UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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January 29, 2018

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: ERRATA—CLINTON POWER STATION—NRC SPECIAL INSPECTION REPORT 05000461/2017012

Dear Mr. Hanson:

The U.S. Nuclear Regulatory Commission (NRC) identified an administrative error in NRC Inspection Report 05000461/2017012 (ML18026A967), dated January 26, 2018. Specifically, the inspection item tracking numbers included in the list of items closed during the inspection contained an erroneous reference to NRC Inspection Report 2013009. As a result, the NRC has reissued the report in its entirety with the correct item tracking numbers included. This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Patrick L. Louden, Director
Division of Reactor Projects

Docket No. 50–461
License No. NPF–62

Enclosure: w/Attachments
Inspection Report 05000461/2017012

cc: Distribution via LISTSERV®

Letter to Bryan Hanson from Patrick Louden dated January 29, 2018

SUBJECT: ERRATA—CLINTON POWER STATION—NRC SPECIAL INSPECTION REPORT 05000461/2017012

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–461
License No:	NPF–62
Report No:	05000461/2017012
Licensee:	Exelon Generation Company, LLC
Facility:	Clinton Power Station
Location:	Clinton, IL
Dates:	December 18 through 21, 2017
Inspectors:	J. McGhee, Byron Senior Resident Inspector (Lead) C. Phillips, Project Engineer
Approved by:	P. Louden, Director Division of Reactor Projects

Enclosure

SUMMARY

Inspection Report 05000461/2017012, Clinton Power Station; Other Activities

This report covers a special inspection performed by two U.S. Nuclear Regulatory Commission (NRC) Region III inspectors in December 2017. The inspection was conducted in accordance with Inspection Procedure 93812. Two Green findings were identified by the inspectors. One of the findings had an associated non-cited violation (NCV) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross Cutting Areas" dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated July 2016.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

Green. The inspectors identified a finding of very low safety significance and an associated NCV of Title 10 of the *Code of Federal Regulations* (CFR) 50, Appendix B, Criterion XVI, "Corrective Actions," for the licensee's failure to take corrective action to preclude repetition (CAPR) of a significant condition adverse to quality. Specifically, CAPRs developed following a December 8, 2013, 480 Volt transformer failure were not completed on Division 2 equipment even though the licensee recognized the 2013 transformer failure as a significant condition adverse to quality. The licensee entered this issue into their corrective action program (CAP) as action request (AR) 04089480. As corrective actions, the licensee planned to perform the testing, which made up the corrective action to prevent recurrence, at the next available opportunity which will be the 2018 refueling outage.

This performance deficiency was determined to be more than minor because it adversely impacted the Equipment Reliability attribute and the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Failure to perform the CAPR commensurate with safety reduced the effectiveness of the CAPR and increased the likelihood of a recurring event. This finding was determined to be of very low safety significance because the finding did not involve the complete or partial loss of a support system that contributes to the likelihood of, or cause, an initiating event and did not affect mitigation equipment. This finding affected the cross-cutting area of human performance, in the aspect of work management where the organization implements a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. Delaying the performance of the testing because it extended the outage did not demonstrate that nuclear safety was the overriding priority. [H.5] (Section 4OA3.3)

Green. The inspectors identified a finding of very low safety significance for the licensee's failure to follow procedure ER–AA–200–1001, "Equipment Classification," Revision 3. Specifically, three non-safety related 4160 volt to 480 volt transformers were not properly classified as operationally critical components. The licensee entered this issue into its CAP as AR 04086449. As corrective actions, the licensee corrected the criticality classifications for 0AP44E 480 VAC Auxiliary Transformer D, 0AP92E 480 VAC Auxiliary Transformer P, and 1AP18E2 480 VAC Auxiliary Transformer 1H. Additionally, the licensee planned to perform a work group evaluation to document the extent of condition to ensure that all dry type transformers onsite have the correct criticality classification.

The performance deficiency was determined to be more than minor, because it was associated with the Initiating Events Cornerstone attribute of Equipment Performance and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the performance of the transformers listed above was not fully evaluated as required by the preventive maintenance program to ensure the likelihood of failure was limited. The inspectors determined this finding was of very low safety significance because although the performance deficiency resulted in a preventive maintenance strategy that may have resulted in lower reliability of the respective 480 volt auxiliary transformers, it would not have resulted in the loss of mitigation equipment relied upon to transition the plant from the onset of the scram to a stable shutdown condition. The inspectors determined this finding affected the cross-cutting area of Human Performance in the aspect of Consistent Process where individuals use a consistent systematic approach to make decisions andrisk insights are incorporated as appropriate. Specifically, the licensee failed to use a consistent classification process to reach the conclusion that the 480 VAC auxiliary transformers 0AP44E, 0AP92E, 1AP18E2 were properly classified as operationally critical components. [H.13] (Section 4OA3.4)

Licensee-Identified Violations

No findings were identified.

REPORT DETAILS

Summary of Plant Event

On Saturday, December 9, 2017, Clinton Power Station control room operators inserted a manual reactor scram from 98.2 percent power following an electrical system perturbation. Multiple alarms were received in the control room upon the unexpected opening of the 1A1 4160 volts alternating current (VAC) bus breaker 1AP07EJ, which feeds 480 VAC Unit Substation A (0AP05E) and 480 VAC Unit Substation 1A (1AP11E). Control room operators noted that the outboard containment isolation valve for instrument air to containment had closed with the loss of 480 VAC power and entered the abnormal procedure for loss of instrument air to containment while attempting to identify the cause of the power loss. Four minutes after the breaker opened, the control room received a low scram pilot air header pressure alarm. Two minutes later, the control rod drift annunciator alarmed as expected and the control room operators inserted a manual scram by taking the Mode Switch to “Shutdown” in accordance with procedural guidance.

