UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, IL 60532-4352

May 13, 2015

EA–15–064

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

SUBJECT: CLINTON POWER STATION–NRC INTEGRATED INSPECTION REPORT 05000461/2015001 AND PRELIMINARY WHITE FINDING

Dear Mr. Hanson:

On March 31, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Clinton Power Station. The enclosed report documents the inspection results, which were discussed on April 15, 2015, with Mr. M. Newcomer, and other members of your staff. Additionally, on April 17, 2015, the NRC discussed with Mr. M. Newcomer of your staff the preliminary White determination for the finding discussed below. This issue was discussed with your staff during the April 15 exit as an issue of concern.

The enclosed inspection report discusses a finding, concerning the failure of the Division 3 shutdown cooling water pump to perform its intended safety function, which has preliminarily been determined to be a White finding with low to moderate safety significance that may require additional inspections. After the Division 3 shutdown cooling water pump failed to start during a surveillance test, the causal investigation determined that the pump failed due to a damaged bushing that rendered the pump inoperable. Inspectors determined the pump design had been modified in October of 1995 after a similar pump failure occurred in 1990 and at that time the licensee failed to verify the design of the suction bell bushing for the replacement pump passed sufficient cooling water flow to the pump internals without being adversely affected and to prevent pump failure due to accumulation of mud and silt from the lake water.

This finding does not represent an immediate safety concern, in that you replaced the pump in September of 2014 with a pump of similar design in combination with additional monitoring of pump performance and provided adequate documentation that assures the pump will remain operable until a different design can be installed by June of 2016.

This finding with the supporting circumstances and details is documented in the enclosed inspection report. The finding was assessed based on the best available information, using the applicable Significance Determination Process. The basis for the NRC's preliminary significance determination is also described in the enclosed report. This finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement

action in accordance with the Enforcement Policy, which can be found on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

In accordance with NRC Inspection Manual Chapter 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of the date of this letter. The significance determination process is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not impact the timeliness of the staff's final determination.

Before the NRC makes a final decision on this matter, you may choose to (1) attend a Regulatory Conference where you can present to the NRC your perspective on the facts and assumptions the NRC used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will issue a public meeting notice and press release to announce the conference. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of your receipt of this letter. If you choose not to request a Regulatory Conference or to submit a written response, you will not be allowed to appeal the NRC's final significance determination.

Please contact Mr. James McGhee at 630–829–9731 and in writing within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. The final resolution of this matter will be conveyed in separate correspondence.

Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for the inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

This report also documents two additional findings of very low safety significance (Green). One of the findings involved a violation of NRC requirements and because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating the above inspector-identified violation as a non-cited violation (NCV) consistent with Section 2.3.2 of the NRC Enforcement Policy.

If you contest any NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555–0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555–0001; and the NRC Resident Inspector at Clinton Power Station. In addition, if you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement to the Regional Administrator, Region III, and the NRC Resident Inspector at Clinton Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Anne T. Boland, Director
Division of Reactor Projects

Docket No. 50–461
License No. NPF–62

Enclosure:
IR 05000461/2015001
w/Attachment: Supplemental Information

cc w/encl: Distribution via LISTSERV®

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50–461
License No:	NPF–62
Report No:	05000461/2015001
Licensee:	Exelon Generation Company, LLC
Facility:	Clinton Power Station, Unit 1
Location:	Clinton, IL
Dates:	January 1 through March 31, 2015
Inspectors:	W. Schaup, Senior Resident Inspector E. Sanchez-Santiago, Resident Inspector C. Hunt, Acting Resident Inspector J. Gilliam, Senior Reactor Inspector S. Bell, Health Physicist M. Jones, Inspector S. Mischke, Resident Inspector, Illinois Emergency Management Agency
Approved by:	J. McGhee, Acting Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000461/2015001, 01/01/15–03/31/15, Clinton Power Station, Unit 1; Operability Determinations and Functional Assessments, Identification and Resolution of Problems and Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three findings were identified by the inspectors. One of these findings was considered an apparent violation 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 June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects 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 February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process" Revision 5, dated February 2014.

Cornerstone: Mitigating Systems

Green. The inspectors identified a Green Finding associated with the licensee's failure to perform a channel calibration with appropriate acceptance criteria to determine the functionality of the stations seismic monitoring equipment used for evaluating earthquakes. Specifically, station procedure CPS 9437.21, "Triax Time-History Accelerometer Channel Calibration," Revision 39c, did not include steps with clear acceptance criteria to ensure that battery backup power was provided to operate the equipment on a loss of the normal power source as part of the operability requirements. The licensee documented the issue in the corrective action program (CAP) as action request (AR) 02454630. The licensee performed an operability evaluation and determined that the original voltage read by the technicians was outside the band described in the procedure but was within the band described by the vendor and therefore was operable. The licensee also planned to change the surveillance test procedure to clarify the acceptance criteria.

The licensee's failure to perform a channel calibration with appropriate acceptance criteria to determine the functionality of the stations seismic monitoring equipment used for evaluating earthquakes was a performance deficiency. Specifically, station procedures did not include steps with clear acceptance criteria to ensure that battery backup power was provided to operate the equipment on a loss of the normal power source. The performance deficiency was more than minor because it adversely impacted the protection against external factors attribute of the Mitigating Systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Using IMC 0609, Attachment 4 "Initial Characterization of Findings," and Appendix A "The Significance Determination Process for Findings at Power", issued June 19, 2012, the inspectors answered "Yes" to the Mitigating Systems cornerstone question, "Does the finding involve the …degradation of equipment…specifically designed to mitigate a seismic…initiating event…." Therefore, the inspectors addressed the questions in Exhibit 4, "External Event Screening Questions." The inspectors answered "No" to the two questions in Exhibit 4. Specifically, 1) if completely failed the seismic monitor would not cause an initiating event or degrade multi-trains or risk-significant systems; and 2)

the finding does not involve the total loss of any safety function. The inspectors determined this finding affected the cross-cutting area of human performance in the aspect of conservative bias where individuals use decision making-practices that emphasize prudent choices over those that are simply allowable and a proposed action is determined to be safe in order to proceed, rather than unsafe in order to stop. Specifically, the licensee documented the issue of the voltage being high out of specification and instead of performing additional corrective actions to determine if leaving the voltage out of specification was appropriate marked the step as not applicable and proceeded with the rest of the procedure. [H.14] (Section 1R15)

Green. The inspectors identified a finding and an associated non-cited violation (NCV) of 10 CFR Part 50 Appendix B, Criterion III, "Design Control," for the failure to maintain safety-related cables for the shutdown service water (SX) system in an environment for which they were designed. Specifically, the licensee failed to maintain SX safety-related cables in an environment for which they were designed when the cables were allowed to be submerged in water inside cable vaults. The design of the system used monitor and pump down the cable vaults did not indicate that the system had failed, leading the licensee to believe that the environmental conditions in which the cables were stored were acceptable even when they were not. The licensee documented this issue in their CAP as AR 02474543. Corrective actions included draining the cable vaults so that the cables were no longer submerged and planned to repair all affected solar powered pumps and associated alarm systems.

The licensee's failure to maintain safety-related cables for the SX system in an environment for which they were designed was a performance deficiency. Specifically, the licensee failed to maintain SX safety-related cables in an environment for which they were designed when the cables were allowed to be submerged in water inside cable vaults. The performance deficiency was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined the finding could be evaluated using IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," issued on June 19, 2012. Specifically, the inspectors used IMC 0609 Appendix A "SDP for Findings At-Power," issued June 19, 2012, Exhibit 2, "Mitigating Systems Screening Questions" to screen the finding. The finding screened as of very low safety significance (Green) because the inspectors answered "Yes" to the question "does the SSC maintain its operability or functionality." Specifically, the SX system submerged cables did not cause the SX system to be inoperable or nonfunctional. The inspectors determined this finding affected the cross-cutting area of problem identification and resolution in the aspect of resolution, where the organization takes effective corrective actions to address issues in a timely manner commensurate with their safety significance. Specifically, the licensee failed to implement effective corrective actions to address an adverse trend of water in cable vaults which led to SX safety-related cables being submerged in water. [P.3] (Section 4OA2)

Preliminary White. A self-revealed finding, preliminarily determined to be of low to moderate safety significance (White) and an associated apparent violation (AV) of 10 CFR Part 50 Appendix B, Criterion III, Design Control was identified for the failure to verify the suitability of the replacement pump design for the Division 3 Shutdown Service Water system. Specifically, the licensee failed to verify the design of the suction bell

bushing for the replacement pump would pass sufficient cooling water flow to the pump internals without being affected by mud and silt from the lake water, resulting in the failure of the pump. This finding was self-revealed on September 16, 2014, during a surveillance test to ensure operability of the Division 3 shutdown cooling water pump, after the pump failed to start due to a damaged bushing rendering the pump inoperable. This finding does not represent an immediate safety concern because the licensee replaced the pump in September of 2014 with a pump of similar design in combination with additional monitoring of pump performance and provided adequate documentation that assures the pump will remain operable until a different design can be installed by June of 2016.

The inspectors determined that the licensee's failure to verify the suitability of the design for the Division 3 SX replacement pump for conditions under which it was to be used, as required by 10 CFR Part 50, Appendix B, Criterion III, Design Control, was a performance deficiency. Specifically, the licensee failed to verify the design of the suction bell bushing for the replacement pump would pass sufficient cooling water flow to the pump internals without being affected by mud and silt from the lake water, resulting in the failure of the pump. 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 was associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. A Significance and Enforcement Review Panel, using IMC 0609, Appendix A, "Significance Determination Process for Findings At-Power," dated June 19, 2012, preliminarily determined the finding to be of low to moderate safety significance (White). The performance deficiency associated with this finding did not reflect current licensee performance; therefore, no cross-cutting aspect was identified with this finding. (Section 4OA3)

REPORT DETAILS

Summary of Plant Status

The unit was operated at or near full power during the inspection period with the following exceptions:

- January 20, 2015, the unit was shut down to perform a maintenance outage. The unit was restarted and returned to full power on January 26, 2015.
- February 15, 2015, power was reduced to 73 percent to perform end of life rod pattern adjustments. The unit was returned to full power the same day.
- March 1, 2015, power was reduced to 78 percent to perform end of life rod pattern adjustments. The unit was returned to full power the same day.
- March 15, 2015, power was reduced to 78 percent to perform end of life rod pattern adjustments. The unit was returned to full power the same day.
- March 22, 2015, power was reduced to 85 percent to perform end of life rod pattern adjustments. The unit was returned to full power the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition–Heavy Snowfall Conditions

a. Inspection Scope

On January 4 and again on January 11, 2015, a winter weather advisory was issued for expected snow falls. The inspectors observed the licensee's preparations and planning for the significant winter weather potential. The inspectors reviewed licensee procedures and discussed potential compensatory measures with control room personnel. The inspectors focused on plant management's actions for implementing the station's procedures for ensuring adequate personnel for safe plant operation and emergency response would be available. The inspectors conducted a site walkdown including walkdowns of various plant structures and systems to check for maintenance or other apparent deficiencies that could affect system operations during the predicted significant weather. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

This inspection constituted one readiness for impending adverse weather condition sample as defined in Inspection Procedure (IP) 71111.01–06.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04Q)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Reactor core isolation cooling following maintenance;
- Instrument air following maintenance; and
- Residual heat removal (RHR) train 'A' during maintenance on RHR train 'B'.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones. The inspectors reviewed operating procedures, system diagrams, Technical Specification (TS) requirements, and the impact of ongoing work activities on redundant trains of equipment. The inspectors verified that conditions did not exist that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components were aligned correctly and available as necessary.

