City of Niles Light Department (City of Niles) – NCR02710 NOC-2650 $0

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2018019840	COM-002-4	R3.	Lower	High	7/1/2016 (when the Standard became mandatory and enforceable on the entity)	3/1/2018 (when the entity provided the training to each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction)	Compliance Audit	3/1/2018	10/21/2019

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 April 30, 2018 through May 8, 2018, ReliabilityFirst determined that the entity, as a Distribution Provider, was in violation of COM-002-4 R3. The entity did not conduct 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. More specifically, the entity did not provide this training to three individuals until March 1, 2018 and the implementation date for COM-002-4 R3 was July 1, 2016. The three individuals had been receiving Operating Instructions prior to receiving the required training on March 1, 2018. During the Compliance Audit, the entity informed the Compliance Audit Team that all oral two-party, person-to-person Operating Instructions are provided with a FirstEnergy (FE) operator on-site who receives instructions from the FE Dispatcher. The FE operator then instructs the entity personnel to perform the operation on the entity equipment after the entity repeats the instruction and the FE operator confirms it. The FE Operator also has written switching orders that are used and followed at the direction of the FE Dispatcher. The entity misinterpreted the Standard and believed that its established communication process with FE negated the need for training of its own personnel. This violation involves the management practices of workforce management and grid operations. The entity did not understand that it needed to provide initial training to its operating personnel. That misunderstanding is a root cause of this violation as it led to the entity not performing the training for operating personnel.
Risk Assessment	This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The risk posed by this violation is that lack of communication training to operating personnel can increase the chance of errors when receiving operating instructions and that could cause harm to the BPS. The risk is not minimal because of the extended almost two year duration. The risk is partially reduced because entity personnel only receive Operating Instructions in the presence of FE operators with written switching orders who ensured instructions were repeated and confirmed. Although entity personnel had not been formally trained on how to receive an oral two-party, person-to-person Operating Instruction, the entity indicated that personnel performed three-part communication in practice when receiving Operating Instructions, thereby reducing the risk. ReliabilityFirst also notes that the entity only has a peak load of 68 MW. No harm is known to have occurred.
Mitigation	To mitigate this violation, the entity: 1) trained the three individuals that can receive an oral two-party, person-to-person Operating Instruction; and 2) updated its procedure to ensure that all future personnel will get training on how to receive an oral two-party, person-to-person Operating Instruction before they are put into a position to receive an Operating Instruction.
Other Factors	ReliabilityFirst reviewed the entity's internal compliance program and considered it to be a neutral factor in the penalty determination. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance. Given the long duration of both violations involved, and the method of discovery, ReliabilityFirst determined that sending a message via a Settlement Agreement instead of an FFT to incent compliance was an important step.

City of Niles Light Department (City of Niles) – NCR02710 NOC-2650 $0

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2018019839	PRC-005-2(i)	R3	High	Severe	10/1/2015 (when the Standard became mandatory and enforceable on the entity)	7/13/2018	Compliance Audit	7/13/2018	TBD

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 April 30, 2018 through May 8, 2018, ReliabilityFirst determined that the entity, as a Distribution Provider, was in violation of PRC-005-2(i) R3. The entity has one set of batteries and one charger that are subject to compliance with PRC-005-6. Although the entity performed quarterly tests (The entity inspected the batteries quarterly for the following: voltage of every cell in the battery, and specific gravity of any cell which has voltage outside the range of 2.12 and 2.27 volts.) and monthly tests (The entity inspected the batteries monthly for the following: float charge voltage at the battery terminal, float charge voltage at the charger, float current, electrolyte levels, pilot cell voltage, electrolyte temperature, evidence of cracks or leaking, and evidence of corrosion of terminals, rack or connectors.) on the protection system equipment, the entity did not perform all required testing. The entity did not perform the following four tests required by PRC-005-6 Table 1-4: (a) Unintentional ground test (must be conducted every four months); (b) Battery terminal connection resistance test (must be conducted every 18 months); (c) Battery intercell or unit to unit connections resistance test (must be conducted every 18 months); and (d) Load test (the entity could not provide evidence of the every 18 months load test or every six years load test). This violation involves the management practices of planning, work management, and grid operations. Planning and work management is involved because by misunderstanding PRC-005 the entity failed to properly schedule battery testing to comply with the standard. Grid operations is involved because a failure to properly test and maintain batteries endangered the entity's ability to function properly. The entity failed to update its Protection System Maintenance Program with the new tests required by PRC-005-6, Table 1-4. That failure to update arises from poor planning and is a root cause of this violation.
Risk Assessment	This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) The risk posed by this violation is that not completing all of the required maintenance and testing activities for the batteries and chargers creates the possibility that they will not function properly when needed, which could negatively affect the reliable operation of the BPS. The risk is not minimal because of the extended almost three-year duration. The risk is partially reduced because the entity was performing quarterly tests and monthly tests on the protection system equipment and that testing would likely indicate to the entity any battery degradation before failure occurred. ReliabilityFirst also notes that the entity only has a peak load of 68 MW. No harm is known to have occurred.
Mitigation	To mitigate this violation, the entity: 1) performed all of the overdue testing: unintentional ground test, battery terminal connection resistance test, battery intercell or unit to unit connections resistance test, and load test; and 2) updated its Protection System Maintenance Program with the new tests required by PRC-005-6, Table 1-4 to prevent recurrence.
Other Factors	ReliabilityFirst reviewed the entity's internal compliance program and considered it to be a neutral factor in the penalty determination. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.

Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017579	TOP-002-2.1b	R1	Medium	High	11/30/2016 (when the work permit was issued)	11/30/2016 (when the work permit was released)	Self-Report	4/1/2017	1/25/2018

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 18, 2017, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it had a potential noncompliance with TOP-002-2.1b R1.

On November 30, 2016, BPA was implementing an outage as a part of the boundary Remedial Action Scheme (RAS), which entailed line loss logic for three separate lines. BPA did not correctly implement the published Study Limit Information Memo (SLIM), as is required by BPA's Operating Plan during the outage. The SLIM for this outage condition specified that a 650 MW System Operating Limit (SOL) should be set at the one boundary's flowgate. The Dispatcher, however, implemented a restricted generation limit of 650 MW at the boundary generation station. BPA did not lower the boundary SOL from 1300 MW to 650 MW. This mistake resulted in BPA operating a boundary SOL that was 650 MW higher than the setting should have been. As a result, the boundary RAS was operated in a degraded state. In addition, BPA had not included the boundary RAS in the list of Special Protection Systems that were incorporated into the Coordinated Outage System and therefore not reported to BPA's RC.

The outage work that resulted in the boundary RAS is usually completed one line at a time. When the SLIM was issued in this case, the Dispatcher also reviewed a Dispatch Standing Order (DSO) but the guidance was not applicable. This misunderstanding between the SLIM and DSO resulted in BPA not manually entering the SOL into the control system. Because the lower SOL was not entered in the control system, the alarm monitoring did not alert to three SOL exceedances between 2:15 PM and 2:45 PM on November 30, 2016. Due to the lack of alarms, the Dispatcher did not realize there were SOL exceedances.

The root cause of the violations associated with TOP-002-2.1b R1, TOP-002-2.1b R4, TOP-004-2 R1, TOP-007-0 R1, and IRO-010-1a R3 was attributed to the confusion of the Dispatcher as to which operating instructions he should follow during an outage--between the SLIM and the DSO. For the violation associated with IRO-005-3.1a R9, the root cause was attributed to BPA's violation of TOP-002-2.1b R1. As a result, BPA:

a. did not correctly implement its Operating Plan using the SLIM, as required by TOP-002-2.1b R1;
b. did not provide its neighboring RC and TOPs with the correct SOL because it had been operating with the incorrect calculation, as required by TOP-002-2.1b R4;
c. did not operate within the SOLs during this outage, as required by TOP-004-2 R1;
d. did not inform its RC that the RAS was operated in a degraded state, as required by IRO-005-3.1a R9;
e. did not provide its RC with the following, as specified in its RC Data Specification:
    i. the correct boundary SOL;
    ii. the notifications of SOL exceedance and actions taken because BPA did not know the correct flow over the boundary path, nor did BPA report on the actions it should have taken to correct the problems;
    iii. boundary RAS being operated in a degraded state, as required by IRO-010-1a R3; and
f. did not notify its RC of the SOL exceedances nor its actions to resolve them due to the lack of alarms that would have alerted BPA that there was an SOL exceedance, as required by TOP-007-0 R1.

These violations began on November 30, 2016 at 8:30 AM, when the work permit was issued, and ended on November 30, 2016 at 3:59 PM, when the work permit was released for a total of one day of noncompliance with each these Standards and Requirements.

Risk Assessment

WECC determined these violations in aggregate posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to:

a. maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each BA and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained, as required by TOP-002-2.1b R1;
b. coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner, as required by TOP-002-2.1b R4;
c. have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs, as required by TOP-002-4 R1;
d. inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits, as required by TOP-007-0 R1;
e. inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected, whenever a Special Protection System that may have an inter-BA, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows, as required by IRO-005-3.1a R9; and
f. provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship, as required by IRO-010-1a R3.

Western Electricity Coordinating Council (WECC) Settlement Agreement (Does Not Contest) O&P

	In this case, BPA was already operating its system with the RAS in a degraded state. If BPA were to have lost another line, the RAS could have caused a loss of load and potentially opened the remaining lines entirely. Further, BPA implemented weak preventative controls. However, BPA implemented effective controls, this issue was discovered during a routine monitoring activity nine days after the issue occurred, on December 9, 2016. As compensation, instead of setting the correct SOL, BPA instructed the main generation station for these lines to limit its generation to 650 MW. This action by BPA reduced the risk because instead of changing the SOL to address its mistake, it instructed the main generation station to limit its generation which then lowered the flows on the path without changing the SOL.
Mitigation	To mitigate this violation, BPA: 1) BPA's Dispatch Manager sent a 10-point message to all dispatchers and its RC specifying the proper implementation of a SLIM for the boundary including the boundary RAS that was related to the lack of Protection System documentation; and 2) as of April 1, 2017, with new versions of the Standards, TOPs were no longer required to notify the RC of SOLs on internal paths nor status changes in RAS Schemes. As well, the Dispatchers were trained on a new use of SLIMs as part of the transition efforts to the new TOP and IRO Standards including how to implement them and what to communicate to the RC and other entities. The additional guidance provided through this training was specifically designed to avoid misunderstandings of when to follow guidance in a SLIM, rather than that provided in a DSO.
Other Factors	WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor. On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation. WECC considered BPA's TOP-002-2.1b R1 compliance history to be an aggravating factor in determining the disposition track, specifically NERC Violation ID WECC2015015074.

Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017591	TOP-002-2.1b	R4	Medium	Moderate	11/30/2016 (when the work permit was issued)	11/30/2016 (when the work permit was released)	Self-Report	4/1/2017	12/27/2017

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 18, 2017, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it had a potential noncompliance with TOP-002-2.1b R4.

On November 30, 2016, BPA was implementing an outage as a part of the boundary Remedial Action Scheme (RAS), which entailed line loss logic for three separate lines. BPA did not correctly implement the published Study Limit Information Memo (SLIM), as is required by BPA's Operating Plan during the outage. The SLIM for this outage condition specified that a 650 MW System Operating Limit (SOL) should be set at the one boundary's flowgate. The Dispatcher, however, implemented a restricted generation limit of 650 MW at the boundary generation station. BPA did not lower the boundary SOL from 1300 MW to 650 MW. This mistake resulted in BPA operating a boundary SOL that was 650 MW higher than the setting should have been. As a result, the boundary RAS was operated in a degraded state. In addition, BPA had not included the boundary RAS in the list of Special Protection Systems that were incorporated into the Coordinated Outage System and therefore not reported to BPA's RC.

The outage work that resulted in the boundary RAS is usually completed one line at a time. When the SLIM was issued in this case, the Dispatcher also reviewed a Dispatch Standing Order (DSO) but the guidance was not applicable. This misunderstanding between the SLIM and DSO resulted in BPA not manually entering the SOL into the control system. Because the lower SOL was not entered in the control system, the alarm monitoring did not alert to three SOL exceedances between 2:15 PM and 2:45 PM on November 30, 2016. Due to the lack of alarms, the Dispatcher did not realize there were SOL exceedances.

The root cause of the violations associated with TOP-002-2.1b R1, TOP-002-2.1b R4, TOP-004-2 R1, TOP-007-0 R1 and IRO-010-1a R3 was attributed to the confusion of the Dispatcher as to which operating instructions he should follow during an outage--between the SLIM and the DSO. For the violation associated with IRO-005-3.1a R9, the root cause was attributed to BPA's violation of TOP-002-2.1b R1. As a result, BPA:

a. did not correctly implement its Operating Plan using the SLIM, as required by TOP-002-2.1b R1;
b. did not provide its neighboring RC and TOPs with the correct SOL because it had been operating with the incorrect calculation, as required by TOP-002-2.1b R4;
c. did not operate within the SOLs during this outage, as required by TOP-004-2 R1;
d. did not inform its RC that the RAS was operated in a degraded state, as required by IRO-005-3.1a R9;
e. did not provide its RC with the following, as specified in its RC Data Specification:
    i. the correct boundary SOL;
    ii. the notifications of SOL exceedance and actions taken because BPA did not know the correct flow over the boundary path, nor did BPA report on the actions it should have taken to correct the problems;
    iii. boundary RAS being operated in a degraded state, as required by IRO-010-1a R3; and
f. did not notify its RC of the SOL exceedances nor its actions to resolve them due to the lack of alarms that would have alerted BPA that there was an SOL exceedance, as required by TOP-007-0 R1.

These violations began on November 30, 2016 at 8:30 AM, when the work permit was issued, and ended on November 30, 2016 at 3:59 PM, when the work permit was released for a total of one day of noncompliance of each these Standards and Requirements.

Risk Assessment

WECC determined that these violations in aggregate posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to:

a. maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each BA and TOP shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained, as required by TOP-002-2.1b R1;
b. coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and TOPs and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner, as required by TOP-002-2.1b R4;
c. have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs, as required by TOP-002-4 R1;
d. inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits, as required by TOP-007-0 R1;
e. inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected, whenever a Special Protection System that may have an inter-BA, or inter-TOP impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows, as required by IRO-005-3.1a R9; and

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	f. provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship, as required by IRO-010-1a R3. In this case, BPA was already operating its system with the RAS in a degraded state. If BPA were to have lost another line, the RAS could have caused a loss of load and potentially opened the remaining lines entirely. Further, BPA implemented weak preventative controls. However, BPA implemented effective controls, this issue was discovered during a routine monitoring activity nine days after the issue occurred, on December 9, 2016. As compensation, instead of setting the correct SOL, BPA instructed the main generation station for these lines to limit its generation to 650 MW. This action by BPA reduced the risk because instead of changing the SOL to address its mistake, it instructed the main generation station to limit its generation which then lowered the flows on the path without changing the SOL.
Mitigation	To mitigate this violation, BPA: 1) BPA's Dispatch Manager sent a 10-point message to all dispatchers and its RC specifying the proper implementation of a SLIM for the boundary including the boundary RAS that was related to the lack of Protection System documentation; and 2) as of April 1, 2017, with new versions of the Standards, TOPs were no longer required to notify the RC of SOLs on internal paths nor status changes in RAS Schemes. As well, the Dispatchers were trained on a new use of SLIMs as part of the transition efforts to the new TOP and IRO Standards including how to implement them and what to communicate to the RC and other entities. The additional guidance provided through this training was specifically designed to avoid misunderstandings of when to follow guidance in a SLIM, rather than that provided in a DSO.
Other Factors	WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor. On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation. WECC considered BPA's TOP-002-.1b R4 compliance history to be an aggravating factor in determining the disposition track specifically, NERC Violation IDs WECC2012009943, WECC2012011098 and WECC2016015703.

Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017588	TOP-004-2	R1	Medium	Severe	11/30/2016 (when the work permit was issued)	11/30/2016 (when the work permit was released)	Self-Report	4/1/2017	12/27/2017

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 18, 2017, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it had a potential noncompliance with TOP-004-2 R1.

On November 30, 2016, BPA was implementing an outage as a part of the boundary Remedial Action Scheme (RAS), which entailed line loss logic for three separate lines. BPA did not correctly implement the published Study Limit Information Memo (SLIM), as is required by BPA's Operating Plan during the outage. The SLIM for this outage condition specified that a 650 MW System Operating Limit (SOL) should be set at the one boundary's flowgate. The Dispatcher, however, implemented a restricted generation limit of 650 MW at the boundary generation station. BPA did not lower the boundary SOL from 1300 MW to 650 MW. This mistake resulted in BPA operating a boundary SOL that was 650 MW higher than the setting should have been. As a result, the boundary RAS was operated in a degraded state. In addition, BPA had not included the boundary RAS in the list of Special Protection Systems that were incorporated into the Coordinated Outage System and therefore not reported to BPA's RC.

The outage work that resulted in the boundary RAS is usually completed one line at a time. When the SLIM was issued in this case, the Dispatcher also reviewed a Dispatch Standing Order (DSO) but the guidance was not applicable. This misunderstanding between the SLIM and DSO resulted in BPA not manually entering the SOL into the control system. Because the lower SOL was not entered in the control system, the alarm monitoring did not alert to three SOL exceedances between 2:15 PM and 2:45 PM on November 30, 2016. Due to the lack of alarms, the Dispatcher did not realize there were SOL exceedances.

The root cause of the violations associated with TOP-002-2.1b R1, TOP-002-2.1b R4, TOP-004-2 R1, TOP-007-0 R1 and IRO-010-1a R3 was attributed to the confusion of the Dispatcher as to which operating instructions he should follow during an outage--between the SLIM and the DSO. For the violation associated with IRO-005-3.1a R9, the root cause was attributed to BPA's violation of TOP-002-2.1b R1. As a result, BPA:

a. did not correctly implement its Operating Plan using the SLIM, as required by TOP-002-2.1b R1;
b. did not provide its neighboring RC and TOPs with the correct SOL because it had been operating with the incorrect calculation, as required by TOP-002-2.1b R4;
c. did not operate within the SOLs during this outage, as required by TOP-004-2 R1;
d. did not inform its RC that the RAS was operated in a degraded state, as required by IRO-005-3.1a R9;
e. did not provide its RC with the following, as specified in its RC Data Specification:
    i. the correct boundary SOL;
    ii. the notifications of SOL exceedance and actions taken because BPA did not know the correct flow over the boundary path, nor did BPA report on the actions it should have taken to correct the problems;
    iii. boundary RAS being operated in a degraded state, as required by IRO-010-1a R3; and
f. did not notify its RC of the SOL exceedances nor its actions to resolve them due to the lack of alarms that would have alerted BPA that there was an SOL exceedance, as required by TOP-007-0 R1.

These violations began on November 30, 2016 at 8:30 AM, when the work permit was issued, and ended on November 30, 2016 at 3:59 PM, when the work permit was released for a total of one day of noncompliance of each these Standards and Requirements.

Risk Assessment

WECC determined that these violations in aggregate posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to:

a. maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each BA and TOP shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained, as required by TOP-002-2.1b R1;
b. coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and TOPs and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner, as required by TOP-002-2.1b R4;
c. have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs, as required by TOP-002-4 R1;
d. inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits, as required by TOP-007-0 R1;
e. inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected, whenever a Special Protection System that may have an inter-BA, or inter-TOP impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows, as required by IRO-005-3.1a R9; and
f. provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship, as required by IRO-010-1a R3.

