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
NPCC2017017379	PRC-005-1.1b	R2.; 2.1	High	Lower	12/5/2014	Present	Self-Report	9/30/2020 (approved completion date)	TBD

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 7, 2017, Exelon Nuclear submitted a Self-Report stating, as a Generator Owner (GO), it was in violation of PRC-005-1.1b R2. (R2.1.). Following extent of condition reviews, Exelon Nuclear updated its Self-Report on August 11, 2017, January 24, 2018, and October 1, 2018. Exelon Nuclear did not perform testing in accordance with its Protection System Maintenance Program ("PSMP") for: (a) Thirteen (13) out of 111 Current Transformers (CTs) and nine (9) out of 150 sections of DC control circuitry at the R.E Ginna Nuclear Power Plant (Ginna). Specifically, this included (i) two (2) sets of the three-phase CTs (six (6) total CTs) that are associated with the 4kV side of the 19/4kV auxiliary transformer differential relay. The auxiliary transformer is directly connected to the main generator and the 19/115kV step up transformer. (The 19kV side CT set associated with the differential relay was tested in accordance with Exelon's PSMP). (ii) Two (2) other sets of three-phase CTs (six (6) total CTs) associated with the generator differential relay. One (1) set of CTs is at the neutral terminals of the main generator, and the other set is at the line terminals of the main generator. (iii) One (1) single phase CT associated with a generator backup directional distance relay for remote transmission faults. It also included (iv) seven (7) sections of DC control circuitry that terminate at Ginna owned breaker trip coils that come from the Transmission Owner breaker backup relays associated with off-site power supply to Ginna. (v) One (1) section of DC control circuitry that terminates at one of the two Ginna output breaker trip coils that come from Transmission Owner breaker backup relays associated with off-site power supply to Ginna. (vi) one (1) section of DC control circuitry from the breaker backup relay to the trip coil of a downstream Ginna breaker that would be sent a signal to open if the particular Ginna output breaker fails to trip when called upon (associated with one of the two Ginna output breakers). (b) Fifty-two (52) out of 372 sections of DC control circuitry and one (1) out of 180 relays at Nine Mile Point Nuclear Station, Units 1 (NMP1). Specifically, this included (i) fourteen (14) sections of the DC control circuitry that terminate at breaker trip coils that are associated with the primary breaker backup protection and the secondary breaker backup protection associated with the two NMP1 output breakers. (ii) Fifteen (15) sections of the DC control circuitry that terminate at breaker trip coils associated with one of the two routes of redundant protection schemes on two (2) - 115kV Transmission Owner lines that provide offsite power to NMP1. (iii) Twenty (20) sections of the DC control circuitry that terminate at breaker trips coils that are associated with redundant differential protection on each of the two (2) transformers that provide off-site power to NMP1 from the two (2) 115kV Transmission Owner lines, (iv) three (3) sections of DC control circuitry associated with a main generator exciter volts/hertz protective relay to the lockout relay and (v) one (1) backup generator undervoltage protection relay that trips one of the two NMP1 output breakers. (c) Nineteen (19) out of 372 sections of DC control circuitry at its Nine Mile Point Nuclear Station, Units 2 (NMP2). Specifically, this included (i) sixteen (16) sections of DC control circuitry that terminate at various Transmission Owner breaker trip coils that are associated with the redundant differential protection schemes on each of the 345/138 kV transformers that provide off-site power to NMP2 from the Transmission Owner's system and (ii) three (3) sections of DC control circuitry between the generator exciter Volts/Hertz relay and the multi-purpose lockout relay. (d) Forty-three (43) out of 150 sensing devices, thirteen relays, eight sudden pressure relays, and four associated pressure sensors at its Jame A. FitzPatrick Nuclear Power Plant (FitzPatrick). Specifically, this included (i) six (6) sensing devices (four (4) Potential Transformers (PTs), one (1) CT)1 and one (1) neutral transformer) associated with generator volts per hertz protection and the generator stator ground fault protection (neutral overcurrent and neutral overvoltage). (ii) twelve (12) CTs (4 CTs with 3 phases each) associated with Main Generator Exciter differential protection. (iii) Three (3) CTs on the high-voltage (HV) bushing of the Station Auxiliary Transformer (SAT) differential relay, (iv) three (3) CTs also on the HV side bushings of the SAT that feed an instantaneous/time overcurrent relay (v) fifteen (15) CTs on the low side (4.16 kV) of the SAT that also feed the SAT differential relay, (vi) two (2) CTs on the X and Y winding neutrals that feed neutral overcurrent relays. (vii) two (2) Main Power Transformer neutral CTs that feed the overcurrent relay for the "A" and "B" Main Power Transformers. These relays provide backup protection for system faults. (viii) thirteen (13) relays associated with an overcurrent protective scheme on the 115 kV system. (ix) eight (8) sudden pressure relays and four (4) associated pressure sensors that support one of the two main power transformers. NPCC determined that the overall root cause of the violation at Ginna, NMP1, and NMP2 was the lack of proper management oversight and attention to detail in the implementation of the Exelon PSMP as the ERO was transitioning from PRC-005-1b to PRC-005-2/6. A contributing factor was that Exelon became the GO and Generator Operator ("GOP") in December 2014 for the three units and there was the need to reconcile the maintenance that was completed by the previous GO with the incoming Exelon PSMP. As such, much of the testing that was not completed was inherited by Exelon. However, there were some aspects of the missed testing that could have been performed after the acquisition had the Exelon Nuclear PSMP not lacked clarity for the performance of those specific maintenance/test activities.