In addition, the inspectors verified that equipment alignment problems were entered into the licensee's CAP with the appropriate characterization and significance. Selected ARs were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

These activities constituted three partial system walkdown samples as defined in IP 71111.04–01.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On March 20, 2015, and March 23, 2015, the inspectors performed a complete system alignment inspection of the battery and the direct current (DC) distribution electrical system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding work orders (WOs) was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved.

These activities constituted one complete system walkdown sample as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Zone A–2a, RHR A Pump and Cooler Rooms–Elevation 707' and 781';
- Fire Zone CB–3d, Division 4 Battery Room–Elevation 781';
- Fire Zone CB–3b, Division 4 Inverter Room–Elevation 781'; and
- Fire Zone CB–6a, Control Room–Elevation 800'.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On March 13, 2015, the inspectors observed a fire brigade activation for a fire in the turbine building. Based on this observation, the inspectors evaluated the readiness of

the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate firefighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07T)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed completed surveillances, vendor manual information, calculations, maintenance records, and cooler inspection results associated with the Division 3 emergency diesel generator (EDG) cooling water heat exchanger and the 1VY05S RHR heat exchanger cubicle cooler. These heat exchangers were chosen based on their risk significance in the licensee's probabilistic safety analysis, their important safety-related mitigating system support functions, their operating history, and their relatively low margin.

For the Division 3 EDG jacket water heat exchanger and the RHR heat exchanger cubicle cooler, the inspectors verified that testing, inspection, maintenance, and monitoring of biotic fouling and macro fouling programs were adequate to ensure proper heat transfer. This was accomplished by verifying the test method used was consistent with accepted industry practices, or equivalent, the test conditions were consistent with the selected methodology, the test acceptance criteria were consistent with the design basis values, and results of heat exchanger flow and resistance testing. The inspectors also verified that the test results appropriately considered differences between testing conditions and design conditions, the frequency of testing based on trending of test results was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values, and test results considered test instrument inaccuracies and differences.

For the Division 3 EDG jacket water heat exchanger, the inspectors reviewed the methods and results of heat exchanger performance inspections. The inspectors verified the methods used to inspect and clean heat exchangers were consistent with as-found conditions identified and expected degradation trends and industry standards, the licensee's inspection and cleaning activities had established acceptance criteria consistent with industry standards, and the as-found results were recorded, evaluated, and appropriately dispositioned such that the as-left condition was acceptable.

In addition, the inspectors verified the condition and operation of the Division 3 EDG jacket water heat exchanger and the RHR heat exchanger cubicle cooler were consistent with design assumptions in heat transfer calculations, and as described in the Final Safety Analysis Report. This included verification that the number of plugged tubes was within pre-established limits based on capacity and heat transfer assumptions. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchangers.

The inspectors verified the performance of ultimate heat sink and safety-related service water system and their subcomponents such as piping, intake screens, pumps, valves, etc. by tests or other equivalent methods to ensure availability and accessibility to the in plant cooling water systems.

The inspectors reviewed the licensee's performance testing of service water system and ultimate heat sink results. This included the review of the licensee's performance test results for key components and service water flow balance test results. In addition, the inspectors compared the flow balance results to system configuration and flow assumptions during design basis accident conditions. The inspectors also verified that the licensee ensured adequate isolation during design basis events, consistency between testing methodologies and design basis leakage rate assumptions, and proper performance of risk significant non-safety related functions.

The inspectors performed a system walkdown of the service water intake structure to verify the licensee's assessment on structural integrity and component functionality. This included the verification that licensee ensured proper functioning of traveling screens and strainers, and structural integrity of component mounts. In addition, the inspectors verified that service water pump bay silt accumulation is monitored, trended, and maintained at an acceptable level by the licensee, and that water level instruments are functional and routinely monitored. The inspectors also verified the licensee's ability to ensure functionality during adverse weather conditions. The inspectors also verified that adequate water would still flow past sand-limiting underwater weir walls during periods of low river or lake level. The inspectors also verified that the licensee had adequately protected against silt introduction during periods of low-flow or low-level.

In addition, the inspectors reviewed condition reports related to the heat exchangers/coolers and heat sink performance issues to verify that the licensee had an appropriate threshold for identifying issues and to evaluate the effectiveness of the corrective actions. The documents that were reviewed are included in the Attachment to this report.

These inspection activities constituted three heat sink inspection samples as defined in Inspection Procedure 71111.07–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On February 4, 2015, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On January 24, 2015, the inspectors observed the operations staff in the control room during reactor plant start up. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;

- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications (if applicable).

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Planned yellow risk during maintenance activities while disconnecting/connecting 1F battery charger to Motor Control Center 1F;
- Planned yellow risk during maintenance on Reactor Core Isolation Cooling system;
- Emergent work on source range monitors ‘B’ ‘C’ and ‘D’ during a maintenance outage;
- Planned yellow risk during system outage maintenance on standby gas treatment system train B;
- Planned yellow risk during system outage maintenance on the RHR train A;
- Unplanned yellow risk due to the Division 2 EDG declared inoperable due to voltage and megavolts amps reactive (MVAR) swings during surveillance testing;
- Unplanned yellow risk due to the Division 1 EDG declared inoperable due to emergent immersion heater replacement; and
- Planned yellow risk during system outage maintenance on RHR system train B.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

These maintenance risk assessments and emergent work control activities constituted eight samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Reactor core isolation cooling room cooler cooling water blockage;
- Non-conforming door seal gasket installed on the fuel building rail road bay airlock inner door 1HC72G;
- RHR trains B/C water leg pump data outside of acceptable range;
- Seismic Monitor declared functional without complete channel calibration; and
- Division 2 EDG inoperable due to abnormal voltage control.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and updated safety analysis report to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of CAP documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

In addition, the inspectors verified that problems related to the operability or functionality of safety-related plant equipment was entered into the licensee's CAP with the appropriate characterization and significance. Selected condition reports were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

This operability inspection constituted five samples as defined in IP 71111.15–05.

b. Findings

Failure to Perform Adequate Channel Calibration on Seismic Instrumentation

Introduction. The inspectors identified a Green Finding associated with the licensee's failure to perform a channel calibration with appropriate acceptance criteria to determine the functionality of the stations seismic monitoring equipment used for evaluating earthquakes. Specifically, station procedure CPS 9437.21, "Triax Time-History Accelerometer Channel Calibration," Revision 39c, did not include steps with clear

acceptance criteria to ensure that battery backup power was provided to operate the equipment on a loss of the normal power source as part of the operability requirements.

Description. On November 12, 2014, station instrument and control technicians completed a channel calibration on the seismic monitoring equipment used for evaluating earthquakes and reported to the operation's staff in the control room that the procedure was completed satisfactorily and all operability requirements had been satisfied. Based upon the report the operation's staff logged on November 12, 2014, at 8:30 p.m. that the seismic instrumentation was functional.

The inspectors reviewed AR 02410683, "Seismic System Power Supply Voltage Found/Left Out Of Specification," on November 13, 2014. The AR described that the power supply voltage was found out of tolerance, an attempt was unsuccessfully made to adjust the voltage to within tolerance, and the voltage was left out of tolerance. The procedure step was marked not applicable and the procedure was completed with no further corrective actions. The inspectors reviewed the channel calibration procedure and questioned the control room operators as to why the out of tolerance voltage found on the power supply was not considered an operability requirement per the channel calibration procedure. The inspectors question was documented in AR 02411232. The licensee performed an operability evaluation and determined that the original voltage read by the technicians was outside the band described in the procedure but was within the band described by the vendor and therefore was operable.

After a further review of procedure CPS 9437.21 and a discussion with the system manager the inspectors determined that the step that was marked not applicable was a voltage check to ensure the voltage applied from the power supply to the battery backup was within specification to maintain the battery charged. The inspectors reviewed the Updated Safety Analysis Report (USAR), specifically section 3.7.4.2.5 "Instrument Performance," which stated that battery backup power is automatically provided to operate the equipment on a loss of the normal power source with the exception of the printer; therefore, the inspectors concluded that battery power is required for the seismic monitor to be functional. This was also in alignment with ANSI N18.5–1976 section 5.1.2 "Power Source," that stated the instrument power source shall have sufficient capacity for a time period longer than the maintenance interval to provide required continuous standby power and sufficient power for a minimum 25 minutes of system operation at any time. The licensee was committed to the ANSI standard through a USAR commitment to Regulatory Guide 1.12, "Nuclear Power Plant Instrumentation for Earthquakes," Revision 1.

The inspectors also reviewed the operational requirements manual (ORM) section 2.2.7 "Seismic Monitoring Instrumentation." Sub-section 4.2.7.2 of the seismic monitoring instrumentation section 2.2.7 stated, in part, "to perform a channel calibration for each of the required seismic monitoring instruments." Section 1.1.3 of the ORM states, in part, "that the channel calibration shall encompass all devices in the channel required for channel operability." The inspectors determined this would include the battery since it is part of the license basis and required to satisfy ANSI N18.5–1976 section 5.1.2.

Analysis. The licensee's failure to perform a channel calibration with appropriate acceptance criteria to determine the functionality of the stations seismic monitoring equipment used for evaluating earthquakes. in accordance with their ORM section 2.2.7, "Seismic Monitoring Instrumentation" and USAR 3.7.4.2.5 "Instrument Performance,"

was a performance deficiency. Specifically, station procedures did not include steps with clear acceptance criteria to ensure that battery backup power was provided to operate the equipment on a loss of the normal power source. The performance deficiency was more than minor because it adversely impacted the protection against external factors attribute of the Mitigating Systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, Attachment 4, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process for Findings at Power," issued June 19, 2012, the inspectors answered "Yes" to the Mitigation Systems cornerstone question, "Does the finding involve the …degradation of equipment…specifically designed to mitigate a seismic…initiating event…." Therefore, the inspectors addressed the questions in Exhibit 4, "External Event Screening Questions." The inspectors answered "No" to the two questions in Exhibit 4. Specifically, 1) if completely failed the seismic monitor would not cause an initiating event or degrade multi-trains or risk-significant systems; and 2) the finding does not involve the total loss of any safety function. Therefore, the finding was screened against the mitigating system cornerstone and determined to be of very low safety significance (Green). The Mitigating Systems cornerstone was applicable because of the requirement in 10 CFR Part 50, Appendix S, Section IV (a)(3), to shut down the reactor if the Operating Basis Earthquake ground motion vibration was exceeded.

