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

August 1, 2014

Mr. Michael J. Pacilio
Senior VP, Exelon Generation Co., LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: CLINTON POWER STATION – NRC INTEGRATED INSPECTION REPORT 05000461/2014003

Dear Mr. Pacilio:

On June 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Clinton Power Station. The enclosed report documents the results of this inspection, which were discussed on July 17, with Mr. K. Taber, and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, four self-revealed findings of very low safety significance were identified. Two of the findings involved a violation of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Clinton Power Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding 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 the Clinton Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* 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 Public Document Room or from the Publicly Available Records System (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Christine A Lipa, Chief
Branch 1
Division of Reactor Projects

Docket No. 50-461
License No. NPF-62

Enclosure:
Inspection Report 05000461/2014-03;
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	05000461/2014003
Licensee:	Exelon Generation Company, LLC
Facility:	Clinton Power Station, Unit 1
Location:	Clinton, IL
Dates:	April 1 through June 30, 2014
Inspectors:	W. Schaup, Senior Resident Inspector K. Carrington, Acting Resident Inspector E. Sanchez-Santiago, Resident Inspector S. Mischke, Resident Inspector, Illinois Emergency Management Agency
Approved by:	Christine Lipa, Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000461/2014003, 04/01/14 – 06/30/14; Clinton Power Station; Operability Determinations and Functionality Assessments and Follow-up of Events and Notices of Enforcement Discretion.

This report covers a three-month period inspection by resident inspectors and announced baseline inspections by regional inspectors. Four Green findings were identified by the inspectors. Two of the findings were considered non-cited violations (NCV) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects within the Cross Cutting Areas" effective date January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. 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.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

Green. The inspectors documented a self-revealing, Green finding associated with a failure to provide adequate work instructions to perform repairs to the shutoff valve for the 1TGCV4 main turbine control valve. Specifically, contrary to station procedure MA-AA-716-010, "Maintenance Planning," Revision 21, the work instructions generated to install the shutoff valve failed to reference the appropriate cap screw size, lubricate the cap screws and install lock washers on the cap screws used to attach the shut off valve to the control valve. This allowed the cap screws to loosen and ultimately fail due to fatigue resulting in a leak of electro hydraulic control fluid of sufficient rate to require a manual scram of Unit 1 on April 26, 2013. The shutoff valve was replaced and successfully tested and the unit was restarted. The licensee documented this issue in the corrective action program (CAP) as Issue Report (IR) 01506929.

The performance deficiency was more than minor because it was associated with the procedure quality attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations and is therefore a finding. 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 finding was screened against the initiating events cornerstone and determined to be of very low safety significance (Green) because the finding did not cause a reactor trip with a coincident loss of mitigating equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined that no cross cutting aspect will be assigned to this performance deficiency since it occurred in 2008 and is not indicative of current plant performance. (Section 4OA3)

- Green. The inspectors documented a self-revealing, Green finding associated with a failure to implement engineering change (EC) 380150 "Upgrade Feed Water Level Control and Turbine Speed." Specifically, contrary to station procedure CC-AA-256, "Process for Managing Plant Modifications Involving Microprocessor Technology," Revision 2, the licensee failed to identify, evaluate and mitigate software component critical parameters in the engineering change that installed the digital feed water system. This resulted in nonlinear reactor water level oscillations when transferring from the motor driven feed pump to the turbine driven feed pump that required the reactor operator to manually scram the reactor prior to reaching the level 8 automatic scram set point. The licensee documented this issue in the corrective action program as IR 1596987.

  The performance deficiency was more than minor because it was associated with the design control attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations and is therefore a finding. 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 finding was screened against the initiating events cornerstone and determined to be of very low safety significance (Green) because the finding did not cause a reactor trip with a coincident loss of mitigating equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined this finding affected the cross-cutting area of human performance in the aspect of documentation where the organization creates and maintains complete, accurate and up-to date documentation. Specifically, the contractors failed to create complete documentation to be used by the licensee when evaluating the software critical parameters. [IMC 0310 H.7] (Section 4OA3)

  Cornerstone: Mitigating Systems

- Green. The inspectors documented a self-revealing non-cited violation of Clinton Power Station Technical Specification 5.4.1, "Procedures," for a failure to prevent foreign material from entering a relay associated with the Division 1 Diesel Generator. Specifically, contrary to station procedure CPS 8501.05, "CV-2 Relay Inspection and Calibration with Doble Test Equipment," Revision 4, the licensee failed to verify that relay 227-DGIKA, CV-2 AB phase was clean and free of all foreign material. The foreign material prevented the relay from operating and satisfying the permissive logic required to close the Division 1 Diesel Generator output breaker resulting in having to declare the Diesel Generator inoperable. The relay was replaced and successfully tested and the licensee documented this issue in the corrective action program as IR 01600935.

  The finding was more than minor because it was associated with the procedure quality 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. Using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," issued June 19, 2012, Exhibit 2 for the Mitigating Systems Cornerstone, the inspectors answered "Yes" to the screening question under the Mitigating Systems Cornerstone "Does the finding represent an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time OR two separate safety systems out-of-service for > its Tech Spec Allowed Outage Time?," since the finding represented an

actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time of 14 days. Therefore, a detailed risk evaluation was performed using IMC 0609, Appendix A. The Senior Reactor Analysts (SRAs) evaluated the finding using the Clinton Standardized Plant Analysis Risk (SPAR) model version 8.17, Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) version 8.1.0 and concluded that the risk increase to the plant due to this finding is very low (Green). The inspectors determined this finding affected the cross-cutting area of human performance in the aspect of work management where the organization implements a process of planning, controlling and executing work activities such that nuclear safety is the overriding priority. Specifically, the licensee's implementation of their foreign material exclusion process for this maintenance activity lacked sufficient planning, controls and execution to prevent foreign material from entering a risk significant piece of safety related equipment. [IMC 0310 H.5] (Section R15)

- Green. The inspectors documented a self-revealing non-cited violation of Clinton Power Station Technical Specification 5.4.1, "Procedures" for a failure to develop adequate procedures for properly pre-planning and performing maintenance affecting the performance of safety-related equipment which resulted in the subsequent failure of the Division 3 Diesel Room Ventilation damper hydramotor on August 15, 2013. Specifically, during pre-scheduled performance testing of the Division 3 (High Pressure Core Spray System) Emergency Diesel Generator Room Ventilation Damper hydramotor, the ventilation supply air intake damper, 1VD01YC, failed to open as a result of Damper Hydramotor 1TZVD003A experiencing an age-related degradation failure. This was due in part to the licensee's failure to properly pre-plan and perform the appropriate preventive maintenance for the hydramotor due to inadequate procedures. Procedure WC-AA-113, "Predefine Database Revisions," Revision 2, did not provide adequate instructions appropriate to the circumstances to properly pre-plan and perform maintenance affecting the performance of safety-related equipment. This resulted in a loss of safety function of the Division 3 Diesel Generator and its supported High Pressure Core Spray system because of the low confidence that diesel room temperature would be maintained to support the diesel during an event when it would be required to perform its function. The licensee replaced the failed hydramotor, performed testing on the new hydramotor, restored the diesel ventilation system to an operable status, and changed WC-AA-113 to ensure that work would be properly scheduled in the future. This issue is documented the corrective action program as IR 1546973 and IR 1547294.

  The performance deficiency was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone attribute 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. Using IMC 0609, Appendix A, "The SDP for Findings At-Power," issued June 19, 2012, Exhibit 2 for the Mitigating Systems Cornerstone. The inspectors answered "Yes" to the screening question under the Mitigating Screening Cornerstone "Does the finding represent a loss of system and/or function?" since the finding resulted in a loss of safety function. Therefore, a detailed risk evaluation was performed using IMC 0609, Appendix A. The SRAs evaluated the finding using the Clinton SPAR model version 8.17, SAPHIRE version 8.1.0 and concluded that the risk increase to the plant due to this finding is very low (Green).

The inspectors determined that no cross-cutting aspect will be assigned to this performance deficiency since it occurred in 2005 and is not indicative of current plant performance. (Section 4OA3)

Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Clinton Power Station (CPS), Unit 1 was operated at or near 97.5 percent power during the inspection period with the following exceptions:

- On May 18, 2014, Control Room operators reduced power to 70 percent to perform control rod sequence exchanges, scram time testing and main steam isolation valve testing. The unit was returned to full power on May 19, 2014.