	At Ginna, NMP1, and NMP2, the duration of the violation is approximately 4 years spanning from December 5, 2014 (effective date of the Exelon Nuclear GO registration for those 3 sites) to December 12, 2018. NPCC determined that the root cause of the violation at FitzPatrick was the lack of proper implementation and documentation of the PRC-005 program by the previous plant owner. The previous owner announced in 2015 that the plant would close in January 2017. On the March 31, 2017 effective date of Exelon Nuclear being registered as the GO/GOP/TO for the plant, the violations already existed. However, Exelon Nuclear also performed a line-by-line walk down of FitzPatrick PSMP components during the September 2018 refueling outage and failed to identify two (2) DC circuitry components that now cannot be tested until the unit is offline for the Fall 2020 refueling outage. Otherwise, all PRC-005 testing and documentation would have been in place at FitzPatrick at the conclusion of the September 2018 outage. At FitzPatrick, the violation start date is March 31, 2017 (effective date of GO registration) and the end date will be September 30, 2020 when the two (2) DC circuitry components are tested during the refueling outage.
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 uncompleted maintenance affected four generating units with an aggregate nameplate rating of approximately 3,375 MW. The failure to maintain and test the affected components could have caused the Protection System to either misoperate or fail to operate. Under certain conditions, this could cause the generating units to either trip offline unnecessarily, operate in an unstable manner potentially leading to cascading outages under stressed system conditions, and/or cause the nuclear site to exceed its Technical Specification for off-site power where a controlled plant shutdown would be initiated. The Points of Interconnection (POIs) to the BES of the four generating units are in close electrical proximity to one another and in the same generation corridor. In particular, NMP1 and 2 are part of the Oswego Generation Complex, which is listed by the New York Independent System Operator (NYISO) as a stability-constrained Interconnection Reliability Operating Limit (IROL) interface in the New York Control Area. If the violation had caused the loss of all of Exelon Nuclear's generating capacity during a system event, the aggregate capacity of the four non-compliant generators significantly exceeds the current NYISO daily Operating Reserve of 1,965 MW. However, this would be a highly improbable situation as the overall redundancy associated with the overwhelming majority of the unmaintained aspects of the relay protection systems (e.g. DC wiring associated with the breaker backup relays and redundant transmission line protective relaying) and the other tests performed by Exelon Nuclear that indirectly provided some indication of the functionality of the unmaintained equipment reduced the probability of a misoperation and reduced the risk to the BPS. No harm is known to have occurred as a result of this violation.
Mitigation	To mitigate this violation, Exelon Nuclear: 1. completed the maintenance activities at Ginna, NMP1, NMP2 and most of the maintenance activities at FitzPatrick,with the exception of two DC circuitry components associated with relays. 2. performed a line-by-line Protection System component review of all four units to ensure that all activities listed apply to each component listed in the PRC-005 matrix, that all information is aligned to the work control system codes, and that all procedure descriptions are accurate. 3. revised its PSMP procedure to more clearly identify the exciter DC circuitry as being included in the PSMP. Although the procedure already included the exciter DC circuitry, specific references within an addendum were clarified to prevent any possible confusion in the future. 4. developed new site-specific procedures for each of the four generating units that each individual site will have revision and content control over. The PRC-005 matrix for each unit within the procedures was independently reviewed and verified by a contracted third-party engineering firm to ensure that all protection system components were appropriately scoped within Exelon Nuclear's PRC-005 program. 5. reviewed all governance documents to ensure that adequate prompts and barriers are in place to ensure PRC-005 implications are evaluated for any change. 6. conducted awareness briefings to the Ginna, NMP, and FitzPatrick Site Leadership Teams on the importance of the proper execution and challenge of PRC-005 related maintenance, testing, and scoping. 7. performed a formal benchmarking of a recommended PRC-005 program at another Nuclear GO/GOP to identify lessons learned and best practices. To mitigate this violation, Exelon Nuclear will 1. Compete the maintenance activities for two DC Circuits at the FitzPatrick unit during the next refueling outage.
Other Factors	NPCC considered that Exelon Nuclear self-reported this violation and awarded some mitigating credit for self-reporting. NPCC reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. NPCC considered Exelon Nuclear's compliance history and determined that there is a prior relevant instance of affiliate noncompliance in NPCC and NPCC considered that prior noncompliance to be an aggravating factor in the penalty determination.