The inspectors determined this finding affected the cross-cutting area of Human Performance in the aspect of conservative bias where individuals use decision making-practices that emphasize prudent choices over those that are simply allowable and a proposed action is determined to be safe in order to proceed, rather than unsafe in order to stop. Specifically, the licensee documented the issue of the voltage being high out of specification and instead of performing additional corrective actions to determine if leaving the voltage out of specification was appropriate marked the step as not applicable and proceeded with the rest of the procedure [H.14].

Enforcement. This finding does not involve enforcement action because no violation of a regulatory requirement was identified. The procedure in question was neither safety-related nor was it a procedure described in Regulatory Guide 1.33, Appendix A. The licensee performed an operability evaluation and determined that the original voltage read by the technicians was outside the band described in the procedure but was within the band described by the vendor and therefore was operable. The licensee also planned to change the surveillance test procedure to clarify the acceptance criteria. The Licensee placed this into the CAP as AR 2454630. Because this finding does not involve a violation and is of very low safety significance, it is identified as a FIN. **(FIN 05000461/2015001–01, "Failure to Perform Adequate Channel Calibration on Seismic Instrumentation.")**

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance (PM) activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Testing of the secondary containment railroad bay;
- Testing of the high pressure core spray (HPCS) chiller air operated valves;
- Testing of the HPCS shut down service water relief valves;
- Testing of the reactor core isolation cooling pump steam line inboard isolation valve;
- Testing of the reactor core isolation cooling pump suction from suppression pool valve thermal overload;
- Testing of the reactor water cleanup line flow to main condenser flow detector; and
- Testing of control room ventilation train 'B' hydramotors.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed CAP documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted seven post-maintenance testing sample as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Maintenance Outage C1M21 (71111.20)

a. Inspection Scope

The inspectors evaluated outage activities during a Unit 1 maintenance outage C1M21, which began on January 20, 2015. Unit 1 was placed into cold shutdown from 98.5 percent power to repair a leak on the reactor core isolation cooling pump steam line inboard isolation valve in the drywell and to perform other maintenance activities. The unit was restarted on January 24, 2015, and returned to 98.5 percent power on January 26, 2015, after repairing the leak.

The inspectors reviewed and evaluated the conduct of outage activities to ensure that the licensee considered risk in developing, planning, and implementing the maintenance outage schedule. The inspectors observed or reviewed plant equipment configuration and risk management, electrical lineups, startup activities, and identification and resolution of problems associated with the outage.

This inspection constituted one outage activities sample as defined in IP 71111.20.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- CPS 9054.01C002, “RCIC (1E51–C001) High Pressure Operability Checks” (In-service Test);
- CPS 9080.02, “Diesel Generator 1B Operability-Manual and Quick Start Operability” (Routine Test);
- CPS 9333.30, “Division II 4.16KV Degraded Voltage Trip–Functional Test” (Routine Test);
- CPS 90803.1, “Division III Diesel Generator Individual Engine Over Speed Test and Adjustment” (Routine Test);
- CPS 9051.01, “High Pressure Core Spray Pump and High Pressure Core Spray water Leg Pump Operability” (In-Service Test);
- CPS 9052.01, “LPCS Pump (section 8.3) and RHR A Pump (section 8.2) Operability” (In-Service Test); and
- CPS 9861.03, “Type B local Leak Rate Tests–Drywell Air Lock Seal Leak Rate Test” (Routine).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted four routine surveillance testing samples and three in-service testing samples as defined in IP 71111.22, Section–02 and–05.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a licensee table top emergency drill on March 25, 2015 to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06–05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation (71124.08)

This inspection constituted one complete sample as defined in IP71124.08–05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the solid radioactive waste system description in the Final Safety Analysis Report (FSAR), the Process Control Program, and the recent radiological Effluent Release Report for information on the types, amounts, and processing of radioactive waste disposed.

The inspectors reviewed the scope of quality assurance audits in this area since the last inspection to gain insights into the licensee's performance, and inform the "smart sampling" inspection planning.

b. Findings

No findings were identified.

.2 Radioactive Material Storage (02.02)

a. Inspection Scope

The inspectors selected areas where containers of radioactive waste were stored, and evaluated whether the containers were labeled in accordance with Title 10, *Code of Federal Regulations* (CFR) 20.1904, "Labeling Containers," or controlled in accordance with 10 CFR 20.1905, "Exemptions to Labeling Requirements."

The inspectors assessed whether the radioactive material storage areas were controlled and posted in accordance with the requirements of 10 CFR Part 20, "Standards for Protection against Radiation." For materials stored or used in the controlled or unrestricted areas, the inspectors evaluated whether they were secured against unauthorized removal and controlled in accordance with 10 CFR 20.1801, "Security of Stored Material," and 10 CFR 20.1802, "Control of Material Not in Storage."

The inspectors evaluated whether the licensee established a process for monitoring the impact of long term storage (e.g., buildup of any gases produced by waste decomposition, chemical reactions, container deformation, loss of container integrity, or re-release of free-flowing water) that was sufficient to identify potential unmonitored, unplanned releases or non-conformance with waste disposal requirements.

The inspectors selected containers of stored radioactive material, and assessed for signs of swelling, leakage, and deformation.

b. Findings

No findings were identified.

.3 Radioactive Waste System Walkdown (02.03)

a. Inspection Scope

The inspectors walked down accessible portions of select radioactive waste processing systems to assess whether the current system configuration and operation agreed with the descriptions in the FSAR, Offsite Dose Calculation Manual, and the Process Control Program.

The inspectors reviewed administrative and/or physical controls (i.e., drainage and isolation of the system from other systems) to assess whether the equipment which is not in service or abandoned in place would not contribute to an unmonitored release path and/or affect operating systems, or be a source of unnecessary personnel exposure. The inspectors assessed whether the licensee reviewed the safety significance of systems and equipment abandoned in place in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments."

The inspectors reviewed the adequacy of changes made to the radioactive waste processing systems since the last inspection. The inspectors evaluated whether changes from what is described in the FSAR were reviewed and documented in accordance with 10 CFR 50.59, as appropriate, and to assess the impact on radiation doses to members of the public.

The inspectors selected processes for transferring radioactive waste resin and/or sludge discharges into shipping/disposal containers, and assessed whether the waste stream mixing, sampling procedures, and methodology for waste concentration averaging were consistent with the Process Control Program, and provided representative samples of the waste product for the purposes of waste classification as described in 10 CFR 61.55, "Waste Classification."

For those systems that provide tank recirculation, the inspectors evaluated whether the tank recirculation procedures provided sufficient mixing.

The inspectors assessed whether the licensee's Process Control Program correctly described the current methods and procedures for dewatering and waste stabilization (e.g., removal of freestanding liquid).

b. Findings

No findings were identified.

.4 Waste Characterization and Classification (02.04)

a. Inspection Scope

The inspectors selected the following radioactive waste streams for review:

- 10 CFR 61 Analysis; "Concentrated Waste";
- 10 CFR 61 Analysis; "Spent Resin"; and
- 10 CFR 61 Analysis; "Fuel Pool Sludge."

For the waste streams listed above, the inspectors assessed whether the licensee's radiochemical sample analysis results (i.e., "10 CFR Part 61" Analysis) were sufficient to support radioactive waste characterization as required by 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste." The inspectors evaluated whether the licensee's use of scaling factors and calculations to account for difficult-to-measure radionuclides was technically sound and based on current 10 CFR Part 61 analyses for the selected radioactive waste streams.

The inspectors evaluated whether changes to plant operational parameters were taken into account to: (1) maintain the validity of the waste stream composition data between the annual or biennial sample analysis update; and (2) assure that waste shipments continued to meet the requirements of 10 CFR Part 61 for the waste streams selected above.

The inspectors evaluated whether the licensee had established and maintained an adequate Quality Assurance Program to ensure compliance with the waste classification and characterization requirements of 10 CFR 61.55, and 10 CFR 61.56, "Waste Characteristics."

b. Findings

No findings were identified.

.5 Shipment Preparation (02.05)

a. Inspection Scope

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness. The inspectors assessed whether the requirements of applicable transport cask certificate of compliance had been met. The inspectors evaluated whether the receiving licensee was authorized to receive the shipment packages. The inspectors evaluated whether the licensee's procedures for cask loading and closure procedures were consistent with the vendor's current approved procedures.

The inspectors observed radiation workers during the conduct of radioactive waste processing, and radioactive material shipment preparation and receipt activities. The inspectors assessed whether the shippers were knowledgeable of the shipping regulations and whether shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to:

- As appropriate, the licensee's response to U.S. Nuclear Regulatory Commission Bulletin 79–19, "Packaging of Low-Level Radioactive Waste for Transport and Burial," dated August 10, 1979; and
- Title 49 CFR Part 172, "Hazardous Materials Table, Special Provisions, Hazardous Materials Communication, Emergency Response Information, Training Requirements, and Security Plans," Subpart H, "Training."

Due to limited opportunities for direct observation, the inspectors reviewed the technical instructions presented to workers during routine training. The inspectors assessed whether the licensee's training program provided training to personnel responsible for the conduct of radioactive waste processing, and radioactive material shipment preparation activities.

b. Findings

No findings were identified.

.6 Shipping Records (02.06)

a. Inspection Scope

The inspectors evaluated whether the shipping documents indicated the proper shipper name; emergency response information and a 24-hour contact telephone number; accurate curie content and volume of material; and appropriate waste classification, transport index, and UN number for the following radioactive shipments:

- Radioactive Waste Shipment W14–015; Spent Resin; dated March 1, 2014;
- Radioactive Waste Shipment W14–005; Concentrated Waste; dated December 10, 2014;
- Radioactive Material Shipment M13–033; Calibration Source; dated September 9, 2013; and
- Radioactive Waste Shipment W14–016; Powered Resin; dated November 25, 2014.

Additionally, the inspectors assessed whether the shipment placarding was consistent with the information in the shipping documentation.

b. Findings

No findings were identified.

.7 Identification and Resolution of Problems (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with radioactive waste processing, handling, storage, and transportation, were being identified by the licensee at an appropriate threshold, were properly characterized, and were properly addressed for resolution in the licensee's CAP. Additionally, the inspectors evaluated whether the corrective actions were appropriate for a selected sample of problems documented by the licensee that involve radioactive waste processing, handling, storage, and transportation.

The inspectors reviewed results of selected audits performed since the last inspection of this program, and evaluated the adequacy of the licensee's corrective actions for issues identified during those audits.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator (PI) for the period from the first quarter 2014 through the fourth quarter 2014. To determine the accuracy of the PI data reported during those periods, guidance contained in Nuclear Energy Institute (NEI) 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted one unplanned scrams per 7000 critical hours sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications performance indicator for the period from first quarter 2014 through the fourth quarter 2014. To determine the accuracy of the PI data reported during those periods, guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted one unplanned scrams with complications sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Unplanned Transients per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients per 7000 Critical Hours performance indicator for the period from the first quarter 2014 through the fourth quarter 2014. To determine the accuracy of the PI data reported during those periods, guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted one unplanned transients per 7000 critical hours sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.4 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator for the period from the first quarter 2014 through the fourth quarter

2014. To determine the accuracy of the PI data reported during those periods, guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, and NUREG–1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance, were used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted one safety system functional failures sample as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline IPs discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 (Closed) Unresolved Item 05000461/2014005–02 Potential Failure to Maintain Safety Related Cables in a Qualified Environment

a. Inspection Scope

On October 14, 2014, the licensee commenced their periodic inspection of safety related cable vaults. These cable vaults housed cables related to all 3 divisions of SX and the division 3 EDG. When the licensee opened the cable vaults, they found that 6 out of 10 vaults contained water at a level that would cause the cables to be in a submerged condition. The inspectors pursued this issue in order to determine whether the cables were operable and whether the licensee was taking appropriate actions to address the issue.

The inspectors reviewed previous CAP documents related to a similar issue as well as operating experience from other nuclear sites. The inspectors also reviewed industry documents, and regulatory documents related to safety related cable submergence. These reviews were conducted in order to understand what the requirements for safety related cables are and whether the actions taken by the licensee were in compliance with those requirements.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152–05.

b. Findings

Unqualified Safety-Related Cables Used in a Submerged Environment

Introduction. The inspectors identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to maintain shutdown SX safety-related cables in an environment for which they were designed. Specifically, the licensee failed to maintain SX safety-related cables in an environment for which they were designed when the cables were allowed to be submerged in water inside cable vaults.

Description. In 2007 the component design basis inspection (CDBI) team issued an NCV for 10 CFR Part 50, Appendix B, Criterion III, "Design Control" to Clinton for having continuously submerged safety-related cables. During the 2007 inspection the licensee initiated issue report 00692997, "CDBI—Submerged Cable Long Term Asset Management Strategy," dated November 01, 2007, with corrective actions to review their cable monitoring program and initiate long term corrective actions.

As a corrective action to the violation in 2009 the licensee installed solar powered sump pumps in all of the cable vaults on site. The system included a float mechanism that would provide local indication when water was accumulating in the vaults; a yellow light would indicate water had reached a level requiring pump down of the vault. A red light would indicate water had reached the cables, and therefore immediate actions should be taken to pump down the cable vaults.

In October of 2014 when the licensee was conducting their periodic inspection of the safety-related cable vaults they found that 6 vaults contained water to a level where the cables were submerged. The licensee discovered the lights were not lit, as expected, as the vaults were found to be full of water. After further investigation the licensee concluded that in some cases the float switches that trigger the lights were not functioning properly and in other cases the light bulbs were not functional. The cable vaults which were discovered to be full of water included medium and low voltage SX cables which provide power and control to the SX pump motors. The licensee's calculated time for the SX cables being submerged was prior to the modification put in place in 2009 (~22 years). The licensee was not able to calculate the total amount of time the cables were submerged, post installation of the sump pump modification.

When the cables were found to be under water, the inspectors attempted to determine if the cables were designed to withstand submergence. When no qualifying documentation could be identified, the inspectors reviewed the site's operability evaluation. Subsequently, the licensee documented they believed the cables were rated for submergence because of a study performed by the manufacturer of the cables; Okonite. After further reviews and discussions with subject matter experts form the NRC headquarters, the inspector's added value to this issue by determining the cables were not qualified for submergence and additional evaluations would be necessary to support the licensee's operability determination. The licensee performed a technical evaluation and determined the cables are currently operable. The bases for this decision were the results of the planned inspection of the exterior of the cables, which found no evidence of cable degradation. In addition, the licensee stated that the SX pumps were tested periodically and have run without issue. The licensee also planned to perform additional testing on the cables during the system outage windows for the SX system.

The licensee initiated AR 02398273, "Cable Vault Flooding," with actions to drain the cable vaults.

Analysis: The inspectors determined the licensee's failure to maintain safety-related cables for the SX system in an environment for which they were designed was contrary to 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency. Specifically, the licensee failed to maintain SX safety-related cables in an environment for which they were designed when the cables were allowed to be submerged in water inside cable vaults. The performance deficiency was determined to be more than minor because the finding was associated with the Mitigating Systems

Cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings,” issued on June 19, 2012. Specifically, the inspectors used IMC 0609 Appendix A “SDP for Findings At-Power,” issued June 19, 2012, Exhibit 2, “Mitigating Systems Screening Questions” to screen the finding. The finding screened as of very low safety significance (Green) because the inspectors answered "Yes" to the question “does the SSC maintain its operability or functionality.” Specifically, the SX system submerged cables did not cause the SX system to be inoperable or nonfunctional.

This finding has a cross-cutting aspect in the area of problem identification and resolution in the aspect of resolution, where the organization takes effective corrective actions to address issues in a timely manner commensurate with their safety significance. Specifically, the licensee failed to implement effective corrective actions to address an adverse trend of water in cable vaults which led to SX safety-related cables being submerged in water for extended periods of time [P.3].

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. It further requires, in part, that these measures include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above, since about February 14, 2013, through October 14, 2014, the licensee failed to assure that deviations from a specified standard were controlled. Specifically, the licensee failed to maintain ‘SX’ safety-related cables in an environment for which they were designed, as specified by the design qualification document, when the cables were allowed to be submerged in water inside the cable vaults. The design of the system used to monitor and pump down the cable vaults did not indicate that the system had failed, leading the licensee to believe that the environmental conditions in which the cables were stored were acceptable even when they were not. The licensee pumped down all affected cable vaults and planned to repair all affected solar powered pumps and associated alarm systems. Because this violation was of very low safety significance and was entered into the licensee’s CAP as AR 02474543 this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000461/2015001–02, “Unqualified Safety-Related Cables Used in a Submerged Environment.”)**

4OA3 Follow-Up of Events and Notices of Enforcements Discretion (71153)

.1 (Closed) Licensee Event Report 2014–003–00: Misapplication of Support System Technical Specification Requirements Resulted in Implementation of Non-Conservative Guidance For Removal of Essential Switchgear Heat Removal System in Service.

a. Inspection Scope

On June 22, 2014, during a planned outage of the Division 1 essential switchgear heat removal (VX) system, the inspectors questioned the practice of the licensee entering the actions of the stations ORM for the VX system instead of entering any plant TS limiting condition for operation and the required actions for the systems that VX supports. As a result of the question, the licensee determined that the actions in the ORM were not applicable and that the appropriate action would be to enter into the TS limiting condition for operation and the required actions for TSs 3.8.4 or 3.8.5, Divisional DC Sources, 3.8.7 or 3.8.8, Divisional Inverters, and 3.8.9 or 3.8.10, Electrical Power Distribution Systems.

The licensee performed an investigation and determined that the cause of the condition was that a misapplication of TS 3.0.6 for support systems with TSs was used as a bases for implementation of a non-conservative operation requirements manual administrative control for the removal of the VX system from service instead of applying the TS definition for operable that states in part that all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function is capable of performing their related support function.

The inspectors issued an NCV for the licensee's failure to enter the TSs and complete the associated actions prior to the completion time when auxiliary equipment required to support electrical power system safety function was out of service in inspection report 2014004 **(NCV 05000461/2014004–01, "Technical Specification Allowed Outage Time Exceeded for Electrical Power Systems Due to Auxiliary Equipment Out of Service.")**

Additionally, the inspectors reviewed the root cause evaluation as well as the proposed corrective actions to address this issue. The inspectors also reviewed procedures, USAR, logbook entries, completed work orders, post maintenance testing and previous CAP documents related to this system. Based on this review the inspectors did not identify any additional performance deficiencies related to this event.

This licensee event report (LER) is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report 05000461/2014–005–00: Failure of Shutdown Service Water Pump Results in Loss of Division 3 Emergency Diesel Generator and High Pressure Core Spray Safety Functions

a. Inspection Scope

On September 16, 2014, during the operability testing of the Division 3 SX pump, the pump started and tripped off after approximately 36 seconds due to thermal overload protection. There was no evidence the pump had rotated. Operators immediately declared the Division 3 SX system, Division 3 EDG, and the HPCS system inoperable due to the pump trip as required by TS. A new pump of similar design was installed, post maintenance testing was completed with acceptable results, and the pump was restored to an operable status on September 21, 2014.

The licensee determined that the cause for this event was a failure of the suction bell bushing assembly of the pump. The licensee performed an apparent cause evaluation and determined that the failure of the suction bell bushing assembly was due to the design of the suction bell bushing being inadequate to pass sufficient cooling flow in a low velocity location of the pump without being adversely affected by the build-up of mud and silt from the lake water.

The inspectors reviewed the design of the Division 3 SX pump along with the licensee's root cause analysis. The inspectors determined that the current Division 3 SX pump does not represent an immediate safety concern because the new pump was installed in September of 2014 and the licensee provided adequate documentation that assures that the pump will remain operable until a different design for the suction bell bushing that failed can be installed by June of 2016. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

Failure of the Division 3 Shutdown Service Water Pump due to an Inadequate Bushing Design

Introduction. A self-revealed finding, preliminarily determined to be of low to moderate safety significance (White) and an associated AV of 10 CFR Part 50 Appendix B, Criterion III, Design Control, was identified for the failure to verify the suitability of the replacement pump design for the Division 3 SX system. Specifically, the licensee failed to verify the design of the suction bell bushing for the replacement pump would pass sufficient cooling water flow to the pump internals without being affected by mud and silt from the lake water, resulting in the failure of the pump.