- On June 10, 2014, Control Room operators commenced raising power to the full licensed thermal power of 3473 MWth in 0.5 percent increments with 24 hour monitoring periods in between. The unit achieved 98.5 percent power on June 12, 2014.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternate alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- The compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- The re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- The required communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

The inspectors performed a walkdown of the switchyard to observe the material condition of the offsite power sources. The inspectors also reviewed the status of outstanding work orders to assess whether corrective actions for any degraded conditions were scheduled with the TSO with the appropriate priority.

This inspection constituted one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Condition – Tornado/High Winds

a. Inspection Scope

Since a Tornado Watch was issued in the vicinity of the facility on April 28, 2014, the inspectors reviewed the licensee's overall preparations/protections for the expected conditions. The inspectors toured the plant grounds in the vicinity of the main power transformers, unit auxiliary transformer, reserve auxiliary transformers, emergency reserve auxiliary transformer, and static volt amp reactive compensators to look for loose debris, which if present could become missiles during a tornado or with high winds. During the inspections, the inspectors focused on plant-specific design features and the licensee's procedure used to respond to tornado and high winds conditions.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

.3 Readiness For Impending Hot Summer Weather Conditions

a. Inspection Scope

The inspectors evaluated the licensee's preparations for hot summer weather conditions, focusing on the electrical distribution system and the plant chilled water system. During the weeks of May 28 and June 10, the inspectors performed a detailed review of severe weather and plant de-winterization procedures and performed general area plant walkdowns. The inspectors focused on plant-specific design features and implementation of procedures for responding to or mitigating the effects of hot summer weather conditions on the operation of the plant. The inspectors reviewed system health reports and system engineering summer readiness review documents for the above systems.

This inspection constituted one seasonal extreme weather readiness inspection sample as defined in IP 71111.01-05.

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:

- Low Pressure Core Spray System, a single train risk significant system
- Division 2 Diesel Generator following Division 1 Diesel Generator surveillance testing
- Residual Heat Removal train A during Residual Heat Removal train C system outage

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 corrective action program with the appropriate characterization and significance. Selected action requests 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 71111.04-05.

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-3f, Division 2 Switchgear Room - Elevation 781'
- Fire Zone A-5, Division 2 Battery Room - Elevation 781'
- Fire Zone A-3b, Residual Heat Removal C Pump Room - Elevation 707'6"
- Fire Zone F-1b, High Pressure Core Spray Pump Room - Elevation 712'
- Fire Zone D-1, Division 3 Diesel Fuel Tank Room - Elevation 712'

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

In addition, the inspectors verified that fire protection related problems identified during the inspection were entered into the licensee's corrective action program and selected action requests were reviewed to verify the corrective actions were appropriate and implemented.

These activities constituted five quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the Updated Final Safety Analysis Report (UFSAR), engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the corrective action program to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant areas to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- High Pressure Core Spray Pump Room
- Low Pressure Core Spray Pump Room

This inspection constituted two internal flooding samples as defined in IP 71111.06-05.

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 April 30, 2014, 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 During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On June 10 and 11, 2014, the inspectors observed control room operators performing power ascension to the extended power uprate licensed thermal limit. 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 71111.11-05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- Action Request 01656173: Maintenance rule function CD-04 unavailability not tracked (main turbine)

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system.

In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization.

This inspection constituted one quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

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 work activities the week of April 7 – April 11; yellow risk due to maintenance activities on DC battery charger 1DC07E system outage
- Planned work activities the week of April 28 – May 2; yellow risk due to Reactor Core Isolation Cooling system outage
- Planned work activities the week of May 19 – May 25; yellow risk due to Emergency Reserve Auxiliary Transformer system outage

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.

In addition, the inspectors verified that problems associated with the effectiveness of plant maintenance were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected action requests were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

These maintenance risk assessments and emergent work control activities constituted three 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 pump suction pressure high;
- Division 1 Diesel Generator output breaker failed to close during synchronization;
- Shutdown Service Water pump C room temperature switch common mode failure;
- Control Room Ventilation B chiller condenser pressure low;
- Late preventative maintenance for breaker 1AP60E2A for the motor operator for valve 1SX020A was; and
- Emergency Reserve Auxiliary Transformer tripped two times in less than 24 hours.

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.

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

This inspection constituted six samples as defined in IP 71111.15-05.

b. Findings

Foreign Material in Relay Prevents Emergency Diesel Generator Output Breaker from Closing

Introduction. The inspectors documented a self-revealing NCV for a failure to prevent foreign material from entering a relay associated with the Division 1 Emergency Diesel Generator (EDG). Specifically, contrary to station procedure CPS 8501.05, "CV-2 Relay Inspection and Calibration with Doble Test Equipment," Revision 4, the licensee failed to verify that relay 227-DGIKA, CV-2 AB phase was clean and free of all foreign material. The foreign material prevented the relay from operating and satisfying the permissive logic required to close the Division 1 EDG output breaker resulting in having to declare the diesel generator inoperable.

Description. On December 26, 2013, while performing the Division 1 EDG monthly test, the control room operators attempted to close the Division 1 EDG output breaker and did not receive indication in the control room that the breaker had closed. Two additional attempts were made from the control room with similar results. Electrical maintenance department personnel locally inspected the sync relay, 225-DG1KA, for proper operation and determined that the relay was functioning correctly based on local panel indication and no immediate failure cause. Two more attempts were made from the control room

with the electrical maintenance personnel at the local panel observing operation of the relay with both attempts failing with similar indication. The control room operators then declared the diesel generator inoperable.

Troubleshooting was performed and it was identified that relay 227-DG1KA, CV-2 AB phase relay did not operate as expected. A relay technician observed the position of the contacts on the CV-2 AB relay to be in the correct position prior to the start of the diesel generator and noted that after the diesel generator was started that the relay contacts did not operate. The cubical door that houses the relay was mechanically agitated and the relay immediately responded as expected. The diesel was secured and the CV-2 relay was removed for inspection and replacement. The relay and case were immediately inspected for foreign material with none being noted.

The licensee sent the relay to a failure analysis laboratory, where it was determined that the most probable cause of the relay failure was a chip of foreign material that restricted rotation of the timing disk preventing the contacts from opening. This was based on a rounded scoring mark that was typical of mechanical damage cause by foreign material getting between the disc to magnet gap during disk rotation and a magnetic chip found on the magnet itself. There was also evidence of aluminum on the edge of the chip which would be consistent with the chip being dragged over the timing disk and the location where the chip was found was in line with the scoring mark on the disk. The licensee's root cause investigation also came to the same conclusion.

The licensee periodically removes relays to perform inspections and calibrations to ensure proper operation. For the CV-2 AB phase relay, portions of this work are done per station procedure CPS 8501.05, "CV-2 Relay Inspection and Calibration with Doble Test Equipment," Revision 4. In conjunction with this procedure, station procedure MA-AA-716-008,"Foreign Material Exclusion Program," Revision 9, is used to implement controls to prevent the introduction of foreign material into the relay during maintenance. These controls would extend from removal of the component from the panel, transport to the calibration room, work performed, storage of the relay until returned to service, transport back to the panel and reinstallation.

Independent review by NRC inspectors identified the following. Step 9.1 of station procedure CPS 8501.05, "CV-2 Relay Inspection and Calibration with Doble Test Equipment" states as part of the acceptance criteria that "the relay shall be clean and free of all foreign material."

The foreign material exclusion procedure, MA-AA-716-008, is a reference use procedure at the station and is not required to be on the job site or read directly while actually implementing foreign material exclusion controls. The procedure discusses in Step 5.5.1, which states, in part "that foreign material exclusion plans should be developed for more complex and critical activities commensurate with the probability and consequence of foreign material exclusion." No plan was developed for this maintenance activity on a risk significant piece of safety related equipment. Attachment 2, Step 1.3.1 of the procedure states, in part "that if the work activity involves opening a component to identify special requirements and to include appropriate steps in the work package." No specific foreign material exclusion controls were incorporated into the work package or the inspection and calibration procedure.

During an interview with technicians that have performed this type of work, it was stated that a non proceduralized practice for maintaining foreign material exclusion during the work was used based on previous performance of the work and from knowledge of the foreign material exclusion procedure that is not required to be on the job site.

The inspectors determined, based upon the implementation of foreign material exclusion practices for this maintenance activity, that the foreign material was introduced during the maintenance activity.