Operators began cooling down the reactor by directing steam to the main condenser using the main steam bypass valves and auxiliary steam equipment. As reactor pressure lowered operators removed auxiliary equipment from service to maintain the cooldown rate within Technical Specification (TS) limits and maintained reactor water level using the condensate and feedwater pumps which remained available throughout the event. The partial loss of Division 1 480 VAC power de-energized the Division 1 containment isolation solenoid valves and isolated instrument air to the containment when the outboard containment isolation valve, 1IA005, closed. In addition to isolating the air supply to the scram air header, closure of 1IA005 resulted in a loss of air supply to all containment loads including the inboard main steam isolation valves (MSIVs). Operators lined up the main steam line drains to maintain pressure control and continue the cooldown in anticipation of MSIV closure as containment air pressure lowered. The last inboard MSIV indicated full closed about 4 hours after the instrument air containment isolation valve closed, but the main steam line drain valves remained available to the operators. The drains were used in conjunction with the reactor core isolation cooling (RCIC) turbine to continue to cooldown to Mode 4 within the time limits required by TS.

The partial loss of Division 1 4160/480 VAC power rendered several components inoperable. Low pressure core spray (LPCS) and the ‘A’ train of residual heat removal (RHR) were inoperable and unavailable. The RCIC system was also declared inoperable because the AC powered RCIC water leg pump could not function. The Division 1 battery charger also lost power causing operators to reduce loading on the battery while the swing battery charger was aligned.

Based on the deterministic criteria provided in NRC Management Directive (MD) 8.3, “NRC Incident Investigation Program,” this event met MD 8.3 Criterion (d), because there was a loss of secondary containment when the Fuel Building Ventilation fans lost power and were unable to maintain the secondary containment differential pressure within the TS limits. This condition existed for approximately 15 minutes until the standby gas treatment system was manually aligned to the Fuel building and differential pressure was restored. Also, LPCS, a single train safety system, and RHR “A” were considered inoperable due to loss of the water leg fill pumps and loss of power to motor operated valves. In addition, the event also met MD 8.3 criterion (g), in that the loss of power to the Division 1 480 VAC bus was very similar to a failure that occurred in December 2013 when the A1 4160/480 VAC transformer failed. The initial risk assessment resulted in an estimated Conditional Core Damage Probability (CCDP) range of 4.0E–6 to 9E–6. The Special Inspection Team (SIT) was dispatched to the site and arrived on December 18, 2017.

The SIT charter is included with this report in the Supplemental Information.

4OA3 Special Inspection (93812)

.1 Establish an Overview of Events Related to the Transformer Failure, Reactor Scram, and Plant Recovery Actions. Review Related Licensee Actions with Respect to Monitoring of Plant Conditions, Procedure Usage, and Decision Making.

a. Inspection Scope

The special inspection charter charged the team with establishing an overview of events related to the December 9, 2017, event including the licensee's actions prior to the event as well as during and recovery from the event. To that end, inspectors reviewed operating logs, plant parameter recordings, testing and trend information, and other maintenance records. Inspectors reviewed statements prepared by control room operators following the event. In addition, the inspectors compared the resulting sequence of events to the licensee generated sequence of events to ensure completeness and accuracy of both documents. Pertinent historical information and the timing of those activities such as previous preventative maintenance dates and maintenance inspections performed are discussed in the following sections of the report.

The inspectors also reviewed the licensee actions with respect to monitoring of plant conditions, procedure usage and decision-making. The inspector-generated sequence of events is included with this report in the Supplemental Information.

Documents reviewed are included in the Supplemental Information.

b. Discussion

The team concluded that the plant responded as designed to the failure and the resulting transient with a small number of equipment failures. The licensee staff appropriately identified, evaluated, and corrected the equipment failures prior to restarting the unit which included installing a modification to replace the failed transformer and the performance of immediately required extent of condition testing. Additionally, the team concluded that operator decisions were appropriate and procedures were implemented correctly in response to the event.

c. Findings

No findings were identified.

.2 Review the Operation of the Plant equipment in Response to the Transient, Including Adequacy of Procedures and Whether Equipment Operated in Accordance with its Design.

a. Inspection Scope

The inspectors reviewed the anticipated plant response to a manual scram, loss of electrical power, and a loss of instrument air described in the Clinton Power Station Updated Final Safety Analysis Report (UFSAR) Chapter 15. Additionally, several procedures were reviewed and compared to the plant response and the actions taken by the operators during the event. The inspectors reviewed the licensee's operations narrative logs for the time period just prior to the transformer failure on December 9, 2017, at 1:47 p.m., to the time that the unit reached Mode 4 at 8:00 p.m. on December 10, 2017. The inspectors also reviewed statements documented by operators that were on shift at the time of the event. The inspectors also reviewed plant parameter recordings and the post trip review completed by the licensee. The inspectors compared the operator and plant response to a similar transformer failure event that occurred on December 8, 2013. The results of the 2013 transformer failure are documented in Clinton Power Station NRC Special Inspection Report 05000461/2013009.

The inspectors reviewed the licensee's corrective action program (CAP) documentation to ensure the licensee had identified other non-consequential, non-safety related equipment failures and degraded conditions that occurred during the event and entered those failures into the CAP. Documents reviewed are included in the Supplemental Information.

b. Discussion

The loss of alternating current (AC) power was the direct cause of the loss of instrument air to containment, loss of secondary containment integrity when dampers closed tripping ventilation exhaust fans, and inoperability of LPCS and RHR "A" due to loss of water leg pumps and motor operated safety-related valves. The inspectors reviewed the operating procedures and design for the instrument air containment isolation valves. The instrument air supply to the air operated containment isolation valves was regulated and aligned to open the valve through AC powered solenoid operated valves. The solenoid for 1IA005, Containment Outboard Isolation Valve, lost power when the Division 1 480 VAC busses were de-energized and the air operated instrument air containment isolation valves failed closed as expected. The inspectors determined that the operators correctly identified the loss of AC power and closure of the containment isolation valves. The operators implemented the correct station procedures and focused on the parameters called out in those procedures to identify when the reactor was required to be shutdown. As stated previously, loss of instrument air to containment subsequently resulted in a loss of air pressure to the inboard MSIVs, reactor water cleanup system components and control rod drive system components including the scram air header.