Description. On September 16, 2014, the licensee performed CPS 9069.01, "Shutdown Service Water Operability Test," under WO 1625961. The Division 3 SX pump, 1SX01PC, motor tripped off 36 seconds after starting. The licensee found mud and silt in each of the pump sections with an increasing amount present in the lower sections of the pump during disassembly. The last section of the pump to be inspected was the suction bell, which is the lowest part of the pump. The licensee noted that the disassembly of the suction bell was difficult and required extra force to separate the shaft from the suction bell bushing. Upon further investigation, the licensee found the

suction bell bushing was damaged and determined the damage was the most probable cause for the pump to fail to start.

The licensee contracted Applied Technical Services to perform a failure analysis and concluded that the apparent cause for the pump failing to start was that the design of the suction bell bushing was inadequate to pass sufficient cooling flow in a low velocity location without being affected by lake water. The insufficient cooling flow resulted in damaging the internals of the pump resulting in the failure.

The design of the bottom of the suction bell bushing had a clearance of .00035" per side and a single spiral cooling groove in the inside diameter. The cooling slots in the bushing and the clearances between the bushing and shaft sleeve were susceptible to mud and silt accumulation. Starting the pump could help clear the passages, however, due to the tight tolerances and low flow condition in this section of the pump, flow through the bottom of the bushing was not sufficient to entirely clear all passages. As the accumulation of mud and silt built up, the passages became tighter and allowed less flow. As a result of blockage of the cooling channels by mud and silt, the bushing was subjected to thermal cycles, which caused stress in the affected components. The area most susceptible to damage caused by the thermal cycles was the spray metal hardfacing. The thermal cycles across the hardfacing resulted in cracking and with each additional cycle, the cracking increased to a point where contact with the bushing occurred and pieces of hardfacing broke off to cause failure. The inspector's concurred with the licensee's determination that the final failure of the suction bell bushing assembly occurred during the last successful run of the Division 3 SX pump on May 30, 2014.

The suction source for the SX pumps was Clinton Lake, which was a fresh water lake known to contain mud and silt due to run off from farm land. In the original design of the Division 3 SX pump, the lower two bushings were supplied cooling and flushing water via individual water lines off the pump casing using lake water as the source. On August 17, 1990, the licensee documented a condition in CR 1–90–08–037 where the Division 3 SX pump failed to start. The licensee disassembled the pump and found excessive amounts of mud and silt in the bushings, enclosure tube, and casing cooling/flushing lines from lake water used in the cooling lines. The root cause evaluation performed as a result of this issue documented in the corrective action plan the need to develop a modification which, when implemented would provide a pump that did not require bearing water. The purpose of this corrective action was to prevent the accumulation of mud and silt in the pump as a result of using lake water for cooling/flushing the pump internals. On October 3, 1995, the licensee installed a kit modifying the original pump design by replacing the original pump bushings with a self-lubricating bronze bushing design that would no longer require the use of internal flushing and cooling lines. The licensee noted in the change package that the new design would be similar to the self-lubricating bushings that are used in the Division 1 and Division 2 SX pumps, which have not shown any issues related to this design feature. The Division 1 and Division 2 SX pumps are a different size than the Division 3 SX pumps and were designed and manufactured by a different vendor. Another key difference between the Division 3 SX pump and Division 1 and 2 is that all the Division 1 and 2 SX bushing are self-lubricating except the pump suction bell bushings. The suction bell bushings for the Division 1 and 2 SX pumps are grease packed and have sand caps installed to prevent lake water from flushing the grease out of the bushings, therefore the suction bell bushings are not subjected to the raw lake water.

The inspectors identified that although the licensee noted the design modification for the Division 3 SX pump would be similar in design to the Division 1 and 2 SX pumps, they did not document an analysis showing what design differences existed or if those differences had the potential to adversely affect the performance of the new bushing. Similarly, the licensee did not perform an analysis of the new pump modification with sufficient rigor to determine its susceptibility to prolonged operation in raw lake water that could potentially lead to the buildup of mud and silt in the pump internals.

Analysis. The inspectors determined that the licensee's failure to verify the suitability of the design for the Division 3 SX replacement pump installed in 1995 for conditions under which it was to be used, as required by 10 CFR Part 50, Appendix B, Criterion III, Design Control, was a performance deficiency. Specifically, the licensee failed to verify the design of the suction bell bushing for the replacement pump would pass sufficient cooling water flow to the pump internals without being affected by mud and silt from the lake water, resulting in the failure of the pump. 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 was associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and is, therefore, a finding.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 4, "Initial Characterization of Findings," dated June 19, 2012 and Appendix A, "The Significance Determination Process for Findings at Power," Exhibit 2, "Mitigating Systems Screening Questions," dated June 19, 2012. The finding represented an actual loss of system safety function of the HPCS system for greater that its Technical Specification 3.5.1 condition B.2 allowed outage time of 14 days. Therefore, a detailed risk evaluation was performed is accordance with IMC 0609, Appendix A.

Internal Events Risk Contribution

The Senior Reactor Analysts (SRAs) evaluated the finding using the Clinton Standardized Plant Analysis Risk (SPAR) model version 8.17, and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) version 8.1.2.0. The basic event representing SX Pump C failing to run was set to TRUE.

The purpose of the Division 3 SX is to provide cooling water to Division 3 cooling loads including the HPCS pump room coolers, the Division 3 EDG, and the Division 3 switchgear heat removal system. The Division 3 SX header is normally supplied by cooling water from the Station's non-safety related plant service water system (WS). Under design basis event conditions such as Loss of Offsite Power (LOOP) or Loss of Coolant Accidents (LOCAs), a Division 3 SX pump (SX pump C) start signal is generated and the cross-tie valve (1SX014C) from the WS System closes. The risk due to this performance deficiency is dominated by LOOP initiating events which render unavailable the non-safety related WS pumps.

The pump failed its surveillance test on September 16, 2014, while performing a 2-year comprehensive pump test. A new pump was installed and returned to service on September 21, 2014. The last successful run prior to failure was on May 30, 2014, for

surveillance testing. The pump ran for 49 minutes and at that time had no abnormal vibration levels or unusual differential pressure readings from previous surveillance testing.

However, the time of the actual failure of the pump was determined by the licensee to be when the pump was secured on May 30, 2014; therefore a "T/2" exposure does not apply. Specifically, the licensee's apparent cause report stated that final failure of the suction bell bushing assembly would have occurred during the last successful run of SX Pump C on May 30, 2014.

Common cause failure was not assumed because the SPAR Model does not include the SX Pump C in any common cause component group. The two divisional SX pumps (A and B) do share a common cause component group.

The SRAs assumed that the SX Pump C failure could not be recovered. Upon disassembly the pump suction bell bushing was found extremely damaged and was packed with mud and silt.

The dominant sequence for internal events was a station blackout with failure of long term inventory control and failure of decay heat removal. The specific failures comprising the dominant core damage sequence following the station blackout initiating event were as follows:

- Failure of HPCS;
- Failure of operator actions to extend reactor core isolation cooling (RCIC) operation after initial success;
- Failure of manual reactor depressurization; and
- Failure to recover AC power at 4-hours.

The total internal events change in core damage frequency (ΔCDF) for the exposure period was 5.49E–6/year.

External Events Risk Contribution

The Clinton SPAR Model does not include external events. The SRAs estimated the risk due to external events using information from the licensee and the NRC's Risk Assessment Standardization Project external events handbook guidance. Seismic and flooding risk contributions were negligible. The external event risk contribution was dominated by fires.

The SRAs evaluated fire initiating events that could result in a LOOP since LOOP events were the largest contributors to a change in risk. The SRAs used information from licensee letter U–603468, dated March 22, 2001, which supported a licensee TS Amendment Request to extend the Division 1 and 2 EDG allowed outage times from 72-hours to 14-days, to obtain fire information needed for this assessment. Table 3 of the letter, *Individually Modeled Fire Scenarios from the Fire PRA Involving the LOOP Initiator*, and the licensee's answer to Question 5 in the letter, contained information to evaluate the fire risk for this finding.

Based on information from a prior SDP and Table 3 of the U–603468 letter, (Areas 6, 8, and 9) in Fire Zone CB–3a (781' and 790' Control, DC/UPS Equipment) had failures that

would disable both the Division 1 and 2 buses. Electrical Panel 1PL89JA (General Protective Relay Panel) in Fire Zone CB–3a involved a loss of feedwater combined with a LOOP. Since all LOOP events also result in a loss of feedwater, this scenario is a LOOP event with no additional loss of equipment. Transient Area 2 (781' Radwaste, General Access Area) in Fire Zone R–1t likewise included a loss of feedwater and other balance of plant equipment. Panel 1H13–P870 in the main control room had Division 1 and 2 equipment but was limited to containment isolation valves. Thus the impact of this panel fire is essentially equivalent to the LOOP initiator alone.

The SRAs calculated a ΔCDF for fires using the fire frequencies for each listed in Table 3 as a surrogate for the LOOP frequencies. The conditional effects were accounted for in the SPAR model. As an example, as mentioned for Areas 6, 8, and 9 in Fire Zone CB–3a have failures that would disable both the Division 1 and 2 buses. The SRAs included the failure of the Division 1 and 2 buses in the base case conditional core damage probability (CCDP) calculation for these areas and then failure of the SX Pump C along with failure of the buses to obtain a deficient case CCDP. A ΔCCDP was re-calculated for each area which was multiplied by the area frequencies to obtain a ΔCDF for each fire area. The ΔCDF from the individual fire areas were summed to obtain a total fire risk.

The total ΔCDF for fires and for the exposure period was computed as approximately 1.09E–06/yr. This was also the total external events ΔCDF for the exposure period (i.e., total external events ΔCDF was 1.09E–06/yr).

Large Early Release Frequency

The potential risk contribution due to large early release frequency (LERF) was considered using IMC 0609 Appendix H, "Containment Integrity Significance Determination Process." The Clinton plant is a General Electric BWR–6 [Boiling Water Reactor] with a Mark III containment. Generally, only a subset of those sequences contributing to CDF significance of a finding has the potential to impact LERF. For BWR Mark III plants, findings related to inter-system loss of coolant accidents, transients, small break LOCAs, and station blackout (SBO) events are the subsets of interest.

Per the State-of-the-Art Reactor Consequence Analyses, Table 4 of NUREG–1935, the time from the start of core damage to the time of lower head failure (and release to the environment) for the representative BWR without high pressure coolant injection or reactor core isolation cooling was approximately 7 hours.

For this performance deficiency, the dominant accident sequences involved 4-hour core damage SBO events. The SRAs reviewed licensee document, "Evacuation Time Estimates for Clinton Power Station Plume Exposure Pathway Emergency Planning Zone," dated December 2012. The time estimates summary showed that evacuation times are in the 3–5 hour timeframe, depending on the time of year and weather conditions.

Based on the 3–5 hour evacuation time being shorter than the 7-hour time from core damage to lower head failure and release, the SRAs believed that in most cases emergency planning zone evacuation would be completed before early release to the environment. Thus the SRA did not perform any further refinement to characterize LERF significance. The SRAs determined that the change in risk due to LERF would be

no greater than the change in risk due to core damage. The SRAs concluded that the total estimated change in risk is best characterized by the ΔCDF result.

Licensee's Risk Evaluation

The licensee provided no formal risk evaluation for discussion at the Significance and Enforcement Review Panel Meeting. The licensee did provide a ΔCDF value for internal events along with a table of sensitivities for internal events to the SRAs via email dated April 13, 2015. The licensee's internal events risk was a ΔCDF of 3.4E–06/yr for the exposure time. No external events risk information was provided except that the licensee PRA staff verbally stated that the ΔCDF for fires was 1.3E–06/yr for the exposure time.

The inspectors and SRAs rejected the licensee's application of the sensitivity values for repair credit, credit for no or low maintenance during summer months, and credit for use of "T/2" exposure time as applicable to the best estimate risk for this finding.

For repair credit, the licensee credited an 85 percent success rate for recovery of the failed pump after 4 hours. In general, the NRC grants no recovery or repair credit when there is insufficient time, lack of cues, insufficient resources, no procedures, or no training. The licensee provided no analysis to address these factors and furthermore, there was no evidence that the pump could provide the required flow and pressure at the completion of these actions. The licensee did state that the mechanics were able to get the pump to rotate freely within several hours of troubleshooting but this was not enough justification to credit recovery of the failed pump.

Regarding credit for no or low maintenance during summer months, the NRC rejected this because the SDP considers the full spectrum of plant conditions that could have been in place when the performance deficiency existed, not just actual conditions existing during the time. Furthermore, according to the February 2015 "Analysis of Loss-of-Offsite-Power Events 1998–2013," report available at the NRC's 2013 Reactor Operational Experience Results and Databases (http://nrcoe.inel.gov/resultsdb/), the mean frequency of LOOP events during summer months is nearly double that of non-summer months.

For "T/2" credit, the NRC rejected this because the licensee's apparent cause investigation report clearly stated that final failure of the suction bell bushing assembly would have occurred during the last successful run of the pump on May 30, 2014.

Total Estimated Change in Risk

The total ΔCDF was the sum of the internal and external events ΔCDF risk, or about 6.6E–6/yr. This was a low to moderate safety significance (White) finding.

A SERP held on April 16, 2015, using IMC 0609, Appendix A, "Significance Determination Process For Findings At-Power," dated June 19, 2012, made a preliminary determination that the finding was of low to moderate safety significance (White) based on the quantitative analysis performed during the detailed risk evaluation.

The performance deficiency associated with this finding occurred more than three years ago and did not reflect current licensee performance; therefore, no cross-cutting aspect was identified with this finding.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, Design Control, requires in part, that measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components.

Technical Specifications 3.7.2 and 3.5.1 require in part that the Division 3 SX subsystem and the HPCS system be operable in various modes of operation. On October 3, 1995, the licensee failed to verify the suitability of a replacement pump for the Division 3 SX system as required by 10 CFR Part 50, Appendix B, Criterion III, Design Control. Specifically, the licensee failed to ensure that the replacement pump suction bushing was suitable for use in a fresh water lake system. This resulted in the pump being inoperable from May 30, 2014, to September 16, 2015, a period greater than the allowed limiting condition for operation outage times provided in TS 3.7.2 and 3.5.1. This apparent violation of 10CFR Part 50, Appendix B, Criterion III, Design Control, which has a low to moderate safety significance, was identified during the inspectors' review of the licensee's Division 3 SX pump failure apparent cause evaluation report. The licensee documented this issue in AR 02381871.

Corrective actions implemented included replacing the pump with a pump of similar design, performing an operability evaluation for continued use of the current bushing design, performing additional monitoring during pump operation, and determining a more suitable design for the lower bushing and installing the design by June 1, 2016. **(AV 05000461/2015001–03, "Failure of the Division 3 Shutdown Service Water Pump due to an Inadequate Bushing Design.")**

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 15, 2015, the inspectors presented the inspection results to Mr. M. Newcomer, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary. Additionally on April 17, 2015, the inspectors presented the preliminary determination results of the significance of the Division 3 SX pump failure (Section 4OA3) to Mr. M. Newcomer. This issue had been addressed during the April 15, 2015, exit as an issue of concern.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the triennial heat sink inspection with Mr. T. R. Stoner, and other members of the licensee staff, on January 30, 2015. The licensee acknowledged the issues presented.

- The inspection results for the area of radioactive solid waste processing and radioactive material handling, storage, and transportation inspection with Mr. M. Newcomer, Site Vice President, and other members of the licensee staff, on February 13, 2015.

The inspectors confirmed that none of the potential report input discussed was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Anthony, Corporate NDE Services Manager
R. Bair, Chemistry Manager
K. Baker, Regulatory Assurance Manager
J. Bond, Emergency Preparedness Manager
B. Brooks, Security Manager
B. Campbell, Chemistry General Supervisor
R. Campbell, RP Technical Manager
J. Cunningham, Acting Regulatory Assurance Manager
C. Dunn, Training Director
R. Freeman, Emergency Preparedness Manager
M. Friedman, Radiation Protection Operations Manager
N. Hightower, Radiation Protection Manager
T. Krawcyk, Shift Operations Superintendent
D. Kemper, Acting Plant Manager/Operations Director
S. Kowalski, Senior Manager Design Engineering
K. Leffel, Operations Support Manager
M. Mayer, Acting Security Manager
S. Mohundro, Engineering Programs Manager
M. Newcomer, Site Vice President
C. Propst, Nuclear Oversight Manager
R. Schenck, Work Management Director
D. Shelton, Operations Services Manager
J. Smith, Acting Site Engineering Director
D. Snook, Operations Training Manager
T. Stoner, Plant Manager
J. Stovall, Maintenance Director

NRC

G. Roach, Acting Chief, Reactor Projects Branch 1
J. McGhee, Acting Chief, Reactor Projects Branch 1
W. Schaup, Clinton Senior Resident Inspector
E. Sanchez-Santiago, Clinton Resident Inspector
C. Hunt, Acting Clinton Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000461/2015001–03	AV	Failure of the Division 3 Shutdown Service Water Pump due to an Inadequate Bushing Design

Opened/Closed

05000461/2015001–01	FIN	Failure to perform adequate channel calibration on seismic instrumentation
05000461/2015001–02	NCV	Unqualified safety-related cables used in a submerged environment

Closed

05000461/2014005–02	URI	Potential Failure to Maintain Safety Related Cables in a Qualified Environment
05000461/2014–003–00	LER	Misapplication of Support System Technical Specification Requirements Resulted in Implementation of Non-Conservative Guidance For Removal of Essential Switchgear Heat Removal System in Service.
05000461/2014–005–00	LER	Failure of Shutdown Service Water Pump Results in Loss of Division 3 Emergency Diesel Generator and High Pressure Core Spray Safety Functions

Discussed

05000461/2014004–01	NCV	Technical Specification Allowed Outage Time Exceeded for Electrical Power Systems Due to Auxiliary Equipment Out of Service)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather, that selected sections of 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.

1R01 Adverse Weather Protection

- EP-AA-113-F-07, "MW Emergency Director – Site Assembly, Accountability and Evacuation," Revision G
- AD-AA-101-F-01, "Document Site Approval Form," Revision 4
- CPS 1860.01C005, "Blizzard/Severe Weather Preparation Checklist," Revision 0
- CPS 1860.01, "Cold Weather Operation," Revision 8b
- CPS 1860.01C001, "Operations Department Cold Weather Preparations Checklist," Revision 7c
- SY-AA-101-146, "Severe Weather Preparation and Response," Revision 1
- OP-AA-108-111-1001, "Severe Weather and Natural Disaster Guidelines," Revision 12
- EP-AA-120-1002, "Offsite Readiness Evaluation," Revision 3
- WC-AA-107, "Seasonal Readiness," Revision 14
- EP-AA-120-106, "EP Reportability – Loss of Emergency preparedness Capabilities," Revision 2
- DC-SD-01-CP, "Structural Design Criteria – General Structural Project Criteria," dated April 16, 1999
- DWG S26-1201-01A, "Auxiliary Building – Section 6A – 6A Area 1 – Upper Clinton Power Station," Revision N
- DWG S26-1101-01A, "Auxiliary Building – Section 5A – 5A Area 1 – Upper Clinton Power Station," Revision N
- WO 01694039, "Initiate Cold Weather Preparations," dated September 2, 2014

1R04 Equipment Alignment

- CPS 3310.01V001, "Reactor Core Isolation Cooling Valve Lineup," Revision 12e
- CPS 3310.01E001, "Reactor Core Isolation Cooling Electrical Lineup," Revision 16
- CPS 3214.01V001, "Plant Air Valve Lineup," Revision 25d
- CPS 3214.01E001, "Plant Air Electrical Lineup," Revision 10a
- AR 02453439, "EOID- #2 SA Compressor Suction Filter Is Dirty"
- CPS 3503.01E001, "Battery and DC Distribution Electrical Lineup"
- CPS 3312.01E001, "Residual Heat Removal Electrical Lineup," Revision17
- CPS 3312.01V001, "Residual Heat Removal Valve Lineup," Revision 17a
- CPS 3312.01V002, "Residual Heat Removal Instrumentation Valve Lineup," Revision 9a

1R05 Fire Protection

- OP-AA-201-009, "Control of Transient Combustible Material," Revision 13
- CPS 1019.05, "Transient Equipment/Materials," Revision 21
- Clinton Power Station Updated Final Safety Analysis Report, Appendix E, "Fire Protection Evaluation Report – Clinton Power Station Unit 1," Revision 16
- Clinton Power Station Updated Final Safety Analysis Report, Appendix F, "Fire Protection Safe Shutdown Analysis – Clinton Power Station Unit 1," Revision 16
- OP-AA-201-003, "Fire Drill Performance," Revision 14

- CPS 1893.04M710, “737 Turbine: General Access Area Prefire Plan,” Revision 6b
- AR 02468083, “Fire Brigade Equipment Replaced During Fire Drill U2015-03”
- CPS 1893.04M102, “707-781’ Auxiliary: RHR ‘A’ Pump and Heat Exchanger Room Pre-Fire Plan,” Revision 5
- AR 02448568, “Items Identified During NRC Inspector Walkdown”
- CPS 1893.04M351, “781’ Control: Aux. Elect. Equip., Inverter & Battery Rooms Pre-Fire Plan,” Revision 7b
- CPS 1893.04M364, “800’ Control: Main Control Room Pre-Fire Plan”

1R07 Heat Sink Performance

Section 1R07T

- Work Order (WO) 00489275, “Inspect, Boroscope, Clean, Eddy Current and Hydrolase as Required-1VY05AA,” dated January 19, 2006
- WO 00561228, “Inspect, Boroscope, Clean, Eddy Current and Hydrolase as Required-1VY05AB,” dated January 19, 2006
- WO 01093525, “Obtain Air Flow Measurements for Room,” dated June 9, 2009
- WO 01161961, “Visually Inspect Strainer Internals and Clean as Necessary,” dated April 14, 2009
- WO 01260958, “Eddy Current Exam Final Report for RHR HX Room Cooling Colis/ 1VY05AA”
- WO 01269141, “Inspect/Clean Screen house Structure (GL 89-13 Program),” dated February 22, 2012
- WO 01477362, “9069.02 Ver SX Valve Oper (Pit for 1SX003A, 4A, 11A),” dated February 2013
- WO 01519493, “Inspection Shows Traveling Screen Chain Needs Replaced,” dated November 30 2012
- WO 01580126, “9861.09 LRT Boundary Valve Leak Testing (1SX082A),” dated June 26, 2014
- WO 01634419, “9861.09M20 LRT SX Boundary Valve Leak Testing (1SX020B),” dated October 8, 2014
- WO 01678373, “9861.09L20 LRT SX Boundary Valve Leak Testing (1SX020A),” dated December 30, 2014
- WO 01756268, “9069.01B20 Op SX Pump Oper Test (SX Pump B),” dated October 7, 2014
- WO 01773177, “9069.01A20 OP SX Pump Oper Test (SX Pump A),” dated December 22, 2014
- WO 01775963, “9069.01 SX Pump Oper Test (SX Pump B),” dated January 5, 2015
- WO 1427474, “Visually Inspect Strainer Internals and Clean as Necessary,” dated September 23, 2014
- WO 1500482, “Obtain Air Flow Measurements for Room – 1VY05S,” dated June 15, 2014
- WO1481659, “1WS01FB Plant Service Water Strainer B Not rotating During B/W,” dated October 28, 2011
- WO 1215001, “Division III Sx System Testing IAW 2700.14,” dated September 23, 2010
- WO 1397301, “Division 2 SX Flow Balance,” dated June 12, 2012
- 1VY05 RHR B Heat Exchanger Room Fan Vibration Trend Data, dated April 18, 2012 - December 11, 2014
- “Eddy Current Examination Final Report - Division III DGJW Clr/1DG13A,” dated September 23, 2009
- “Eddy Current Examination Final Report - Division III DGJW Clr/1DG13A,” dated September 20, 2011
- ECN 27799, “Design Document Changes that Reflect use of 95 degree F Service Water Temperature,” dated March 23, 2000

- M05-1116, “P&ID ECCS Equipment Room Cooling (VY),” Revision 1
- DC-ME-09-CP, “Equipment Environmental Design Conditions,” Revision 12
- EC 359078, “Evaluation of DG Testing vs. Routine Inspection,” Revision 0
- IP-M-0486
- VY-45, “Performance Evaluation of VY System Cooling Coils Under SX Flow Acceptance Limits,” Revision 5
- VY-47, “Evaluate ECCS Room Cooling with one Cooler Operating,” Revision 0
- EC354296, “ECCS Availability During Maintenance on VY Cooling Coils,” Revision 0
- 3C10-1079-001, “Secondary Containment Functional Design,” Revision 10
- AR 01329583, “RHR Availability With Room Fan Out of Service”
- AR 01265623, “As Found Division 3 DG Heat Exchanger Inspection Results,” dated September 20, 2011
- AR 01619578, “Division 3 DG Heat Exchanger Inspection Results,” dated February 11, 2014
- AR 2444865, “Procedure Enhancement Opportunity for 3312.01,” dated January 30 2015
- AR 2444858, “NRC Identified Data Sheets not Fully Completed,” dated January 30, 2015
- AR 1329583, “RHR Availability with a Room Fan Out of Service,” dated February 21, 2012
- AR 01339705, “ECCS Rm Cooler Controller Class and MR Funct. Overly Conservative,” dated March 12, 2012
- AR 01523503, “1VY05S – Air Flow Too Close to Max Allowed,” dated June 11, 2013
- CPS 3211.01, “Shutdown Service Water,” Revision 31c
- CPS 2700.14, “Division 3 SX System Flow Verification and Balance,” Revision 5
- CPS 1003. 10, “Clinton Power Station (CPS) Program for NRC Generic Letter 89-13 (Service Water Problems Affecting Safety-Related Equipment),” Revision 7
- OP-AA-108-117, “Protected Equipment Program,” Revision 4
- CPS-4006.01, “Loss of Shutdown Cooling,” Revision 5
- CPS 3506.01C001, “Diesel Generator 1A Pre-Start Checklist,” Revision 16a
- ER-AA-340-1002, “Service Water Heat Exchanger Inspection Guide,” Revision 6
- CPS 8130.01, “Heat Exchanger Maintenance and Repairs,” Revision 4
- CPS 1860.01, “Cold Weather Operation,” Revision 8b
- EN-CL-402-005, “Extreme Heat Implementation Plan,” Revision 7

1R11 Licensed Operator Requalification Program

- TQ-AA-155, “Conduct of Simulator Training and Evaluation,” Revision 2
- EP-AA-125-1002, “Emergency Response Organization Performance Indicators Guidance,” Revision 9
- OP-AA-101-111-1001, “Operations Standards and Expectations,” Revision 14
- OP-CL-108-101-1003, “Operations Department Standards and Expectations,” Revision 34
- TQ-AA-150, “Operator Training Programs,” Revision 10
- CPS 3005.01, “Unit Power Changes,” Revision 42c
- CPS 3001.01, “Preparation for Startup and Approach to Critical,” Revision 27a
- CPS 3001.01C001, “Preparation for Startup Checklist,” Revision 18d
- CPS 3001.01C002, “Mode 2 Checklist,” Revision 17
- CPS 3002.01, “Heat up and Pressurization,” Revision 31b
- CPS 3002.01C001, “Heat up and Pressurization Checklist,” Revision 10
- CPS 3002.01C002, “Mode 1 Checklist,” Revision 12b

1R13 Maintenance Risk Assessments and Emergent Work Control

- ER-AA-600-1011, “Risk Management Program,” Revision 13
- ER-AA-600-1042, “On-line Risk Management,” Revision 9

- ER-AA-600, “Risk Management,” Revision 7
- ER-AA-600-1012, “Risk Management Documentation,” Revision 9
- ER-AA-600-1014, “Risk Management Configuration Control,” Revision 6
- WC-AA-101, “On-Line Work Control Process,” Revision 19
- WC-AA-104, “Integrated Risk Management,” Revision 21
- AD-AA-3000, “Nuclear Risk Management Process,” Revision 0
- OP-AA-108-117, “Protected Equipment Program,” Revision 3
- AR02460173, “RHR A Pump Seal Replacement Exceeded Scheduled Duration”
- - AR02460098, “Work Control/Procedure Enhancement RHR A Pump”
- - AR02462729, “WW 1509 RHR A SOW Critique”
- AR02447334, “Division 2 Diesel Generator inoperable due to Abnormal Voltage Control”

1R15 Operability Evaluations

- OP-AA-108-115, “Operability Determinations (CM-1),” Revision 13
- OP-AA-108-115-1002, “Supplemental Consideration for On-shift Immediate Operability Determinations (CM-1),” Revision 2
- OP-AA-108-104, “Technical Specification Compliance,” Revision 1
- CC-AA-309-101, “Engineering Technical Evaluations,” Revision 13
- AR02447013, “RCIC Room Cooler Cooling Water Blockage”
- AR02444668, “LL: EOP-8 Entry On RCIC Room Cooler Return To Service”
- AR02445016, “1E31N005A: MCR Received 5063-8C”
- AR02451727, “Non-Conforming Door Seal Gasket Installed on 1HC72G”
- AR02467321, “RHR B/C WLP Data Outside of Acceptable Range”
- WO 01617661, “9437.21R21 CC Triax Time-History Accelerometer”
- CPS 9437.21, “Triax Time-History Accelerometer Channel Calibration,” Revision 39c
- CPS 4301.01, “Earthquake,” Revision 15a
- CPS 5009.01, “Alarm Panel 5009 Annunciators – Row 1,” Revision 29
- ANSI N18.5 – 1974, “Earthquake Instrumentation Criteria for Nuclear Power Plants,”
- AR 02410683, “Seismic System Power Supply Voltage Found/Left Out of Specification”
- AR 02410975, “9437.21 Procedure Enhancement”
- AR 02411232, “NRC Resident Question Regarding 9437.21 Acceptance Criteria”
- AR 02454630, “Seismic System Backup Power Supply Requirements’
- Field Engineering Change Notice No. 21929, K2931-0002. Instrument Manual
- 95-0059, Operation and Maintenance Manual CPS-117 R Power Supply/Battery Charger, Revision A
- AR02447334, “Division 2 Diesel Generator inoperable due to Abnormal Voltage Control”

1R19 Post-Maintenance Testing

- MA-AA-716-012, “Post Maintenance Testing,” Revision 19
- Work Order WO01224540, “Perform Thrust Verify/Clean and Inspect – 1E51F031”
- CPS 9381.01, “MOV Thermal Overload Bypass Verification,” Revision 38
- MA-CL-725-5611, “Hydramotor Actuator – Model AH95 and NH95 Preventative Maintenance,” Revision 7
- WO 1404227-01, “Perform Hydramotor 0FZVC103B/Damper 0VC24YB PM”
- WO 1404227-02, “Post Maintenance Test Hydramotor 0FZVC103B/Damper 0VC24YB”
- WO 1404228-01, “Perform Hydramotor 0FZVC103A/Damper 0VC21YB PM”
- WO 1404228-02, “Post Maintenance Test Hydramotor 0FZVC103B/Damper 0VC24YB”
- WO 1609119-01, “Perform Hydramotor 0FZVC103C/Damper 0VC27YB PM”
- WO 1609119-02, “Post Maintenance Test Hydramotor 0FZVC103C/Damper 0VC27YB”