Analysis. The failure to prevent foreign material from entering a relay associated with the division 1 diesel generator was a performance deficiency. The performance deficiency was more than minor because it was associated with the procedure quality 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. Using IMC 0609, Appendix A, "The SDP [significance determination process] for Findings At-Power," issued June 19, 2012, Exhibit 2 for the Mitigating Systems Cornerstone. The inspectors answered "Yes" to the screening question under the Mitigating Systems Cornerstone "Does the finding represent an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time OR two separate safety systems out-of-service for > its Tech Spec Allowed Outage Time?," since the finding represented an actual loss of function of at least a single Train for > its Tech Spec Allowed Outage Time of 14 days. Therefore, a detailed risk evaluation was performed using IMC 0609, Appendix A. The SRAs evaluated the finding using the Clinton SPAR model version 8.17, SAPHIRE version 8.1.0. Adjustments were made to the model to adjust the common cause failure potential as appropriate. The failed relay was installed for service on the Division 1 EDG on September 26, 2012. Accordingly, the exposure time for this performance deficiency was 1-year, the maximum allowed by the SDP. Since installation of the deficient relay, the Division 1 EDG output breaker successfully operated to the closed position 18 times and failed to close on the 19th attempt. The SRAs used this information in a Bayesian update and obtained a revised failure probability for the output breaker of 7.79E-02, which was also used to represent the value of the "failure to start" probability of the Division 1 EDG during the exposure time. Treatment of potential recovery of the failed Division 1 EDG output breaker was applied to this analysis using the Standardized Plant Analysis Risk-Human Reliability Analysis (SPAR-H) method. The overall increase in risk without the considering repair time resulted in a delta core damage frequency (ΔCDF) of 7.07E-07/yr. The unavailability of the Division 1 EDG during the 12-hours repair time resulted in a ΔCDF 1.51E-08/yr. The ΔCDF risk contribution due to fire, seismic, and flooding was 1.04E-08/yr. Therefore the total risk for this finding was 7.32E-07/yr. The potential risk increase due to large early release frequency (LERF) was negligible. Based on the detailed risk evaluation, the total ΔCDF for this finding was 7.32E-07/yr, and therefore characterized as a finding of very low safety-significance (Green). The inspectors determined this finding affected the cross-cutting area of human performance in the aspect of work management where the organization implements a process of planning, controlling and executing work activities such that nuclear safety is the overriding priority. Specifically, the licensee's implementation of their foreign material exclusion process for this maintenance activity lacked sufficient planning, controls and execution to prevent foreign material from entering a risk significant piece of safety related equipment. (IMC 0310 H.5)

Enforcement. Clinton Power Station Technical Specification 5.4.1, "Procedures," requires in part that "written procedures shall be established, implemented, and maintained" as recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, Section 9, "Procedures for Performing Maintenance," states in part that "maintenance is performed in accordance with written procedures appropriate to the circumstance." Step 9.1 of station procedure CPS 8501.05, "CV-2 Relay Inspection and Calibration with Doble Test Equipment", Revision 4, states as part of the acceptance criteria that "the relay shall be clean and free of all foreign material." Contrary to the above on September 21, 2012, the licensee failed to verify that relay 227-DGIKA, CV-2 AB phase was clean and free of all foreign material. The foreign material prevented the relay from operating and satisfying the permissive logic required to close the Division 1 EDG output breaker resulting in diesel generator inoperablility. The licensee replaced the failed relay and successfully tested the diesel generator and declared it operable on December 26, 2013. Because the violation was of very low safety significance and was entered into the licensee's corrective action program as IR 01600935, this violation is being treated as an NCV, consistent with Section 3.2.2 of the Enforcement Policy.
(**NCV 05000461/2014003-001, Foreign Material in Relay Prevents Emergency Diesel Generator Output Breaker from Closing).**

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification:

- 1B21-N543, EC 397600, Provide Manual Bypass of Pressure Controller, Rev. 0

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the Updated Final Safety Analysis Report (UFSAR), and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modification was installed as directed and consistent with the design control documents; the modification operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one temporary modification sample as defined in IP 71111.18-05.

b. Findings

No findings were identified.

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:

- Control Room Ventilation B train testing following system maintenance;
- Drywell Ventilation B chiller vane timing and load testing after maintenance;
- Reactor Core Isolation Cooling trip throttle valve testing after maintenance;
- Control Rod Drive Hydraulic Control Unit 32-25 leak check and scram-time testing after maintenance;
- Division 1 Diesel Generator air compressor A and B skid function and leak checks after maintenance; and
- 1SX016B motor operator thrust and valve stroke testing after motor rebuild.

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.

In addition, the inspectors reviewed corrective action program documents associated with post-maintenance testing to verify that identified problems were entered into the licensee's corrective action program with the appropriate characterization. Selected action requests were reviewed to verify that the corrective actions were appropriate and implemented as scheduled.

This inspection constituted six post-maintenance testing samples as defined in IP 71111.19-05.

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 9065.02, “Secondary Containment Integrity” (Routine Test);
- CPS 9080.02, “Diesel Generator 1B Operability – Manual and Quick Start Operability” (Routine Test);
- CPS 9051.01, “High Pressure Core Spray Pump and High Pressure Core Spray Water Leg Pump Operability” (In-Service Test);
- CPS 9054.01, “Reactor Core Isolation Cooling Pump and Valve Operability and Cold Quick Start” (In-Service Test);
- CPS 9015.06, “Standby Liquid Control System Valve Operability” (In-Service Test); and
- CPS 9915.01, “Standby Liquid Control (SLC) Chemical Sampling” (Routine Test).

The inspectors observed selected portions of the test activities to verify that the testing was accomplished in accordance with plant procedures. The inspectors reviewed the test methodology and documentation to verify that equipment performance was consistent with safety analysis and design basis assumptions, and that testing acceptance criteria were satisfied.

In addition, the inspectors verified that surveillance testing problems were entered into the licensee’s corrective action program with the appropriate characterization and significance. Selected action requests were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

This inspection constituted three routine surveillance testing samples and three in-service testing samples as defined in IP 71111.22, Sections -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 routine licensee emergency drill on April 29, 2014, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Simulator and 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 corrective action program. 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.

4. OTHER ACTIVITIES

Cornerstones: Mitigating Systems

4OA1 Performance Indicator (PI) Verification (71151)

.1 Review of Submitted Quarterly Data

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the First Quarter 2014 Performance Indicators for any obvious inconsistencies prior to its public release in accordance with IMC 0608, "Performance Indicator Program."

This inspection was not considered to be an inspection sample as defined in IP 71151.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - High Pressure Injection Systems performance indicator for the period from the second quarter 2013 through the first quarter 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of April 1, 2013 through March 31, 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one MSPI high pressure injection system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Heat Removal System performance indicator for the period from the second quarter 2013 through the first quarter 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period April 1, 2013 through March 31, 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one MSPI heat removal system sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Residual Heat Removal System performance indicator for the period from the second quarter 2013 through the first quarter 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period April 1, 2013 through March 31, 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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 MSPI residual heat removal system 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 inspection procedures 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 Corrective Action Program 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 Corrective Action Program 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 Corrective Action Program. 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 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of January 1, 2014 through June 30, 2014, although some examples expanded beyond those dates where the scope of the trend warranted.

The reviews also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This review constituted one semi-annual trend inspection sample as defined in IP 71152-05.

b. Assessment and Observations

Adverse Trend in Evaluating Degraded/Nonconforming Plant Conditions for Operability, Functionality and/or Reportability

The inspectors had previously noted an adverse trend with the licensee's evaluation of degraded/nonconforming plant conditions for operability, functionality and/or reportability. Fewer examples of deficiencies with evaluations for operability, functionality and reportability were observed by the inspectors during this assessment period and no finding of significance was identified; however, the inspectors will continue to inspect evaluations for operability, functionality and reportability as a focus area.

c. Findings

No findings were identified.

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

.1 (Closed) Licensee Event Report (LER) 05000461/2013-004-00: Loss of Emergency Diesel Room Ventilation Due to Damper Hydramotor Failure.

a. Inspection Scope

The failure, which occurred on August 15, 2013, was discovered during pre-scheduled performance testing of the Division 3 (High Pressure Core Spray) Emergency Diesel Generator (EDG) Room Ventilation system when the supply air intake damper did not exhibit the expected behavior of opening upon start of the EDG ventilation fan. The licensee's subsequent investigation and vendor failure analysis determined the supply

air damper's hydramotor had experienced an age-related degradation failure due to having been installed beyond its recommended service-life. Corrective actions taken by the licensee included replacing the failed damper hydramotor, testing the new hydramotor, conducting an extent of condition evaluation and apparent cause analysis, and replacing and scheduling for replacement ten other hydramotors susceptible to the same failure. The inspectors reviewed the licensee's corrective actions and determined the corrective actions could be viewed as reasonable to prevent recurrence. This LER is closed.

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

b. Findings

Failure to Develop Adequate Procedures for Pre-planning and Performing Maintenance Affecting Safety-Related Equipment

Introduction. The inspectors documented a self-revealing NCV of Technical Specification 5.4.1, "Procedures," for the licensee's failure to develop an adequate procedure for properly pre-planning and performing maintenance that could affect the performance of safety-related equipment. Specifically, station procedure WC-AA-113, "Predefine Database Revision," Revision 2 did not meet the requirements of Regulatory Guide 1.33, such that the licensee failed to replace a hydramotor that was known to be past the service life. The hydramotor subsequently failed due to age-related degradation preventing the diesel room supply air intake damper from operating resulting in diesel generator inoperability.

Description. On August 15, 2013, licensee maintenance personnel were performing testing on the supply air intake modulation damper for the Division 3 Diesel Generator Ventilation System. Maintenance personnel started the diesel generator ventilation fan and observed Damper 1VD01YC response. Upon start of the fan, the licensee noticed that the damper response was not as expected and the test flow data was inconsistent with previous test flow data. Having identified anomalies, the licensee made the decision to suspend the test until later in the day when outside temperatures were projected to be at or above 70 degrees, the actual set point at which the damper would be required to function. After restarting the EDG fan at a temperature above 70 degrees and not obtaining the desired response, operations personnel secured the diesel ventilation fan and declared the Division 3 EDG inoperable.

The licensee's subsequent investigation and vendor failure analysis determined the damper hydramotor, 1TZVD003A, had experienced end-of-life failure of the internal hydraulic pump or an age-related degradation failure due to having been installed beyond its recommended service life. Based on a review of licensee documents and interviews with licensee personnel, the inspectors determined the hydramotor had been in service since the life of the plant without having ever been rebuilt or replaced despite the licensee's preventive maintenance (PM) template recommendation to replace or rebuild the hydramotor every ten years.

In 2005, the licensee adopted a new PM template revising the scope and frequency of preventive maintenance for the hydramotor. The new PM template required that the hydramotor be rebuilt or replaced every ten years. At the time of implementation of the new template, the hydramotor had been in service for approximately 18 years. This put the hydramotor past the template's recommended frequency for replacement. Instead of

scheduling the replacement at the next available opportunity the licensee scheduled the hydramotor to be replaced in October 2013 based on a previously completed preventive maintenance activity in 2003.

Station procedure WC-AA-113, Revision 002, “Predefine Database Revisions,” governs changes, additions, and deletions made to the PM database. The procedure requires personnel generate service requests for an addition, change, deletion, suspension, or retirement of a PM activity in the predefine database. Sections 4.2, “Adds,” and 4.3, “Changes,” of the procedure state the specifics for generating the service request when adding or making changes to a PM activity or predefine in the database. The licensee generated Service Request 37765 to change the scope and frequency of the PM activity in accordance with WC-AA-113. The service request described the change being made to the PM template but failed to consider the fact that the PM had already exceeded the template’s recommended performance frequency and needed to be scheduled as soon as possible. The procedure and service request relied heavily upon licensee personnel to schedule the PM activity at the appropriate time.

The inspectors determined the procedure lacked the necessary guidance to ensure preventive maintenance activities were properly scheduled. The procedure did not contain provisions to ensure PM templates that have had their scopes changed are identified as new preventive maintenance activities that have never been performed and that those activities when scheduled do not exceed the template’s recommended frequency for performance. Consequently, the preventive maintenance for the hydramotor was not scheduled in a timely fashion and resulted in the damper hydramotor failure on August 15, 2013.

The issue was entered into the licensee’s corrective action program as Issue Reports (IRs) 1546973 and 1547294. The licensee replaced the failed hydramotor, performed testing on the new hydramotor and restored the diesel ventilation system to operable, performed an extent of condition evaluation to identify other hydramotors which were potentially susceptible to the same failure, scheduled dates for replacement of the hydramotors.

Analysis. The inspectors determined the failure to develop adequate procedures and instructions appropriate to the circumstances to properly pre-plan maintenance for the diesel room ventilation damper hydramotor was contrary to the requirements of TS 5.4.1 and was a performance deficiency. The performance deficiency was more than minor because it was associated with the equipment performance 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. Using IMC 0609, Appendix A, “The SDP for Findings At-Power,” issued June 19, 2012, Exhibit 2 for the Mitigating Systems Cornerstone. The inspectors answered “Yes” to the screening question under the Mitigating Screening Cornerstone “Does the finding represent a loss of system and/or function?” since the finding resulted in a loss of safety function. Therefore, a detailed risk evaluation was performed using IMC 0609, Appendix A. The SRAs evaluated the finding using the Clinton SPAR model version 8.17, SAPHIRE version 8.1.0. The EDG was in its normal standby lineup when the failed damper was discovered. Thus the EDG was assumed failed starting after its last successful run on August 14, 2013. The damper and the EDG were restored to operable status on August 17, 2013, following repairs. The assumed exposure time was 4 days. In the

SPAR model, the SRA set the basic event representing the EDG failure to run (and the supported high pressure core spray system) to "True" (i.e., failed) and assumed no recovery of room ventilation. The result was a delta core damage frequency (ΔCDF) for internal events of 2.4E-07/yr. The dominant sequence involved a loss of offsite power (weather-related) initiating event and station blackout (SBO), and failure to recover either offsite or emergency onsite power in 4-hours. The risk due to external events and LERF was judged to be small relative to the internal events risk. That is, the total risk for this finding would not exceed 1E-06/yr. This is based on conservative assumptions (e.g., the EDG was assumed failed although it was capable of running for some period of time and no credit was applied to restoring room cooling). Also, this issue is similar to a separate finding issued in NRC Inspection Report 05000461/2012-004 that involved failure of a EDG air supply damper with a 36-day exposure time and had low risk significance. Based on this, the SRA concluded that the risk increase to the plant due to this finding is very low (Green). The inspectors determined that no cross-cutting aspect will be assigned to this performance deficiency since it occurred in 2005 and is not indicative of current plant performance.

Enforcement. Technical Specification 5.4.1., "Procedures," requires in part that "written procedures be established, implemented, and maintained" as recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, Section 9, "Procedures for Performing Maintenance," states in part "maintenance affecting performance of safety-related equipment should be properly pre-planned and performed in accordance with procedures, instructions, or drawings appropriate to the circumstances."

Contrary to the above, following a change in the licensee's preventive maintenance requirements for hydramotors in 2005, the licensee failed to properly pre-plan and perform the required preventive maintenance for the Division 3 (High Pressure Core Spray System) Emergency Diesel Generator Room Ventilation damper hydramotor because Procedure WC-AA-113, Revision 002, "Predefine Database Revisions," did not include provisions appropriate to the circumstance to ensure maintenance affecting the performance of safety-related equipment was properly pre-planned and performed. The licensee replaced the failed hydramotor, performed testing on the new hydramotor and restored the diesel ventilation system to an operable status, and changed WC-AA-113 to ensure that work would be properly scheduled in the future. Because this violation is of very low safety significance and was entered into the licensee's corrective action program as IR 1546973 and IR 1547294, this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy.
(**NCV 05000461/2014003-02, Failure to Develop Adequate Procedures for Pre-planning and Performing Maintenance Affecting Safety-Related Hydramotor).**

.2 (Closed) Licensee Event Report 05000461/2013-003-00: Manual Reactor Scram Due To Main Electro-Hydraulic Control System Failure

a. Inspection Scope

The event, which occurred on April 26, 2013, was discovered after the main control room received a main electro-hydraulic control (EHC) pressure alarm due to level lowering in the main EHC oil reservoir. The licensee's subsequent investigation and vendor failure analysis determined that a cap screw securing a shutoff valve had failed due to fatigue cracking associated with relatively high stresses resulting in a leak of electro hydraulic

control fluid of sufficient size to require a manual scram of Unit 1 on April 26, 2013. Corrective actions taken by the licensee included replacing the failed shutoff valve, testing the new electro-hydraulic control system, conducting an extent of condition evaluation and common cause analysis, and performing future maintenance activities on the electro-hydraulic control system with station personnel instead of using vendors. The inspectors reviewed the licensee's corrective actions and determined the corrective actions could be viewed as reasonable to prevent recurrence. This LER is closed.