Procedure CPS [Clinton Power Station] EOP–1; "RPV [reactor pressure vessel] Control," lists main turbine bypass valves and main steam line (MSL) drain lines possible means of pressure control if the MSIVs are open. The MSL drains remained available after the inboard MSIVs closed. Procedure CPS 4100.01, "Reactor Scram," directs the operator to use an appropriate cooldown method listed in CPS 9000.06, "Unit Shutdown."
In CPS 9000.06, Section 8.8, "Cooldown With Main Condenser," MSL drain valves were

one method listed and included a statement that it is “OK to shut MSIVs” when using this method. The control room supervisor stated that he considered using RCIC for pressure control, but determined that he did not need to immediately because the main condenser remained available and he was able to control pressure and the cooldown rate using MSL drains and bypass valves until the last MSIV closed.

The control room supervisor indicated that although the RCIC water leg keep fill pump had lost power, he determined RCIC was inoperable but available and requested an engineering review to validate his assessment. During the 2013 special inspection, the inspectors reviewed RCIC annunciator and system operating procedures to evaluate RCIC availability under these conditions. At that time, the inspectors also interviewed the RCIC system manager and two program engineers that perform ultrasonic testing on piping to look for voids. The inspectors also reviewed computer printouts of RCIC suction and discharge pressure from the beginning of the 2013 event until the plant reached Mode 4 and reviewed calculations for net positive suction head for the RCIC pump from both of its suction sources. The inspectors concluded in 2013 that the RCIC system, although appropriately declared inoperable due to the power loss to the water leg pump, was available for operation if necessary for pressure/inventory control and for decay heat removal. The inspectors reviewing the 2017 event arrived at the same conclusion. At 6:59 p.m. on December 9, 2017, the operating crew placed RCIC in service in the pressure control mode operating tank to tank and the system remained in service until 11:39 a.m. on December 10, 2017, after instrument air had been returned to containment and the MSIVs were reopened. The RHR “B” train was started in shutdown cooling mode at 7:37 p.m. on December 10, 2017, and the plant entered Mode 4 at 8:00 p.m. that same day.

c. <u>Findings</u>

No findings were identified.

.3 <u>Evaluate the Licensee Planned and Completed Corrective Actions Following the 2013 Transformer Failure and to the Extent Possible, Assess if Prior Opportunities (e.g. Surveillances, Maintenance) Existed to Have Identified Transformer Degradation or Failure, at an Earlier Point in Time.</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee’s root cause evaluation (RCE) 01594407, Automatic Trip of Breaker 1AP07EJ – 0AP05E2 Transformer Failure and associated CAP documentation. Documents reviewed are included in the Supplemental Information Section of this report.

b. <u>Discussion</u>

The licensee considered the transformer failure in 2013 to be a low probability event since a very low percentage of these dry transformers had failed within the nuclear industry. As part of the extent of condition from the 2013 event the licensee visually inspected and megger tested the 0AP79E2 transformer and found it in good condition (IR 01594407 Assignment 34). Based on the result of this single inspection the licensee assumed the other transformers were also in good condition. The inspectors considered this to be a weak assumption based on a single observation. The inspectors also noted that the licensee planned to install infrared windows in the transformer cabinets so that the temperature of the windings could be monitored. The licensee canceled that action because the transformers had installed thermocouples which would have been a better method of monitoring temperature. However, the thermocouples were only in one phase winding of the transformers, which significantly reduced the effectiveness of this type of monitoring, and the licensee stopped monitoring the temperatures in 2015.

The inspectors determined that there were no prior opportunities to perform the testing needed to identify the transformer degradation to the Division I 480 VAC substation transformer that failed on December 8, 2017. However, the inspectors determined that the licensee had a prior opportunity to perform testing designated as a corrective action to prevent recurrence on the Division II 480 VAC substation transformers and failed to do so.

c. Findings

Introduction: The NRC identified a finding of very low safety significance and an associated non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, for the licensee's failure to take corrective action to preclude repetition in the case of a significant condition adverse to quality. Specifically, corrective actions for an event that the licensee recognized as a significant condition adverse to quality were not completed commensurate with safety.

Description: The inspectors reviewed the corrective actions associated with licensee RCE 1594407, "Automatic Trip of Breaker 1AP07EJ–0AP05E2 Transformer Failure." This event occurred on December 8, 2013, when the 480 VAC Unit Substation 0AP05E2 Transformer failed and caused of a loss of Division I 480 volt loads and a subsequent reactor scram. On June 6, 2016, the licensee finalized root cause report (RCR) 01594407, "Automatic Trip of Breaker 1AP07EJ—0AP05E2 Transformer Failure," in accordance with station procedure PI–AA–125–1001, "Root Cause Analysis Manual," Revision 2.

The inspectors identified that the RCE neither established a root cause nor were corrective actions to prevent recurrence created as required by PI–AA–125–1001 after the RCE was issued. The NRC issued NCV 05000461/2017002–07, "Root Cause Evaluation Failed to Identify Corrective Action to Preclude Repetition," on August 11, 2017. (The issuance of this violation had been delayed for several months determining an outcome of an issue regarding the CAP program that impacted all Exelon sites.) The licensee then determined that the root cause of the transformer failure was insulation degradation of the phase windings over time. The corrective action to prevent recurrence (CAPR) included implementation of Doble testing on dry type transformers to predict and identify indicators of insulation degradation over time. Doble testing includes a series of individual tests performed with specialized equipment to determine the amount of internal insulation degradation, if any, that existed on different transformer components. This testing was intrusive and required the electrical busses associated with the transformers to be de-energized.

The licensee's RCE and CAP documentation stated that the implementation of the Doble testing was to be performed by updating the model work orders for all safety-related and non-safety related dry type transformers. The licensee designated the revision of the model work orders as a CAPR in October 2016, completed revising the model work orders on November 18, 2016, and closed the CAPR. However, the inspectors determined that revising the model work orders alone was not a CAPR. In order for the

CAPR to be considered implemented, the licensee needed to complete actual Doble testing of the transformers.