	In determining the penalty, NPCC concluded that despite some aspects of the missed testing that could have been performed after the acquisition of the New York plants, much of the testing that was identified and found to be incomplete was inherited by Exelon Nuclear. This circumstance limits the aggravation of Exelon Nuclear's previous compliance history. As a non-monetary sanction, ReliabilityFirst and NPCC will conduct a spot check of Exelon Nuclear in the summer of 2021 to evaluate Exelon Nuclear's ongoing compliance with PRC-005-6 R2.

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
RFC2018019546	PRC-005-1.1b	R2; 2.1	High	Lower	1/1/2015 (the date Exelon Nuclear missed its first required maintenance and testing activity)	12/18/2019 (Mitigation Plan completion)	Self-Report	12/18/2019	4/15/2020

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 5, 2018, Exelon Nuclear submitted a Self-Report to ReliabilityFirst stating that, as a Generator Owner (GO), it was in violation of PRC-005-1.1b R2.

During an extent of condition review, which was performed across the Exelon Nuclear fleet, and the results of which were addressed in mitigation for RFC2016015585, Exelon Nuclear discovered that the procedure section for the Byron Station Unit 1 Unit Auxiliary Transformer (UAT) 141-1 differential relay sensing circuit testing was marked as "not applicable," which indicates that testing was not performed when initially scheduled. The implementation procedure at Byron Station requires sensing circuit testing for the Protection System to be performed once each refueling cycle (typically every 18 months). However, Exelon Nuclear's procedure permits an extension of that interval by processing a deferral when based on documented justification (e.g., for personnel safety reasons). In this case, the procedure requires the station to generate an "Issue Report" to document that the sensing circuit testing could not be performed and to track the incomplete portion of the testing to ensure completion at a later date within the interval or to process a deferral as necessary. The entity should have generated an Issue Report to document that, on the scheduled day of the testing, the sensing circuit testing could not be performed due to the electrical line-up (i.e., the circuit was energized and therefore due to safety concerns the testing could not be executed). The Issue Report, if written, would have tracked either rescheduling the testing within the defined testing interval or initiating a deferral of the testing per the PRC-005-1.1b program.

In this case, Byron Station did not generate an Issue Report as required per Exelon Nuclear's procedure. (If a deferral had been processed, the incomplete testing would have been justified based on the electrical line-up and the safety concerns listed above.) As such, the testing was not rescheduled and a deferral was not processed.

After discovering the issue at Byron Station Unit 1, Exelon Nuclear continued performing its PRC-005 extent of condition review and identified the following additional instances when testing was not completed at eight additional nuclear units in RF (at the time of the extent of condition review, Exelon Nuclear had 18 nuclear units under the NERC Registration (NCR00778) in the RF Region):

(a) Byron Station (Unit 1) (i) UAT 141-2 CTs associated with the Differential Relay (2015 Refueling Outage (RFO)) were not tested (12 Current Transformers (CTs) - CT testing was not completed due to personnel safety concerns, but an Issue Report was not generated. (ii) UAT 141-1 CTs associated with the Differential Relay (2017 RFO) were not tested (12 CTs) due to personnel safety concerns, but an Issue Report was not generated. (iii) UAT 141-2 CTs associated with the Differential Relay (2017 RFO) were not tested (12 CTs) due to personnel safety concerns, but an Issue Report was not generated.

(b) Dresden (Units 2 and 3) (i) Six instances of missed sensing device (CTs) testing associated with auxiliary transformers due to not using a tracking mechanism to reschedule the testing or process a deferral. (ii) One instance of missed sensing device (CT) testing associated with generator protection due to procedure step omission. (iii) One instance of missed DC circuitry trip testing due to procedure step omission.