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

b. Findings

Electro-Hydraulic Control System Leak Results in Manual Scram

Introduction. The inspectors documented a self-revealing, Green finding associated with a failure to provide adequate work instructions to perform repairs to the shutoff valve for 1TGCV4 main turbine control valve. Specifically, contrary to station procedure MA-AA-716-010, "Maintenance Planning," Revision 21, the work instructions generated to install the shutoff valve failed to reference the appropriate cap screw size, and the requirements to lubricate and install lock washers on the cap screws used to attach the shut off valve to the control valve. This allowed the cap screws to loosen and ultimately fail due to fatigue resulting in a leak of electro-hydraulic control fluid of sufficient rate to require a manual scram of Unit 1 on April 26, 2013.

Description. On April 26, 2013, the main control room received a main EHC pressure alarm due to lowering level in the main EHC oil reservoir. A non-licensed operator was dispatched and reported the oil reservoir level at minus 4.25 inches and rapidly lowering. Additionally, an oil mist was reported on the 800-foot elevation of the turbine building. Based on the reports, the control room operators manually scramed the reactor by placing the mode switch in the shutdown position.

As part of the post shutdown actions, the turbine building was walked down by mechanical maintenance personnel. During the walkdown personnel were able to determine the source of the leak after discovering a broken socket head cap screw used to attach a hydraulic shutoff valve to main steam turbine control valve number four. Additionally, the three other mounting cap screws used to attach the valve were loose and one of those was slightly bent.

The valve and associated failed components were removed from the system and sent off site for failure analysis. The failure analysis report stated that the broken cap screw had failed due to fatigue cracking associated with relatively high stresses and noted no material defects associated with the crack. Additionally, the report stated that the likely cause of the fatigue fracture was the cap screw being loose.

The licensee determined that the shutoff valve was installed under Work Order 00705492-01 in January of 2008. A review of the work order noted the following deficiencies with the instructions to install the valve: the instructions did not specify the use of required lock washers, did not specify lubrication of the cap screws, referenced the wrong size cap screw and listed an incorrect document in the reference section of the procedure. The licensee performed a root cause evaluation that determined the root cause for the cap screw failure to be inadequate work instructions to install the valve.

Analysis. The failure to provide adequate work instructions to install the appropriate cap screw size, lubricate the cap screws and install lock washers on the cap screws was a performance deficiency. The performance deficiency was more than minor because it was associated with the procedure quality attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations and is therefore a finding. 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 finding was screened against the initiating events cornerstone and determined to be of very low safety significance (Green) because the finding did not cause a reactor trip with a coincident loss of mitigating equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined that no cross cutting aspect would be assigned to this performance deficiency since it occurred in 2008 and is not indicative of current plant performance.

Enforcement. This finding does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding does not involve a violation and is of very low safety significance, it is identified as a finding.
(FIN 05000461/2014003-003, Electro-Hydraulic Control System Leak Results in Manual Scram).

.3 (Closed) Licensee Event Report 05000461/2013-009-00: Software Errors in New Digital Feedwater Control System Result in Manual Reactor Scram Due to Approaching High Reactor Pressure Vessel Water Level Setpoint.

a. Inspection Scope

The event, which occurred on December 13, 2013, occurred at approximately 18 percent power while control room operators were transitioning from the motor driven feed pump to the "A" turbine driven feed pump. The licensee's subsequent investigation determined that software component critical parameters were not identified, evaluated or mitigated in accordance with station procedures. Corrective actions taken by the licensee included revising the software and station procedures to ensure proper operation of the digital feedwater system. The inspectors reviewed the licensee's corrective actions and determined the corrective actions could be viewed as reasonable to prevent recurrence. This LER is closed.

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

b. Findings

Failure to Implement Engineering Change Results in Manual Reactor Scram

Introduction. The inspectors documented a self-revealing finding associated with a failure to implement engineering change EC 380150 "Upgrade Feed Water Level Control and Turbine Speed." Specifically, contrary to station procedure CC-AA-256, "Process for Managing Plant Modifications Involving Microprocessor Technology," Revision 2, the licensee failed to identify, evaluate and mitigate software component critical parameters in the engineering change that installed the digital feed water system. This resulted in nonlinear reactor water level oscillations when transferring from the motor driven feed

pump to the turbine driven feed pump that required the reactor operator to manually scram the reactor prior to reaching the level 8 automatic scram set point.

Description. On December 13, 2013, Unit 1 was at approximately 18 percent power and control room operators were transitioning from the motor driven feed pump to the "A" turbine driven feed pump. As the turbine driven feed pump began to increase the amount of feed water flow it was providing the motor driven feed pump began to reduce the amount of feed water flow it was providing. Over the next few minutes flow from the feed pumps began to oscillate resulting in reactor water vessel level oscillations. The operators recognized the condition and took manual control of the motor driven feed pump flow control valve to fully shut the valve. This action caused the turbine driven feed pump speed to increase rapidly resulting in increased flow rate to the reactor vessel and subsequent increase in reactor vessel water level. Prior to reactor water level reaching the level 8 automatic scram set point the reactor operator placed the mode switch in shut down initiating a manual reactor scram.

The licensee performed a root cause investigation that determined the following software component critical parameters were not identified, evaluated or mitigated in accordance with station procedures: speed demand curve for the turbine drive feed pump, feed water header pressure, and the automatic level set point switch over function.

An assumption made by the contractors during development of the speed demand curve for the turbine driven feed pump above 2900 rpm resulted in a high gain response at low speeds for the pump and was not included in required documentation to site engineering for incorporation into the engineering change. This assumption was found to be incorrect and not supported by operating history which resulted in not establishing operating limits in the software code or the operating procedure.

Additionally, an error was found in the software algorithm for calculating feed water header pressure. The contractor writing the software stated they had good experience in calculating the pressure drop across feed valves and used engineering judgment to validate the feed water header pressure. The calculated pressure differences were higher than the actual pressure differences because the feed water valve curve was not corrected for water temperatures less than 400°F. It should be noted that the licensee had real time data for this value on the plant computer and the real time data could have been used to benchmark the model.

Finally, while reviewing the automatic level set point switchover function the "bring pump online" command program logic had no preset time criteria for how long the 200 rpm permissive had to be satisfied before going to automatic. This allowed the turbine driven pump to operate in a high gain region on the flawed speed demand curve discussed earlier. The contractor incorrectly believed that placing the pump in automatic was preferred regardless of level stability which was not a valid assumption on the high gain region of the pump curve.

The software errors identified as part of the licensee root cause investigation impacted critical parameters that were not previously evaluated and mitigated in the engineering change package. This was contrary to station procedure CC-AA-256, "Process for Managing Plant Modifications Involving Microprocessor Technology," Revision 2, that requires validating critical vendor information. Additionally, the purchase specification to the contractor required the contractor to clearly state any and all assumptions

concerning unknown or unstated requirements at any level in the software; however, the contractor documentation failed to include all assumptions and engineering judgment.

Analysis. The failure to identify, evaluate and mitigate software component critical parameters in the engineering change that installed the digital feed water system was a performance deficiency. The performance deficiency was more than minor because it was associated with the design control attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations and is therefore a finding. 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 finding was screened against the initiating events cornerstone and determined to be of very low safety significance (Green) because the finding did not cause a reactor trip with a coincident loss of mitigating equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined this finding affected the cross-cutting area of human performance in the aspect of documentation where the organization creates and maintains complete, accurate and up-to date documentation. Specifically, the contractors failed to create complete documentation to be used by the licensee when evaluating the critical parameters. (IMC 0310 H.7)

Enforcement. This finding does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding does not involve a violation and is of very low safety significance, it is identified as a finding.
(**FIN 5000461/2014003-004, Failure to Implement Engineering Change Results in Manual Reactor Scram).**

4OA6 Management Meeting

.1 Exit Meeting Summary

On July 17, 2014, the inspectors presented the inspection results to Mr. K. Taber 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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Anthony, Corporate NDE Services Manager
M. Baig, Engineering Programs, ISI
R. Bair, Chemistry Manager
K. Baker, Regulatory Assurance Manager
R. Bedford, Licensed Operator Requalification Lead
J. Bond, Emergency Preparedness Manager
B. Brooks, Security Manager
R. Campbell, RP Technical Manager
J. Cunningham, Acting Regulatory Assurance Manager
A. Droppers, Health Physicist
C. Dunn, Training Director
R. Frantz, Regulatory Assurance
M. Friedman, Radiation Protection Operations Manager
N. Hightower, Radiation Protection Manager
T. Krawcyk, Shift Operations Superintendent
K. Leffel, Operations Support Manager
D. Kemper, Operations Director
S. Kowalski, Senior Manager Design Engineering
M. Mayer, Acting Security Manager
S. Mohundro, Engineering Programs Manager
W. Padgett, Work Management
C. Propst, Nuclear Oversight Manager
D. Reoch, Radiation Protection General Supervisor
F. Sarantakos, Engineering Programs
R. Schenck, Work Management Director
D. Shelton, Operations Services Manager
D. Smith, Design Engineering
J. Smith, Acting Site Engineering Director
D. Snook, Operations Training Manager
T. Stoner, Plant Manager
J. Stovall, Maintenance Director
B. Taber, Site Vice President
R. Zacholski, Acting Nuclear Oversight Manager

NRC

W. Schaup, Clinton Senior Resident Inspector
E. Sanchez-Santiago, Clinton Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened/Closed

05000461/2014003-01	NCV	Foreign Material in Relay Prevents Emergency Diesel Generator Output Breaker from Closing (1R15)
05000461/2014003-02	NCV	Failure to Develop Adequate Procedures for Pre-planning and Performing Maintenance Affecting Safety-Related Hydramotor (4OA3.1)
05000461/2014003-03	FIN	Electro-Hydraulic Control System Leak Results in Manual Scram (4OA3.2)
05000461/2014005-04	FIN	Failure to Implement Engineering Change Results in Manual Reactor Scram (4OA3.3)

Closed

05000461/2013-004	LER	Loss of Emergency Diesel Room Ventilation Due to Damper Hydramotor Failure (4OA3.1)
05000461/2013-003	LER	Manual Reactor Scram Due to Main Electro-Hydraulic Control System Failure (4OA3.2)
05000461/2013-009	LER	Software Errors in New Digital Feedwater Control System Result in Manual Reactor Scram Due to Approaching High Reactor Pressure Vessel Water Level Setpoint (4OA3.3)

Discussed

None

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

- Clinton Power Station Site Certification Letter for Summer Readiness- Attachment 2, May 15 2014
- CPS 4302.01, "Tornado/High Winds," Revision 21a
- CPS Plant Manager System Review Attestation Form," February 28, 2014
- NES-MS-02.6, "Guidelines for Preventive Maintenance of HVAC Chillers and Condensing Units," Revision 4
- NSED-I-EE-6, "Transmission Grid Conditions for Clinton Power Station," Revision 4
- OP-AA-108-111-1001, "Severe Weather and Natural Disaster Guidelines," Revision 12
- OP-CL-108-107-1002, "Degraded Grid Actions," Revision 6
- Safety Guide 23, "Onsite Meteorological Programs," February 17, 1972
- AR 01652787, "Entered Tornado/ High Winds Off Normal"
- AR 01653761, "1 Phase of Disconnect 1375 0YA (138 KV) Needs Repaired Cameren"
- AR 01529337, "ERAT SVC North Bard Unit Concern"
- AR 01660766, "Sharp Degrading Conditions in CW Valve Pit Due to Moisture"
- AR 01660838, "NOS Id Untimely Actions Address Switchyard Lightning Study"
- AR 01661453, "Net Electric Higher than Projected"
- AR 01460202, "Walkdown of Transformers and Switchyard"
- AR 01473761, "Stability Study Identifies Generator Instability"
- AR 01474807, "Stability Study Identifies Generator Instability"
- AR 01483225, "Findings Concerning Rising Line Transient of FEB 2013"
- AR 01485673, "Elevated Temperature on Switchyard Disconnect Switch"
- AR 01499015, "Improvement Suggestion for Offsite Power Restoration"

1R04 Equipment Alignment

- CPS 3313.01E001, "Low Pressure Core Spray Electrical Lineup," Revision 11a
- CPS 3313.01V001, "Low Pressure Core Spray Valve Lineup," Revision 13a
- CPS 3313.01V002, "Low Pressure Core Spray Instrument Valve Lineup," Revision 8a
- CPS 3312.01E001, "Residual Heat Removal Electrical Lineup", Revision 17
- CPS 3312.01V001, "RHR System A Valve Lineup", Revision 17a
- CPS 3312.01V002, RHR System A Instrumentation Valve Lineup", Revision 9a
- CPS 1893.04M132, "781 Auxiliary (East): Div 1 Switchgear Prefire Plan," Revision 5
- CPS 3402.01, "Control Room HVAC," Revision 27c
- CPS 3402.01E001, "Control Room HVAC Electrical Lineup," Revision 10b
- CPS 3402.01P001, "Control Room HVAC (VC) Train Shifting," Revision 5a
- CPS 3402.01V001, "Control Room HVAC Valve Lineup," Revision 16e
- CPS 3402.01V002, "Control Room HVAC Instrument Valve Lineup," Revision 6
- CPS 3506.01, "Diesel Generator and Support Systems (DG)," Revision 37a.
- CPS 3506.01E001, "Diesel Generator and Support Systems Electrical Lineup," Revision 18c.
- CPS 3506.01P001, "Division 1 Diesel Generator Operations," Revision 5
- CPS 3506.01V001, "Diesel Generator and Support Systems Valve Lineup," Revision 13a.

- CPS 3506.01P002, “Diesel Generator Operations,” Revision 3
- CPS 3402.01, “Appendix C: Main Control Room Envelope Boundary,” Revision 27c
- Drawing IS-1035-C, “Inservice Inspection Schematic Diesel Generator (DG) System,” Sheet 1, Revision E
- Drawing IS-1035-S, “Inservice Inspection Schematic Diesel Generator (DG) System,” Sheet 1, Revision B
- Drawing IS-1036-C, “Inservice Inspection Schematic Diesel Generator Fuel Oil System,” Sheet 1, Revision C
- Drawing M05-1035, “Diesel Generator Cooling System,” Sheet 4, Revision I
- Drawing M05-1035, “Diesel Generator Cooling System,” Sheet 6, Revision H
- Drawing M05-1035, “Diesel Generator Cooling System,” Sheet 7, Revision H
- Drawing M05-1102, “Control Room HVAC (VC),” Sheet 1, Revision U
- Drawing M05-1102, “Control Room HVAC (VC),” Sheet 2, Revision J
- Drawing M05-1102, “General Arrangement Control Bldg.; Main Floor Plan El. 800’-0,” Sheet 3, Revision N
- AR 01664825, “Moisture Indicator Cover is Cracked”
- AR 01639856, “Revise Procedure: 3402.01E001, VC HVAC Electrical Lineup”
- AR 01645410, “Calibration Sheet Discrepancy Between Loop and Controller”
- AR 01645885, “VC-B Chiller Oil Heater Temperature Switch Not Working”
- AR 01646016, “Problems with VC ‘B’ Oil Temp Switch Installation”
- AR 01665054, “Oil Mist Did Not Spray Out of 1DG16MB and 1DG16MM”
- AR 01650318, “Failed PMT on Hydramotor 0VC21YA”

<u>1R05 Fire Protection</u>

- CPS 1893.04M105, “707’ Auxiliary RHR ‘C’ Pump Room Pre-fire Plan,” Revision 5
- CPS 1893.04M130, “781-790’ Auxiliary Division 2 Switchgear Pre-fire Plan,” Revision 5
- CPS 1893.04M400, “712’ Fuel Basement Pre-fire Plan,” Revision 5
- CPS 1893.04M135, “781’ Auxiliary (West) Division 2 Battery Room Pre-Fire Plan,” Revision 6
- CPS 1893.04M500, “712 Diesel Generator: Division 3 Diesel Fuel Tank Room Pre-fire Plan,” Revision 5

<u>1R06 Flooding</u>

- Equipment as a Result of Backflow Through the Equipment and Floor Drain System,” August 30, 1990
- IE Circular No. 78-06, “Potential Common Mode Flooding of ECCS Equipment Rooms at BWR Facilities,” May 31, 1978
- CPS 4411.03, “Injection/Flooding Sources,” Revision 10a
- CPS 4304.01; “Flooding;” Revision 6
- OP-TM-AOP-0021, “Flood Basis Document,” Revision 7
- NSE-97-064, “Calculation 3C10-0485-001,” Revision 8-E
- AR 01324504, “Question Raised on Potential Spray/Flooding Concern”
- AR 01399374, “NRC Questions Clinton Power Station Applicability to BY & BW Issue”
- AR 00976295, “ECCS Room Floor Drain Piping Connected to RW Pipe Tunnel”

<u>1R11 Licensed Operator Requalification Program</u>

- 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 2857.00, “100% Core Thermal Power Power Ascension Special Procedure,” Revision 0

1R12 Maintenance Effectiveness

- NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 2
- ER-AA-310, “Implementation of Maintenance Rule,” Revision 9
- ER-AA-310-1001, “Maintenance Rule Scoping,” Revision 4
- ER-AA-310-1002, “Maintenance Rule Functions – Safety Significance Classification,” Revision 3
- ER-AA-310-1003, “Maintenance Rule – Performance Criteria Selection,” Revision 4
- ER-AA-310-1004, “Maintenance Rule – Performance Monitoring,” Revision 11
- ER-AA-310-1005, “Maintenance Rule – Dispositioning Between (a)(1 and (a)(2),” Revision 6
- AR 01656173, “Maintenance Rule Function CD-04 Unavailability Not Tracked”

1R13 Maintenance Risk Assessments and Emergent Work Control

- Protected Equipment Posting Map ERAT OOS, May 19, 2014
- Clearance Order (CO) 00104269, Checklist 005, “Emergency Reserve Aux Transformer,” May 21, 2014SY-AA-101-146, “Severe Weather Preparation and Response,” Revision 0
- 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-106, “Work Screening and Processing,” Revision 13
- 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
- AR 01662679, “ERAT Restoration Lessons Learned”
- AR 01662818, “Entered Tornado/High Winds Off Normal”

1R14 Drill Evaluations

- 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

1R15 Operability Determinations/Functionality Assessments

- 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
- CPS 9082.01, “Offsite Source Power Verification,” Revision 40b
- CPS 4200.01, ”Loss of AC Power,” Revision 23c

- CPS 9080.01, “Diesel Generator 1A Operability – Manual and Quick Start Operability,” Revision 55
- CPS 3506.01C001, “Diesel Generator 1A Pre-Start Checklist,” Revision 16
- CPS 9080.01D001, “Diesel Generator 1A Operability – Manual and Quick Start Data Sheet,” Revision 44e
- CPS 3506.01C005, “Diesel Generator Start Log,” Revision 1a
- CPS 3506.01D001, “Diesel Generator 1A Operating Logs,” Revision 5
- MA-AA-716-008, “Foreign Material Exclusion Program,” Revision 9
- WO 00018648-01, “Perform 1TSVH006 Calibration IAW CPS,” May 30, 2001
- WO 00644853-01, “Perform 1TSVH006 Calibration IAW CPS 8801.01,” March 22, 2005
- WO 1069360-01, “Perform 1TSVH006 Calibration IAW CPS 8801.01,” March 8, 2010
- WO 01426769, “Test Division 1 DG Protective Relays”
- WO 01685370, “DG 1A Operability Test”
- EC 397726, “Evaluation of Breaker 1AP60E2A and Valve 1SX020A,” Revision 0
- EC 387113, “Replace Main Control Room Air Conditioning Head Pressure Controller,” Revision 1
- EC 397555, “RCIC Pump Suction Pressure Alarm”
- Operability Evaluation 1016498-02, “Extend Time for Chiller Oil Return System”
- Equipment Apparent Cause Report 01600935, “Division 1 DG Output Breaker Failed to Close During Sync”
- AR, 01672918, “Unexpected Trip of The Emergency Reserve Auxiliary Transformer Static Variable Compensator”
- AR 01673008, “Emergency Reserve Auxiliary Transformer Static Variable Compensator Tripped for Second Time in Less Than 24 Hours”
- AR 01673345, “Emergency Reserve Auxiliary Transformer Static Variable Compensator Loose Wire and Trip”
- AR 01644078, “1AP60E24, Molded Case Circuit Breaker for 1SX020A Valve, Preventative Maintenance Went Late on April 5, 2014”
- AR 01636631, “0VC10CB, Main Control Room Air Conditioning Condenser, Head Pressure to Low”
- AR 01637547, “Received 5063 – 1D, RCIC Pump Suction Pressure High Alarm”

1R18 Plant Modifications

- CC-AA-10, “Configuration Control Process Description,” Revision 7
- CC-AA-20, “Configuration Management,” Revision 1
- CC-AA-102, “Design Input and Configuration Change Impact Screening,” Revision 27
- CC-AA-103, “Configuration Change Control for Permanent Physical Plant Changes,” Revision 25
- CC-AA-112, “Temporary Configuration Changes,” Revision 20
- EC 397600, “Provide Manual Bypass of Pressure Controller 1B21N543,” Revision 0

1R19 Post-Maintenance Testing

- CPS 9813.01, “Control Rod Scram Time Testing,” Revision 40a
- CPS 9813.01C001, “Control Rod Scram Timing Checklist,” Revision 32f
- CPS 9813.01D003, “Scram Time Testing – Containment Data Sheet,’’ Revision 31
- CPS 9813.01D004, “Scram Time Testing – MCR Data Sheet,” Revision 31b
- CPS 9813.01D005, “Control Rod Scram Timing/Stopwatch,” Revision 31a
- CPS 9813.01D006, “Control Rod Scram Time Option B205 Insertion Calculation,” Revision 31
- CPS 9813.01D007, “Control Rod Scram Time Option B OLMCPR Calculation,” Revision 31

- CPS 3320.01, “Drywell Cooling System (VP),” Revision 21c
- CPS 3310.01, “Reactor Core Isolation Cooling (RI),” Revision 20
- CPS 9061.06, “Containment Drywell Isolation Valve 24 Month Operability Check,” Revision 41b
- CPS 9061.06C013, “Division 2 Fuel Pool Makeup Isolation Valve Operability Checklist,” Revision 37
- CPS 9061.06D013, “Division 2 Fuel Pool Makeup Isolation Valve Operability Data Sheet,” Revision 37
- CPS 9381.01, “MOV Thermal Overload Bypass Verification,” Revision 37
- CPS 9381.01C001, “MOV Thermal Overload Bypass Verification Checklist,” Revision 35
- CPS 9381.01C002, “MOV Thermal Overload Bypass Post Maintenance Verification Checklist,” Revision 28
- MA-AA-716-012, “Post-Maintenance Testing,” Revision 11
- MA-AA-723-300, “Diagnostic Testing of Motor Operated Valves,” Revision 8
- ER-AA-300, “Motor Operated Valve Program Administrative Procedure,” Revision 7
- ER-AA-302, “Motor Operated Valve Program Engineering Procedure,” Revision 5
- Drawing IS-1074-S, “Inservice Inspection Schematic High Pressure Core Spray System (HPCS),” Sheet 1, Revision D
- Drawing E02-1VP99, “Drywell Cooling Sys (VP) Drywell Water Chiller Skid (1VP04CB),” Sheet 20, Revision L
- WO 01589413-01, “9054.01, 1E51C001 Comprehensive Pump Test,” April 29, 2014
- WO 01720969-01, “9070.01B21 OP CNTR RM M/U Air Filt Flow/Htr Oper-Trn B,” April 11, 2014
- WO 01729342-03, “VP ‘B’ Chiller Vanes Timer Hanging Up” April 14, 2014
- WO 01709602, “9054.02A20 OP RCIC Valve Operability (D001),” April 27, 2014
- WO 01725153-01, “9054.06R20 Ver RI Sys Flo Path/Filled & Ctrlr Alignment,” April 27, 2014
- WO 01593349, “Disassemble, Inspect/Rework Air Dryer Check”
- WO 01592977, “Disassemble, Inspect/Rework Air Dryer Check”
- WO 01523400, “Replace Internal O-rings 1DG162”
- WO 01690473, “1DG03CA Sample and Change Starting Air Compressor Oil”
- WO 01546328, “Division 3 DG Start Air Comp ‘A’ Relief Valve Test”
- WO 01688381, “Scram 10% Control Rods”
- WO 01396103, “Replace Actuator Grease in MOV 1SX016B”
- OPS PMT – Start and Load VP ‘B’ Chiller
- AR 01645885, “VC-B Chiller Oil Heater Temperature Switch Not Working,” April 10, 2014
- AR 01646203, “VP ‘B’ Chiller Vanes Timer Hanging Up”
- AR 01654060, “EOID Erratic Reading on RCIC Turb Gland Steam Seal Indicator”
- AR 01661405, “Hydraulic Control Unit 1225 Scram Pilot Valve Hum”
- AR 01661412, “Failed to Receive 5006-4G (Rod Drift) During Test”
- AR 01661052, “Pressure Switch is Degrading”
- AR 01661556, “Rod 28-25 Reading High at 265 F”

<u>1R22 Surveillance Testing</u>

- CPS 9015.01, “Standby Liquid Control System Operability,” Revision 41.
- CPS 9015.01D001, “SLC Pump and Valve Data Sheet,” Revision 38a.
- CPS 9054.01C001, “RCIC Water Leg Pump (1E51-C003) Operability Test 1E51-F040 Closure Test and 1SX037 Stroke Timing,” Revision 9
- CPS 9054.01D004, “Combined RCIC (1E51-C001) High Pressure Operability Checks and RCIC Cold Quick Restart Checklist,” Revision 3
- CPS 1893.04M103, “707 Auxiliary: RCIC Pump Room Prefire Plan,” Revision 5

- CPS 3310.01, “Reactor Core Isolation Cooling (RI),” Revision 20
- CPS 4003.01C003, “RSP- RCIC Alarm Light Responses,” Revision 1
- CPS 4410.00C001, “Defeating RCIC Interlocks,” Revision 5a
- CPS 9054.01C004, “Combined RCIC (1E51-C001) High Pressure Operability Checks and RCIC Cold Quick Restart,” Revision 5b
- CPS 9054.02, “Reactor Core Isolation Cooling Valve Operability Checks,” Revision 42
- CPS 9054.02D001, “RCIC Valve Operability Data Sheet,” Revision 41
- CPS 9054.06, “RCIC Discharge Header Filled and Flow Path Verification, and Flow Controller Checks,” Revision 27b
- CPS 9051.01, “HPCS Pump & HPCS Waterleg Pump Operability,” Revision 47c
- CPS 9051.01D001, “HPCS Pump & HPCS Waterleg Pump Operability Data Sheet,” Revision 48
- CPS 9051.01, “HPCS Pump & HPCS Water Leg Pump Operability,” Revision 47c
- CPS 9054.01C001, “RCIC Water Leg Pump (1E51-C003) Operability Test; 1E51-F040 Closure Test and 1SX037 Stroke Timing,” Revision 9
- CPS 9051.01D001, “HPCS Pump & HPCS Water Leg Pump Operability Data Sheet,” Revision 48
- CPS 9065.02, “Secondary Containment Integrity,” Revision 30
- CPS 9065.02D001, “Secondary Containment Integrity Data Sheet,” Revision 29e
- CPS 9080.02, “Diesel Generator 1B Operability – Manual and Quick Start Operability,” Revision 52
- CPS 9080.02C001, “Diesel Generator 1B Pre-Start Checklist,” Revision 12
- CPS 9080.02D001, “Diesel Generator 1B Operability – Manual and Quick Start Data Sheet,” Revision 43
- CPS 3506.01C005, “Diesel Generator Start Log,” Revision 1a
- CPS 3506.01C005, “Diesel Generator 1 B Operating Logs,” Revision 5a
- CPS 9915.01, “Standby Liquid Control Chemical Sampling,” Revision 40
- CPS 9915.01, “Standby Liquid Control Data Sheet,” Revision 36a
- Drawing IS-1074-S, “Inservice Inspection Schematic High Pressure Core Spray Sys (HP),” Sheet 1, Revision D
- Drawing M05-1074, “High Pressure Core Spray (HP),” Sheet 1, Revision AH
- WO 01614674-01, “9054.01D20 OP RCIC Pump Operability (Quick Start),” May 2, 2014
- WO 01614674-05, “9054.01D20 OP RCIC Pump Operability (Quick Start),” April 29, 2014
- WO 01713604-01, “9054.01A20 OP RCIC Pump Oper (High Pressure Test & Valve OP),” April 28, 2014
- WO 01586124-01, “9051.01 1E22C001 Comprehensive Pump Test,” April 18, 2014
- WO 01706210-01, “9051.01R22 OP HPCSS Pump & Wtr Leg Pump Oper (RCIC Strg Tank),” April 18, 2014
- AR 01663889, “SLC Tank Boron Concentration Exceeds Non-Technical Spec Goal”
- AR 01649321, “5 DPM Packing Leak on 1E22F378A,” April 18, 2014
- AR 01644032, “Incorrect RCIC Pump High Press Setpoint in 5063.01”
- Clinton Power Station, Inservice Testing (IST) Program
- AR 01642828, “RCIC Readiness Enhancement Following RPV Press Test”

<u>4OA1 Performance Indicator Verification</u>

- Nuclear Energy Institute 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7
- ER-AA-2008, “Mitigating Systems Performance Index (MSPI) Monitoring and Margin Evaluations”, Revision 3
- LA-AA-2200, “Mitigating System Performance Index Data Acquisition & Reporting”, Revision 5

- CL-MSPI-01, “Clinton MSPI Basis Document,” Revision 10
- MSPI Derivation Report, Unreliability Index, MSPI Residual Heat Removal System, March 2014
- MSPI Derivation Report, Unreliability Index, MSPI Heat Removal System, March 2014
- MSPI Derivation Report, Unreliability Index, MSPI High Pressure Injection System, March 2014
- MSPI Derivation Report, Unavailability Index, MSPI High Pressure Injection System, March 2014
- MSPI Derivation Report, Unavailability Index, MSPI Heat Removal System, March 2014
- MSPI Derivation Report, Unavailability Index, MSPI Residual Heat Removal System, March 2014
- AR 1496401, “RCIC SOW Delayed Due to Clearance Order Hang”
- AR 1561186, “1E51-C002 – Defer PM Per SR Process RCIC Turbine Overhaul”
- AR 1575354, “PMC System Manager Identified High Oil Level in RCIC Turbine 1E51-C002”
- AR 1574686, “1E51C002E: RCIC Trip Valve Limit Switch Nuts Loose”
- AR 1556195, “1E51R606 RCIC Flow Meter Indicates Flow with Pump Shutdown”
- AR 1617860, “EOID: Small Steam Leak from RCIC Valve”
- AR 1615120, “NRC ID: Question RCIC Valve Operability Surveillance per CPS 9054”
- AR 1571296, “1E12-F014A and 1E12-F068A Backseat Angle Deviation”
- AR1523392, “RHR ‘C’ Pump Suction Pressure High While in Standby”
- AR 1599969, “RHR B/C Water Leg Pump Dynamic Suction Pressure Low During 9053.07”
- AR 1572240, “HPCS Manual Injection Valve Too Difficult to Operate”
- AR 1537228, “Unexpected Annunciator 5062-8D During HPCS Pump Run”

<u>4OA3 Follow-up of Events and Notices of Enforcement Discretion</u>

- CPS 8501.05, “CV-2 Relay Inspection and Calibration with Doble Test Equipment,” Revision 9
- CPS 8501.05D001, “CV-2 Relay Calibration Data Sheet,” Revision 4
- CPS 3103.01, “Feedwater,” Revision 29c
- CC-AA-256, “Process for Managing Plant Modifications Involving Microprocessor Technology,” Revision 2
- WC-AA-113, “Predefine Data Base Revisions,” Revision 2
- WC-AA-120, “Preventive Maintenance (PM) Database Revision Requirements,” Revision 1
- WC-AA-120, “Preventive Maintenance (PM) Program Requirements,” Revision 0
- ER-AA-200, “Preventive Maintenance Program,” Revision 0
- LS-AA-125-1003, Revision 10: Equipment Apparent Cause Report- Division 3 Diesel Generator Supply Air Damper Did Not Open
- MA-AA-716-010, “Maintenance Planning,” Revision 21
- MA-AA-716-010, “Maintenance Planning,” Revision 9
- Common Cause Analysis Report 192243, “Trend of Hydramotor Failures in 2003,” June 4, 2004
- Root Cause Investigation 01596987-13, “Manual Scram Due to Reactor Water Level Oscillations While Initiating the Digital Feedwater Bring Pump Online Command”
- Root Cause investigation Report #0156929, “Manual Scram Due to Loss of EHC Fluid”
- Licensee Event Report 05000461/2013-004-00, “Loss of Emergency Diesel Room Ventilation Due to Damper Hydramotor Failure,” October 11, 2013
- Licensee Event Report 2013-009-00, “Software Errors in New Digital Feedwater Control System Result in Manual Reactor Scram Due to Approaching High Reactor Pressure Vessel Water Level Setpoint,” February 10, 2014
- Licensee Event Report 2013-003-00, “Manual Reactor Scram Due to Main Electro-Hydraulic Control System Failure,” June 24, 2013

- EC 396436, “Evaluation of the Scram During the Transition from the MDRFP to the A TDRFP”
- WO 00705492, “Replace 1TGCV4 Shut Off Valve”
- AR 01546973, “1VD01YC Damper Would Not Open When Fan 1VD01CC Was Run”
- AR 01547294, “1VD01YC; Div 3 DG Supply Air Damper Does Not Open as Expected”
- AR 01659043, “NRC Question - Review of LER 2013-004 – