGCS submitted a Self-Report stating that, as a Generator Operator, it was in violation with PRC-024-2 R2. Specifically, AGCS reported that it did not set the protective relaying settings correctly on its solar generating Facility per the requirements of PRC-024-2 R2, Attachments 2 by July 1, 2016. AGCS's parent corporation, reported that it implemented a plan in 2015 that included its entire fleet of generating Facilities within the Western Interconnection for a single compliance approach. However, in March 2017, AGCS's parent corporation changed this incorrect approach based upon NERC guidance to demonstrate compliance with the Standard on a Registered Entity basis rather than its entire fleet of generating Facilities. As a result of this guidance, AGCS then completed the required analyses and required adjustments of its inverter frequency and voltage trip settings for its applicable Facility; one solar generating unit which generates 320 MWA, on July 25, 2017. After reviewing all relevant information, WECC determined that AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R2, Attachments 2. The root cause of these issues was due to the incorrect interpretation of the implementation of PRC-024-2 R2, by AGCS and by its parent company. Specifically, that the implementation plan applied to the entire fleet of solar generating Facilities owned by AGCS's parent company, instead of the implementation plan applying to individual entities that AGCS's parent company owned separately. This incorrect interpretation resulted in AGCS missing the compliance deadline specified in the implementation plan. WECC determined that the issues began on July 1, 2016, when AGCS failed to change its generating unit's inverter settings and ended on July 25, 2017, when AGCS changed the inverters to not trip within the "no trip zone," for a total of 390 days of noncompliance.
Risk Assessment	WECC determined that these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R2. Such failure could potentially result in the premature tripping of the generating Facility due to voltage excursions within the "no trip zone." AGCS owns and operates 242 MVA solar generating Facility that was applicable to this issue. Its previous setting for under-frequency would have operated between 57 - 59.3 Hz for 0.16 seconds before tripping within the "no trip zone." If the Facility had experienced a voltage excursion, its previous setting for under-voltage would have operated at 0.5 pu voltage for 0.16 seconds before tripping within the "no trip zone." Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. AGCS implemented weak preventative controls to prevent the above issue from occurring. Specifically, AGCS's parent corporation provided compliance support to AGCS through its corporate regulatory compliance program that contributed to this issue. However, the 242 MVA is an intermittent resource and there was no substation frequency and voltage ride through trips equipped at this Facility. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred. WECC determined that AGCS has no relevant compliance history for this noncompliance.
Mitigation	AGCS completed mitigating activities to address its issues with the Standards and WECC verified AGCS's mitigating activities. To remediate and mitigate these issues, AGCS: a. completed analysis for frequency and voltage trips for the Facility and adjusted the inverter settings as required by the Standard; and b. instituted an internal quarterly control measures form to identify any changes in its frequency and voltage settings to ensure compliance with the Standard. This form states that the plant personnel are required to document proposed inverter frequency and voltage setting changes and notify the engineering group prior to making any changes. The plant personnel must select an appropriate statement from a list of scenarios including whether or not changes have been made to the inverter frequency and voltage settings and whether they were communicated to the engineering and consultants to verify compliance.

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

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	PSE discovered February 16, 2017 that it inadvertently supplied inaccurate or incomplete information in response to an ongoing data request from its Reliability Coordinator (RC). PSE's four data items that were not accurately and completely provided to the RC were: a. PSE's hourly Unit Commitment for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities. This information is required to be submitted daily; by 10 a.m. Pacific Prevailing Time, for the current day through the next four business days; b. PSE's hourly Unit Commitment for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities 10 minutes prior to the hour, every hour, plus the next four hours; c. PSE's Hourly Operational Minimum MW for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by Peak RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities. This information is required to be submitted daily; by 10 a.m. Pacific Prevailing Time, for the current day through the next four business days; and d. PSE's Hourly Operational Minimum MW for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities 10 minutes prior to the hour, every hour, plus the next four hours. When the data request was issued, PSE staff created the reporting formulas in the MCG Energy Solutions software (MCG), which reports the data to the RC. However, the data that was generated by MCG was not verified to be accurate prior to sending the information to the RC. Specifically, when MCG made its calculation, it was using business days instead of calendar days, causing the transmitted data to be inaccurate. Additionally, MCG was reporting inaccurate data due to Pmax and Pmin values being calculated inaccurately during outages. The root cause of the issue was PSE's lack of internal controls. Specifically, PSE did not verify the calculations and resulting data generated in its MCG for accuracy prior to starting the automated data transmittal. WECC determined that this issue began on April 1, 2016, when the first inaccurate dataset was sent to the RC and ended on January 24, 2017, when PSE provided complete and accurate data to the RC for a total of 298 days of noncompliance.