(c) Three Mile Island (Unit 1) (Exelon Nuclear permanently shut down Three Mile Island Unit 1 on September 20, 2019 and removed that unit from the NERC Registration for Exelon Nuclear (NCR00778) on October 11, 2019. The shutdown of this unit mitigates the issue identified at Three Mile Island Unit 1.) (i) Testing of the DC circuit paths for the main generator output breakers' (GB1-02 and GB1-12) failure scheme did not include the wiring continuity from one output breaker's failure lockout contacts to the primary and back-up trip coils of the other output breaker due to unclear and ineffective testing procedures. (The purpose of the breaker failure scheme is to trip all surrounding breakers should a breaker fail to open due to a fault somewhere in the system or due to a fault with the breaker itself which still allows current flow.)

(d) LaSalle Station (Units 1 and 2) (i) Two instances where relays were not functionally tested due to an omission of a procedure step. (ii) Four instances of missed DC circuity testing due to an omission of a procedure step. (iii) Missed sensing device testing on four Main Power Transformer (MPTs) high voltage neutral CTs and CTs providing input to Auxiliary Transformers (SAT and UAT) differential current protective relays due to an omission of a procedure step.

(e) Oyster Creek (Exelon Nuclear permanently shut down Oyster Creek on September 17, 2018 and removed that unit from NERC Registration for Exelon Nuclear (NCR00778) on November 16, 2018. The shutdown of this unit mitigates the issue identified at Oyster Creek.) (i) One protective relay function of the Digital Protective Relay System "A" (DPRS-A) was not specifically tested during performance of the maintenance activity due to unclear and ineffective testing procedures. The protective function is the Accidental Energization (50AE) microprocessor protective relay.

(f) Limerick Generation Station (Units 1 and 2) (i) Power load unbalance relays 86-RLY-386-PLUA and 86-RLY-386-PLUB for both units were not specifically tested during performance of the maintenance activity prior to 2014 (Unit 1) and 2015 (Unit 2) due to unclear and ineffective testing procedures. The Limerick review identified that prior to a modification being installed in 2014 (Unit 1) and 2015 (Unit 2) no records could be identified clearly documenting that these power load unbalance relays picked up at appropriate electrical input levels.

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
RFC2018019546	PRC-005-1.1b	R2; 2.1	High	Lower	1/1/2015 (the date Exelon Nuclear missed its first required maintenance and testing activity)	12/18/2019 (Mitigation Plan completion)	Self-Report	12/18/2019	4/15/2020

	RF determined that this violation involves the management practices of work management and verification. RF considers Exelon Nuclear's work procedures for maintaining and testing Protection System devices to be complicated and finds that these complicated work procedures led to missed or overdue maintenance and testing. RF identified those complicated and unclear work procedures as the root cause of this violation. Exelon Nuclear also did not have an effective verification control in place to ensure that all maintenance and testing for Protection System devices was timely and properly completed and documented.
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 not timely maintaining and testing Protection System devices could negatively impact the BPS by, for example, causing the unit to trip. The risk is not minimal because of the long multiyear duration of this violation and Exelon Nuclear's compliance history with PRC-005, addressed below. For each of the station's instances identified, an evaluation of the potential risk of impact to the BPS was provided. Exelon Nuclear timely completed all relay calibrations and associated sensing device testing for the above listed relays per its PRC-005-1.1b program. Lastly, during the violation, there were no internal transformer faults or fault conditions on any associated wiring that would have challenged the function of the differential circuit.
Mitigation	Exelon Nuclear remediated all of the instances described above in (a) through (f) by completing all required testing for all instances of missed testing identified by the extent of condition through a phased testing approach based on individual Unit refueling outage schedules. To prevent recurrence, Exelon Nuclear performed the following actions: 1) conducted a two-day workshop with each station to present lessons learned and provide instructions to the stations on how to perform 100% review activities in a consistent manner; 2) conducted a management briefing and engagement presentation; 3) completed a 100% review of PRC-005 activities for protective relays, sensing devices, DC circuity, and communication systems across the fleet including reporting to RF any instances of potential non-compliance identified. (Exelon Nuclear performed an extensive review across its fleet that includes 100% review of the implementing documents that identify the maintenance activities for the testing required under PRC-005 (all versions). The review also included 100% verification of the last two completed maintenance activity records to ensure all components under the scope of PRC-005 were tested and activities completed in accordance with the applicable PRC-005 maintenance and testing program (PRC-005.1.1b and/or PRC-005-2/6). These reviews included an independent 100% verification by a separate individual. In addition, Exelon Nuclear is implementing proactive quarterly reporting. The actions associated with 100% verification of scope and implementing documents together with proactive reporting will reduce the probability of any further violations of PRC-005-1.1b or PRC-005-6 in the future. For each of the instances associated with missed testing of Sensing Circuits, performing the requirements of PRC-005-6 Table 1-3 will supersede the PRC-005-1.1b testing at issue (e.g., lamping) and therefore reduces the likelihood of a repeat violation.); 4) generated tracking items for fleet-wide Engineering NERC reporting to include verification and status of PRC-005 maintenance and testing activities for protective relays, sensing devices, DC circuity and communication systems and status of PRC-005-6 percentage implementation.
Other Factors	RF considered that Exelon Nuclear self-reported this violation and awarded some mitigating credit for self-reporting. RF reviewed the entity's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. RF considered Exelon Nuclear's compliance history and determined there is a prior relevant instance of noncompliance in RF and RF considered that prior noncompliance to be an aggravating factor in the penalty determination. As a non-monetary sanction, ReliabilityFirst and NPCC will conduct a spot check of Exelon Nuclear in the summer of 2021 to evaluate Exelon Nuclear's ongoing compliance with PRC-005-6 R2

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
WECC2017017872	COM-002-4	R5	High	Moderate	12/8/2016 (when PGE did not confirm the receiver's response nor repeat the Operating Instruction, related to five calls during an EEA)	12/8/2016 (when the EEA ended)	Self-Report	6/15/2017	8/2/2018

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, alleged, or confirmed violation.)	On June 29, 2017, PGE submitted Self-Reports stating, as Balancing Authority (BA), it was in violation of COM-002-4 R5. On December 8, 2016, one of PGE's generation Facilities tripped off line, losing approximately 180 MW of generation. At 4:33 PM, the BA Operator notified PGE's Reliability Coordinator (RC) that PGE had insufficient generation to maintain its reserves and requested an Energy Emergency Alert (EEA), which the RC declared at 4:34 PM as an EEA1, and then escalated to EEA2 at 4:39 PM. PGE then obtained assistance from its neighboring entities and was able to recover its reserves. At 5:11 PM, the RC removed all EEAs for PGE. Later, PGE evaluated the receiving and issuing of oral two-party, person-to-person Operating Instructions before, during and after the time of the EEA. It found the following calls were not issued or received, per the Standard Requirements: a. On December 8, 2016 at 3:45 PM, PGE's BA Operator contacted one of its generation facilities and issued an Operating Instruction to set the plant at its base rate. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5. b. At 4:21 PM the same day, the BA Operator contacted another generation facility and requested that the Operator increase the plant's output level to the highest extent that was reasonably possible. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5. c. At 4:50 PM, when the BA Operator contacted the generation facility that had tripped offline and issued an Operating Instruction to return the steam turbine to service. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5. d. At 4:51 PM, when the BA Operator contacted another generating facility and issued an Operating Instruction to not set the output level of the plant to a level that could negatively affect the plant's output. The plant Operator did repeat the Operating Instruction, but the BA Operator did not confirm that it was correct, as required by COM-002-4 R5. e. During another call also at 4:51 PM, the BA Operator contacted another generation facility and issued an Operating Instruction to set the plant output to a reasonable level, according to the Operator. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5. The root cause of the issues associated with COM-002-4 R5 was attributed to the lack of follow-up training for the System Operators to reinforce the proper method to perform three-way communications. This issue began on December 8, 2016, when PGE did not confirm the receiver's response nor repeat the Operating Instruction, related to five calls during an EEA and ended on December 8, 2016 when the EEA ended.
Risk Assessment	This violation posed a moderate risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, PGE failed, on five occasions, to both confirm the receiver's response if the repeated information is correct and repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, as required by COM-002-4 R5. Failure to ensure the Operating Instructions were confirmed and repeated could lead to a misunderstanding of the actions to be performed. Approximately 2,000 MW of generation within PGE's BA footprint could have been impacted and further could have impacted the Western Interconnection during the EEA. However, as compensation, PGE participated in a regional reserve sharing group during the EEA that it was able to utilize to receive assistance. In addition, audio recordings between PGE and the RC showed that no load had been shed during the EEA. Even though the series of communications occurred before and during the EEA, WECC confirmed there was no confusion between the issuers and the receivers of the Operating Instructions, reducing the risk of miscommunications or the carrying out of inappropriate instructions. Furthermore, there were no Operating Instructions issued by the RC to the BA Operators at PGE.
Mitigation	To mitigate this violation, PGE: 1) updated its internal procedure to clarify what constitutes an Operating Instruction and the required response. The internal procedure is required to be reviewed and signed at the beginning of every shift; 2) issued a reminder email from PGE's responsible Vice President to remind employees of their obligation to comply with the Standards, which was circulated by the plant operators who were required to review and sign; 3) added a more detailed description of Operating Instructions and three-way communication to the annual NERC Reliability Standards training that all plant operators are required to complete; 4) added a question about proper performance of three-way communication as part of the BA Operator quarterly performance evaluation;

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
WECC2017017872	COM-002-4	R5	High	Moderate	12/8/2016 (when PGE did not confirm the receiver's response nor repeat the Operating Instruction, related to five calls during an EEA)	12/8/2016 (when the EEA ended)	Self-Report	6/15/2017	8/2/2018

	5) sent an email to all BA operators asking them to describe what constitutes an Operating Instruction to reaffirm understanding of an Operating Instruction; and 6) implemented a plan to continue spot checking BA Operator recorded phone calls to ensure that proper communication is being used for issuing Operating Instructions.
Other Factors	WECC reviewed PGE's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although PGE does have a documented ICP, WECC determined that it was not effective in detecting or preventing multiple instances of noncompliance with the violations in this disposition. WECC considered PGE's compliance history with COM-002-4 and determined there were no relevant instances of noncompliance. WECC applied mitigation credit in the penalty determination because PGE: (i) was cooperative throughout the enforcement process, (ii) admitted to the violation, and (iii) agreed to settle the violation.

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
WECC2017017873	COM-002-4	R6	High	Moderate	12/8/2016 (when PGE did not confirm the receiver's response nor repeat the Operating Instruction, related to four calls during an EEA)	12/8/2016 (when the EEA ended)	Self-Report	6/15/2017	8/2/2018

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 29, 2017, PGE submitted Self-Reports stating, as a Generation Operator (GOP) it was in violation of COM-002-4 R6. On December 8, 2016, one of PGE's generation Facilities tripped off line, losing approximately 180 MW of generation. At 4:33 PM, the BA Operator notified PGE's Reliability Coordinator (RC) that PGE had insufficient generation to maintain its reserves and requested an Energy Emergency Alert (EEA), which the RC declared at 4:34 PM as an EEA1, and then escalated to EEA2 at 4:39 PM. PGE then obtained assistance from its neighboring entities and was able to recover its reserves. At 5:11 PM, the RC removed all EEAs for PGE. Later, PGE evaluated the receiving and issuing of oral two-party, person-to-person Operating Instructions before, during and after the time of the EEA. It found the following calls were not issued or received, per the Standard Requirements: a. On December 8, 2016 at 3:45 PM, PGE's BA Operator contacted one of its generation facilities and issued an Operating Instruction to set the plant at its base rate. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6. b. At 4:21 PM the same day, the BA Operator contacted another generation facility and requested that the Operator increase the plant's output level to the highest extent that was reasonably possible. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6. c. At 4:50 PM, when the BA Operator contacted the generation facility that had tripped offline and issued an Operating Instruction to return the steam turbine to service. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6. d. During another call also at 4:51 PM, the BA Operator contacted another generation facility and issued an Operating Instruction to set the plant output to a reasonable level, according to the Operator. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6. The root cause of the issues associated with COM-002-4 R6 was attributed to the lack of follow-up training for the System Operators to reinforce the proper method to perform three-way communications. This issue began on December 8, 2016, when PGE did not confirm the receiver's response nor repeat the Operating Instruction, related to four calls during an EEA and ended on December 8, 2016 when the EEA ended.
Risk Assessment	This violation posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, PGE failed, on four occasions, to both confirm the receiver's response if the repeated information is correct and repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, as required by COM-002-4 R6. Failure to ensure the Operating Instructions were confirmed and repeated could lead to a misunderstanding of the actions to be performed. Approximately 2,000 MW of generation within PGE's BA footprint could have been impacted and further could have impacted the Western Interconnection during the EEA. However, as compensation, PGE participated in a regional reserve sharing group during the EEA that it was able to utilize to receive assistance. In addition, audio recordings between PGE and the RC showed that no load had been shed during the EEA. Even though the series of communications occurred before and during the EEA, WECC confirmed there was no confusion between the issuers and the receivers of the Operating Instructions, reducing the risk of miscommunications or the carrying out of inappropriate instructions. Furthermore, there were no Operating Instructions issued by the RC to the BA Operators at PGE.
Mitigation	To mitigate this violation, PGE: 1) updated its internal procedure to clarify what constitutes an Operating Instruction and the required response. The internal procedure is required to be reviewed and signed at the beginning of every shift; 2) issued a reminder email from PGE's responsible Vice President to remind employees of their obligation to comply with the Standards, which was circulated by the plant operators who were required to review and sign; 3) added a more detailed description of Operating Instructions and three-way communication to the annual NERC Reliability Standards training that all plant operators are required to complete; 4) added a question about proper performance of three-way communication as part of the BA Operator quarterly performance evaluation; 5) sent an email to all BA operators asking them to describe what constitutes an Operating Instruction to reaffirm understanding of an Operating Instruction; and 6) implemented a plan to continue spot checking BA Operator recorded phone calls to ensure that proper communication is being used for issuing Operating Instructions.
Other Factors	WECC reviewed PGE's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although PGE does have a documented ICP, WECC determined that it was not effective in detecting or preventing multiple instances of noncompliance with the violations in this disposition.

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
WECC2017017873	COM-002-4	R6	High	Moderate	12/8/2016 (when PGE did not confirm the receiver's response nor repeat the Operating Instruction, related to four calls during an EEA)	12/8/2016 (when the EEA ended)	Self-Report	6/15/2017	8/2/2018
			WECC considered PGE's compliance history with COM-002-4 and determined there were no relevant instances of noncompliance. WECC applied mitigation credit in the penalty determination because PGE: (i) was cooperative throughout the enforcement process, (ii) admitted to the violation, and (iii) agreed to settle the violation.						

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
WECC2017017874	VAR-002-2b	R3	Medium	Severe	12/20/2013 (when PGE did not report the status change of its wind farm DSTATCOM alternative voltage controlling device to its TOP)	2/22/2017 (when PGE provided its TOP with the correct information about the status change of the alternative voltage controlling device)	Self-Report	10/31/2018	3/28/2019

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 June 30, 2017, PGE submitted a Self-Report stating, as a GOP, it was in violation of VAR-002-4 R3. In addition, during a Compliance Audit conducted July 10, 2017 to July 21, 2017, WECC determined PGE had additional instances of noncompliance which changed the start date to predate the current version of the Standard and therefore the violation is of VAR-002-2b R3.

Per PGE's self-report, on December 14, 2016, PGE's wind farm plant technician interpreted several distribution static synchronous compensator (DSTATCOM) equipment alarms at the wind farm to indicate a loss of reactive power capability. Understanding DSTATCOM equipment alarms to be a reportable change of a voltage controlling device, PGE's wind plant technician immediately called PGE's System Control Center (SCC) to report the event. PGE's SCC then notified its Transmission Operator (TOP) that the DSTATCOM was out of service with no expected time of return. However, the DSTATCOM equipment alarms only indicated that individual +/- 1 MVAR inverters were off-line and that the status of the wind farm DSTATCOM alternative voltage controlling device had not changed, remaining online and providing reactive power/voltage support.

Later, on January 10, 2017 at 8:29 AM, one of PGE's wind farm plant technicians contacted its SCC's Transmission and Distribution (T&D) dispatcher and required that three breakers be opened so that the plant staff could replace nine individual inverter trays related to the December 14, 2016 DSTATCOM equipment alarms. However, PGE did not notify its TOP of the status change in the alternative voltage controlling device because it assumed that the wind farm DSTATCOM alternative voltage controlling device was out of service and that it had already notified its TOP of the status change of the wind farm DSTATCOM alternative voltage controlling device on December 14, 2016.

On January 12, 2017, at 3:32 PM, the plant technician contacted the SCC's T&D Dispatcher to request that the breakers be closed to return the wind farm DSTATCOM alternative voltage controlling device to service. However, PGE did not notify its TOP of the wind farm DSTATCOM alternative voltage controlling device status change.

In both instances, PGE did not notify the TOP of the wind farm DSTATCOM alternative voltage controlling device status change within the 30 minutes of such change. However, PGE's TOP was provided with the correct information about the status change of the wind farm DSTATCOM alternative voltage controlling device on February 22, 2017. The root cause of these instances was attributed to less than adequate procedures that were not well-defined, understood, or enforced by management causing the plant technician to incorrectly interpret the alternative voltage controlling device to be offline; further, resulting in PGE not notifying its TOP of the alternative voltage controlling device status change.

The WECC Compliance Audit identified 10 additional instances between December 30, 2013 and October 19, 2015 for which PGE was unable to document that it had notified its TOP of changes in status of the wind farm's DSTATCOM alternative voltage controlling device within the required timeframe. PGE was unable to show that it had notified its TOP of the restoration of power system stabilizer (PSS) operability after scheduled PSS outages at a second plant on October 27, 2015 and at a third plant on January 28, 2014 and February 12, 2015. The root cause for these instances of noncompliance was insufficient staff training for reporting the notifications to its TOP.

For Plant 1: seven of the 10 instances identified at the WECC Compliance Audit were associated with the DSTATCOM of a wind generating facility with a nameplate capacity rating of 518 MVA. In these instances, the TOP was not notified of the status of the DSTATCOM. In seven of the 10 instances, the TOP was not notified of the DSTATCOM being returned to service. This could have reasonably resulted in the TOP not including the correct status of the voltage controlling device for this generating facility in its Operating Plan and Real-Time Assessment.

For Plant 2: one of the 10 instances identified at the WECC Compliance Audit were associated with a PSS at a hydro generating facility with a nameplate capacity rating 108 MVA. This facility has three generating units. In this instance, the TOP was not notified of the restoration of a PSS at this facility. This could have reasonably resulted in the TOP not including the correct PSS status for the generating unit in its Operating Plan and Real-Time Assessment.

For Plant 3: two of the 10 instances identified at the WECC Compliance Audit were associated with a PSS at a hydro generating facility with a nameplate capacity rating of 413 MVA. This facility has three generating units. In this instance the TOP was not notified of the restoration of a PSS at this facility. This could have reasonably resulted in the TOP not including the correct PSS status for the generating unit in its Operating Plan and Real-Time Assessment.

These instances began on December 20, 2013, when PGE did not report the status change of its wind farm DSTATCOM alternative voltage controlling device to its TOP, and ended on February 22, 2017, when PGE provided its TOP with the correct information about the status change of the alternative voltage controlling device, for a total of 12 instances over 1,161 days 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
WECC2017017874	VAR-002-2b	R3	Medium	Severe	12/20/2013 (when PGE did not report the status change of its wind farm DSTATCOM alternative voltage controlling device to its TOP)	2/22/2017 (when PGE provided its TOP with the correct information about the status change of the alternative voltage controlling device)	Self-Report	10/31/2018	3/28/2019

Risk Assessment	This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, PGE failed to notify its associated TOP 12 times of a status change on voltage controlling device within 30 minutes of the change, as required by VAR-002-4 R3. As compensation, there was no expected loss of generation, load, or transmission elements, for a failure to report the status of the voltage controlling device. Additionally, none of the 12 instances occurred simultaneously. For all three affected plants, a majority of the 12 instances were for failing to notify the TOP of the PSS or voltage control device being put back into service. This fact reduces the impact of potential harm because the device was back in service and operating as expected instead of a more serious condition, such as the TOP not being aware that the device was out of service and would therefore need to take manual action to compensate for the devices. The inverter trays associated with the DSTATCOM at Plant 1 only resulted in a 1 MVAR loss of reactive power capability. The loss of 1 MVAR of reactive power capability would have had minimal, if any, impact on the BPS. Additionally, for Plants 2 and 3, which had PSS, the generating Facilities were small and located in fairly remote areas, thus reducing the impact they could have had for damping oscillations on the system.
Mitigation	To mitigate this violation, PGE: 1) submitted correct status information for the AVR, PSS, or alternative voltage controlling device that interconnect with their TOP in real-time via ICCP for generating units in the instant violation; 2) automated notifications of AVR and PSS status via EMS for certain generating units to the System Control Center (SCC). This will allow the AVR/PSS status points to be transmitted in real-time via remote terminal unit (RTU) to the SCC Energy Management System (EMS). The EMS alarms will alert the System Operators when there are status changes; 3) provided combined real-time AVR/PSS status indication via EMS to the GOP and TOP System Control Center for all generating units; 4) revised generating facility compliance procedures to reflect that plant operators need to notify the SCC of status changes by phone in the event of an RTU failure. The SCC procedures were revised to instruct System Operators to notify plant operators of any RTU failures and to notify the TOP by phone of any reactive power status changes in the event of an ICCP failure; and 5) delivered operator training on the new processes to both plant operators and SCC System Operators once the revised procedures are in place.
Other Factors	WECC reviewed PGE's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although PGE does have a documented ICP, WECC determined that it was not effective in detecting or preventing multiple instances of noncompliance with the violations in this disposition. WECC considered PGE's VAR-002 compliance history to be an aggravating factor in the penalty determination and disposition track. WECC applied mitigation credit in the penalty determination because PGE: (i) was cooperative throughout the enforcement process, (ii) admitted to the violation, and (iii) agreed to settle the violation.