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	In this case, BPA was already operating its system with the RAS in a degraded state. If BPA were to have lost another line, the RAS could have caused a loss of load and potentially opened the remaining lines entirely. Fur Further, BPA implemented weak preventative controls. However, BPA implemented effective controls, this issue was discovered during a routine monitoring activity nine days after the issue occurred, on December 9, 2016. As compensation, instead of setting the correct SOL, BPA instructed the main generation station for these lines to limit its generation to 650 MW. This action by BPA reduced the risk because instead of changing the SOL to address its mistake, it instructed the main generation station to limit its generation which then lowered the flows on the path without changing the SOL.
Mitigation	To mitigate this violation, BPA: 1) BPA's Dispatch Manager sent a 10-point message to all dispatchers and its RC specifying the proper implementation of a SLIM for the boundary including the boundary RAS that was related to the lack of Protection System documentation; and 2) as of April 1, 2017, with new versions of the Standards, TOPs were no longer required to notify the RC of SOLs on internal paths nor status changes in RAS Schemes. As well, the Dispatchers were trained on a new use of SLIMs as part of the transition efforts to the new TOP and IRO Standards including how to implement them and what to communicate to the RC and other entities. The additional guidance provided through this training was specifically designed to avoid misunderstandings of when to follow guidance in a SLIM, rather than that provided in a DSO.
Other Factors	WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor. On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation. WECC considered BPA's TOP-004-2 R1 compliance history to be an aggravating factor in determining the disposition track specifically, NERC Violation IDs WECC2012009942 and WECC2015015075.

Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017589	TOP-007-0	R1	High	Severe	11/30/2016 (when the work permit was issued)	11/30/2016 (when the work permit was released)	Self-Report	4/1/2017	12/21/2017

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 18, 2017, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it had a potential noncompliance with TOP-007-0 R1.

On November 30, 2016, BPA was implementing an outage as a part of the boundary Remedial Action Scheme (RAS), which entailed line loss logic for three separate lines. BPA did not correctly implement the published Study Limit Information Memo (SLIM), as is required by BPA's Operating Plan during the outage. The SLIM for this outage condition specified that a 650 MW System Operating Limit (SOL) should be set at the one boundary's flowgate. The Dispatcher, however, implemented a restricted generation limit of 650 MW at the boundary generation station. BPA did not lower the boundary SOL from 1300 MW to 650 MW. This mistake resulted in BPA operating a boundary SOL that was 650 MW higher than the setting should have been. As a result, the boundary RAS was operated in a degraded state. In addition, BPA had not included the boundary RAS in the list of Special Protection Systems that were incorporated into the Coordinated Outage System and therefore not reported to BPA's RC.

The outage work that resulted in the boundary RAS is usually completed one line at a time. When the SLIM was issued in this case, the Dispatcher also reviewed a Dispatch Standing Order (DSO) but the guidance was not applicable. This misunderstanding between the SLIM and DSO resulted in BPA not manually entering the SOL into the control system. Because the lower SOL was not entered in the control system, the alarm monitoring did not alert to three SOL exceedances between 2:15 PM and 2:45 PM on November 30, 2016. Due to the lack of alarms, the Dispatcher did not realize there were SOL exceedances.

The root cause of the violations associated with TOP-002-2.1b R1, TOP-002-2.1b R4, TOP-004-2 R1, TOP-007-0 R1 and IRO-010-1a R3 was attributed to the confusion of the Dispatcher as to which operating instructions he should follow during an outage--between the SLIM and the DSO. For the violation associated with IRO-005-3.1a R9, the root cause was attributed to BPA's violation of TOP-002-2.1b R1. As a result, BPA:

a. did not correctly implement its Operating Plan using the SLIM, as required by TOP-002-2.1b R1;
b. did not provide its neighboring RC and TOPs with the correct SOL because it had been operating with the incorrect calculation, as required by TOP-002-2.1b R4;
c. did not operate within the SOLs during this outage, as required by TOP-004-2 R1;
d. did not inform its RC that the RAS was operated in a degraded state, as required by IRO-005-3.1a R9;
e. did not provide its RC with the following, as specified in its RC Data Specification:
    i. the correct boundary SOL;
    ii. the notifications of SOL exceedance and actions taken because BPA did not know the correct flow over the boundary path, nor did BPA report on the actions it should have taken to correct the problems;
    iii. boundary RAS being operated in a degraded state, as required by IRO-010-1a R3; and
f. did not notify its RC of the SOL exceedances nor its actions to resolve them due to the lack of alarms that would have alerted BPA that there was an SOL exceedance, as required by TOP-007-0 R1.

These violations began on November 30, 2016 at 8:30 AM, when the work permit was issued, and ended on November 30, 2016 at 3:59 PM, when the work permit was released for a total of one day of noncompliance of each these Standards and Requirements.

Risk Assessment

WECC determined that these violations in aggregate posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to:

a. maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each BA and TOP shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained, as required by TOP-002-2.1b R1;
b. coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and TOPs and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner, as required by TOP-002-2.1b R4;
c. have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs, as required by TOP-002-4 R1;
d. inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits, as required by TOP-007-0 R1;
e. inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected, whenever a Special Protection System that may have an inter-BA, or inter-TOP impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows, as required by IRO-005-3.1a R9; and
f. provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship, as required by IRO-010-1a R3.

In this case, BPA was already operating its system with the RAS in a degraded state. If BPA were to have lost another line, the RAS could have caused a loss of load and potentially opened the remaining lines entirely. Further, BPA implemented weak preventative or detective controls. However, as compensation, instead of setting the correct SOL, BPA instructed the main generation station for these lines

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	limit its generation to 650 MW. This action by BPA reduced the risk because instead of changing the SOL to address its mistake, it instructed the main generation station to limit its generation which then lowered the flows on the path without changing the SOL.
Mitigation	To mitigate this violation, BPA: 1) BPA's Dispatch Manager sent a 10-point message to all dispatchers and its RC specifying the proper implementation of a SLIM for the boundary including the boundary RAS that was related to the lack of Protection System documentation; and 1) as of April 1, 2017, with new versions of the Standards, TOPs were no longer required to notify the RC of SOLs on internal paths nor status changes in RAS Schemes. As well, the Dispatchers were trained on a new use of SLIMs as part of the transition efforts to the new TOP and IRO Standards including how to implement them and what to communicate to the RC and other entities. The additional guidance provided through this training was specifically designed to avoid misunderstandings of when to follow guidance in a SLIM, rather than that provided in a DSO.
Other Factors	WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor. On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation. WECC considered BPA's TOP-007-0 R1 compliance history to be an aggravating factor in determining the disposition track specifically, NERC Violation ID WECC2012009941.

Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017584	IRO-005-3.1a	R9	Lower	Severe	11/30/2016 (when the work permit was issued)	11/30/2016 (when the work permit was released)	Self-Report	4/1/2017	12/14/2017

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 18, 2017, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it had a potential noncompliance with IRO-005-3.1a R9.

On November 30, 2016, BPA was implementing an outage as a part of the boundary Remedial Action Scheme (RAS), which entailed line loss logic for three separate lines. BPA did not correctly implement the published Study Limit Information Memo (SLIM), as is required by BPA's Operating Plan during the outage. The SLIM for this outage condition specified that a 650 MW System Operating Limit (SOL) should be set at the one boundary's flowgate. The Dispatcher, however, implemented a restricted generation limit of 650 MW at the boundary generation station. BPA did not lower the boundary SOL from 1300 MW to 650 MW. This mistake resulted in BPA operating a boundary SOL that was 650 MW higher than the setting should have been. As a result, the boundary RAS was operated in a degraded state. In addition, BPA had not included the boundary RAS in the list of Special Protection Systems that were incorporated into the Coordinated Outage System and therefore not reported to BPA's RC.

The outage work that resulted in the boundary RAS is usually completed one line at a time. When the SLIM was issued in this case, the Dispatcher also reviewed a Dispatch Standing Order (DSO) but the guidance was not applicable. This misunderstanding between the SLIM and DSO resulted in BPA not manually entering the SOL into the control system. Because the lower SOL was not entered in the control system, the alarm monitoring did not alert to three SOL exceedances between 2:15 PM and 2:45 PM on November 30, 2016. Due to the lack of alarms, the Dispatcher did not realize there were SOL exceedances.

The root cause of the violations associated with TOP-002-2.1b R1, TOP-002-2.1b R4, TOP-004-2 R1, TOP-007-0 R1 and IRO-010-1a R3 was attributed to the confusion of the Dispatcher as to which operating instructions he should follow during an outage--between the SLIM and the DSO. For the violation associated with IRO-005-3.1a R9, the root cause was attributed to BPA's violation of TOP-002-2.1b R1. As a result, BPA:

a. did not correctly implement its Operating Plan using the SLIM, as required by TOP-002-2.1b R1;
b. did not provide its neighboring RC and TOPs with the correct SOL because it had been operating with the incorrect calculation, as required by TOP-002-2.1b R4;
c. did not operate within the SOLs during this outage, as required by TOP-004-2 R1;
d. did not inform its RC that the RAS was operated in a degraded state, as required by IRO-005-3.1a R9;
e. did not provide its RC with the following, as specified in its RC Data Specification:
    i. the correct boundary SOL;
    ii. the notifications of SOL exceedance and actions taken because BPA did not know the correct flow over the boundary path, nor did BPA report on the actions it should have taken to correct the problems;
    iii. boundary RAS being operated in a degraded state, as required by IRO-010-1a R3; and
f. did not notify its RC of the SOL exceedances nor its actions to resolve them due to the lack of alarms that would have alerted BPA that there was an SOL exceedance, as required by TOP-007-0 R1.

These violations began on November 30, 2016 at 8:30 AM, when the work permit was issued, and ended on November 30, 2016 at 3:59 PM, when the work permit was released for a total of one day of noncompliance of each these Standards and Requirements.

Risk Assessment

WECC determined that these violations in aggregate posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to:

a. maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each BA and TOP shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained, as required by TOP-002-2.1b R1;
b. coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and TOPs and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner, as required by TOP-002-2.1b R4;
c. have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs, as required by TOP-002-4 R1;
d. inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits, as required by TOP-007-0 R1;
e. inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected, whenever a Special Protection System that may have an inter-BA, or inter-TOP impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows, as required by IRO-005-3.1a R9; and
f. provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship, as required by IRO-010-1a R3.

In this case, BPA was already operating its system with the RAS in a degraded state. If BPA were to have lost another line, the RAS could have caused a loss of load and potentially opened the remaining lines entirely. Further, BPA implemented weak preventative controls. However, BPA implemented effective controls, this issue was discovered during a routine monitoring activity nine days after the issue

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	occurred, on December 9, 2016. As compensation, instead of setting the correct SOL, BPA instructed the main generation station for these lines to limit its generation to 650 MW. This action by BPA reduced the risk because instead of changing the SOL to address its mistake, it instructed the main generation station to limit its generation which then lowered the flows on the path without changing the SOL.
Mitigation	To mitigate this violation, BPA: 1) BPA's Dispatch Manager sent a 10-point message to all dispatchers and its RC specifying the proper implementation of a SLIM for the boundary including the boundary RAS that was related to the lack of Protection System documentation; and 1) as of April 1, 2017, with new versions of the Standards, TOPs were no longer required to notify the RC of SOLs on internal paths nor status changes in RAS Schemes. As well, the Dispatchers were trained on a new use of SLIMs as part of the transition efforts to the new TOP and IRO Standards including how to implement them and what to communicate to the RC and other entities. The additional guidance provided through this training was specifically designed to avoid misunderstandings of when to follow guidance in a SLIM, rather than that provided in a DSO.
Other Factors	WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor. On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation. WECC considered BPA's IRO-005-3.1a R9 compliance history and determined there were no relevant instances of noncompliance.

Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017585	IRO-010-1a	R3	Medium	Severe	11/30/2016 (when the work permit was issued)	11/30/2016 (when the work permit was released)	Self-Report	4/1/2017	12/21/2017

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 18, 2017, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it had a potential noncompliance with IRO-010-1a R3.

On November 30, 2016, BPA was implementing an outage as a part of the boundary Remedial Action Scheme (RAS), which entailed line loss logic for three separate lines. BPA did not correctly implement the published Study Limit Information Memo (SLIM), as is required by BPA's Operating Plan during the outage. The SLIM for this outage condition specified that a 650 MW System Operating Limit (SOL) should be set at the one boundary's flowgate. The Dispatcher, however, implemented a restricted generation limit of 650 MW at the boundary generation station. BPA did not lower the boundary SOL from 1300 MW to 650 MW. This mistake resulted in BPA operating a boundary SOL that was 650 MW higher than the setting should have been. As a result, the boundary RAS was operated in a degraded state. In addition, BPA had not included the boundary RAS in the list of Special Protection Systems that were incorporated into the Coordinated Outage System and therefore not reported to BPA's RC.

The outage work that resulted in the boundary RAS is usually completed one line at a time. When the SLIM was issued in this case, the Dispatcher also reviewed a Dispatch Standing Order (DSO) but the guidance was not applicable. This misunderstanding between the SLIM and DSO resulted in BPA not manually entering the SOL into the control system. Because the lower SOL was not entered in the control system, the alarm monitoring did not alert to three SOL exceedances between 2:15 PM and 2:45 PM on November 30, 2016. Due to the lack of alarms, the Dispatcher did not realize there were SOL exceedances.

The root cause of the violations associated with TOP-002-2.1b R1, TOP-002-2.1b R4, TOP-004-2 R1, TOP-007-0 R1 and IRO-010-1a R3 was attributed to the confusion of the Dispatcher as to which operating instructions he should follow during an outage--between the SLIM and the DSO. For the violation associated with IRO-005-3.1a R9, the root cause was attributed to BPA's violation of TOP-002-2.1b R1. As a result, BPA:

a. did not correctly implement its Operating Plan using the SLIM, as required by TOP-002-2.1b R1;
b. did not provide its neighboring RC and TOPs with the correct SOL because it had been operating with the incorrect calculation, as required by TOP-002-2.1b R4;
c. did not operate within the SOLs during this outage, as required by TOP-004-2 R1;
d. did not inform its RC that the RAS was operated in a degraded state, as required by IRO-005-3.1a R9;
e. did not provide its RC with the following, as specified in its RC Data Specification:
    i. the correct boundary SOL;
    ii. the notifications of SOL exceedance and actions taken because BPA did not know the correct flow over the boundary path, nor did BPA report on the actions it should have taken to correct the problems;
    iii. boundary RAS being operated in a degraded state, as required by IRO-010-1a R3; and
f. did not notify its RC of the SOL exceedances nor its actions to resolve them due to the lack of alarms that would have alerted BPA that there was an SOL exceedance, as required by TOP-007-0 R1.

These violations began on November 30, 2016 at 8:30 AM, when the work permit was issued, and ended on November 30, 2016 at 3:59 PM, when the work permit was released for a total of one day of noncompliance of each these Standards and Requirements.

Risk Assessment

WECC determined that these violations in aggregate posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to:

g. maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each BA and TOP shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained, as required by TOP-002-2.1b R1;
h. coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and TOPs and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner, as required by TOP-002-2.1b R4;
i. have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs, as required by TOP-002-4 R1;
j. inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits, as required by TOP-007-0 R1;
k. inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected, whenever a Special Protection System that may have an inter-BA, or inter-TOP impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows, as required by IRO-005-3.1a R9; and
l. provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship, as required by IRO-010-1a R3.

In this case, BPA was already operating its system with the RAS in a degraded state. If BPA were to have lost another line, the RAS could have caused a loss of load and potentially opened the remaining lines entirely. Further, BPA implemented weak preventative or detective controls. However, as compensation, instead of setting the correct SOL, BPA instructed the main generation station for these lines limit its generation to 650 MW. This action by BPA reduced the risk because instead of changing the SOL to address its mistake, it instructed the main generation station to limit its generation which then lowered the flows on the path without changing the SOL.

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Bonneville Power Administration (BPA) – NCR05032 NOC-2657 No Penalty

Mitigation	To mitigate this violation, BPA: 1) BPA's Dispatch Manager sent a 10-point message to all dispatchers and its RC specifying the proper implementation of a SLIM for the boundary including the boundary RAS that was related to the lack of Protection System documentation; 2) as of April 1, 2017, with new versions of the Standards, TOPs were no longer required to notify the RC of SOLs on internal paths nor status changes in RAS Schemes; and 3) the Dispatchers were trained on a new use of SLIMs as part of the transition efforts to the new TOP and IRO Standards including how to implement them and what to communicate to the RC and other entities. The additional guidance provided through this training was specifically designed avoid misunderstandings of when to follow guidance in a SLIM, rather than that provided in a DSO.
Other Factors	On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation. WECC considered BPA's compliance history and determined there were no relevant instances of noncompliance.

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Idaho Power Company (IPCO) – NCR05191 NOC-2656 $0

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2018020114	PRC-005-2(i)	R3	High	Lower	1/1/2016 (when IPCO missed the first 18-month maintenance interval)	7/14/2017 (when IPCO completed maintenance activities for the VLA battery)	Self-Report	7/2/2018	3/1/2019

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 24, 2018, IPCO submitted a Self-Report stating, as a Transmission Owner, it was in potential noncompliance with PRC-005-2(i) R3. Specifically, IPCO did not maintain one Protection System Station Vented Lead-Acid (VLA) battery used for emergency situations to power communications equipment during an emergency outage at a 230 kV substation for two 18-month intervals, as required by PRC-005-2(i) R3, Table 1-4(a). The VLA battery was maintained on June 30, 2014, however this issue began on January 1, 2016, when IPCO missed the first 18-month maintenance interval and ended on July 14, 2017, when IPCO completed maintenance activities for the VLA battery, for a total of 561 days. The root cause of the issue was attributed to a miscommunication between different departments. Specifically, a Transmission and Distribution Engineer disabled the battery maintenance trigger because he understood that the Communications group was responsible for tracking the maintenance and testing activites. However, the change in responsibility was not communicated to the Communications group, resulting in a miscommunication about the final responsibility for the maintenance of this VLA battery. As well, the secondary maintenance trigger in IPCO's management system had been inadvertently disabled, thus removing the VLA battery from tracking.
Risk Assessment	This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, IPCO failed to maintain one VLA battery included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Table 1-4(a), as required by the Standard. Such failure could result in local service interruption and possibly increased restoration time during an emergency at the substation. However, as compensation, the VLA battery voltage was continuously monitored by the energy management system (EMS) during the timeframe of the violation. Had a battery failure occurred during an outage, the System Operators would have received a generalized summary alarm and a technician would have been sent on-site to identify the reason for the alarm.
Mitigation	To mitigate this violation, IPCO: 1) completed maintenance activities on one affected VLA battery; 2) requested staff to identify and report to leadership gaps in maintenance at the time issues of noncompliance are discovered; 3) implemented new policy that any changes to maintenance activity testing were to be reviewed monthly by the Communications Engineer to prevent inadvertent responsibility changes that caused these maintenance triggers for the VLA battery to be disabled; and 4) the Protection System Maintenance Program (PSMP) was updated to reflect a new review of changes to maintenance settings.
Other Factors	WECC reviewed IPCO's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. WECC considered IPCO's PRC-005 compliance history to be an aggravating factor in determining the disposition track specifically NERC Violation IDs WECC200800628, WECC200901452, WECC201102886 and WECC2017017203.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
TRE2016015849	FAC-008-3	R1	Lower	Severe	11/19/2013 (noncompliance started when the Entity's registration became effective)	11/27/2018 (noncompliance ended when the Entity's documented process was adopted)	Audit	6/4/2019	9/19/2019

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 16, 2016 through June 16, 2016, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with FAC-008-3 R1. Specifically, during the Compliance Audit, the Entity was unable to provide any documentation described by FAC-008-3 R1 for determining the Facility Ratings of its generator Facilities. The root cause of this issue is that the Entity did not have any documented process for compliance with FAC-008-3 beginning from the date when it was registered as a GO. As a result, the Entity did not document or implement processes necessary for compliance with FAC-008-3 R1. The noncompliance started on November 19, 2013, when the Entity was registered as a GO, and ended on November 27, 2018, when the Entity implemented a documented process that includes a documented methodology, Facility Ratings, and relevant documentation necessary for compliance with FAC-008-3 R1, R2, and R6.
Risk Assessment	This issue posed a moderate risk and did not pose a serious or substantial risk to the bulk power system (BPS) based on the following factors. A lack of accurate Facility Ratings and Equipment Ratings could result in overloading on equipment, potentially damaging the affected Facilities, and resulting in unanticipated outages. In addition, the duration of this issue was approximately five years, lasting from November 19, 2013, when the Entity was registered as a GO, until November 27, 2018, when the Entity created a process and documents sufficient for compliance with FAC-008-3 R1, R2, and R6. In addition, during the noncompliance, the Entity's Amistad Facility was designated as a Black Start resource through 2017, and the Entity's Falcon Facility was designated as a Black Start resource through 2015. Neither Facility is designated in the 2018 Black Start plan. However, the risk posed by this issue was reduced by the following factors. First, the Entity's Facilities have limited impact on other portions of the BPS and are limited to two hydroelectric Facilities, comprising two 31.556 MW generating units at the Amistad Facility and three 11 MW generating units at the Falcon Facility. During the noncompliance, the average net production for the Amistad Facility was approximately 9.5 MW per hour and for the Falcon Facility was approximately 5.5 MW per hour. The Entity's Facilities produce power intermittently and are not relied on in planning cases for reliability or capacity purposes during peak summer conditions. These Facilities are also not located inside a major load center, and the potential unavailability of the Facilities would be unlikely to cause a loss of load or interfere with Transmission flows. Finally, the unit information in the Resource Asset Registration Form already on file with the Electric Reliability Council of Texas, Inc. was consistent with the Facility Ratings documentation created by the Entity to end this noncompliance. No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, the Entity: 1) implemented a documented process that was drafted by a compliance consultant and that includes a documented methodology, Facility Ratings, and relevant documentation necessary for compliance with FAC-008-3 R1, R2, and R6; 2) approved a documented internal compliance program, which includes a process for identifying applicable current and new NERC Reliability Standards; 3) established a compliance committee, as described in the documented internal compliance program, which determines upcoming deadlines at regular meetings and implements the Entity's process for identifying applicable Reliability Standards; and 4) conducted training regarding the Entity's process for compliance with FAC-008-3 and regarding the Entity's overall compliance program.
Other Factors	On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as Texas RE, could not impose monetary penalties against federal governmental entities such as SWPA. The Entity is a federal governmental entity, and Texas RE is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, Texas RE has assessed no monetary penalty for this violation. Texas RE reviewed the Entity's compliance history and determined that there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
TRE2016015850	FAC-008-3	R2	Medium	Severe	11/19/2013 (noncompliance started when the Entity's registration became effective)	11/27/2018 (noncompliance ended when the Entity's documented process was adopted)	Audit	6/4/2019	9/19/2019

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 16, 2016 through June 16, 2016, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with FAC-008-3 R2. Specifically, the Entity did not have a documented methodology for determining the Facility Ratings of its generator Facilities as required by FAC-008-3 R2. The root cause of this issue is that the Entity did not have any documented process for compliance with FAC-008-3 beginning from the date when it was registered as a GO. As a result, the Entity did not document or implement processes necessary for compliance with FAC-008-3 R2. The noncompliance started on November 19, 2013, when the Entity was registered as a GO, and ended on November 27, 2018, when the Entity implemented a documented process that includes a documented methodology, Facility Ratings, and relevant documentation necessary for compliance with FAC-008-3 R1, R2, and R6.
Risk Assessment	This issue posed a moderate risk and did not pose a serious or substantial risk to the bulk power system (BPS) based on the following factors. A lack of accurate Facility Ratings and Equipment Ratings could result in overloading on equipment, potentially damaging the affected Facilities, and resulting in unanticipated outages. In addition, the duration of this issue was approximately 5 years, lasting from November 19, 2013, when the Entity was registered as a GO, until November 27, 2018, when the Entity created a process and documents sufficient for compliance with FAC-008-3 R1, R2, and R6. In addition, during the noncompliance, the Entity's Amistad Facility was designated as a Black Start resource through 2017, and the Entity's Falcon Facility was designated as a Black Start resource through 2015. Neither Facility is designated in the 2018 Black Start plan. However, the risk posed by this issue was reduced by the following factors. First, the Entity's Facilities have limited impact on other portions of the BPS and are limited to two hydroelectric Facilities, comprising two 31.556 MW generating units at the Amistad Facility and three 11 MW generating units at the Falcon Facility. During the noncompliance, the average net production for the Amistad Facility was approximately 9.5 MW per hour and for the Falcon Facility was approximately 5.5 MW per hour. The Entity's Facilities produce power intermittently and are not relied on in planning cases for reliability or capacity purposes during peak summer conditions. These Facilities are also not located inside a major load center, and the potential unavailability of the Facilities would be unlikely to cause a loss of load or interfere with Transmission flows. Finally, the unit information in the Resource Asset Registration Form already on file with the Electric Reliability Council of Texas, Inc. was consistent with the Facility Ratings documentation created by the Entity to end this noncompliance. No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, the Entity: 1) implemented a documented process that was drafted by a compliance consultant and that includes a documented methodology, Facility Ratings, and relevant documentation necessary for compliance with FAC-008-3 R1, R2, and R6; 2) approved a documented internal compliance program, which includes a process for identifying applicable current and new NERC Reliability Standards; 3) established a compliance committee, as described in the documented internal compliance program, which determines upcoming deadlines at regular meetings and implements the Entity's process for identifying applicable Reliability Standards; and 4) conducted training regarding the Entity's process for compliance with FAC-008-3 and regarding the Entity's overall compliance program.
Other Factors	On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as Texas RE, could not impose monetary penalties against federal governmental entities such as SWPA. The Entity is a federal governmental entity, and Texas RE is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, Texas RE has assessed no monetary penalty for this violation. Texas RE reviewed the Entity's compliance history and determined that there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
TRE2016015851	FAC-008-3	R6	Medium	Severe	11/19/2013 (noncompliance started when the Entity's registration became effective)	11/27/2018 (noncompliance ended when a documented process was adopted)	Audit	6/4/2019	9/19/2019

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 16, 2016 through June 16, 2016, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with FAC-008-3 R6. Specifically, the Entity did not have Facility Ratings that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings as required by FAC-008-3 R6. During the noncompliance, the Entity did not retain documentation necessary for determining Facility Ratings that accounted for all of the Entity's applicable equipment, and the Entity did not have a documented methodology for determining the Facility Ratings of its generator Facilities. Accordingly, although the Entity had previously submitted facility ratings information to the Electric Reliability Council of Texas, Inc. that included capacity ratings for its generating units, the Entity was unable to demonstrate that it had Facility Ratings that were consistent with an associated Facility Ratings methodology or with associated documentation. The root cause of this issue is that the Entity did not have any documented process for compliance with FAC-008-3 beginning from the date when it was registered as a GO. As a result, the Entity did not document or implement processes necessary for compliance with FAC-008-3 R6. The noncompliance started on November 19, 2013, when the Entity was registered as a GO, and ended on November 27, 2018, when the Entity implemented a documented process that includes a documented methodology, Facility Ratings, and relevant documentation necessary for compliance with FAC-008-3 R1, R2, and R6.
Risk Assessment	This issue posed a moderate risk and did not pose a serious or substantial risk to the bulk power system (BPS) based on the following factors. A lack of accurate Facility Ratings and Equipment Ratings could result in overloading on equipment, potentially damaging the affected Facilities, and resulting in unanticipated outages. In addition, the duration of this issue was approximately 5 years, lasting from November 19, 2013, when the Entity was registered as a GO, until November 27, 2018, when the Entity created a process and documents sufficient for compliance with FAC-008-3 R1, R2, and R6. In addition, during the noncompliance, the Entity's Amistad Facility was designated as a Black Start resource through 2017, and the Entity's Falcon Facility was designated as a Black Start resource through 2015. Neither Facility is designated in the 2018 Black Start plan. However, the risk posed by this issue was reduced by the following factors. First, the Entity's Facilities have limited impact on other portions of the BPS and are limited to two hydroelectric Facilities, comprising two 31.556 MW generating units at the Amistad Facility and three 11 MW generating units at the Falcon Facility. During the noncompliance, the average net production for the Amistad Facility was approximately 9.5 MW per hour and for the Falcon Facility was approximately 5.5 MW per hour. The Entity's Facilities produce power intermittently and are not relied on in planning cases for reliability or capacity purposes during peak summer conditions. These Facilities are also not located inside a major load center, and the potential unavailability of the Facilities would be unlikely to cause a loss of load or interfere with Transmission flows. Finally, the unit information in the Resource Asset Registration Form already on file with the Electric Reliability Council of Texas, Inc. was consistent with the Facility Ratings documentation created by the Entity to end this noncompliance. No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, the Entity: 1) implemented a documented process that was drafted by a compliance consultant and that includes a documented methodology, Facility Ratings, and relevant documentation necessary for compliance with FAC-008-3 R1, R2, and R6; 2) approved a documented internal compliance program, which includes a process for identifying applicable current and new NERC Reliability Standards; 3) established a compliance committee, as described in the documented internal compliance program, which determines upcoming deadlines at regular meetings and implements the Entity's process for identifying applicable Reliability Standards; and 4) conducted training regarding the Entity's process for compliance with FAC-008-3 and regarding the Entity's overall compliance program.
Other Factors	On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as Texas RE, could not impose monetary penalties against federal governmental entities such as SWPA. The Entity is a federal governmental entity, and Texas RE is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, Texas RE has assessed no monetary penalty for this violation. Texas RE reviewed the Entity's compliance history and determined that there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
TRE2016015852	PRC-005-1b	R1	High	Severe	11/19/2013 (noncompliance started when the Entity's registration became effective)	10/05/2018 (noncompliance ended when the Entity adopted version 1.0 of its PSMP)	Audit	6/4/2019	9/19/2019

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 16, 2016 through June 16, 2016, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with PRC-005-1b R1. Specifically, IBWC did not have a Protection System Maintenance and Testing Program (PSMP), as required by PRC-005-1b R1, and was unable to provide documentation of a PSMP or of the implementation of a PSMP, as required by PRC-005-1b R2. This noncompliance began on November 19, 2013, when PRC-005-1b was effective, and continued through the periods when PRC-005-1.1b, PRC-005-2, PRC-005-2(i), and PRC-005-6 were effective. The root cause of the noncompliance is the failure to have a sufficient process for compliance with PRC-005-1b. The Entity did not have a documented process and did not retain documents sufficient for compliance with this Reliability Standard. This noncompliance started on November 19, 2013, when the Entity was first registered as a GO, and ended on October 5, 2018, when the Entity adopted a PSMP.
Risk Assessment	This issue posed a moderate risk and did not pose a serious or substantial risk to the bulk power system (BPS) based on the following factors. This risk posed by this issue is that, without a PSMP and evidence of the implementation of a PSMP, the Entity will not know whether its Protection System devices will function as intended. In addition, the duration of this issue was approximately 5 years, lasting from November 19, 2013, when the Entity was registered as a GO, until October 5, 2018, when the Entity adopted a PSMP consistent with the requirements of PRC-005-6 R1. Further, during the noncompliance, the Entity's Amistad Facility was designated as a Black Start resource through 2017, and the Entity's Falcon Facility was designated as a Black Start resource through 2015. Neither Facility is designated in the 2018 Black Start plan. However, the risk posed by this issue was reduced by the following factors. First, the Entity had verified the voltage and specific gravity of certain dc supply devices during 2016 and had verified the settings for certain protective relays during 2012, and these activities included devices that would have been included in a PSMP. Second, the Entity's Facilities have limited impact on the BPS and are limited to two hydroelectric Facilities, comprising two 31.556 MW generating units at the Amistad Facility and three 11 MW generating units at the Falcon Facility. During the noncompliance, the average net production for the Amistad Facility was approximately 9.6 MW per hour and for the Falcon Facility was approximately 5.6 MW per hour. The Entity's Facilities produce power intermittently and are not relied on in planning cases for reliability or capacity purposes during peak summer conditions. These Facilities are also not located inside a major load center, and a trip caused by a Protection System Misoperation or similar event would be unlikely to cause a loss of load or interfere with Transmission flows. No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, the Entity: 1) adopted a PSMP that is consistent with the requirements of PRC-005-6; 2) approved a documented internal compliance program, which includes a process for identifying applicable current and new NERC Reliability Standards; 3) established a compliance committee, as described in the documented internal compliance program, which determines upcoming deadlines at regular meetings and implements the Entity's process for identifying applicable Reliability Standards; and 4) conducted training regarding the Entity's process for compliance with PRC-005-6 and regarding the Entity's overall compliance program.
Other Factors	On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as Texas RE, could not impose monetary penalties against federal governmental entities such as SWPA. The Entity is a federal governmental entity, and Texas RE is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, Texas RE has assessed no monetary penalty for this violation. Texas RE reviewed the Entity's compliance history and determined that there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
TRE2016015853	PRC-005-1b	R2	High	Severe	11/19/2013 (when IBWC's registration became effective)	10/05/2018 (when IBWC adopted version 1.0 of its PSMP)	Audit	12/1/2019 (approved completion date)	TBD

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 16, 2016 through June 16, 2016, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with PRC-005-1b R2. Specifically, the Entity did not have a Protection System Maintenance and Testing Program (PSMP), as required by PRC-005-1b R1, and was unable to provide documentation of a PSMP or the implementation of a PSMP, as required by PRC-005-1b R2. This noncompliance began on November 19, 2013, when PRC-005-1b was effective, and continued through the periods when PRC-005-1.1b, PRC-005-2, PRC-005-2(i), and PRC-005-6 were effective. During the Compliance Audit, the Entity stated that it did not have a documented PSMP, and the Entity was unable to provide an inventory of its in-scope Protection System devices. In addition, the Entity did not have evidence that it had implemented a PSMP or conducted maintenance activities for all its Protection System devices. Specifically, the Entity provided testing records for protective relays and batteries associated with the Entity's two Facilities. However, the documents provided by the Entity do not address current or voltage sensing devices or control circuitry. Further, the Entity indicated that, at the time of the Compliance Audit, nine relays associated with the Falcon Facility had never been calibrated. To address the noncompliance, the Entity engaged a consultant to assist with drafting the required documented process to implement a PSMP. On October 5, 2018, the Entity adopted a PSMP. However, the noncompliance regarding PRC-005-1b R2 remains ongoing, as the Entity requires additional time to conduct and document the required maintenance activities. The root cause of the noncompliance is the failure to have a sufficient process for compliance with PRC-005-1b. The Entity did not have a documented process and did not retain documents sufficient for compliance with this Reliability Standard. This noncompliance started on November 19, 2013, when the Entity was first registered as a GO and is currently ongoing.
Risk Assessment	This issue posed a moderate risk and did not pose a serious or substantial risk to the bulk power system (BPS) based on the following factors. This risk posed by this issue is that, without a PSMP and evidence of the implementation of a PSMP, the Entity will not know whether its Protection System devices will function as intended. In addition, the duration of this issue was over 5 years, lasting from November 19, 2013, when the Entity was registered as a GO, until the present. In addition, during the noncompliance, the Entity's Amistad Facility was designated as a Black Start resource through 2017, and the Entity's Falcon Facility was designated as a Black Start resource through 2015. Neither Facility is designated in the 2018 Black Start plan. However, the risk posed by this issue was reduced by the following factors. First, the Entity was performing testing for several of the Protection System devices that would have been included in a PSMP. Second, the Entity's Facilities have limited impact on the BPS and are limited to two hydroelectric Facilities, comprising two 31.556 MW generating units at the Amistad Facility and three 11 MW generating units at the Falcon Facility. From the beginning of the noncompliance through April 30, 2019, the average net production for the Amistad Facility was approximately 9.7 MW per hour and for the Falcon Facility was approximately 5.6 MW per hour. The Entity's Facilities produce power intermittently and are not relied on in planning cases for reliability or capacity purposes during peak summer conditions. These Facilities are also not located inside a major load center, and a trip caused by a Protection System Misoperation or similar event would be unlikely to cause a loss of load or interfere with Transmission flows. No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, the Entity: 1) adopted a PSMP that is consistent with the requirements of PRC-005-6; 2) approved a documented internal compliance program, which includes a process for identifying applicable current and new NERC Reliability Standards; 3) established a compliance committee, as described in the documented internal compliance program, which determines upcoming deadlines at regular meetings and implements the Entity's process for identifying applicable Reliability Standards; and 4) conducted training regarding the Entity's process for compliance with PRC-005-6 and regarding the Entity's overall compliance program. Furthermore, the Entity submitted a Mitigation Plan to address the following actions that will be completed by December 1, 2019. 1) complete a list of assets that need to be tested pursuant to the PSMP for the Falcon and Amistad Facilities; 2) perform Protection System maintenance activities for the Falcon Facility; 3) perform Protection System maintenance activities for the Amistad Facility; and 4) document and review documentation of the completion of the maintenance activities for Amistad and Falcon Facilities. The Entity requires until December 1, 2019, because it is still in the process of developing the list of Protection System devices that require maintenance activities, which will be necessary before obtaining maintenance services from a vendor.
Other Factors	On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as Texas RE, could not impose monetary penalties against

International Boundary and Water Commission, US Section (IBWC) – NCR11392 NOC-2647 No penalty

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
TRE2016015853	PRC-005-1b	R2	High	Severe	11/19/2013 (when IBWC's registration became effective)	10/05/2018 (when IBWC adopted version 1.0 of its PSMP)	Audit	12/1/2019 (approved completion date)	TBD
			federal governmental entities such as SWPA. The Entity is a federal governmental entity, and Texas RE is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, Texas RE has assessed no monetary penalty for this violation. Texas RE reviewed the Entity's compliance history and determined that there were no relevant instances of noncompliance.						

Gridforce Energy Management, LLC (GRID) – NCR11393 NOC-2616 $50,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2016016377	EOP-008-1	R1., R1.1, 1.5, 1.2.4, 1.2.5, 1.6.2,	Medium	Severe	11/22/2013	12/28/2017	Compliance Audit	12/28/2017	3/1/2018

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 September 26, 2016 through October 7, 2016, WECC determined that the entity, as a Balancing Authority (BA), had a violation of EOP-008-1 R1. Specifically, WECC found several issues with the entity's Operating Plan: a. it defined the backup functionality as being provided by remotely accessing the BA functionality from specified hotel lobbies and using laptops instead of transferring operations to a specific backup facility. The entity incorporated an incorrect definition of facility, citing the use of laptops in a hotel lobby as implementing backup functionality in addition to an "alternate" Control Center, which did not meet the criteria of backup functionality provided by FERC's directives in Order 693 (R1.1); b. the laptop batteries were listed as the backup power supply to the hotel building power for use from the hotel lobbies (R1.2.4); c. it did not include physical or cyber security in the hotel lobbies (R1.2.5); d. the entity did not include a transition period between the loss of primary control center functionality and the time to transition to the alternate control center in Austin, Texas which was used for low probability high impact events, such as hurricanes requiring evacuation of Houston, Texas. Specifically, the primary Control Center and the alternate Control Center were two and a half hours away from each other by car resulting in a period over the two-hour limit (R1.5); e. for these reasons, the entity did not include actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality because the entity assumed that its operators would be able to gain full operational functionality in under two hours from the hotel lobbies whenever required (R1.6.2). After reviewing all relevant information, WECC determined that the entity failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. The root cause of the violation was the entity's incorrect assumptions regarding the criteria for its Operating Plan and previous implementation of its Operating Plan. The entity did not consider the specific sub-requirements of EOP-008-1 R1 nor FERC's directives when it designed and created its Operating Plan. This violation began on November 22, 2013, when GRID registered as a BA and ended on December 28, 2017, when GRID established its new Operating Plan and designated a new backup Facility, for a total of 1,499 days of noncompliance.
Risk Assessment	This violation posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, the entity failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BPS in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. The entity did not have effective internal controls to detect or prevent this issue. However, the entity's EOP-008 Operating Plan was used successfully for backup control center functionality on January 6, 2016, due to a false fire alarm, and on December 14, 2012, due to a bomb threat. In addition, the Operating Plan was used successfully during hurricane evacuation conditions and for routine training and testing of remote functionality verifying all functions could be performed using remote access functionality from 2012 through 2016. For these reasons, WECC determined that there was a moderate likelihood of causing intermediate harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this violation, the entity: a. engaged a real estate firm to assist with identification of a space that will be the entity-managed facility that is accessible in approximately 90 minutes or less; b. visited spaces that have been identified by the real estate firm as potential entity facilities; c. modified the Operating Plan to include a summary of the risk assessment for power supply needs during a loss of primary control center condition based on new understanding of the requirements of the Standard;

Western Electricity Coordinating Council, Inc. (WECC) Settlement Agreement (Neither Admits nor Denies) O&P

Gridforce Energy Management, LLC (GRID) – NCR11393 NOC-2616 $50,000

	d. negotiated the lease and build-out requirements; e. established the new EOP-008 Operating Plan that is inclusive of the entity-managed designated facility; f. established a new Operating Plan inclusive of the new entity-managed facility; and g. built out the leased space to meet requirements for backup functionality established in the EOP-008 risk-based assessment.
Other Factors	WECC considered the entity's compliance history with EOP-008-1 R1 and determined the entity did not have any relevant compliance history.

Western Electricity Coordinating Council, Inc. (WECC) Settlement Agreement (Neither Admits nor Denies) O&P

Gridforce Energy Management, LLC (GRID) – NCR11393 NOC-2616 $50,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2016016323	INT-006-4	R1.1,	Lower	Severe	7/5/2016	7/5/2016	Self-Report	3/29/2017	5/24/2017

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, the entity submitted a Self-Report stating that, as a Balancing Authority (BA), it was in violation of INT-006-4 R1. Specifically, the entity 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 AI. The entity should have denied or curtailed the request for the AI. The downward modification or curtailment resulted in an AI that was below the low operating limit of the generating Facility. At 1:50 PM, the modified CI resulted in an over-generation condition in which the entity was producing more than the expected magnitude of Interchange and ramp because of the minimum generation levels at the generating Facility. The entity then directed the generating Facility 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 directing the generator offline the entity returned to compliance when the schedules ramped in to match the output of the generating facility at 2:56 PM. After reviewing all relevant information, WECC determined that the entity 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 the entity's electronic tagging system, which automatically accepted an AI, even though the entity could not support the magnitude of the Interchange. This violation began on July 5, 2016 at 1:50 pm, when the entity automatically accepted the Arranged Interchange (AI) request and ended on July 5, 2016, when the entity directed the generating Facility to achieve the output of the magnitude of the interchange, for a total of 66 minutes of noncompliance.
Risk Assessment	WECC determined that this violation posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, the entity 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 Net Scheduled Interchange (NSI) information to the Interconnection and BAAL deviations which affected another Requirement, WECC2016016013, BAL-001-2 R2. The risk was reduced because the amount of over-generation relative to the Western Interconnection was small (Entity 2 ACE +100 MWs, the entity ACE +40MW) during the event. The entity provides interchange authority services for 4,800 MW of generation for seven BAs. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate. However, this over-frequency (outside of BAAL limits) lasted a total of 66 minutes and the entity was in communication with its Reliability Coordinator during the entire event. Based on this, WECC determined that there was a moderate likelihood of causing intermediate harm to the BPS. No harm is known to have occurred.
Mitigation	To remediate and mitigate this violation, the entity: a. directed the generating Facility to reconfigure its generation blocks to achieve the magnitude of the interchange; b. developed a lessons learned document to help the entity System Operators identify and prevent such an issue in the future and improve their situational awareness for potential BAAL related violations; c. developed the entity System Operator Guidance documents to provide guidance in a BAAL event for what steps they might consider for mitigation; and d. implemented changes in the electronic scheduling software to provide the entity System Operators additional time to evaluate adjustments which may result in a NSI below the minimum operating limit. The software now delays automatically approving Interchange requests, so the entity System Operators can determine if the modified Interchange can be supported before approving the request.
Other Factors	WECC considered the entity's compliance history with INT-006-4 R1 and determined the entity did not have any relevant compliance history.

Los Angeles Department of Water and Power (LDWP) – NCR05223 NOC-2644 $59,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017742	VAR-002-4	R3	Medium	Severe	2/10/2017	2/11/2017	Self-Report	12/11/2017	1/31/2018

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 12, 2017, the entity submitted a Self-Report stating, as a Generator Operator (GOP), it was in violation of VAR-002-4 R3. The entity is vertically integrated and serves as the TOP for this Standard and Requirement. Specifically, on February 10, 2017 at 4:19 PM, the entity placed a 37 MW unit online but did not place the power system stabilizer (PSS) online. During a shift change at 11:26 PM that same day, the plant operator realized that the PSS had not been placed online and did so immediately, allowing him until 11:56 PM to notify the TOP of the change, per the Standard. The plant operator later verbally informed his supervisor of the status change but not the TOP control center load dispatcher directly. The supervisor later notified the TOP control center load dispatcher at 9:05 AM the following morning. After reviewing all relevant information, WECC determined the entity failed to notify its associated TOP of a PSS status change within 30 minutes of the change, when the status had not been restored within 30 minutes of the change, as required by VAR-002-4 R3. The root cause of the issue was a lack of comprehensive training and clear understanding of the procedures for all plant operators. This issue began on February 10, 2017 at 11:57 PM, 31 minutes after the PSS status change, and ended February 11, 2017 at 9:05 AM, when the TOP was notified of the PSS status change, for a total of nine hours and nine minutes of noncompliance.
Risk Assessment	WECC determined this violation 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 notify its associated TOP of a PSS status change within 30 minutes of the change, when the status had not been restored within 30 minutes of the change, as required by VAR-002-4 R3. However, the entity implemented good detective controls to identify this issue. Specifically, every shift change for plant operators started with a station and equipment status check immediately after assuming duties, which is how this issue was identified. Additionally, the entity reviewed all PSS logs quarterly to identify potential issues of noncompliance. The entity also implemented good compensating controls. Specifically, the plant operators at the control desk maintained visibility of the Facility to monitor voltage and ensured it was maintained within the specified range. This ensured that the unit was prepared to respond to any unexpected voltage excursions. Lastly, the AVR maintained the generator output voltage. Had this 37 MW generation tripped offline, the entity had sufficient generation reserves to meet its generation needs using internal generation resources.
Mitigation	To remediate and mitigate this violation, the entity has: a. notified its TOP control center dispatcher of the PSS status change; b. required all system operators to review and sign that they understand the voltage monitoring and reporting requirements outlined within the internal documented procedures; c. reminded system operators via email to log AVR/PSS status even if it is not offline whenever they report the generating unit is on to the ECC. Requiring the plant operator in issue to both acknowledge via a sign-in sheet and to send a confirmation response to an email sent by the Facility Managers; d. the compliance officer and compliance group, control center management, and key SMEs performed a comprehensive in-person VAR-002-4 R3 training at the unit in issue, and all plant operators and traveling relief operators were required to attend; e. placed small laminated signs next to the AVR auto/manual buttons and on monitors as a reminder of the appropriate procedures pertaining to all plant operators; and f. required operators who were absent at the in-person training to watch a recorded video of the training of VAR-002-4 R3 and to review internal documents until all applicable personnel were trained.
Other Factors	WECC determined that the proposed penalty of $59,000 within this Expedited Settlement Agreement is appropriate for the following reasons: a. Base penalty factors: i. The Violation Risk Factor is Medium, and the Violation Severity Level is Severe for this violation. ii. This violation posed a Minimal risk to the reliability of the BPS. iii. This violation duration was nine hours and nine minutes as described above. iv. This Requirement has a Real-time Operations violation time horizon expectation for remediation of the Requirement within one hour or less to preserve the reliability of the BPS. b. WECC applied a mitigating credit for the following reasons: i. The entity was cooperative throughout the process. ii. The entity accepted responsibility and admitted to the violation. iii. The entity agreed to settle this violation and penalty. iv. The entity self-reported this violation. c. WECC considered the following as aggravating factors: i. NERC Violation IDs WECC201102819 and WECC201002387 to be relevant noncompliance history to this violation and therefore supports the expedited settlement disposition option and penalty. d. Other Considerations: i. WECC did not apply mitigating credit for the entity's Internal Compliance Program (ICP). Although the entity does have a documented ICP, WECC determined that the entity did not implement its ICP with effective internal controls sufficient to identify, assess, report, and mitigate in a timely manner for the above violation.

Western Electricity Coordinating Council (WECC) Settlement Agreement (Admits) O&P

Los Angeles Department of Water and Power (LDWP) – NCR05223		NOC-2644	$59,000
	ii. The entity did not fail to complete any applicable compliance directives. There was no evidence of any attempt by the entity to conceal the violation. There was no evidence that the violation was intentional. The entity submitted all requested documentation and/or mitigation plans timely. iii. WECC determined there were no other aggravating factors warranting a penalty higher than the proposed penalty.		

Western Electricity Coordinating Council (WECC)	Settlement Agreement (Admits)	O&P

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
FRCC2018019629	FAC-003-4	R3. 3.1.	Lower	Moderate	10/01/2016	3/22/2018	Self-Report	6/1/2022 (approved completion date)	TBD

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, TAL submitted a Self-Report stating that, as a Generator Owner and Transmission Owner, it was in noncompliance with FAC-003-4 R3.1. During a review on December 7, 2017, TAL discovered that it could not reproduce the data supporting its maximum blowout conditions for applicable lines under FAC-003-4 R3.1. TAL was unable to replicate the maximum blowout calculations previously used to determine trim distances. The assumption data required to replicate the previous calculations made and used for compliance with this Standard has been lost, deleted, or was never originally documented. Only the summary results of the calculations were stored, and those results could not be replicated. This noncompliance started on October 1, 2016, when TAL's documented maintenance procedures to prevent encroachment of vegetation into the Minimum Vegetation Clearance Distance (MVCD) of its applicable lines became effective and the specifications used to account for the movement of applicable line conductors under their Rating and all Rated Electrical Operations were not retained. The noncompliance ended on March 22, 2018, when TAL updated its documented maintenance procedures to reflect new trim calculations documenting the known system information and assumptions. TAL began performing increased trimming in 2018 based on the new trim calculations. The cause for this noncompliance was the TAL staff member originally chosen to be the subject matter expert for this component of the Standard did not have a clear understanding of the document retention requirements surrounding NERC compliance, and therefore, had not stored the assumptions used in the previous calculations in a location that was routinely backed up, nor had he completed any manual backups of the assumptions used.
Risk Assessment	This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The recalculation using known system information and other appropriate assumptions resulted in numbers with enough variance to affect trim distances in the field. The risk was moderate because TAL maintained its mowing, trimming, and visual inspection schedules appropriately in accordance with its vegetation management program. At no time during this period did any vegetation present a threat to a transmission line, nor were there any vegetation-related outages on any applicable lines. No harm is known to have occurred.
Mitigation	To mitigate this violation, TAL: 1) recalculated maximum blowout for all applicable lines using known, verified, and recorded assumptions; 2) revised its Standard Operating Procedure (SOP) to reflect the new trim distances, which will be the baseline upon which annual trimming work plans will be based; 3) re-assigned responsibility for the oversight, performance, and documentation of the engineering component of this compliance obligation; 4) reinforced with applicable staff that corporate regulatory or operational information cannot be stored on an individual laptop or in any software application that is not accessible by one's chain of command and that calculations must be thoroughly documented; 5) stored assumptions and calculations performed across different applications including those routinely backed up to a server; 6) implemented an internal control to require an annual internal determination of whether sufficient regulatory, environmental, or system conditions warrant a recalculation of maximum blowout calculations. This determination will be made annually by Power Delivery supervisory staff and the TAL compliance division; 7) implemented a work plan. To mitigate this violation, TAL will: 1) perform clearing and maintenance work for applicable lines and report status of effort completed to the Region on a quarterly basis (6/1/2022).
Other Factors	The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty. FRCC considered the Entity's ICP to be a neutral factor in the penalty determination. This noncompliance is being processed as a $0 SNOP due to the extended duration of the mitigation.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020344	EOP-004-2	R1	Lower	Severe	3/29/2017	11/1/2017	Self-Report	4/8/2019	4/11/2019

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 5, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO) and Generator Operator (GOP), it was in violation of EOP-004-3 R1. Specifically, the Entity did not have an event report Operating Plan in place in accordance with EOP-004-3 Attachment 1. This violation began on March 29, 2017 and spans multiple versions of the Standard. NPCC applied the violation to EOP-004-2 which was the earliest applicable version of the Standard. The violation started on March 29, 2017, when the Entity first synchronized with the grid and was registered with NERC after recommissioning, and concluded on November 1, 2017, when the Entity developed an event reporting Operating Plan. The violation was discovered after the entity hired a third-party company to help them evaluate and implement a compliance program. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to have an Operating Plan in place could result in the failure to timely submit Reportable Events to the correct entities. However, as a GO and GOP with a nameplate capability of 112.5 MW, only two of the 18 Event Types are applicable to the entity: Damage or destruction of a Facility or Physical threats to a Facility. This requirement refers specifically to event reporting after an incident has occurred and the Entity's ability to recover from an event would not have been impacted. The Entity owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, even if an event occurred at the Facility and the notification was not provided, it is unlikely to have a negative impact on BPS reliability. No harm is known to have occurred as a result of this violation.
Mitigation	To mitigate this violation, the Entity: 1) developed an event reporting Operating Plan including protocols for reporting to the Reliability Organization and Reliability Coordinator and a training interval for all plant staff; 2) developed a facility-specific procedure to ensure maintained compliance with EOP-004-3 R1; 3) developed an ongoing contract with a third-party consulting firm to provide continual NERC compliance services and support. This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to all plant staff on the Operating Plan and other compliance responsibilities; and 5) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020343	EOP-004-2	R3	Medium	Severe	3/29/2017	11/1/2017	Self-Report	4/8/2019	4/11/2019

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 5, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO) and Generator Operator (GOP), it was in violation with EOP-004-3 R3. Specifically, the Entity did not have an event report Operating Plan in accordance with EOP-004-3 Attachment 1, and therefore had not validated all contact information contained in the Operating Plan. This violation began on March 29, 2017 and spans multiple versions of the Standard. NPCC applied the violation to EOP-004-2 which was the earliest applicable version of the Standard. The violation started on March 29, 2017, when the Entity first synchronized with the grid and was registered with NERC after recommissioning, and concluded on November 1, 2017, when the Entity developed an event reporting Operating Plan and validated all contact information in the Plan. The violation was discovered after the entity hired a third-party company to help them evaluate and implement a compliance program. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to validate contact information contained in an Operating Plan in place could result in the failure to submit Reportable Events to the correct contacts. However, as a GO and GOP with a nameplate capability of 112.5 MW, only two of the 18 Event Types are applicable to the entity: Damage or destruction of a Facility or Physical threats to a Facility. This requirement refers specifically to event reporting after an incident has occurred, and the impact would have been reduced to limited information available to analyze an event on the BPS. The Entity's ability to recover from an event would not have been impacted. The Entity owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW and 132.4 MVA, which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, the capacity of this unit can be replaced by the NYISO in the event of an unnecessary trip or loss of generating capability. No harm is known to have occurred as a result of this violation.
Mitigation	To mitigate this violation, the Entity: 1) developed an event reporting Operating Plan and validated all contact information in the Plan; 2) developed a facility-specific procedure to ensure maintained compliance with EOP-004-3; 3) developed an ongoing contract with a third party consulting firm to provide continual NERC compliance services and support This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to relevant staff on validating all contact information; and 4) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020342	FAC-008-3	R1	Lower	Severe	3/29/2017	11/1/2017	Self-Report	4/8/2019	4/11/2019

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 5, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO), it was in violation with FAC-008-3 R1. Specifically, the Entity did not have a documented methodology for determining facility ratings for its generator equipment. The violation started on March 29, 2017, when the Entity first synchronized with the grid and was registered with NERC after recommissioning, and concluded on November 1, 2017, when the Entity developed and documented a facility rating methodology in accordance with FAC-008-3 R1. The violation was discovered after the entity hired a third-party company to help them evaluate and implement a compliance program. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). An entity with an undocumented facility ratings methodology could result in equipment damage and/or loss of equipment life. The Entity owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW and 132.4 MVA, which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, the capacity of this unit can be replaced by the NYISO in the event of an unnecessary trip or loss of generating capability. There were no issues during the violation period due to exceeding equipment capabilities, and the Entity operated according to interconnection agreements with its interconnection Transmission Owner that identified the capabilities of the facility. No harm is known to have occurred as a result of this violation.
Mitigation	To mitigate this violation, the Entity: 1) developed a facility rating methodology in accordance with the requirements of FAC-008-3 R1 and documented facility ratings according to the methodology; 2) developed a facility specific procedure to ensure maintained compliance with FAC-008-3 R1; 3) developed an ongoing contract with a third party consulting firm to provide continual NERC compliance services and support This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to relevant staff on determining facility ratings; and 5) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020341	FAC-008-3	R2	Medium	Severe	3/29/2017	11/1/2017	Self-Report	4/8/2019	4/11/2019

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 5, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO), it was in violation with FAC-008-3 R2. Specifically, the Entity did not have a documented methodology for determining facility ratings for its equipment to the point of interconnection with the Transmission Owner. The violation started on March 29, 2017, when the Entity first synchronized with the grid and was registered with NERC after recommissioning, and concluded on November 1, 2017, when the Entity developed and documented a facility rating methodology in accordance with FAC-008-3 R2. The violation was discovered after the entity hired a third-party company to help them evaluate and implement a compliance program. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). An entity with an undocumented facility ratings methodology could result in equipment damage and/or loss of equipment life. The Entity owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW and 132.4 MVA, which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, the capacity of this unit can be replaced by the NYISO in the event of an unnecessary trip or loss of generating capability. There were no issues during the violation period due to exceeding equipment capabilities, and the Entity operated according to interconnection agreements with its interconnection Transmission Owner that identified the capabilities of the facility. No harm is known to have occurred as a result of this violation.
Mitigation	To mitigate this violation, the Entity: 1) developed a facility rating methodology in accordance with the requirements of FAC-008-3 R2; 2) developed a facility specific procedure to ensure maintained compliance with FAC-008-3 R2; 3) developed an ongoing contract with a third party consulting firm to provide continual NERC compliance services and support This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to relevant staff on determining facility ratings; and 5) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020340	PRC-019-2	R1	Medium	Lower	3/29/2017	6/25/2018	Self-Report	4/8/2019	4/11/2019

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 5, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO), it was in violation with PRC-019-2 R1. Specifically the Entity did not have documentation that it coordinated voltage regulating controls with applicable Protection System devices. The violation started on March 29, 2017, when the Entity first synchronized with the grid and was registered with NERC after recommissioning, and concluded on June 25, 2018, when the final report for the coordination study was completed. The report indicated that there were not any coordination changes that were needed. The violation was discovered after the entity hired a third-party company to help them evaluate and implement a compliance program. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The Entity's failure to coordinate the Protection System could cause an unnecessary trip, or failure to trip of the unit. The Entity owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW and 132.4 MVA, which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, the capacity of this unit can be replaced by the NYISO in the event of an unnecessary trip or loss of generating capability. The completed coordination study found that the Entity was fully compliant with PRC-019 and that no changes needed to be made. No harm is known to have occurred as a result of this violation.
Mitigation	To mitigate this violation, the Entity: 1) contracted an engineering firm to perform the PRC-019-2 R1 coordination study and completed the study, determining no changes were necessary; 2) developed a facility-specific procedure to ensure maintained compliance with PRC-019-2 R1; 3) developed an ongoing contract with a third party consulting firm to provide continual NERC compliance services and support This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to relevant staff on coordinating voltage regulating controls; and 5) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020563	MOD-025-2	R1	Medium	Severe	4/1/2018	3/29/2019	Self-Report	4/8/2019	4/11/2019

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 22, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R1. Specifically, the Entity did not perform the necessary Real Power capability testing required by MOD-025-2 R1 at its plant within twelve calendar months of commercial operation, and therefore was unable to provide its Transmission Planner with verification of its Real Power capability. The plant became commercial on March 27, 2017. The noncompliance started on April 1, 2018, twelve calendar months after the Entity's commercial operation date, and concluded on March 29, 2019 when the Entity provided its Real Power capability test results to its Transmission Planner. The actual Real Power capability testing took place on June 6, 2018, but there was a delay in acquiring the test report from the electrical contractor. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
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 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. However, the entity synchronized the Facility on March 29, 2017 and the net active power output identified during commissioning testing was approximately equal to the 106 MWs, which is the same value provided by the June 6, 2018 power test. The Entity owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW and 132.4 MVA, which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, the capacity of this unit can be replaced by the NYISO in the event of an unnecessary trip or loss of generating capability due to inaccurate information. No harm is known to have occurred as a result of this noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) contracted an engineering firm to perform Real Power capability testing and provided its Transmission Planner with the results; 2) developed a facility specific procedure to ensure maintained compliance with MOD-025-2 R1; 3) developed an ongoing contract with a third party consulting firm to provide continual NERC compliance services and support This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to relevant employees on real power capability testing; and 5) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

Greenidge Generation LLC – NCR11753 NOC-2637 $10,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020564	MOD-025-2	R2	Medium	Severe	4/1/2018	3/29/2019	Self-Report	4/8/2019	4/11/2019

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 22, 2018, Greenidge Generation LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R2. Specifically, the Entity did not perform the necessary Reactive Power capability testing required by MOD-025-2 R2 at its plant within twelve calendar months of commercial operation, and therefore was unable to provide its Transmission Planner with verification of its Reactive Power capability. The plant became commercial on March 27, 2017. The noncompliance started on April 1, 2018, twelve calendar months after the Entity's commercial operation date, and concluded on March 29, 2019, when the Entity provided its Reactive Power capability test results to its Transmission Planner. The actual Reactive Power capability testing took place on June 6, 2018. There was a delay in acquiring the test report from the electrical contractor. The root cause of this violation was a lack of awareness of several NERC Reliability Standard requirement obligations as the plant was being recommissioned. In particular, the Entity did not incorporate amendments to the NERC Reliability Standards into its compliance program. Therefore, certain requirements were not reviewed, assessed, or implemented when the Entity recommissioned the Facility.
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 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 owns and operates a single steam turbine generator with nameplate capabilities of 112.5 MW and 132.4 MVA, which interconnect with the host Transmission Owner's BES substation via two 65 MVA generator step-up transformers. The rated capability of the generator is 5.7% of the Entity's Balancing Authority (NYISO) required Operating Reserve (1965 MW). In addition, the generator operated at capacity factors of 23.23% in 2017 and 20.82% in 2018. Therefore, the capacity of this unit can be replaced by the NYISO in the event of an unnecessary trip or loss of generating capability due to inaccurate information. No harm is known to have occurred as a result of this noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) contracted an engineering firm to perform Reactive Power capability testing and provided its Transmission Planner with the results; 2) developed a facility specific procedure to ensure maintained compliance with MOD-025-2; 3) developed an ongoing contract with a third party consulting firm to provide continual NERC compliance services and support This includes quarterly meetings and monthly phone calls between the consultant and plant staff; 4) provided training to relevant employees on reactive power capability testing; and 5) implemented Gensuite software to function as a compliance calendar to track periodic compliance activities.
Other Factors	NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered the entity's compliance history and determined there were no relevant instances of noncompliance. Although the violation posed a minimal risk to the reliability of the bulk power system, NPCC determined that Compliance Exception treatment was not appropriate and that a sanction was appropriate based on the lack of due diligence and overall lack of NERC compliance awareness to ensure NERC Reliability Standard requirements were considered and implemented as the entity was recommissioning the facility.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
FRCC2018020484	BAL-001-2	R2.	Medium	Lower	9/24/2018	9/24/2018	Self-Report	2/21/2019	3/13/2019

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, HST submitted a Self-Report stating that, as a Balancing Authority, it was in violation of BAL-001-2 R2. This violation started on September 24, 2018, when HST's Balancing Authority ACE Limit (BAAL) High alarm exceeded 30 consecutive minutes and ended on September 24, 2018, when BAAL returned to within limits after one additional minute. HST exceeded the BAAL high limit for 31 consecutive minutes (one (1) minute beyond the allowable 30 consecutive clock-minutes), over-generating by approximately eight (8) MWs during this period. The System Operator was monitoring the BAAL High Limit Exceeded Alarms on the Alarm Summary, which were occurring every five (5) minutes as designed. The System Operator's relative inexperience (< 1 year) and a series of prior alarms received earlier in the morning that cleared by themselves, resulted in the operator expecting the BAAL High Limit exceedance to return within limits without taking any additional actions, such as curtailing transactions, as required by HST's BAAL Alarm procedure. The System Operator adjusted the next hour schedule lower. The BAAL high limit exceedance cleared at 08:02, for a total of 31 minutes. The cause for this violation was the System Operator's misjudgment and relative inexperience (< 1 year) paired with a lack of management oversight.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HST's failure to take actions and bring the BAAL back within limits could lead to further high frequency excursion with the over-generation and cause neighboring BA entities to unnecessarily reduce generation, impacting the potential stability of the BPS. This risk was reduced because HST only exceeded the BAAL High limit by one (1) minute and the excursion was only for eight (8) MWs during this period. HST's 107 MW system is less than 0.2% of the FRCC Region summer load. No harm is known to have occurred.
Mitigation	To mitigate this violation, HST: 1) identified the issue and provided reinforcement training to the involved System Operator; 2) provided the System Operator a written performance letter, emphasizing the importance of taking action on BAAL alarms, especially at the 20 minute alarm and greater; 3) performed an extent-of-condition review to check for other occurrences since the quarterly review and no additional instances were found; 4) created a cause and effect diagram and performed root cause analysis; 5) revised the BAAL Alarm Procedure and updated to include actions to be taken with the addition of HST generation now back on line, in addition to current transaction curtailment; BAAL procedure revision version 7; 6) completed training on the revised BAAL procedure version 7 for all System Operators; 7) executed revised BAAL procedure, version 8, to clarify System Operators required actions and to provide for the inclusion of additional preventative controls. Additional preventative controls include: a. Starting the use of the check list when the alarms first start to occur, b. Modifying the check list to allow the System Operator to record the date/time for actions taken as well as a section for related comments, c. Requiring completion of the check list by the System Operator at the 20 minute mark and greater, d. Providing for management review of completed check lists with feedback to the System Operator to improve future responses to alarms, 8) provided reinforcement training on the revised BAAL Alarm procedure, version 8, and revised check list to all applicable System Operators; 9) started exporting BAAL supervisory control and data aquistion (SCADA) alarms to key personnel once the first alarm occurs after 10 minutes, followed by subsequent alarm notifications after 15, 20, 25, 26, 27, 28, and 29 minutes. These notifications include the Sr. Manager of System Operations, Senior System Operator, Assistant Director, Director, and others as designated by the Director. The designated additional personnel will contact the System Operator to discuss required actions needed to bring the BAAL within NERC specifications.
Other Factors	This instant issue is a repeat of FRCC2016015952 and FRCC2017018469, which are considered an aggravating factor. Since the enforcement date of July 1, 2016, HST has violated this standard on several occasions. After each instance management has put additional safeguards in place; however, these actions have been insufficient to correct the situation and management oversight was considered an aggravating factor. The Internal Compliance Program was considered a neutral factor and no credit was granted as the program has not corrected the issue. Minimal credit was granted for the Self-Report and cooperation.

Consolidated Edison Co of NY, Inc (CECONY) – NCR07046 NOC-2633 $50,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018019020	IRO-010-2	R3	Medium	Lower	10/9/17	10/10/17	Self-Report	2/28/2018	1/11/2019

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 23, 2018, Consolidated Edison Co. of NY, Inc. (CECONY) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in violation of IRO-010-2 R3. CECONY did not use the mutually agreed format between itself and its Reliability Coordinator (NYISO) for data specifications related to NYISO's Real-Time monitoring. Specifically, CECONY failed to observe the NYISO's communication protocol and provision of Real Time data protocol associated with the scheduled derate of two 345 kV Transmission Facilities: Feeders 41 and 42. CECONY scheduled the derates for pipe-type Underground Feeders 41 and 42 (associated with Feeder 41 and 42 cooling plant work) in advance through the NYISO outage scheduling process for the derates to begin at 7:00 am on October 9, 2017. However, and in violation of CECONY's internal procedure, substation field personnel made status changes to the cooling plant at 11:21 am on October 9, 2017 without asking permission from the CECONY System Operator. As a result, both feeders were derated in Real Time to a Summer Normal rating of 554 MW without the knowledge of the CECONY System Operator or the NYISO. The CECONY EMS carried an incorrect Summer Normal Rating of 649 MW for both Feeders. The CECONY EMS communicates via ICCP with the NYISO EMS. The NYISO's protocol associated with Real Time monitoring required CECONY's System Operator to contact the NYISO via phone prior to the scheduled start time to acquire an additional verbal approval for the scheduled derates to begin. Only upon NYISO's approval would the CECONY System Operator have normally changed both Feeder ratings in the EMS and provided permission to the CECONY substation field personnel to begin the cooling plant work. The violation started at 11:21 am on October 9, 2017, when substation personnel made the cooling plant adjustments that began the derates, and ended at 5:33 pm on October 10, 2017 when the CECONY System Operator notified the NYISO of the derates and adjusted the Summer Normal ratings in the EMS. The root cause of this violation was the failure of the CECONY substation working group to follow internal protocol to acquire approval from the System Operator before scheduled work began at a substation that affects equipment ratings.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The existence of incorrect ratings in the EMS could negatively impact the reliability of the BPS under stressed system conditions if the operating authority is unknowingly operating to a higher rating than the equipment can accommodate. In this case, however, pre-outage studies were performed by CECONY and the NYISO as part of the NYISO's scheduling and approval process. The scheduling process allows the opportunity for the CECONY or NYISO to study and possibly deny the outage request one week in advance and then an opportunity to study again and possibly deny the outages as the October 9, 2017 operational day was beginning. On October 9, 2017, the NYISO and/or CECONY System Operator would have cancelled the job before the scheduled 7:00 am start time had system conditions warranted such cancellation. At no time during the approximate 30-hour duration of the violation did the system configuration change to cause an increase in loading on either feeder that exceeded the 554 MW reduced ratings. No harm is known to have occurred.
Mitigation	To mitigate this violation, CECONY: 1) Conducted an Operating Incident investigation upon the discovery of the violation through CECONY's Substation Operations and System Operations staff; 2) Provided additional training to its Substation Shift Managers and operators on the derate notification and approval process and its importance to the reliability of the Bulk Power System; 3) Directed the Substation Planner responsible for making future outage requests for scheduled dielectric cooling plant work at substations to add a distinct notification step to the System Operator outage switching card; and 4) Updated its Substation procedure 0900-0002 – *Operation and Maintenance of High Pressure Dielectric Fluid Cooling Plants (PURS)* - with the documentation of the requirement to request approval from the System Operator before cooling plant work begins.
Other Factors	NPCC reviewed CECONY's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. CECONY's ICP is documented in procedure TP-7560-18 *Management of the Compliance Process for NERC and NPCC Reliability Standards*. CECONY's internal compliance function is managed by the NERC Reliability Compliance Section (NRC). The NRC Section consists of a manager and a staff of six engineers. The function of the NRC Section is to manage the NERC compliance process for CECONY. Through its ICP, the NRC Section has identified all NERC Standards applicable to CECONY and assigned each to the appropriate corporate organization. The NRC Section manages the NERC CMEP for CECONY and is responsible for the submittal of all required periodic documentation such as guided self-certification evidence and forms. The NRC Section also coordinates audit responses to NPCC. The NRC Section manages a documented process

	for evaluating issues of possible noncompliance. As part of the ICP, the NRC Section maintains archives of CECONY compliance documentation. The NRC Section actively participates in the NERC and NPCC Standards development process and represents Con Edison on the NPCC Compliance Committee and Regional Standards Committee. In recognition of its extensive ICP and robust culture of compliance, CECONY was qualified for self-logging by NPCC in 2016. As a self-logging entity, CECONY has demonstrated its ability to identify, assess and correct issues of possible noncompliance. CECONY has effectively implemented its self-logging authority and has limited its use of self-logging to instances of minimal risk noncompliance. NPCC considered CECONY's compliance history and determined there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018019446	FAC-009-1	R1	Medium	Moderate	6/18/2007	1/30/2018	Self-Report	12/26/2018	1/10/2019

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, 2018, Consolidated Edison Co. of NY, Inc. (CECONY) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in violation of FAC-008-3 R6. CECONY did not establish Facility Ratings consistent with its Facility Rating Methodology (FRM) for nine Facilities. NPCC later determined that the violation began under FAC-009-1 R1. Accordingly, NPCC determined that CECONY was in violation of FAC-009-1 R1 from June 18, 2007 until December 31, 2012 and then was in violation of FAC-008-3 R6 from January 1, 2013 until January 30, 2018. NPCC further determined that, for purposes of this violation, there was no substantive change in CECONY's compliance obligations under the two applicable Standard Requirements. CECONY's FRM requires the use of the most-limiting element (MLE) as the Facility Rating for its Facilities. CECONY initially discovered this violation through an on-watch System Operator who discovered that the ratings used in CECONY's Energy Management System (EMS) for two Bulk Electric System (BES) feeders that utilized the Dynamic Feeder Ratings (DFR) system did not respect the most limiting element of the feeders. Subsequently, the issue was determined to be with the DFR feeders and CECONY performed an extent of condition review on all 24 DFR feeders and discovered this violation affected nine (9) of its twenty-four (24) BES pipe type fluid filled transmission feeders that utilize the DFR system. CECONY has a total of 175 BES transmission feeders. The other 151 transmission feeders do not utilize the DFR system. These 9 feeders represent 5.1% (9/175) of CECONY's BES feeders. The DFR is an advanced software tool that allows for greater real-time operational flexibility by calculating real-time Facility Ratings exclusively for underground transmission cable portion of the feeder by considering the load history and dielectric fluid temperature during real-time operation and then automatically uploads the Facility Ratings into CECONY's EMS. There are 3 different modes of dielectric fluid circulation through the pipe type fluid filled feeders and the DFR calculates a Normal, LTE, and STE rating on the cable portion for each mode, and then also considers the Summer and Winter ratings of all series connected equipment. As a result, there are 18 different ratings possible for each feeder. In the case of these 9 feeders, the Facility Rating being used by the EMS that had been calculated by the DFR did not take into account that certain disconnect switches were the most limiting in-series piece of equipment or MLE either under certain pumping mode scenarios or due to recent loading history on the feeder. The noncompliant Facilities consisted of six 345 kV transmission feeders and three 138 kV transmission feeders, all of which are located within CECONY's New York City Transmission Load Area. This violation started on June 18, 2007, the enforcement date of the standard and requirement and ended on January 30, 2018, when CECONY suspended use of the DFR pending the completion of an extent of condition. In lieu of the DFR, CECONY reverted back to using the book value ratings in the EMS. The root cause of this violation is inadequate oversight and controls over the coordination between the DFR software and the Energy Control Center (ECC) SCADA server. Prior to FAC-009-1 coming into effect in 2007, CECONY had a facility ratings methodology that followed the accepted utility practices of the time. After the effective date of FAC-009-1, CECONY's methodology for establishing feeder ratings included identifying the most limiting element. However, CECONY did not ensure that the pre-2007 Facility Ratings calculated by DFR software respected the MLE and that that correct ratings were displayed on the SCADA system to the System Operator.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The use of the inaccurate DFR ratings in the EMS could affect the reliability of the BPS under stressed real-time system conditions if the operating authority is unknowingly operating to a higher rating than the equipment can accommodate. Advance planning studies that involved these 24 feeders that have DFR was performed using the more conservative book ratings, not the dynamic rating. • The three 138 kV feeders became BES elements on 7/1/2016. The historical data for 2016 and 2017 shows that, for the majority of hours where any rating exceeded the MLE, the only rating that exceeded MLE was the Short Term Emergency (STE) rating. There were minimal instances where the EMS had an inaccurate rating for the Long Term Emergency (LTE) and NORMAL ratings. In Real-Time, there were no occurrences where power flows exceeded any of the rating levels (NORMAL, LTE, STE) that should have shown in the EMS had the MLE been properly considered in developing the Facility Rating. • The six 345 kV feeders became BES elements on 6/18/2007. The historical data for 2010 through 2017 shows that, for the majority of hours where any rating exceeded the MLE, the only rating that was inaccurate was the Short Term Emergency (STE) rating. There were minimal instances where the EMS had an inaccurate rating for the LTE and NORMAL ratings. In real time, there were no occurrences where power flows exceeded any of the rating levels (NORMAL, LTE, STE) that should have shown in the EMS had the MLE been properly considered in developing the Facility Rating. However, the risk of this noncompliance was reduced by the following factors: 1) CECONY operates the transmission system on an N-2 basis secured to NORMAL ratings. 2) The violation consisted, largely, of the EMS showing an incorrect STE Rating to the Operator, which are rarely reached even after a contingency occurs. 3) The CECONY methodology for operating the power system keeps real time power system flows under the NORMAL rating under normal operating conditions and obligates the System Operator to return facilities back to under NORMAL ratings in response to any contingency as soon as possible. The methodology also does not allow for an STE contingency alarm that results from the Real Time Contingency Analysis program to remain; the System Operator must adjust the system immediately to clear the STE contingency alarm. 4) When real-time issues occur, the CECONY System Operator operates in a conservative fashion to prolong the life of BES elements. The System Operator must clear an Over Normal alarm within 3 hours instead of the Planning allowance of 24 hours. The System Operator must clear an Over LTE alarm within 15 minutes instead of the Planning allowance of 3 hours. The System Operator must clear an Over STE alarm within 5 minutes instead of the Planning allowance of 15 minutes.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018019446	FAC-009-1	R1	Medium	Moderate	6/18/2007	1/30/2018	Self-Report	12/26/2018	1/10/2019

	5) Based on a review of historical data, there were no instances during the period of noncompliance where the nine feeders experienced real time flows that exceeded any of the corrected ratings level (Normal, LTE, STE) of the MLE. No harm is known to have occurred.
Mitigation	To mitigate this violation, CECONY: 1) Suspended the use of its DFR tool and began using the book ratings from the Engineering department and performed an extent of condition review; 2) Implemented and tested equipment book rating limits for all series transmission equipment in its EMS system for all DFR-rated feeders in accordance with its documented FRM 3) Enhanced the coordination between the DFR server and ECC SCADA server so that the ECC SCADA server provides the most limiting series element rating to the EMS for the Operator's use.
Other Factors	Although this was a minimal risk issue, NPCC aggravated this violation to an SNOP with a penalty. FAC-008-3 R6 has been identified as an area of focus in the ERO Enterprise CMEP Implementation Plans from 2016 through 2019. For a large TO such as CECONY, it is expected that Facility Ratings discrepancies be identified and addressed through detective controls and not discovered as part of another capital project or incidentally by an on-watch system operator. Additionally, NPCC reviewed CECONY's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. CECONY's ICP is documented in procedure TP-7560-18 *Management of the Compliance Process for NERC and NPCC Reliability Standards*. CECONY's internal compliance function is managed by the NERC Reliability Compliance Section (NRC). The NRC Section consists of a manager and a staff of six engineers. The function of the NRC Section is to manage the NERC compliance process for CECONY. Through its ICP, the NRC Section has identified all NERC Standards applicable to CECONY and assigned each to the appropriate corporate organization. The NRC Section manages the NERC CMEP for CECONY and is responsible for the submittal of all required periodic documentation such as guided self-certification evidence and forms. The NRC Section also coordinates audit responses to NPCC. The NRC Section manages a documented process for evaluating issues of possible non-compliance. As part of the ICP, the NRC Section maintains archives of CECONY compliance documentation. The NRC Section actively participates in the NERC and NPCC Standards development process and represents Con Edison on the NPCC Compliance Committee and Regional Standards Committee. In recognition of its extensive ICP and robust culture of compliance, CECONY was qualified for self-logging by NPCC in 2016. As a self-logging entity, CECONY has demonstrated its ability to identify, assess and correct issues of possible noncompliance. CECONY has effectively implemented its self-logging authority and has limited its use of self-logging to minimal risk noncompliance. The violation duration was 3,879 days. CECONY did not have any detective controls in place that could have helped identify the issue sooner to lessen the violation duration and thereby lessen the risk. NPCC considered CECONY's compliance history and determined there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
NPCC2018020745	FAC-008-3	R6	Medium	Lower	7/1/2016	11/9/2018	Self-Report	11/15/2018	1/11/2019

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 November 30, 2018, Consolidated Edison Co. of NY, Inc. (CECONY) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in violation of FAC-008-3 R6. CECONY did not establish Facility Ratings consistent with its Facility Rating Methodology (FRM) for eight Facilities. CECONY's FRM requires the use of the most-limiting element (MLE) as the Facility Rating for its Facilities. CECONY initially discovered this violation as part of the planning for a capital project to replace 138 kV disconnect switches when it discovered the thermal ratings of a 138 kV intra-substation feeder did not respect the most MLE of the Facility. CECONY performed an extent of condition review and discovered this violation affected eight (8) of its one hundred and fifty-one (151) BES transmission feeders that are non-DFR feeders. CECONY has a total of 175 BES transmission feeders with 24 of them being in the DFR system. In the case of these 8 feeders that represent 4.6% of CECONY's BES feeders, the Facility Rating did not respect the most limiting in-series piece of equipment or MLE. The noncompliant Facilities consisted of two 345 kV transmission feeders and six 138 kV transmission feeders, all of which are located within CECONY's New York City Transmission Load Area and all of which became BES elements on July 1, 2016. This violation started on July 1, 2016, the date when all eight Facilities were identified as BES Elements under the revised Bulk Electric System definition and ended on November 9, 2018, when CECONY corrected the Facility Ratings to be consistent with its FRM for all eight feeders. In particular, CECONY corrected the ratings for the eight Facilities in its "Tie Feeder Rating Tabulation" (a.k.a the "book" rating) that is developed by Transmission Engineering and entered the correct ratings into its EMS/SCADA system. Since the time that NERC standards came into effect in 2007, CECONY has had a mature methodology for establishing facility ratings that included identifying the MLE. However, a review of the ratings of the newly identified BES elements conducted prior to the effective date of the BES definition (7/1/2016) was not fully effective. These are all non-DFR feeders. The root cause of this violation is that CECONY's verification of the ratings of new BES transmission elements was not fully effective prior to providing the ratings to the System Operation Department. The eight feeders are not part of CECONY's Dynamic Feeder Rating (DFR) software and thus, were not part of the review that took place under NPCC2018019446, FAC-009-1 R1.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The use of incorrect book ratings in the EMS could affect the reliability of the BPS under stressed system conditions if the operating authority is unknowingly operating to a higher rating than the equipment can accommodate. Planning and operating studies depend on the use of accurate book ratings such that the BES can withstand a variety of predetermined contingencies. All eight of the feeders (2 - 345 kV and 6 – 138 kV) became BES elements on July 1, 2016. The first 345 kV feeder has three modes of dielectric fluid circulation and CECONY develops three different ratings (Normal, LTE, STE) for both the summer and winter period. As a result, the 345 kV feeder had 18 different possible ratings levels. The only rating of the 18 that was incorrect was the Summer STE rating. In addition, the feeder is operated in series with another 345 kV feeder that was rated correctly and that was more limiting than the 345 kV feeder with the ratings issue. However, both of those 345 kV feeders were monitored by the System Operator and had alarms points for flows (Normal, LTE, STE) in the EMS. As such, there was no operational risk because the System Operator would have seen, and reacted to, the EMS alarms on the more limiting feeder first. The second 345 feeder served the high side of a 345/138 kV autotransformer and does not have circulating dielectric fluid. It was discovered that all six ratings (Normal, LTE, STE for Summer and Winter) on the 345 kV feeder needed adjustment to take into account that the 345 kV side of the autotransformer was limiting. The Summer Normal rating was 28% higher than the correct Summer Normal rating. However, the 138 kV feeders on the low side of the autotransformer had the correct ratings, were more limiting than the 345 kV feeder, and were equal to the rating of the low side of the transformer. The 138 kV feeders also had alarm points for flows (Normal, LTE, STE for Summer and Winter) in the EMS. As such, there was no operational risk because the System Operator would have seen, and reacted to, the EMS alarms on the more limiting feeders first. With regard to the six 138 kV feeders: • The initial discovery of the limiting disconnect switch that led to the CECONY extent of condition review resulted in the corrected ratings for one intra-substation 138 kV feeder for all six ratings (Normal, LTE, STE for both Summer and Winter). The Summer Normal rating was 36% higher than the correct Summer Normal rating. • One 138 kV feeder has two modes of dielectric fluid circulation and has a switchable reactor connected to it. The feeder has 24 possible different ratings and only the Winter STE rating was incorrect in one mode. The other 23 ratings were correct. • By the strict implementation of the CECONY ratings methodology, four electrically equivalent and parallel 138 kV BES feeders needed the Summer and Winter Normal ratings adjusted due to the discovery that the high side transformer winding on each corresponding 138 kV to 69 kV transformer was incorrect. These four feeders serve a radial 69 kV load area. The Summer Normal rating

	was 16% higher than the correct Summer Normal rating. The transformer is the limiting series element in all cases; however, the 4 transformers are non-BES elements. The other four ratings (LTE and STE for both Summer and Winter) did not change on all 4 feeders. However, the risk of this noncompliance was lessened by the following factors: 1) CECONY operates the transmission system to an N-2 basis secured to Normal ratings. 2) The CECONY methodology for operating the power system keeps real time power system flows under the NORMAL rating under normal operating conditions and obligates the System Operator to return facilities back to under NORMAL ratings in response to any contingency as soon as possible. The methodology also does not allow for an STE contingency alarm that results from the Real Time Contingency Analysis program to remain; the System Operator must adjust the system immediately to clear the STE contingency alarm. 3) When real-time issues occur, the CECONY System Operator operates in a conservative fashion to prolong the life of BES elements. The System Operator must clear an Over Normal alarm within 3 hours instead of the Planning allowance of 24 hours. The System Operator must clear an LTE alarm within 15 minutes instead of the Planning allowance of 3 hours. The System Operator must clear an STE alarm within 5 minutes instead of the Planning allowance of 15 minutes. 4) None of the four parallel 138 kV BES feeders were ever operated over the rating of the BES cable portion. It was only the non-BES 138/69 kV series transformers that were exposed to the incorrect ratings. No harm is known to have occurred.
Mitigation	To mitigate this violation, CECONY: 1) Performed an extent of condition review on all non-DFR BES transmission Facilities and determined that a total of eight (8) feeders were noncompliant with the requirement due to a failure to respect the associated most limiting series element for those feeders; 2) Published corrected ratings for the eight noncompliant (8) feeders in its "Tie Feeder Rating Tabulation" document and implemented them in its EMS/SCADA system; and 3) Enhanced an existing software database tool to automatically identify the limiting element of non-DFR BES transmission facilities in order to determine ratings that comply with the requirement and made this tool the central repository for non-DFR BES feeder ratings and associated equipment ratings.
Other Factors	Although this was a minimal risk issue, NPCC aggravated this violation to an SNOP with a penalty. FAC-008-3 R6 has been identified as an area of focus in the ERO Enterprise CMEP Implementation Plans from 2016 through 2019. For a large TO such as CECONY, it is expected that Facility Ratings discrepancies be identified and addressed through detective controls and not discovered as part of another capital project or incidentally by an on-watch system operator. Additionally, NPCC reviewed CECONY's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. CECONY's ICP is documented in procedure TP-7560-18 *Management of the Compliance Process for NERC and NPCC Reliability Standards*. CECONY's internal compliance function is managed by the NERC Reliability Compliance Section (NRC). The NRC Section consists of a manager and a staff of six engineers. The function of the NRC Section is to manage the NERC compliance process for CECONY. Through its ICP, the NRC Section has identified all NERC Standards applicable to CECONY and assigned each to the appropriate corporate organization. The NRC Section manages the NERC CMEP for CECONY and is responsible for the submittal of all required periodic documentation such as guided self-certification evidence and forms. The NRC Section also coordinates audit responses to NPCC. The NRC Section manages a documented process for evaluating issues of possible non-compliance. As part of the ICP, the NRC Section maintains archives of CECONY compliance documentation. The NRC Section actively participates in the NERC and NPCC Standards development process and represents Con Edison on the NPCC Compliance Committee and Regional Standards Committee. In recognition of its extensive ICP and robust culture of compliance, CECONY was qualified for self-logging by NPCC in 2016. As a self-logging entity, CECONY has demonstrated its ability to identify, assess and correct issues of possible noncompliance. CECONY has effectively implemented its self-logging authority and has limited its use of self-logging to minimal risk noncompliance. NPCC considered CECONY's compliance history and determined there were no relevant instances of noncompliance.

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017976	PRC-005-6	R3	High	Lower	4/2/2017	7/18/2017	Self-Report	7/20/2017	6/14/2018

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 21, 2017, the entity submitted a Self-Report stating, as a Transmission Owner, it was in violation of PRC-005-6 R3. Specifically, the entity reported that the 18-month testing for one volts direct current (VDC) battery bank had not been completed, per Table 1-4(a) of the Standard, due to errors with the manual entry of maintenance milestones in the tracking software. In particular, the battery continuity, battery terminal connection resistance, and battery intercell connection resistance maintenance activities had not been completed in accordance with the maintenance intervals stated in the entity's Protection System Maintenance Program (PSMP). The float voltage of battery charger, cell conditions, and physical condition of the battery rack maintenance activities had been completed quarterly. The 18-month testing period requirement for the switchyard VDC battery bank had not been completed prior to the required date of April 1, 2017. 100% of Protection System devices that adhere to a one to two calendar year testing and maintenance interval must be maintained and tested, per the Implementation Plan for PRC-005-6. Upon discovery of the missing tests, the required testing for the VDC battery bank was completed on July 18, 2017. After reviewing all relevant information, WECC determined the entity failed to maintain one VDC battery bank that is included within the time-based maintenance program in accordance with the maximum maintenance intervals prescribed within Table 1-4(a), as required by PRC-005-6 R3. The root cause of the violation was inadequate tracking of testing and maintenance activities in the software tracking system for testing and maintenance dates of the switchyard VDC battery bank. This violation began April 2, 2017, when the entity was required to have 100% Protection System device test completion, and ended on July 18, 2017, when the entity completed all required testing for the VDC battery bank, for a total of 108 days of noncompliance.
Risk Assessment	This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System. In this instance, DOPD failed to maintain one VDC battery bank that is included within the time-based maintenance program in accordance with the maximum maintenance intervals prescribed within Table 1-4(a), as required by PRC-005-6 R3. The entity did not have effective preventative or detective controls to prevent or detect this violation. However, the entity did maintain all testing and maintenance for the other VDC battery banks applicable to the Standard and Implementation Plan. Furthermore, as a compensating measure, the entity completed float voltage of battery charger, cell conditions, and physical condition maintenance for all VDC battery banks on a quarterly basis which would have alerted entity personnel with issues with the batteries. In addition, the switchyard subject to this violation has AC power coming from multiple sources outside of the switchyard itself, which lessens the risk.
Mitigation	To mitigate this violation, the entity: a. completed battery continuity, battery terminal connection resistance, and battery intercell connection resistance testing for the switchyard VDC battery bank; b. updated its PSMP to provide better clarity on battery testing responsibilities; and c. added batteries to the PSMP tracking software.
Other Factors	WECC determined that the Expedited Settlement Agreement disposition option without a penalty is appropriate for the following reasons: WECC did not apply mitigating credit for the entity's Internal Compliance Program (ICP) as WECC has not reviewed a documented ICP for this entity. WECC considered the entity's PRC-005 compliance history in determining the disposition track. WECC considered the entity's PRC-005 compliance history to be an aggravating factor in the penalty determination (WECC200800997 and WECC2014014179).

Catalina Solar, LLC (CATA) – NCR11484 NOC-2618 $32,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017041	VAR-002-2b	R2	Medium	Severe	This violation began on 7/14/2014, when CATA registered as a Generator Operator.	This violation ended on 7/28/2017 when CATA began using an Operations Control Center to monitor and alarm voltage.	Self-Report	10/17/2017	11/2/2017

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 16, 2017, CATA submitted a Self-Report stating that, as a Generator Operator, it was in violation with VAR-002-2b R2. Specifically, CATA reported that, for its 110 MW photovoltaic power station, it had not consistently monitored voltage and therefore had not maintained or made notifications to the Transmission Operator (TOP) when the generator voltage had traversed outside the voltage schedule. However, during the time in which voltages were not monitored, the interconnecting utility would make requests when the need arose to control voltage and CATA would respond accordingly. CATA failed to maintain the generator voltage schedule directed by the TOP as required by VAR-002-2b R2. The root cause of the violation was CATA's lack of controls to ensure its Facility's voltage monitoring, alarming, and communication equipment support and comply with the TOP's generator voltage schedule. WECC determined that this violation began on July 14, 2014, when CATA registered as a Generator Operator and ended on July 28, 2017, when CATA began using an Operations Control Center to monitor and alarm voltage for a total of 1110 days of noncompliance.
Risk Assessment	This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In this instance, CATA failed to maintain the generator voltage schedule directed by the TOP as required by VAR-002-2b R2. Such failure could potentially result in undamped voltage oscillations and the unplanned tripping of the Facility. CATA owns and operates 110 MW of generation that was applicable to this issue. CATA implemented the practice of responding immediately to requests from the interconnecting utility to control voltage and would respond accordingly.
Mitigation	To mitigate this violation, CATA: 1) implemented controls and telemetry so the Operations Control Center (OCC) can monitor and control the facility to the point of interconnection; 2) transmitted voltage data from the facility to the OCC; 3) set up alarms and started monitoring voltage and alarms on voltage deviations 24/7 on the Monarch Energy Management System at the OCC; 4) refreshed VAR-002-4 communication training with OCC staff; 5) purchased the webCompliance tool from OATI; and 6) increased required skills for new OCC employees.
Other Factors	WECC considered CATA's and its affiliates' VAR-002 R2 compliance history in determining the penalty. WECC considered CATA's and its affiliates' VAR-002 R2 compliance history to be an aggravating factor in the penalty determination (NERC Violation ID WECC2016015506 and WECC2016015507). WECC also considered that the violation duration is 1110 days as described above. CATA did not have sufficient controls in place that could have helped identify the issue sooner to lessen the violation duration and thereby lessen the risk. WECC did not give credit for CATA's Internal Compliance Program (ICP). Although CATA does have a documented ICP, WECC determined that it did not aid in the discovery of this noncompliance or mitigate the risk while noncompliant.

Gila Bend Operations Company –NCR11372 NOC-2621 $0

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2018019603	PRC-001-1	R1	High	Severe	6/18/2007 when the Standard and Requirement became mandatory and enforceable	5/29/2018 when GBOC completed its Protection Systems Training documentation in accordance with the Standard and Requirement	Self-Report	11/14/2018	12/18/2018

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 30, 2018, GBOC submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with PRC-001-1 R1. Specifically, GBOC reported that during an internal compliance review in March of 2018, it discovered that it had not maintained adequate evidence to demonstrate that 10 plant operators at one generating station were familiar with the purpose and limitation of the protection system schemes that GBOC had applied in the plant area. The GBOC plant operating personnel team each had more than 5 years of experience working at this plant as either a Lead Operator and/or a Control Room operator. As part of normal operations, GBOC assigned more than one of these individuals to be present on-site at all times. Additionally, GBOC had trained the 10 plant operators on the plant area's protection system schemes through on-the-job knowledge transfer and hands on learning, although it had never had a formal training program for such activities. After reviewing all relevant information, WECC determined that GBOC failed to demonstrate with evidence that its operating personnel were familiar with the purpose and limitations of protection system schemes applied to one of its generating stations, as required by PRC-001-1 R1. The root cause of the violation was the lack of a formalized training program for the R1 activities and therefore GBOC was not able to demonstrate through evidence that it had ensured compliance with R1.
Risk Assessment	WECC determined that this violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, GBOC failed to demonstrate with evidence that its operating personnel were familiar with the purpose and limitations of protection system schemes applied to one of its generating stations, as required by PRC-001-1 R1. GBOC owned and operated approximately 2,200 MW of generation located at this plant and also operated and maintained one Protection System scheme on a 230 kV transmission line to a substation with 836 MVA of generation. Such failure could result in an unintended loss of the 836 MVA of generation, 2,200 MW of generation, or impact the 230 kV transmission elements if the operating personnel were unfamiliar with the Protection System scheme. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate. However, GBOC had controls in place that required at least one experienced generating operator was on staff at all times at the generating station in scope. Additionally, this violation was related to maintaining proper training evidence rather than a true lack of familiarity or understanding of protection system schemes. 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 remediate and mitigate this violation, GBOC: 1) created a training document on protection system schemes for operating personnel and established that the training should be repeated at a minimum of every 36 months; 2) executed training on protection system schemes for the required personnel and captured the evidence to demonstrate compliance; 3) identified a team at GBOC to determine if the computer based training program needs to be updated for changes in protection system schemes, who will be responsible for coordinating the changes as well as how the changes will be communicated with the rest of the required personnel; and 4) developed a computer based training on protection system schemes as a required part of the operator onboarding.
Other Factors	WECC applied an aggravating factor for the following reason: i. WECC escalated the disposition option to an expedited settlement due to the significant violation duration, which is 3,999 days as described above. Other Considerations: i. WECC did not apply a credit for GBOC's Internal Compliance Program because it did not have any detective controls in place that could have helped identify the violation sooner to lessen the violation duration. ii. WECC considered GBOC's compliance history and determined GBOC did not have any relevant compliance history.

Idaho Power Company (IPCO) – NCR05191 NOC-2619 $0

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
WECC2017017203	PRC-005-1.1b	R2	High	High	1/1/2015, when IPCO failed to provide documentation of the implementation of maintenance and testing the metering devices that send signals to one relay (Current Transformers and Potential Transformers)	2/24/2017, when IPCO completed and documented a Relay Meter Calibration Check for the Protection System relay	Self-Report	4/20/2017	8/17/2017

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 30, 2017, IPCO submitted a Self-Log stating that, as a Generator Owner, it was in violation of PRC-005-2 R3. On February 15, 2017, IPCO was notified that the violation does not qualify for a Self-Log due to the violation duration supported by the original evidence for the reported scope in addition to compliance history with PRC-005. On March 7, 2017, WECC created the Self-Report stating that, as a Generator Owner, IPCO was in violation with PRC-005-1.1b R2. Specifically, IPCO reported that during an internal compliance review in December 2016, it identified missing maintenance and testing records for ten Protection System relays. The testing should have been completed on January 1, 2015, but was not completed until February 24, 2017. After reviewing all relevant information, WECC determined that there was a change in scope from what IPCO originally reported. WECC found that IPCO failed to provide documentation of its Protection System maintenance and testing program and the implementation of that program for the metering devices that send signals to one relay (Current Transformers and Potential Transformers), as required by PRC-005-1.1b R2. The root cause of the violation was not having formally documented controls to verify that relay testing and maintenance were performed within the required timeframe. WECC determined that this violation began on January 1, 2015, when IPCO failed to provide documentation of the implementation of maintenance and testing the metering devices that send signals to one relay (Current Transformers and Potential Transformers) and ended on February 24, 2017, when IPCO completed and documented a Relay Meter Calibration Check, for a total of 786 days of noncompliance.
Risk Assessment	WECC determined this violation 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, IPCO failed to provide documentation of its Protection System maintenance and testing program and the implementation of that program for only one Protection System relay, as required by PRC-005-1.1b R2. However, the Protection System relay is associated with IPCO's 12 kV – 4.16 kV generator bus and could only have tripped the 1.75 MVA generator. This generator runs less than 15% of the time during a typical year, and the IPCO grid is operated to remain stable should that amount of generation trip off.
Mitigation	To mitigate this violation, IPCO: 1) completed testing and maintenance for the Protection System relay; 2) formalized the annual review of Protection System maintenance and testing activities performed by the area Generation Technician Leaders by implementing two SharePoint workflows and associated reminders; and 3) improved a checklist of required items for maintenance and testing and incorporated the checklist into the workflow reminders and distributed it to key staff.
Other Factors	WECC considered IPCO's PRC-005 R2 compliance history in determining the disposition track. WECC considered IPCO's PRC-005 R2 compliance history to be an aggravating factor in the disposition determination (NERC Violation IDs WECC200800628, WECC200901452, and WECC201102886). WECC did not apply mitigating credit for the entity's Internal Compliance Program (ICP). Although the entity does have a documented ICP, WECC determined that it was not effective in detecting or preventing the above violation.

Duquesne Light Company (Duquesne) – NCR00762 NOC-2615 $40,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2017018162	FAC-008-3	R6	Medium	Lower	4/28/2015 (when the first incorrect substation conductor rating was entered into the Tool)	7/31/2017 (Mitigation Plan completion)	Self-Report	7/31/2017	5/11/2018

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 4, 2017, the entity submitted a Self-Report stating that, as a Transmission Owner, it was in violation of FAC-008-3 R6. The entity discovered inconsistences with certain substation conductor ratings. Correcting these inconsistencies led to ratings changes for 30 substation conductor types. Overall, this resulted in a reduction of the overall Facility Rating for three transformers. This violation is not indicative of a systemic issue with Duquesne's FAC-008 program. Only approximately three percent (3%) of Duquesne's Bulk Electric System (BES) transmission Facilities were affected. Duquesne undertook an extensive extent of condition review as part of its mitigation for this violation and that extent of condition did not reveal any other Facility Ratings inconsistencies. More specifically, as background, during a proactive review of the entity's System Ratings Database, the entity discovered possible inconsistencies with certain substation conductor ratings. Following this discovery, the entity conducted a deeper dive into the calculations used in the Substation Conductor Ratings Determination Tool (Tool). The Tool is used to calculate the ratings and create the ratings sheets for substation conductor's types. (The Tool, which is used to calculate the ratings and create the ratings sheets for substation conductor's types, was developed in November 2010 by the PJM Substation Bus Rating Task Force, which was a task force of the PJM Transmission and Substation Design Committee.) The entity adopted use of the Tool in 2012 in advance of the implementation date for FAC-008-3. The Tool uses user-based assumptions as well as equations from various Institute of Electrical and Electronic Engineers (IEEE) standards and other documented sources to calculate parameters for the equations and ultimately the ambient temperature ratings of the desired substation conductor types. The entity determined that the inconsistencies with certain substation conductor ratings it discovered arose from a data input error while using the Tool to calculate the ratings of new substation conductor types. The equations in the Tool were correct, but an input value to one of the equations was entered incorrectly, and the entity lacked an effective verification control to detect and correct that error quickly. Once the entity identified these inconsistencies, the entity began a review of all input assumptions and parameters used within the Tool to ensure that the parameters were in alignment with the accepted industry standards. During its review, the entity verified approximately 700 input parameters and 568 ratings for 71 substation conductors. The majority of these parameters were verified to be in accordance with accepted industry standards or methods. (For each of the entity's eight temperature sets, the entity subsequently recalculated the normal, emergency, and load dump conductor ratings for all substation conductor types, which the entity utilizes.) Correcting these inconsistencies in input parameters led to ratings changes for 30 substation conductor types. The changes resulted in lower ratings for 24 BES conductor types, ratings increases for 3 conductor types, and a combination of increases and decreases of the various ratings sets for 3 conductor types. (Three of the 30 subject conductors were added to the Tool in 2015 following a comprehensive field review performed as part of the entity's RFC2014013430 self-report and mitigation. When the conductors were added in 2015, the entity initially determined that the three conductors were the most limiting elements for three entity Facilities: Carson No. 1 - 345/138kV autotransformer and Cheswick Unit 1A & 1B Generator Step Up transformers. During the current review of all input assumptions and parameters, the entity discovered that these three conductors were entered into the Tool incorrectly in 2015. After rerating these three conductors (which resulted in ratings reductions), the entity determined that the conductor for the Carson No. 1 – 345/138 kV autotransformer was the most limiting element, but the conductors for two Cheswick Step Up transformers were not the most limiting elements.) The entity operates 108 BES Transmission Facilities (which the entity defines as circuits, transformers, reactors, and capacitor banks). This violation resulted in a reduction of the overall Facility Rating for three transformers. This means that approximately 3% of the entity's BES transmission Facilities were affected by this violation. For each transmission Facility, the entity maintains eight temperature sets where each temperature set contains a normal, emergency, and load dump rating. Therefore, each transmission Facility has a total of 24 normal, emergency, and load dump ratings. The total number of normal, emergency, and load dump rating reductions for the three aforementioned facilities was 23 out of a possible 72. This violation involves the management practices of validation and verification. The entity determined one cause to be a data input error while using the Tool to calculate the ratings of new substation conductor types. The equations in the Tool were correct but an input value to one of the equations was entered in error. The user entered an incorrect value for the material properties of the same conductor types leading to an incorrect calculation of the conductivity of the conductor types. This error was compounded by the fact that the entity did not have a validation and verification control in place to verify that all input values were correct. That input error is a root cause of this violation.
Risk Assessment	This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this violation is that incorrect and inconsistent substation conductor ratings could negatively affect the reliable operation of the BPS by allowing inconsistent Facility Ratings to exist for an entity's solely and jointly owned facilities that could lead to equipment failure. The risk is increased because of the long multi-year duration of the violation but the risk is lessened (and not serious) because only one of the incorrect substation conductor ratings were the most limiting factor for these Facilities. (Historical data was gathered and verified against the most limiting rating of each Facility which had an overall Facility rating change. None of these Facilities experienced current flows at or above the updated overall rating of each Facility.) The changes that did result in a Facility Ratings change did not impact the load dump ratings at any ambient temperature set but did impact the normal and emergency ratings. Only 3% of the entity's BES Transmission Facilities were affected by this violation. Additionally, none of the

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Admits) O&P

Duquesne Light Company (Duquesne) – NCR00762 NOC-2615 $40,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2017018162	FAC-008-3	R6	Medium	Lower	4/28/2015 (when the first incorrect substation conductor rating was entered into the Tool)	7/31/2017 (Mitigation Plan completion)	Self-Report	7/31/2017	5/11/2018

	equipment changes were associated with Facilities which have Interconnection Reliability Operating Limits (IROLs). Lastly, ReliabilityFirst notes that no harm to BES Facilities occurred due to these errors. No harm is known to have occurred.
Mitigation	To mitigate this violation, the entity: 1) reviewed, validated, and implemented logic to the calculations within the Tool to reduce future data entry errors. A drop-down menu has been implemented in the Excel-based tool which will eliminate the need for the user to type in material parameters, such as conductivity, within the data entry page; 2) re-rated and peer reviewed all conductors with ratings calculated using the Tool and any changes were then updated in the Ratings Database; 3) updated the entity's Transmission Planning Manual to include the changes of all new conductor rating additions within the Tool that will require a peer review; and 4) developed a procedure to explain in detail how to use the Tool and correctly apply the entity's assumptions and the material properties.
Other Factors	ReliabilityFirst reviewed the entity's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. ReliabilityFirst considered certain aspects of the entity's compliance program and awarded mitigating credit. Although this violation contains a number of instances, the entity's compliance program still deserved mitigating credit because of the aggressive and thorough mitigation that the entity undertook and completed for this violation which is indicative of its strong compliance culture. In the past several years, the entity has made many improvements to its processes, procedures, and training which support its FAC-008 program. These enhancements have resulted in increased awareness and collaboration between groups as well as a more sustainable Facility Ratings process. (Duquesne estimates that the total cost of performing the extensive reviews and field inspections was approximately $296,000, which includes nearly $200,000 in equipment rental costs with the remaining costs associated with labor.) ReliabilityFirst recognizes that this violation is a remnant of the entity's less mature FAC-008 program and not an appropriate reflection of the entity's current FAC-008 practices. The entity's compliance program has significant support from its Board of Directors and Executive leadership. The entity's dedicated internal compliance program (Corporate Compliance) operates under the overall direction and guidance of the Vice President, Rates and Regulatory Affairs, General Counsel and Corporate Secretary who is a member of the executive leadership team and reports directly to the entity's President and Chief Executive Officer. Corporate Compliance provides an independent oversight and advisory function for the entity's internal compliance program and is the core of the entity's NERC and PJM compliance efforts. The Chief Compliance Officer is a key member of the entity's management team, and has full access to all officers and the Board of Directors, and provides periodic updates directly to the Audit Committee of the Board. The entity's senior management is active in compliance with NERC Reliability Standards, as evidenced by the entity Executive Compliance Committee's monthly meetings to review compliance matters and discuss any necessary changes to the entity's internal compliance program. Furthermore, the entity emphasizes compliance training for its employees that is customized based on job function and self-assessments to identify compliance issues. ReliabilityFirst considered the entity's cooperation during the Settlement Agreement process and awarded mitigating credit. The entity has been extremely cooperative throughout the entire enforcement process. The entity met and communicated with ReliabilityFirst on a regular basis, including monthly calls, to discuss the violation, the mitigation, and the status of mitigation. Throughout the enforcement process, the entity voluntarily provided ReliabilityFirst with an abundance of information regarding the violation in a manner that was detailed and timely. The entity also timely responded to requests for information with accurate and relevant information. The entity's cooperation is deserving of mitigating credit. ReliabilityFirst considered the entity's relevant FAC-008/FAC-009 compliance history in determining the penalty and disposition track. ReliabilityFirst considered entity's compliance history to be an aggravating factor in the penalty determination.

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Admits) O&P

Duquesne Light Company (Duquesne) – NCR00762 NOC-2615 $40,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2017018903	FAC-008-3	R6	Medium	Lower	8/13/2014 (when the corrected Facility Rating in the revision of the Clairton-West Mifflin (Z-14) circuit map was not communicated to Transmission Planning)	11/14/2017 (when the entity finished adjusting all of the necessary Facility Ratings)	Compliance Audit	3/31/2018	5/30/2018

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 21, 2017, the entity, as a Transmission Owner, discovered a violation with FAC-008-3 R6 identified during a Compliance Audit conducted from December 4, 2017 through December 13, 2017. Duquesne discovered an incorrect rating for a 138 kV circuit where a section of overhead 795 Aluminum Conductor Steel Reinforced (ACSR) 45/7 stranded conductor was not shown in Duquesne's circuit map, but was determined to be installed on that Facility upon a physical inspection. This was the result of the stranding of the conductor not being labeled. Duquesne also undertook a thorough extent of condition review as part of its mitigation for this violation and that extent of condition revealed only two other instances where the 795 ACSR overhead stranded conductor was mislabeled and the overall facility ratings were incorrect. More specifically, as background, during the Compliance Audit, the entity discovered that its Ratings Database was in error for the Clairton-West Mifflin (Z-14) 138kV circuit, where a section of overhead 795 ACSR 45/7 stranded conductor was not shown, but upon completion of a physical inspection, the entity determined to be installed on this Facility. (The entity utilizes two different stranding ratios for 795 ACSR - 45/7 and 26/7. These stranding ratios refer to the number of aluminum strands and number of steel strands which comprise the conductor. This is the only overhead transmission conductor where the entity uses multiple stranding ratios for the same conductor type. The 795 ACSR 26/7 conductor was utilized until the 1960s at which point the entity transitioned to the 795 ACSR 45/7 conductor. All recent construction has been with the 795 ACSR 45/7 conductor.) The error began in August of 2014. The entity had a procedure in place to notify Transmission Planning when updated transmission circuit maps were issued to make sure that Transmission Planning ensured that all of the updated maps were being used. The source documentation did not contain the appropriate amount of detailed stranding information to fully describe certain sections of overhead conductor. This led to incorrect equipment ratings within the Ratings Database. As such, Transmission Planning was not aware that a new circuit map had been issued. The new revision of the circuit map identified all the variations of 795 ACSR that are actually installed. After discovering this mistake, the entity updated its circuit map, and Transmission Planning conducted a new analysis which resulted in the entity reducing the overall Facility Rating for the Facility. The summer 95°F (35°C) continuous rating was reduced from 932 amperes (A) to 919A; a difference of 13A. The entity subsequently updated its Ratings Database and appropriate operational models on October 18, 2017. The entity operates 85 Bulk Electric System (BES) transmission circuits. This violation resulted in a reduction of the overall Facility Rating for three BES transmission circuits, which means that approximately 4% of the entity's BES transmission circuits were affected by this violation. The entity operates 108 solely and jointly owned bulk power system (BPS) Facilities which the entity defines as transmission circuits, transformers, reactors, and capacitor banks. As such, this violation resulted in a reduction of the overall Facility Rating for approximately 3% of the entity's solely and jointly owned BPS Facilities. This violation involves the management practice of asset and configuration management because the entity failed to include a section of overhead 795 ACSR stranded conductor in its ratings database. The entity did not have an effective control in place to ensure that all relevant conductors were included in its Ratings Database and then communicated to Transmission Planning. That lack of an effective control is a root cause of this violation.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this violation is that the incorrect rating for a 138 kV circuit could negatively affect the reliable operation of the BPS by allowing an inconsistent Facility Rating to exist for an entity's solely and jointly owned facilities, which could lead to equipment failure. The risk is increased because of the long multi-year duration of the violation, but the risk is lessened (and still minimal) because the change in rating on the 138 kV circuit was minimal: just 13 amperes. The rating changed from 932 amperes to 919 amperes. The other two ratings changes were also minimal. (After a reduction of 3 amperes to correct the rating, (a 0.3% change), the Dravosburg-Wilmerding (Z-76) 138 kV circuit historically did not exceed 52% of its new normal current rating. After a reduction of 3 amperes to correct the rating, (a 0.3% change), the Dravosburg-Wilmerding (Z-77) 138 kV circuit historically did not exceed 49% of its new normal current rating.) Additionally, the entity confirmed that during the violation, all impacted 138 kV lines were rarely heavily loaded so the potential for failure was correspondingly low. (In order to evaluate risk to the entity transmission system, the entity performed a comprehensive review of historical data to summarize the loading of potentially affected circuits under the most conservative assumption of conductor rating. Based on over eight million hourly measurements from the entity's PI historian from November 2010 to November 2018, for all of the applicable circuits, the seasonal peak load is below the limit of the Assumed Limiting Conductor and the seasonal average loading is below 50% of the normal rating, which indicates a low average utilization of these circuits.) No harm is known to have occurred.
Mitigation	To mitigate this violation, the entity:

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Admits) O&P

Duquesne Light Company (Duquesne) – NCR00762 NOC-2615 $40,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2017018903	FAC-008-3	R6	Medium	Lower	8/13/2014 (when the corrected Facility Rating in the revision of the Clairton-West Mifflin (Z-14) circuit map was not communicated to Transmission Planning)	11/14/2017 (when the entity finished adjusting all of the necessary Facility Ratings)	Compliance Audit	3/31/2018	5/30/2018

	1) conservatively chose to include the 795 ACSR 45/7 stranded conductor in the Ratings Database entry for Z-14, updated all of its operational models, and communicated the ratings reduction to PJM until the conductor could be field verified. (When the possible error was discovered, the entity took immediate action to perform an exhaustive search of its drawing repository to find supporting documentation [e.g., sag data sheets, construction drawings, etc.] that could verify the stranding of the installed 795 ACSR conductor. While the investigation was pending, the entity proactively updated the Facility Rating in the Database with the more conservative of the two possible rating sets for the 795 stranded conductors until the conductor type could be field verified. Although the difference in the rating sets was minimal, all operational models were updated and the ratings reduction was communicated to PJM.); 2) verified that the 795 ACSR 45/7 conductor was installed through a physical inspection and hand counting the number of outside strands; 3) reviewed each circuit map that has been updated since January 1, 2014, in order to confirm all circuit map revisions were appropriately incorporated into the Ratings Database since the review, and verified that the conductors shown on these circuit maps matched the equipment contained within the Ratings Database. This review did not result in any changes to the Ratings Database; and 4) identified all instances of 795 ACSR overhead conductor used on its transmission system. The entity completed this through a review of the circuit maps for each of the entity's 84 BPS circuits which contain an overhead or underground conductor. In order to prevent errors, each circuit map was independently reviewed by two separate engineers. Through this review, the entity identified 34 BPS Facilities which utilize either variation of the 795 ACSR conductor. (The entity has not used either version of the 795 ACSR conductor on any of its 345 kV circuits. The entity utilizes transmission voltages of 69 kV, 138 kV, and 345 kV.) For these 34 BPS Facilities, the entity engineers performed an exhaustive search of its drawing repository to locate drawings that document circuit changes and corroborated the conductor stranding shown in the Ratings Database. The review found 13 instances where sufficient drawing information could not be obtained to validate conductor type. Duquesne then scheduled Facility outages for each of the 13 Facilities in accordance with the PJM outage scheduling requirements and physically inspected the conductor in order to verify its type. As a precautionary measure, Duquesne proactively derated applicable Facilities to more conservative ratings in its operational models and communicated the ratings change to PJM until the inspections could be performed. (In order to reduce the risk to the BPS until these conductors have been field verified, Duquesne adjusted the ratings for these Facilities with the conservative approach to assume that the lower rated 795 ACSR 45/7 conductor is installed. The largest percentage reduction in ratings that would potentially be experienced by these Facilities is 2.3% (44A) for the summer 95°F (35°C) continuous rating. All available historical data was collected for the three circuits where the ratings could potentially decrease as well as for Z-14. The historical data for all four circuits reaches back to approximately 2010 and has shown that the reduced seasonal ratings for each Facility were not exceeded in that timeframe.) Of the 13 instances, seven Facilities did not result in a change to the Facility Rating or the Ratings Database, two Facilities did not result in a change to the Facility Rating but did require updates to the Ratings Database, three Facilities resulted in minor reductions to the Facility Rating as a result of an update to the Ratings Database, and one Facility resulted in minor increases to the Facility Rating as a result of an update to the Ratings Database; 5) adjusted the ratings for all four Facilities; and 6) reviewed and made improvements to its procedures related to the communication of changes to circuit map drawings. Specifically, the transmission circuit map notification procedure has been updated to formalize a distribution to communicate all circuit map revisions to internal stakeholders including the Transmission Planning group. Duquesne also provided all required notifications of these ratings changes to its Reliability Coordinator, Balancing Authority, and Transmission Operator.
Other Factors	ReliabilityFirst reviewed the entity's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. ReliabilityFirst considered certain aspects of the entity's compliance program and awarded mitigating credit. Although this violation contains a number of instances, the entity's compliance program still deserved mitigating credit because of the aggressive and thorough mitigation that the entity undertook and completed for this violation which is indicative of its strong compliance culture. In the past several years, the entity has made many improvements to its processes, procedures, and training which support its FAC-008 program. These enhancements have resulted in increased awareness and collaboration between groups as well as a more sustainable Facility Ratings process. (Duquesne estimates that the total cost of performing the extensive reviews and field inspections was approximately $296,000, which includes nearly $200,000 in equipment rental costs with the remaining costs associated with labor.) ReliabilityFirst recognizes that this violation is a remnant of the entity's less mature FAC-008 program and not an appropriate reflection of the entity's current FAC-008 practices. The entity's compliance program has significant support from its Board of Directors and Executive leadership. The entity's dedicated internal compliance program (Corporate Compliance) operates under the overall direction and guidance of the Vice President, Rates and Regulatory Affairs, General Counsel and Corporate Secretary who is a member of the executive leadership team and reports directly to the entity's President and Chief Executive Officer. Corporate Compliance provides an independent oversight and advisory function for the entity's internal compliance program and is the core of the entity's NERC and PJM compliance efforts. The Chief Compliance Officer is a key member of the entity's management team, and has full access to all officers and the Board of Directors, and provides periodic updates directly to the Audit Committee of the Board. The entity's senior management is active in compliance with NERC Reliability Standards, as evidenced by the entity Executive Compliance Committee's monthly meetings to review compliance matters and discuss any necessary changes to the entity's internal compliance program. Furthermore, the entity emphasizes compliance training for its employees that is customized based on job function and self-assessments to identify compliance issues.

Duquesne Light Company (Duquesne) – NCR00762 NOC-2615 $40,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2017018903	FAC-008-3	R6	Medium	Lower	8/13/2014 (when the corrected Facility Rating in the revision of the Clairton-West Mifflin (Z-14) circuit map was not communicated to Transmission Planning)	11/14/2017 (when the entity finished adjusting all of the necessary Facility Ratings)	Compliance Audit	3/31/2018	5/30/2018
			ReliabilityFirst considered the entity's cooperation during the Settlement Agreement process and awarded mitigating credit. The entity has been extremely cooperative throughout the entire enforcement process. The entity met and communicated with ReliabilityFirst on a regular basis, including monthly calls, to discuss the violation, the mitigation, and the status of mitigation. Throughout the enforcement process, the entity voluntarily provided ReliabilityFirst with an abundance of information regarding the violation in a manner that was detailed and timely. The entity also timely responded to requests for information with accurate and relevant information. The entity's cooperation is deserving of mitigating credit. ReliabilityFirst considered the entity's relevant FAC-008/FAC-009 compliance history in determining the penalty and disposition track. ReliabilityFirst considered entity's compliance history to be an aggravating factor in the penalty determination.					

FirstEnergy Utilities (FEU) – NCR11315 NOC-2613 $75,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2016015998	PRC-005-1b	R2	High	Lower	3/14/2012 (when the Standard became mandatory and enforceable on the entity)	12/29/2017 (Mitigation Plan completion)	Self-Report	12/29/2017	1/26/2018

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 8, 2016, the entity submitted a Self-Report to ReliabilityFirst stating that, as a Transmission Owner, it was in violation of PRC-005-1b R2. The entity discovered 154 out of 38,168 in-scope PRC-005 relays (0.4%) were outside of the entity's defined maintenance interval. The entity identified two separate contributing causes for the 154 instances. First, for 46 of the 154 relays, the entity discovered that, in its maintenance and testing Cascade Database, the relays were incorrectly part of the non-Bulk Electric System (BES) Maintenance Program, which has slightly longer intervals than required by its BES program under PRC-005 (six years). The entity discovered this as a result of preparation for PRC-005-2 and PRC-005-6 implementation. Of the 46 relays that were part of the non-BES Maintenance Program, 37 were maintained within seven years, 6 were maintained within eight years, and 3 were maintained within nine years or more. Second, for the remaining 108 relays out of the 154 relays, the entity discovered that those relays were not in its maintenance and testing Cascade Database at all and were thus missing records to show that these 108 relays were maintained and tested. The entity found all 108 of the missing relays during the completion of mitigating activities that included reviewing station diagrams at BES locations to identify PRC-005 relays that were missing from the Cascade Database. These relays were older relays that never made it into the Cascade Database. Additionally, there was one battery/charger at a new substation that was not entered into the Cascade Database in a timely manner and, therefore, orders for maintenance on that battery/charger were delayed. This violation involves the management practices of asset and configuration management, verification, and validation. The root cause of the overdue maintenance was twofold. First, the entity failed to enter all of the required relay schemes into the Cascade Database for tracking purposes, which reveals ineffective asset and configuration management and ineffective verification and validation controls to ensure that all relays were properly entered into the Cascade Database. Second, the process for data entry into the Cascade Database was de-centralized across several entity operating companies rather than being centrally managed which made verification and validation difficult.
Risk Assessment	This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this violation is the loss of equipment or facilities due to misoperation of the protection system equipment where the relay schemes were not maintained and tested in a timely manner. The risk is not minimal because of the number of devices at issue (154 relays) and the relatively long duration for the 108 relays for which the entity lacked testing and maintenance records. (The entity identified two applicable relays at issue that were part of an Interconnection Reliability Operating Limit (IROL). One relay is microprocessor-based and contains self-monitoring which will send relay failure alarms back to the Control Center. Therefore, if an issue were identified, a corrective action would have been taken. Additionally, this line has backup relaying that was maintained. The second relay was found to be within tolerance when tested and there are multiple overlapping relays that were maintained as well and those overlapping relays would act in case of a breaker failure to trip on that second relay thereby reducing the risk. For these reasons, while two relays were part of an IROL, additional and overlapping measures were in place to maintain reliability.) The risk is not serious because this violation involved less than half of one percent of the entity's in-scope PRC-005 relays. Additionally, of the 154 relays at issue, 46 were part of the entity's non-BES Maintenance Program and thus were tested between only one and three years later than the required six-year interval. Specifically, 37 were tested only one year late, 6 were tested two years late, and 3 were tested three years late. Of the 108 relays that were not in the Cascade Database, 64 are microprocessor-based and contain self-monitoring (which will send relay failure alarms back to the Control Center if a failure occurs) and 10 had backup relays that would function in case the primary relay failed. For the one new battery/charger at a new substation that was not entered into the entity's database in a timely manner, the battery/charger was being monitored via low-voltage alarm and the entity performed periodic checks on the battery/charger during routine station inspections. Accordingly, the violation posed a moderate risk to the reliability of the bulk power system. No harm is known to have occurred.
Mitigation	The entity had already maintained and tested all but one relay scheme by the time the entity discovered all of the issues. The entity issued a maintenance and testing order for the remaining relay scheme and confirmed that work was completed as of April 7, 2016. For every issue, the entity made the appropriate modifications to the Cascade Database by August 8, 2016, to ensure that the equipment is correctly scheduled for future maintenance per the entity's PRC-005 PSMP. The entity's mitigating actions directly address the root causes of this violation. First, the entity conducted an extensive review to ensure all relay schemes are appropriately "flagged" in the Cascade Database as being part of the BES Protection System Maintenance Program. (To identify existing equipment potentially in scope of PRC-005 that is missing in Cascade, the entity established a project with dedicated resources to review about 790 substations. The entity re-reviewed the 79 CIP Medium substations that are part of the Bar Coding initiative. In addition, the entity will review approximately 710 additional substations located in its entity-East and entity-West operating areas. For those substations with equipment in scope of PRC-005, the entity will compare substation protective equipment

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	drawings against Cascade records to identify data integrity issues. Substations in the entity's other operating area, entity-South (former Allegheny Power), are not included in this mitigating activity because these locations are considered low risk based on a documented substation inventory walk-down completed in 2010 as part of a formal Mitigation Plan (Docket # RFC201000237). The entity has prioritized this work based on risk to its BES transmission system. Top priority is 230 kV and higher substations and secondary priority is remaining BES substations. These activities have a target completion date of March 31, 2019.) Second, the entity has taken steps to ensure that all new equipment is entered into the Cascade Database upon installation. (First, the "Pre-Energization Checklist," effective May 1, 2016, requires that Project Managers verify that all appropriate equipment has been entered into Cascade. Second, the "New Equipment Entry Process," effective October 10, 2016, ensures that a substation equipment list is generated by the Substation Design group for all projects and that the list is integrated with the BES Flag review conducted by the entity Protection group. The Asset Management and Records Control department then enters the equipment into Cascade. As an additional post-energization control to ensure all newly installed substation assets have been properly recorded in Cascade, the entity implemented a new monthly detective control. The detective control will confirm that all assets reflected as in-serviced in the entity's financial database ("Power Plant") are correctly recorded in the Cascade Database.) The entity has historically employed a de-centralized method for data entry of substation equipment into the Cascade Database. To improve data consistency and integrity, the entity centralized Cascade Database equipment entry within a recently formed corporate department - Asset Management & Records Control (AMRC). In addition, the entity has implemented two new control processes related to new construction and equipment additions at substations and will be implementing an additional control to better ensure new equipment is timely entered into the Cascade Database prior to energization. To mitigate this violation, the entity: 1) reviewed the missing equipment for its CIP Medium and Tier 1 substations; 2) did an extent of condition on 100% of its Tier II substations; 3) implemented a detective control to ensure that the database includes all BES equipment; and 4) reviewed Cascade Database "flags" for a need to shift from the entity's non-BES maintenance program to its PRC-005 Protection System Maintenance Program (PSMP). The entity's mitigating actions will achieve greater assurance regarding the accuracy of the PRC-005 records residing in the Cascade Database. The mitigation actions identified missing protective equipment devices relied upon for BPS reliability and ensured they are properly scheduled as required by the entity PRC-005 PSMP. The mitigation actions also established both detective and preventive internal controls to better position the entity for ongoing accuracy of the records in the Cascade Database.
Other Factors	The Settlement Agreement through which this violation was resolved included two violations, and the factors affecting the penalty determination were considered in relation to both violations together as opposed to each individual violation. ReliabilityFirst reviewed the entity's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. Although both violations contain multiple instances, the entity's compliance program still deserved mitigating credit because of the controls that allowed it to identify the first issue and the entity's aggressive and thorough mitigation that the entity undertook and completed for both violations. The parent company of the entity has a robust internal compliance program that is managed by its FERC Compliance Department (FCD), which has corporate oversight responsibilities and is independent from the business units that are responsible for complying with the NERC Reliability Standards. Corporate Business Unit "Compliance Champions" assist FCD with monitoring activities that encourage opportunities to increase reliability. FCD is responsible for tracking and communicating new and updated Reliability Standards to Corporate Business Unit Compliance Champions and their management. All Reliability Standard action items are recorded and tracked via the entity's compliance software. FCD monitors action items and conducts follow-up meetings as needed. FCD created a Director Dashboard which tracks new Reliability Standards or changes to existing Standards and associated action items. The Director Dashboard is communicated bi-monthly to the entity's Executive Leadership Team, directors, managers, and Compliance Champions. Action items are given priorities with Regulatory deadlines and milestones given the highest level of Critical Compliance that includes VP notification 30 days prior to due date. Effective oversight of the reliability of the BES depends on robust and timely self-reporting by Registered Entities. The entity promptly identified and reported the violation due to the effective execution of its compliance program and the installation of internal controls that yielded identification of the issues prior to the occurrence of any harm. Therefore, ReliabilityFirst awarded some mitigating credit to the entity. ReliabilityFirst considered the entity's cooperation during the Settlement Agreement process and awarded mitigating credit. The entity has been cooperative throughout the entire enforcement process. Following the Self-Reports, the entity met and communicated with ReliabilityFirst on a regular basis, including multiple in-person meetings onsite at ReliabilityFirst to discuss the violations, the mitigation, and the status of mitigation. Throughout the enforcement process, the entity voluntarily provided ReliabilityFirst with an abundance of information regarding the violations in a manner that was detailed and timely. The entity is also in the process of constructing a new Center for Advanced Energy Technology (CAET) facility. This facility will allow for the introduction of new technology to the entity Transmission substation environment, will aid in the connectivity to the field devices, and improve data acquisition. The entity expects the facility to be operational by March 31, 2019.

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Stipulates)

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	Lastly, the entity is installing an Operational Technology Configuration Management (OTCM) Database to manage all configurable devices and configuration files. Previously, the relay setting system was a standalone tool and not connected to any devices in the field, and configurations of non-relay devices were managed locally. This tool is being integrated with the entity's maintenance and testing Cascade Database for consistency and workflow management. The entity is phasing the rollout of these systems and processes across the entity's operating companies beginning in the 4th quarter of 2018 with a targeted completion date in 2019. (The entity estimated the total cost to implement corrective actions and preventive measures for RFC2016015998, RFC2017017902, and related NERC Standards at $78.8 million: Substation walkdowns (includes inventory, barcoding, etc.) = $47.3 Million; Drawing review – compared substation one-line diagrams with Cascade equipment files = $1.65 Million; OTCM Project = $29.4 Million; and Internal labor spent on mitigating activities = $400k.) ReliabilityFirst considered the entity's compliance history in determining the penalty. ReliabilityFirst considered the entity's compliance history to be an aggravating factor in the penalty determination.		

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Stipulates)

FirstEnergy Utilities (FEU) – NCR11315 NOC-2613 $75,000

NERC Violation ID	Reliability Standard	Req.	Violation Risk Factor	Violation Severity Level	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date	Date Regional Entity Verified Completion of Mitigation
RFC2017017902	PRC-005-6	R3	High	Severe	4/2/2017 (when the Standard became mandatory and enforceable on the entity)	6/1/2018 (Mitigation Plan completion)	Self-Report	6/1/2018	6/18/2018

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 30, 2017, the entity submitted a Self-Report to ReliabilityFirst stating that, as a Transmission Owner, it was in violation of PRC-005-6 R3. The entity identified this violation through the PRC-005-3(i) Guided Self Certification process in 2017. The entity discovered that it was incorrectly determining battery performance maintenance by utilizing the average of the string of the battery cell's internal ohmic value to compare to the individual cells rather than using the individual baseline for each battery as specified in the PRC-005-6 R3, Table 1-4(a) - 18 Calendar Months Maintenance Interval. This affected 441 out of 715 in-scope PRC-005 batteries (62%). (When 10% or more of the cells indicated an impedance variation of greater than 20% of the entire string, then further testing would be done to determine if battery replacement was needed. This battery replacement strategy resulted in the installation and replacement of more than 70 Bulk Electric System batteries and chargers ($1.5 million); an additional $1.5 million was spent on working and closing over 5,000 corrective maintenance and preventative maintenance orders over an 18 months period, prior to the Self-Report.) After identifying the violation, the entity performed the correct tests per PRC-005-6 R3 and did not identify any additional battery banks that needed to be replaced. Although the entity was not previously applying the tests using the individual battery baselines across its footprint, the entity's testing method yielded similar results to comparing against battery baselines as required in PRC-005. The entity conducted an investigation to determine how this violation occurred. In 2014 and 2016, the entity added instructions to record the initial average battery baseline impedance as measured 6 to 12 months after a new set of batteries had been installed to two different procedures. Due to an inconsistent implementation of this new maintenance strategy, however, most of the entity's operating companies incorrectly continued to utilize the average of the string of battery cell's internal ohmic value to compare to the individual cells. This violation involves the management practices of work management and validation as the entity failed to validate that its new maintenance strategy for determining battery performance maintenance was consistently implemented across the entity operating companies. That inconsistent implementation across the entity is a root cause.
Risk Assessment	This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. Comparing each battery's measurements every 18 months to the initial baseline helps entities establish deviations as a predictor of age, wear, etc., which would reduce the risk of unexpected battery malfunctions due to those factors. This risk was mitigated in this case by the fact that, although the entity's testing practices were not in strict compliance with the Standard (because the entity was incorrectly determining battery performance maintenance by utilizing the average of the string of the battery cell's internal ohmic value to compare to the individual cells rather than using the battery baseline), the entity was timely performing maintenance and testing on its batteries in a way to maximize battery performance. After the entity established the battery baselines per PRC-005 and compared to testing results, the entity did not identify any additional battery banks that needed to be replaced. (The entity identified 21 applicable lines and two applicable transformers that were part of an Interconnection Reliability Operating Limit (IROL) that utilized batteries at issue in this noncompliance. After the battery baseline was established per PRC-005 and compared to testing results, the entity did not identify any additional battery banks that needed to be replaced. As of June 1, 2018, PJM has removed 14 of the applicable lines and the two applicable transformers as IROL Facilities. Based on the current PJM defined IROLs, only seven applicable lines utilized batteries at issue in this noncompliance.) Although the entity was not comparing to battery baselines across its footprint, the entity's method yielded similar results to comparing against battery baselines as required in PRC-005. (ReliabilityFirst notes that the entity has an established battery replacement strategy that has replaced over 90 battery systems and has worked nearly 1070 Corrective Maintenance orders on batteries over the past 18 months.) No harm is known to have occurred.
Mitigation	To mitigate this violation, the entity: 1) updated the Methods Section 16M testing procedure to incorporate evaluation of the test data to the established baseline impedance. This activity ensures that qualified field technicians will have proper instructions on evaluating battery baseline impedance; 2) has determined baseline impedances for all existing batteries. This activity ensures that all batteries older than 12 months have an established baseline; 3) has created a detective control that will be performed annually to record the average battery impedance of batteries that are between 6 and 15 months old. This activity ensures newer batteries have a recorded baseline; 4) has performed an extent of condition to determine the list of batteries that need to be evaluated against their baseline impedance. This activity ensures that all batteries required per PRC-005-6 R3, Table 1-4(a) are included in the list to be mitigated; 5) developed an instructor-led training module; 6) conducted training on the updated testing procedure for field technicians qualified for battery testing; and 7) collected in-scope battery test data through June 1, 2018 and evaluated results against baseline impedance.

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Stipulates)

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	The entity's mitigating actions implemented process improvements that will ensure qualified field technicians will have proper instructions on evaluating battery baseline impedance; baseline determination to ensure that all batteries older than 12 months have an established baseline; annual baseline updates to ensure newer batteries have a recorded baseline; and training to ensure the reinforcement of the new testing method.
Other Factors	The Settlement Agreement through which this violation was resolved included two violations, and the factors affecting the penalty determination were considered in relation to both violations together as opposed to each individual violation. ReliabilityFirst reviewed the entity's internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. Although both violations contain multiple instances, the entity's compliance program still deserved mitigating credit because of the controls that allowed it to identify the first issue and the entity's aggressive and thorough mitigation that the entity undertook and completed for both violations. The parent company of the entity, has a robust internal compliance program that is managed by its FERC Compliance Department (FCD), which has corporate oversight responsibilities and is independent from the business units that are responsible for complying with the NERC Reliability Standards. Corporate Business Unit "Compliance Champions" assist FCD with monitoring activities that encourage opportunities to increase reliability. FCD is responsible for tracking and communicating new and updated Reliability Standards to Corporate Business Unit Compliance Champions and their management. All Reliability Standard action items are recorded and tracked via the entity's compliance software. FCD monitors action items and conducts follow-up meetings as needed. FCD created a Director Dashboard which tracks new Reliability Standards or changes to existing Standards and associated action items. The Director Dashboard is communicated bi-monthly to the entity's Executive Leadership Team, directors, managers, and Compliance Champions. Action items are given priorities with Regulatory deadlines and milestones given the highest level of Critical Compliance that includes VP notification 30 days prior to due date. ReliabilityFirst considered the entity's cooperation during the Settlement Agreement process and awarded mitigating credit. The entity has been cooperative throughout the entire enforcement process. Following the Self-Reports, the entity met and communicated with ReliabilityFirst on a regular basis, including multiple in-person meetings onsite at ReliabilityFirst, to discuss the violations, the mitigation, and the status of mitigation. Throughout the enforcement process, the entity voluntarily provided ReliabilityFirst with an abundance of information regarding the violations in a manner that was detailed and timely. ReliabilityFirst considered the entity's compliance history in determining the penalty. ReliabilityFirst considered the entity's compliance history to be an aggravating factor in the penalty determination.