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, PSE failed to provide data and information, as specified, to its RC, as required by IRO-010-1a R3, to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area. Such failure could cause the RC to use inaccurate generating capacities in the development of its Operating Plan. Inaccurate capabilities in the Operating Plan may affect real-time or contingent conditions leading to unexpected load shedding and delayed system restoration after an event. PSE owns and/or operates 3711 MW of generation that was applicable to this issue. However, the RC had indicated that the four data items were used primarily for forecasting studies and not daily operations studies. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. Additionally, PSE is a member of a reserves sharing group which made additional generation available if PSE was unable to meet the generation requirements of the Operating Plan. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, PSE: a. permanently changed the MCG calculation methodology to report on calendar days and not business days. The spreadsheet shows that the schedule for submitting the generation forecast was changed from the current day plus four to the current day plus seven. This modification corrected a logic error in the MCG's methodology for populating unit commitment schedules so that it would provide seven full calendar days of data; and b. Establish process to update the Pmax and Pmin values manually in MCG when generation availability changes. The document indicates that the entity established a daily calendar reminder to have the outage coordination personnel in its load office update the minimum and maximum values manually in the application when there is a generation availability change. Page 2 of the document demonstrates that a report is pulled from RC's coordinated outage system to determine if any new outages are scheduled to occur or if any unscheduled generation outages happened as indicated from the COS. This information is then entered into the MCG application which is submitted directly to the RC.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017309	BAL-001-2	R2	Western Area Power Administration - Desert Southwest Region (WALC)	NCR05461	9/6/2016	9/6/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 27, 2017, WALC submitted a Self-Report stating that, as a Balancing Authority (BA), it was in noncompliance with BAL-001-2 R2. On September 6, 2016, the WALC SCADA system was failing to update its information between it and the Bureau of Reclamation (Bureau), which is essential for generation control of 1539 MW from the Hoover power plant. The WALC System Operator called the Hoover Operator inquiring about the values they were seeing and the Hoover control status confirmed WALC's data was not updating. The WALC System Operator requested the Hoover Operator switch his communication channel from "A" to "B", then back to "A" again, to which he observed no resolution. The WALC System Operator then called SCADA Support who suggested that the WALC System Operator log into the ECC Server to check for better visibility, however, the ECC server was not updating either. In the interim, the WALC System Operator called the Hoover Operator to verify generation output levels, on-line capacity, and control status. SCADA support then rebooted the servers and the Data Link appeared to be restored. The WALC System Operator verified with the Hoover Operator that the plant was receiving data and generating to the correct value, but the Data Link issue reoccurred. The WALC System Operator then requested the Hoover Operator call their SCADA personnel to restart their servers. In the interim, WALC's SCADA Support rebooted the WALC servers again and successfully restored the Data Link. The WALC System Operator observed WAPA data updating again and called the Hoover Operator to validate the generation data. Finally, the WALC Operator logged the BAAL exceedance of 39 minutes and reported the exceedance and the Data Link status to the Desk Supervisor (Start BAAL exceedance minute count at 21:02; End BAAL exceedance minute count at 21:40 (39 minutes)). The root cause of the issue was WALC's System Operator failed to follow the established procedure by taking manual control of the communication system when the Data Link failed to transmit accurate data between WALC and the Bureau. This issue began on September 6, 2016, when WALC's clock minute average of reporting ACE exceeded the clock-minute Balancing Authority ACE Limit for the 31st minute and ended on September 6, 2016, when its Data Link servers were rebooted, for a total of 9 minutes of noncompliance.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WALC failed to operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit for more than 30 consecutive clock-minutes calculated in accordance with Attachment 2, as required by BAL-001-2 R2. Such failure could have caused an interconnection frequency excursion outside of defined limits. WALC balances 3066 MW of generation, of which, 1539 MW were applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate. However, WALC was still able to monitor the interconnection from its Reliability Messaging Tool to verify that there was no loss of generation, load or transmission. The generator was aware of the situation, still receiving data and was able to monitor in real-time. Lastly, If the frequency excursions had been detected, WALC would likely have corrected the condition as the entity has implemented strong corrective controls. WALC is part of a reserve sharing group that could have provided more generation if necessary. Based on this, WECC determined that there was a low likelihood of causing intermediate harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, WALC: a. Returned to operate such that the BAAL limit does not exceed 30 minutes; b. Notified and trained System Operators of the existing procedure to be followed for Data Link failures.