The licensee conducted a refueling outage from May 8, to May 29, 2017. The licensee stated that Doble testing on the Division 2 4160 to 480 VAC transformers had been planned for the 2017 refueling outage but not conducted because it would have extended the length of the outage by three days. The implementation of the Doble testing on the safety-related Division 2 4160 to 480 VAC transformers was delayed until the 2018 refueling outage.

The inspectors reviewed NRC guidance related to the timeliness of corrective actions provided in NRC Inspection Manual Chapter 0326, “Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety,” which stated:

> In determining whether the licensee is making reasonable efforts to complete corrective actions promptly, the NRC will consider safety significance, the effects on operability, the significance of the degradation, and what is necessary to implement the corrective action. The NRC may also consider the time needed for design, review, approval, or procurement of the repair or modification; the availability of specialized equipment to perform the repair or modification; and whether the plant must be in hot or cold shutdown to implement the actions. If the licensee does not resolve the degraded or non-conforming condition at the first available opportunity or does not appropriately justify a longer completion schedule, the staff would conclude that corrective action has not been timely and would consider taking enforcement action. Factors that should be considered are (1) the identified cause, including contributing factors and proposed corrective actions, (2) existing conditions and compensatory measures, including the acceptability of the schedule for repair and replacement activities, (3) the basis for why the repair or replacement activities will not be accomplished prior to restart after a planned outage (e.g., additional time is needed to prepare a design/modification package or to procure necessary components), and (4) review and approval of the schedule by appropriate site management and/or oversight organizations.

The inspectors determined that the licensee’s rational for delaying the testing that made up the CAPR was not due to the extenuating circumstances listed above.

Analysis: The inspectors determined that the failure to implement CAPRs in accordance with Title 10 of the *Code of Federal Regulations* (CFR) 50, Appendix B, Criterion XVI, was a performance deficiency. The performance deficiency was determined to be more than minor in accordance with IMC 0612, “Power Reactor inspection Reports,” Appendix B, “Issue Screening,” dated September 7, 2012, because it adversely impacted the Equipment Reliability attribute of the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the failure to perform the CAPR promptly (i.e. at the first outage of sufficient duration or first available opportunity) reduced the effectiveness of the CAPR and increased the likelihood of a recurring event. Using IMC 0609, Attachment 4, “Initial Characterization of Findings at Power,” and Appendix A, “The Significance Determination Process for Findings at Power,” issued June 19, 2012, the finding was screened against the Initiating Events Cornerstone and determined to be of very low safety significance (Green) because the finding did not involve the complete or partial loss of a support system that contributes to the likelihood of, or cause an initiating event that affected mitigation equipment.

The inspectors determined this finding affected the cross-cutting area of human performance, in the aspect of work management where the organization implements a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. Delaying the performance of the testing because it extended the outage did not demonstrate that nuclear safety was the overriding priority. [H.5]

Enforcement: Title 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," required, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above, from May 8, to May 29, 2017, the licensee failed to establish measures to assure that corrective actions to preclude repetition were taken for the Division 2 4160 VAC to 480 VAC transformers following the failure of Division I 480 VAC Unit Substation Transformer 0AP05E2 on December 8, 2013 (a significant condition adverse to quality). Specifically, the licensee scheduled and had the opportunity to perform testing on the Division II 4160 VAC to 480 VAC transformers but failed to perform the testing. The corrective actions in response to this violation are to perform the testing at the next available opportunity which is the 2018 refueling outage. Because this finding was of very low safety significance and was entered in the CAP as AR 04089480, this violation is being treated as an NCV, in accordance with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000461/2017012–01: Failure to Perform a Corrective Action to Prevent Recurrence)**

.4 Review the Licensee's Extent of Condition Evaluation Plan and Related Activities to Evaluate the Licensee's Assessment of the Condition of Similar Installed Transformers.

a. Inspection Scope

The inspectors reviewed the licensee's extent of condition evaluation and plans to test and/or replace existing safety-related and non-safety related 4160 VAC to 480 VAC dry transformers.

b. Discussion

The licensee determined that there were five safety-related and 24 non-safety related dry 4160 VAC to 480 VAC transformers for a total of 29. The licensee had developed two separate plans to replace the safety-related and non-safety related transformers.

The plan to replace the safety-related transformers was scheduled to start with the Division III transformer in 2021. Since the recent failure of the Division I transformer the licensee has subsequently verbally committed to replacing the Division II transformers in the next refueling outage in 2018. The inspectors reviewed the paperwork issued to track that work to completion. Licensee management personnel also stated that they planned to replace the Division III transformer on line sooner than 2021. The Division I transformers were replaced due to the failures in 2013 and 2017.

The plan to replace the non-safety related transformers was delayed until it was determined whether or not the station planned to apply for a license renewal. However, the inspectors identified an issue with the equipment classification of three non-safety related transformers.

c. Findings

Introduction: The NRC identified a finding of very low safety significance for the licensee's failure to follow procedure ER–AA–200–1001, "Equipment Classification," Revision 3. Specifically, three non-safety related 4160 VAC to 480 VAC transformers were not properly classified as operational critical components.

Description: As part of the special inspection conducted from December 18 to December 21, 2017, the inspectors were given a list of the 4160 VAC to 480 VAC dry transformers on site. There were five safety-related and 24 non-safety related transformers. The inspectors questioned if any of the non-safety related 4160 VAC to 480 VAC dry transformers would cause a significant plant transient if it failed. The licensee identified three transformers that would cause a reactor scram upon failure:

- 0AP44E 480 VAC Auxiliary Transformer D;
- 0AP92E 480 VAC Auxiliary Transformer P; and
- 1AP18E2 480 VAC Auxiliary Transformer 1H.

All three of these transformers were classified as non-critical components in the licensee's preventive maintenance program. Per licensee procedure ER–AA–200–1001, "Equipment Classification," Revision 3, Step 4.1, "Component classification provides the key input or basis for the Maintenance Strategy as well as work execution controls as such it is important that the component classification is maintained accurate and the basis for any changes is appropriately documented and approved." Licensee procedure ER–AA–200–1001, "Equipment Classification," Revision 3, Attachment 1, Steps 1.4 and 2.1, stated, in part, that if a component failure resulted in a reactor scram it was to be classified as an operationally critical component.

Analysis: The inspectors determined the failure to properly classify 480 VAC auxiliary transformers 0AP44E, 0AP92E, 1AP18E2 as operationally critical components, in accordance with licensee procedure ER-AA-200-1001 was a performance deficiency. Using guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined that the performance deficiency was more than minor because it was associated with the Initiating Events Cornerstone attribute of equipment performance and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the performance of the transformers listed above was not fully evaluated as required by the preventive maintenance program to ensure the likelihood of failure was limited.

In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors determined that this finding was of very low safety significance (Green) because, although the performance deficiency resulted in a preventive maintenance strategy that may have resulted in lower reliability of the 480 volt auxiliary transformers that would have caused a reactor scram, it would not have resulted in the loss of mitigation equipment relied upon to transition the plant from the onset of the scram to a stable shutdown condition.

The inspectors determined this finding affected the cross-cutting area of Human Performance in the aspect of Consistent Process where individuals use a consistent systematic approach to make decisions and risk insights are incorporated as appropriate. Specifically, the licensee failed to use a consistent classification process to reach the conclusion that the 480 VAC auxiliary transformers 0AP44E, 0AP92E, 1AP18E2 were properly classified as operationally critical components. [H.13]

Enforcement: The inspectors did not identify a violation of a regulatory requirement associated with this finding due to the 480 VAC auxiliary transformers 0AP44E, 0AP92E, 1AP18E2 being classified as a non-safety related components. The licensee entered this issue into its CAP as IR 04086449. As corrective actions, the licensee corrected the criticality classifications for 0AP44E 480 VAC Auxiliary Transformer D, 0AP92E 480V Auxiliary Transformer P, and 1AP18E 480 VAC Auxiliary Transformer 1H. Additionally, the licensee planned to perform a work group evaluation to document the extent of condition to ensure that all dry type transformers onsite have the correct criticality classification. **(FIN 05000461/2017012–02: Failure to Properly Classify Non-Safety Related Auxiliary Transformers as Operationally Critical Components)**

.5 Continually Evaluate the Complexity and Significance of the Event to Determine if the Circumstances Warrant Escalation of the Inspection to an Augmented Inspection Team. Consider Any New Insights or Issues that Indicate Generic Implications, Increase in the Risk Evaluation, or Design Vulnerabilities.

a. Inspection Scope

The inspectors held discussions with licensee personnel, reviewed the response of equipment and operations personnel, and reviewed historical corrective action program and maintenance related documents to evaluate whether a higher level of NRC response was needed to review this event.

b. Discussion

The inspectors did not identify any circumstances of the event that warranted escalation of the inspection to an Augmented Inspection Team. The event itself followed the anticipated sequence according to accident analysis and with a few non-consequential exceptions, plant equipment functioned as designed. While performing the preliminary risk analysis for the MD 8.3 Evaluation to determine the risk criteria, the Senior Reactor Analyst modeled the transient as a "Loss of Condenser Heat Sink" initiating event due to the manual reactor scram and closure of the inboard MSIVs. Direction to use the steam line drains to maintain the condenser as a heat sink when the MSIVs are closed was contained in site procedures. Procedure CPS [Clinton Power Station] EOP–1; "RPV Control," listed MSL drains as one of the systems to be used to control RPV pressure and cooldown rate. Procedure CPS 4100.01; "Reactor Scram," directed the operator to use an appropriate cooldown method listed in CPS 9000.06, "Unit Shutdown." In CPS 9000.06 Section 8.8, "Cooldown With Main Condenser," MSL drain valves were one method listed and included a statement that it was "OK to shut MSIVs" when using this method. In this scenario, the control room supervisor stated that he considered using RCIC for pressure control, but determined that he did not need to because the main condenser remained available and he was able to control the pressure/cooldown rate using the MSL drains to the main condenser. When the final MSIV closed and pressure started to rise, the crew started RCIC in the pressure control mode. The operating crew then continued to cooldown the reactor to Mode 4.

The inspectors identified a concern that evaluation of the generic implications of the transformer failure could only be completed when the root cause of the transformer failure was known. Determination of the actual cause of the transformer failure to ground required an inspection of the damaged transformer at the ABB facility. The dry type transformer was built in 1980 and the design worst-case loading was 40 percent of the transformer rating. This type transformer was used in 29 480 VAC substations in the plant (only 5 of the 29 are safety-related). The safety-related transformers are inspected and megger tested at an 8 year frequency aligned with the safety-related bus outage schedule. The non-safety dry type transformers are inspected and megger tested at an 8 year frequency (some have been extended to 16 years based on performance). No degraded condition was found during the past preventative maintenance activities on the dry type transformers. However, operators at Clinton identified noises coming from one of the non-safety related dry type transformers in 2015. The transformer was removed from service and replaced. The transformer vendor's evaluation identified degraded insulating material as the cause for the noise. Pending additional information from the inspection of the December 2017 transformer failure and the associated root cause investigation, the extent of condition and related activities were determined to be acceptable.

c. Findings

No findings were identified. During the review of the reactor scram and transformer failure that occurred on December 9, 2017, inspectors concluded that sufficient information was not available to identify generic implications or potential performance deficiencies with the design, manufacture or maintenance of the dry-type transformers pending completion of the licensee's root cause analysis to be documented in RCE 04082490, "Reactor Scram from Trip of 1AP07EJ."

This issue is an unresolved item (URI) pending NRC evaluation of the additional information being developed by the licensee. **(URI 05000461/2017012–03: Evaluation of RCE 04082490, Reactor Scram from Trip of 1AP07EJ)**

4OA6 Management Meetings

.1 Exit Meeting

On December 21, 2017, the inspectors presented the inspection results to Mr. T. Stoner and other members of the licensee staff. The licensee acknowledged the issues presented. Proprietary information was examined during this inspection and was returned to the licensee's representatives or destroyed. Specifics of proprietary information are not detailed in this report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Stoner, Site Vice President
J. Cunningham, Maintenance Director (Acting Plant Manager)
T. Krawcyk, Site Engineering Director
M. Prospero, Manager Special Projects
T. Dean, Training Director
A. Siegmund, Security Manager
G. Engelhardt, Deputy Maintenance Director
R. Champley, Shift Operations Superintendent
M. Mayer, Security Operations Manager
D. Shelton, Regulatory Assurance Manager
K. Nicely, Principle Regulatory Engineer
B. Rush, Operations Support Manager
G. Sanders, Regulatory Assurance Engineer
N. Santos, Regulatory Assurance Engineer
K. Pointer, Senior Regulatory Assurance Engineer
J. Edom, Senior Risk Management Engineer
D. Reoch, Radiation Protection Technical Manager
J. Kimler, Acting Online Work Control Manager
G. Lux, Senior Staff Engineering Analyst
M. Heger, Senior Manager Design Engineering
J. Madappat, Engineer
J. Robinson, Senior Site Assessor

U.S. Nuclear Regulatory Commission

L. Kozak, Acting Chief, Reactor Projects Branch 1
J. Hanna, Senior Reactor Analyst
W. Schaup, Clinton Senior Resident Inspector
E. Sanchez-Santiago, Clinton Resident Inspector

Illinois Emergency Management Agency
S. Miscke, IEMA Resident Inspector

LIST OF ITEMS OPENED AND CLOSED

Opened

05000461/2017012–01	NCV	Failure to Perform a Corrective Action to Prevent Recurrence [Section 4OA3.3]
05000461/2017012–02	FIN	Failure to Properly Classify Non-Safety Related Auxiliary Transformers as Operationally Critical Components [Section 4OA3.4]
05000461/2017012–03	URI	Evaluation of RCE 04082490, Reactor Scram from Trip of 1AP07EJ [Section 4OA3.5]

Closed

05000461/2017012–01	NCV	Failure to Perform a Corrective Action to Prevent Recurrence [Section 4OA3.3]
05000461/2017012–02	FIN	Failure to Properly Classify Non-Safety Related Auxiliary Transformers as Operationally Critical Components [Section 4OA3.4]

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Work Orders

- WO 01534764-01, Clean and Inspect Unit Sub 1A (1AP11E)
- WO 04722432-05. Electrical Maintenance (EM) Perform Testing and Inspections and Support Vendor in Performance of Specialized Testing (Doble) on Unit Sub 1A (1AP11E) New Transformer.
- WO 01534764, Unit Sub Cleaning Substation 1A 1AP11E, October, 15, 2013

Corrective Actions

- IR 04082490, Reactor Scram from Trip of 1AP07EJ; December 9, 2017
- IR 01594407, Automatic Trip of Breaker 1AP07EJ, December 9, 2013
- RCE 01594407, Automatic Trip of Breaker 1AP07EJ – 0AP05E2 Transformer Failure
- IR 04082500; TDRFP Failed to Trip; December 9, 2017
- IR 04086449, NRCID: Incorrect Criticality Classification On Transformers, December 21, 2017
- IR 02699149, Old Unit Sub K Xmfr Inappropriately Stored Outside, August 31, 2016
- IR 01506730, Transformer Insulation Resistance did not Meet Minimum Value, December 13, 2013
- IR 01624258, Action Plan to Address Aging Dry Type Transformers, February 21, 2014
- IR 01686987, Divisional Bus Outage Realignment from 6YR to 8YR Plan, July 30, 2014
- IR 04084743, Replace 480 Volt Unit Substation 1B, 1AP12E, December 16, 2017
- IR 04084748, Replace 480 Volt Unit Substation B, 0AP06E, December 16, 2017
- IR 04082501; Unable to Engage Main Turbine Turning Gear; December 9, 2017
- IR 04082623; Loss of AC Power to Fire Protection Detection Panel; December 10, 2017
- IR 04082631; Turbine Generator Did Not Trip after Scram; December 10, 2017
- IR 04082632; 1FW004 Leaks By Complicating Level Control; December 10, 2017
- IR 04082715; Primary to Secondary CTMT D/P OOS; December 11, 2017
- IR 04083264; Suppression Pool Level ITS During EOP-6
- IR 04082533; 1MC048C: Small Packing Leak; December 10, 2017
- IR 04082499; 1CB009A RFP Suction Valve Packing Leak; December 9, 2017
- IR 04082532; Manual Valve Handwheel Fell Off; December 10, 2017
- IR 04082978; Crew C 4.0 Crew Critique for CPS Scram December 9, 2017
- IR 04083060; Crew E 4.0 Critique of 1CF61 S/D

Procedures

- CPS 3002.01C003, Mode 3 Checklist
- CPS 3006.01, Unit Shutdown
- CPS 4100.01, Revision 23c; Reactor Scram
- CPS 4100.02, Revision 17f; Automatic Isolation
- CPS 4200.01, Revision 24d; Loss of AC Power
- CPS 4201.01, Loss of DC Power
- CPS 4004.01, Revision 10; Loss of Instrument Air

- CPS EOP-1, RPV Control
- CPS 4411.09, RPV Pressure Control Sources
- CPS 3310.01, “Reactor Core Isolation Cooling (RI),” Revision 29
- CPS 5063.07, “Reactor Core Isolation Cooling Water Leg Pump Discharge Pressure Low,” Revision 30c
- ER-AA-200-1001, Equipment Classification, Revision 3
- ER-AA-200, Preventive Maintenance Program, Revision 3
- PI-AA-125, Corrective Action Program, Revision 6
- PI-AA-125-1001, Root Cause Analysis Manual, Revision 3
- CPS 8440.01, Insulation Testing, Revision 14

Miscellaneous

- Drawing AP-01, Auxiliary Power, Revision 010
- List of Clinton Station 4160V-480V Dry Transformers, Revision 2
- CPS-14-0014, Plan to Replace Safety-Related Aging Dry Type Transformers
- CPS-17-0092, Plan to Replace Non-Safety Related Aging Dry Type Transformers
- EC 622359, Replacement of Dry Type Transformer 1AP11E2
- Transformer Analysis Report – Unit Sub K Failure Analysis, October 6, 2016
- CPS/UFSAR Section 1.8, Conformance to NRC Regulatory Guides
- CPS/UFSAR Section 7.2.2.1.3.2, Loss of Instrument Air
- CPS/UFSAR Section 7.3, Engineered Safety Features
- CPS/UFSAR Chapter 8, Electric Power
- CPS/UFSAR Section 15A.6.3.2, Required Safety Action/Related Unacceptable Consequences
- CPS/UFSAR Section 15.2.10, Loss of Instrument Air System
- EC 396373, Start RCIC System for Pressure Control Without RCIC Water Leg Pump, Rev.
- Operating Crew Written Statements of Events for December 9, 2017
- Post Transient Review (OP-AA-108-114, Revision 13) Completed by the Licensee in Response to December 9, 2017 Trip
- Scope Change Review Form 10138 for C1R18, dated December 16, 2017; WO 04726293 Replace Substation B1 Transformer
- Scope Change Review Form 10139 for C1R18, dated December 16, 2017; WO 04726315 Replace Substation 1B Transformer

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ADS	Automatic Depressurization System
CAP	Corrective Action Program
CAPR	Corrective Action to Prevent Recurrence
CCDP	Conditional Core Damage Probability
CFR	*Code of Federal Regulations*
CPS	Clinton Power Station
EOP	Emergency Operating Procedure
IA	Instrument Air
IMC	Inspection Manual Chapter
IR	Inspection Report
IR	Issue Report
LPCS	Low Pressure Core Spray
MD	Management Directive
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
NCV	Non-Cited Violation
NRC	U.S. Nuclear Regulatory Commission
RCE	Root Cause Evaluation
RCR	Root Cause Report
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
SIT	Special Inspection Team
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VAC	Volts Alternating Current
VG	Standby Gas Treatment

<u>EVENT TIMELINE [December 9, and 10, 2017]</u>

December 9, 2017

13:47	**<u>Initiating Event</u>**: Trip of 4160 V 1A1 breaker 1AP07EJ, 480V Transformers 1A and A1 Supply Breaker, due to failed unit substation 1AP11E 4160V/480V transformer. Numerous Division 1 loads including Low Pressure Core Spray (LPCS) system components (water leg keep fill pump and motor operated valves), Residual Heat Removal (RHR) A system components (water leg keep fill pump and motor operated valves), and the Reactor Core Isolation Cooling (RCIC) water leg pump lost power. Loss of electrical power to Containment Instrument Air isolation valve 1IA012A caused the 1IA005 Outboard Containment Isolation Valve to close. Control room operators entered the abnormal procedure for loss of instrument air and dispatched an equipment operator to check the 4160V breaker.
13:48	Secondary Containment differential pressure high alarm due to Fuel Building Ventilation fans tripping due to dampers failing closed on the loss of AC power.
13:50	Operators placed the Standby Gas Treatment (VG) system in service due to Fuel Building ventilation tripping off due to loss of power and secondary containment differential pressure exceeding the Technical Specification limits. After starting the VG system, secondary containment differential pressure was restored to within limits in approximately 15 minutes.
13:53	Control rods started to drift in due to instrument air isolation. Operators manually scrammed the reactor by placing the Mode Switch in Shutdown. The operations crew entered Emergency Operating Procedure (EOP) 1, Reactor Pressure Vessel (RPV) Control (4401.01), due to low RPV water level (expected condition with scram) and entered Reactor Scram Procedure 4100.01. Reactor water level was initially maintained by the condensate and feedwater systems. Reactor pressure control was maintained using the turbine bypass valves. Operators also began reducing auxiliary steam loads to control the cooldown rate.
14:00	An equipment operator reported from the field that a relay flag on breaker 1AP07EJ had dropped indicating a phase to ground overcurrent trip.
14:20	Operators started the A Condenser Air Removal Pump and shutdown the 1B steam jet air ejector.
15:18	Operators removed the trip and control power fuses for the LPCS and RHR “A” pumps due to loss of water leg keep fill pumps.
15:55	1AP07EJ breaker door was opened for inspection.
16:12	Operators manually shut control rod drive flow control valve 1C11–F034 to reduce water input to reactor through the scram header (scram could not be reset due to loss of air pressure).

16:35	Operators completed the Division 1 DC load shed procedure to reduce load on Division 1 batteries.
16:48	Control room operators operated main steam line (MSL) drains to augment bypass valve pressure control (anticipating MSIV closure).
17:42	The licensee completed their Emergency Notification System notification (EN 5311). The event notification worksheet (NRC Form 361) included the loss of Division 1 AC power; a manual scram due to loss of instrument air pressure to containment, and a loss of scram air header pressure. Division 1 emergency core cooling (ECCS) systems (including LPCS) were de-energized due to the loss of electrical power. The plant was in Mode 3 and continuing to cool down.
17:50	Last inboard MSIV shut. Pressure control on MSL drains.
18:59	The reactor core isolation cooling system (RCIC) was started in tank-to-tank mode for reactor pressure control.
19:32	Operators placed RHR B in suppression pool cooling to support using RCIC for reactor pressure control.

December 10, 2017

06:44	Operators manually opened 1IA012A per loss of AC procedure to line up backup air bottles to Automatic Depressurization System (ADS) valves to maintain ADS operable.
07:08	1IA005 and 1IA008 gagged open to restore instrument air pressure to containment during loss of Division 1 AC power.
11:34	Control room operators reopened the MSIVs.
11:39	Control room operators shutdown RCIC.
11:46	Control room personnel reset the reactor scram signal.
11:47	RHR “B” shutdown from Suppression Pool Cooling Mode of operation.
12:21	Restored 1C11–F034 to normal lineup.
20:14	Entered Mode 4.
22:05	EOP entry conditions were cleared and the plant was stable in accordance with CPS 3006.01, Unit Shutdown. Operations pesonnel exited EOP–1.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, ILLINOIS 60532-4352

December 15, 2017

MEMORANDUM TO: James McGhee, Senior Resident Inspector
Byron Station
Division of Reactor Projects, Branch 3

FROM: Patrick L. Louden, Director ***/RA/***
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION TEAM CHARTER FOR CLINTON POWER STATION MANUAL SCRAM FOLLOWING LOSS OF DIVISION 1 480 VAC POWER, DECEMBER 9, 2017

On Saturday, December 9, 2017, control room operators manually scrammed the reactor from 98 percent power following an electrical system perturbation. The operators had received multiple alarms in the control room upon the unexpected opening of the 1A1 4160 VAC bus breaker 1AP07EJ, which powers the 1A and A1 480 VAC substation buses. The licensee determined that the breaker opened by design due to a fault on a 4160/480V step-down transformer that feeds the 1A 480 VAC substation bus. Several minutes after the breaker opened, the alarm came in for low scram pilot air header pressure. In response to two control rods drifting into the reactor, control room operators initiated a manual scram (mode switch to shutdown).

The loss of Division 1 480 VAC caused a loss of power to the Division 1 containment isolation solenoid valves and isolated instrument air (IA) to the containment and the drywell. This also resulted in a loss of air pressure to the inboard main steam isolation valves (MSIVs) and caused the inboard MSIVs to start closing sometime after the transformer fault.

The loss of Division 1 480 VAC also caused low pressure core spray (LPCS), a single-train system, and ‘A’ train of residual heat removal system to be rendered inoperable because of the loss of power to the keep fill pumps and AC powered motor operated valves. Reactor Core Isolation Cooling (RCIC) was later declared inoperable because the RCIC water leg pump could not function. The licensee could not be assured that these systems were free of voids.

Based on the deterministic criteria provided in Management Directive (MD) 8.3, “NRC Incident Investigation Program,” the event met MD 8.3 criterion (d), in that there was a loss of RCIC and LPCS, both single-train safety systems, and there was a loss of the secondary containment for 3 minutes. The event also met MD 8.3 criterion (g), in that the loss of power to the Division 1 480V substation bus was very similar to a failure that occurred in December 2013. The risk assessment resulted in an estimated Conditional Core Damage Probability (CCDP) range of 4E–6 to 9E–6 and put the event in the SIT region. The decision is to dispatch a special inspection team to the site beginning December 18, 2017. Although all plant systems appear to have operated per design and there were no operator performance issues, the CCDP for this event warrants a reactive inspection. The focus of the inspection is to gather initial information relative to licensee actions taken following the similar event that occurred in 2013 and to ascertain what the licensee’s plans are to evaluate the circumstances that led to the transformer failure on December 9, 2017. Pending further risk or operational insights that may be

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630–829–9628

Attachment 3

developed as the team gathers and evaluates the facts, an SIT was considered appropriate. On a daily basis, the team should evaluate the need for increasing the scope of the inspection if conditions warrant.

Accordingly, based on the deterministic and risk criteria in MD 8.3, and after consultation with NRR, a Special Inspection Team (SIT) will commence an inspection on December 18, 2017. The SIT will be led by you and will include Charles Phillips. In addition, John Hanna, the Senior Reactor Analyst, and John Robbins in DRS Engineering Branch 3 will be available to assist as needed.

The SIT will establish an overview of the December 9, 2017, event and evaluate the facts, circumstances, and the licensee's actions (taken and planned) surrounding the event. The specific charter for the Team is enclosed.

Docket No. 50–461
License No. NPF–62

Enclosure: Clinton Special Inspection Team Charter

CONTACT: Ken Riemer, DRP
630–829–9628

CLINTON SPECIAL INSPECTION TEAM CHARTER

This special inspection team is chartered to assess the circumstances surrounding the failure of the 4160 to 480 VAC 1A transformer and subsequent manual reactor scram on December 9, 2017. The decision to charter this Special Inspection Team is due to the loss of safety function of multiple safety systems and the failure of the 4160 to 480 VAC transformer and loss of the associated 480 substation buses, as well as the elevated risk resulting from the event and unavailability of these systems (Low pressure core spray, reactor core isolation cooling and secondary containment). The special inspection will be conducted in accordance with Inspection Procedure 93812, "Special Inspection." The special inspection will include, but is not limited to, the items listed below. This charter may be revised based on the results and findings of the inspection and the inspection results will be documented in NRC Inspection Report 05000461/2017012.

1. Establish an overview of events related to the transformer failure, reactor scram, and plant recovery actions. Review related licensee actions with respect to monitoring of plant conditions, procedure usage, and decision making.

2. Review the operation of the plant equipment in response to the transient, including adequacy of procedures and whether equipment operated in accordance with its design.

3. Evaluate licensee planned and completed corrective actions following the 2013 transformer failure and to the extent possible, assess if prior opportunities (e.g., surveillances, maintenance) existed to have identified transformer degradation or failure, at an earlier point in time

4. Review the licensee's extent of condition evaluation plan and related activities to evaluate the licensee's assessment of the condition of similar installed transformers.

5. Continually evaluate the complexity and significance of the event to determine if the circumstances warrant escalation of the inspection to an augmented inspection team (AIT). Consider any new insights or issues that indicate generic implications, increase in the risk evaluation, or design vulnerabilities.

6. Identify any lessons learned from the Special Inspection, and, as appropriate, prepare a feedback form on recommendations for improving reactor oversight process (ROP) baseline inspection procedures.

Special Inspection Team

James McGhee, Byron Senior Resident Inspector, SIT Team Leader
Charles Phillips, Project Engineer, DRP

Charter Approval

/RA Kenneth Riemer Acting for/ 12/15/17	L. Kozak, Acting Chief, Branch 1, Division of Reactor Projects
/RA/ 12/15/17	P. Louden, Director, Division of Reactor Projects
/RA Karla Stoedter Acting for/ 12/15/17	M. Shuaibi, Acting Director, Division of Reactor Safety

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