- WO 1609235-01, “Perform Hydramotor 0FZVC172/Damper 0VC114YB PM”
- WO 1609235-02, “Post Maintenance Test Hydramotor 0FZVC172/Damper 0VC114YB”
- WO 1635148-01, “Perform Hydramotor 0FZVC103F/Damper 0VC36YB PM”
- WO 1635148-02, “Post Maintenance Test Hydramotor 0FZVC103F/Damper 0VC36YB”
- WO 01736902, “Replace Transmitter 1E31N075B”
- WO 01637778-02, “OP PMT for 1SX156B valve and 1SX42BB-3/4” pipe,” January 13, 2015
- WO 01607694, “PMT per EC 395976 – modified 9065.02 – outer door,” December 27, 2014
- CPS 8801.24, “Rosemount Series 1153/1154 Pressure Transmitter Replacement,”
- Revision 1c
- CPS 8801.06C001, “H22 panel Mounted Instrument Valve Operation Checklist,” Revision 33c
- CPS 9432.20, “Reactor Water Cleanup Delta Flow 1E31-N075B/076B/077B Channel Calibration,” Revision 35e
- CPS 9432.20D001, “Reactor Water Cleanup Delta Flow 1E31-N075B/076B/077B Channel Calibration Data Sheet,” Revision 34a
- CPS 9065.02D001, “Secondary Containment Integrity Data Sheet,” Revision 30
- AR 02445059, “Reactor Water Cleanup System High Differential Flow isolation Function”
- AR 02436366, “Enhancement to 9433.22 HPCS flow E22-N056 Channel Calibration”

1R20 Outage Activities

- CPS 3006.01, “Unit Shutdown,” Revision 43d
- CPS 3006.01, “Mode 4 Checklist,” Revision 12b
- CPS 3006.01C007, “Control Rod Withdrawal Checklist – Mode 3,” Revision 4f
- CPS 3006.01F001, “Unit Shutdown Flowchart,” Revision 0
- CPS 3006.01F002, “Unit Power Changes Power Decrease Flowchart,” Revision 0
- CPS 3005.01, “Unit Power Changes,” Revision 42c
- CPS 9000.06D001, “Heat up/Cooldown, Inservice Leak and Hydrostatic Testing 30 Minute Temperature Log,” Revision 30b
- CPS 9000.06D003, “ Shutdown Cooling Temperature Data Sheet,” Revision 30d
- AR 02441228, “C1M21 LL – Delay in Achieving Mode 4”
- AR 02439950, “MCR Regulator Error on SBPC Panel 1H13-P680”

1R22 Surveillance Testing

- CPS 9052.01, “Low Pressure Core Spray/Residual Heat Removal A Pump and Low Pressure Core Spray/Residual Heat Removal A Water Leg Pump Operability,” Revision 48c
- WO 01780192, “CPS 9055.01A21 OP Residual Heat Removal A Pump Operability”
- CPS 9861.03, “Type B Local Leak Rate Testing,” Revision 27
- CPS 9861.03D012, “Drywell Air Lock Seal Leak Rate Test Data Sheet,” Revision 24a
- WO 01709099, “MC212G13 Local Leak Rate Test: (1MD-02W) Drywell Air Lock Seals”
- WO 01802570, “MC212G13 Local Leak Rate Test: (1MD-02W) Drywell Air Lock Seals”
- CPS 9051.01, “High Pressure Core Spray Pump and High Pressure Core Spray Water Leg Pump Operability,” Revision 47d
- CPS 9051.01D001, “High Pressure Core Spray Pump and High Pressure Core Spray Water Leg Pump Operability Data Sheet,” Revision 48
- WO 01778981, “CPS 9051.01R21 OP High Pressure Core Spray Pump and High Pressure Core Spray Water Leg Pump Operability (RCIC Storage Tank)”
- CC-AA-309-101, “Engineering Technical Evaluation,” Revision 14;
- EC 400935, “IR 2447334 Division 2 Diesel Generator Inoperable Due to Abnormal Voltage Control”;
- CPS 9080.02, “Diesel Generator 1B Operability – Many and Quick Start Operability,”

- Revision 52c/d;
- Work Order WO01805070, “Replace Voltage Regulator R3 Rheostat”;
- AR01276244, “Readings from 1TIDG151 are Erratic”;
- AR01276242, “1TIDG150: Erratic Readings from Division 2 DG Exh Temp Indicator”;
- AR02447334, “Division 2 Diesel Generator Inoperable Due to Abnormal Voltage Control”;
- AR02449384, “Need Review of DG System Health”;
- AR02386704, “NRC Interface - Draining Of RCIC Exhaust Drain-Pot Line”;
- AR 02413328, “NRC NCV 2014004-03: RCIC Unacceptable Preconditioning”;
- CPS 9054.01C002, “RCIC (1E51-C001) High Pressure Operability Checks,” Revision 8b;
- CPS 9054.01D002, “RCIC (1E51-C001) High Pressure Operability Checks Checklist,” Revision 26;
- CPS 9333.30, “Division II 4.16 KV Degraded Voltage Trip – Functional Test”;
- CPS 9080.31, “Diesel Generator Individual Engine Overspeed Trip Test and Adjustment”
- AR 02470764, “Division 3 Diesel Generator Overspeed Trip Speed Failed High”;
- AR 02470811, “Broken Tubing Line Support on 1DG01KC”

1EP6 Drill Evaluation

- EP-AA-125-1002, “Emergency Response Organization Performance Indicators Guidance,” Revision 9
- EP-AA-125-001, “Drill and Exercise Scheduling, Development and Conduct,” Revision 19

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation

- Trending for Shifts in Scaling Factors, Fourth Quarter 2014
- Training Records, Various Records
- AR01524958, “Procedural Clarification to RP-AA-603,” dated June 14, 2013
- AR01573668, “Shipping Container Door not Properly Secured,” dated October 17, 2013
- AR01668213, “NOS ID: Radioactive Waste Shipping is an Arma,” dated June 5, 2014
- AR02389364, “Delays in Shipping Casks Impacting Other Exelon Sites,” dated October 1, 2014
- AR02392388, “Question on Shipment of Liner and Cask,” dated October 8, 2014
- AR02398109, “NOS ID: Radioactive Material Shipment Yellow Driver for RP,” dated October 10, 2014
- Radioactive Waste Shipment W14-015, “Spent Resin,” dated March 1, 2014
- Radioactive Waste Shipment W14-005, “Concentrated Waste,” dated December 10, 2014
- Radioactive Material Shipment M13-033, “Calibration Source,” dated September 9, 2013
- Radioactive Waste Shipment W14-016, “Powered Resin,” dated November 25, 2014
- 10 CFR 61 Analysis, “Concentrated Waste,” dated July 15, 2013
- 10 CFR 61 Analysis, “Spent Resin,” dated March 1, 2014
- 10 CFR 61 Analysis, “Fuel Pool Sludge,” dated November 6, 2012
- Self- Assessment, “NRC Inspection 71124.08,” dated March 1, 2013
- Self- Assessment, “NRC Inspection 71124.08,” dated November 20, 2014
- NOS Audit, “Chemistry, Radwaste, Effluent and Environmental Monitoring,” dated June 11, 2014
- CPS 3909.01, “Operating Spent Resin System,” Revision 23c
- RP-AA-602, “Packaging of Radioactive Material Shipments,” Revision 19
- RW-AA-100, “Process Control Program for Radioactive Wastes,” Revision 10

4OA1 Performance Indicator Verification

- Nuclear Energy Institute 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7

4OA2 Identification and Resolution of Problems

- CR 02404378-02, “Cable Vault Dewatering System Failure Investigation”
- EC 399907, “SX Cable Submergence Evaluation,” Revision 0
- ER-AA-300-150, “Cable Condition Monitoring Program,” Revision 0
- AR 00692997, “CDBI- Submerged Cable Long Term Asset Management Strategy”
- AR 00114481, “Water in MPT to UAT Manholes Submerging Power Cables”

4OA3 Followup of Events and Notices of Enforcement Discretion

- CPS 1003.10, “Clinton Power Station Program for NRC Generic Letter 89-13 (Service Water Problems Affecting Safety-Related Equipment),” Revision 7
- CPS 9069.01, “Shutdown Service Water Operability Test,” Revision 48c
- CPS 9069.01D001, “Shutdown System Operability Data Sheet,” Revision 46c
- CPS 8801.12C001, “Local Mounted Instrument Valve Operation Checklist,” Revision 15b
- WO 01625961, “9069.01 1SX01PC Comprehensive Pump Test”
- CPS 2858.01, “Division 3 Shutdown Service Water Baseline Testing,” Revision 0
- CPS 2858.01D001, “Division 3 Shutdown Service Water Baseline Testing Data Sheet,” Revision 0
- CPS 9069.03, “Shutdown Service Water Flow Path Verification,” Revision 28a
- WO 01769847, “Failure of the Outer/Upper Bearing for 1SX01PC”
- WO 01412991, “9069.01 1SX01PC Comprehensive Pump Test”
- WO 01625961, “9069.01 1SX01PC Comprehensive Pump Test”
- AR 01049920, “Declining Performance Trend for Division 3 Shutdown Service Water Pump – 1SX01PC”
- AR 02381871, “Failure of the Outer/Upper Motor Bearing for 1SX01PC”
- AR 02413550, “1SX001C Discharge Check Valve Seat Leakage”
- CPS 9069.01, “Shutdown Service Water Operability Test,” Revision 48d
- CPS 9069.01D001, “Shutdown System Operability Data Sheet,” Revision 46d
- WO 01771503, “9069.01C20 1SX01PC Comprehensive Pump Test (SX Pump C)”
- WO 01797791, “9069.01C20 1SX01PC Comprehensive Pump Test (SX Pump C)”
- CC-AA-309-1012, “10CFR Part 21 Technical Evaluations,” Revision 3
- CR 1-90-08-037, “Shutdown Service Water Pump 1SX01PC Failure to Start on Demand”
- IP-S-0132, “Acceptance Criteria for Allowable Sediment Depth (Siltation) in the Circulating Water Screen House”
- D/C 223184 (N), Metallurgical Failure Analysis of Pump Shaft bushing and Sleeve Components, dated 10/31, 2014
- EC 27398, “Allow use of bronze bushings in lieu of cutlass rubber bushings and modified pump parts for division 3 shutdown service water pump 1SX01PC”
- K2828-B, “Purchase Agreement for one (1) Shutdown Service Water Pump”
- Modification Control Form for SXF022

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agency-wide Documents and Management System
AR	Action Request
AV	Apparent Violation
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CCDP	Conditional Core Damage Probability
CDBI	Component Design Basis Inspection
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DC	Direct Current
EDG	Emergency Diesel Generator
FIN	Finding
FSAR	Final Safety Analysis Report
HPCS	High Pressure Core Spray
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MVAR	MegaVolts Amps Reactive
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
ORM	Operational Requirements Manual
PARS	Publicly Available Records
PI	Performance Indicator
PM	Post Maintenance
PRA	Probabilistic Risk Assessment
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
SAPHIRE	Systems Analysis Programs for Hands-on Integrated Reliability Evaluations
SBO	Station Blackout
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Risk Analyst
SX	Shutdown Service Water
TS	Technical Specification
USAR	Updated Safety Analysis Report
VX	Switchgear Heat Removal
WO	Work Order

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Sincerely,

/RA/

Anne T. Boland, Director
Division of Reactor Projects

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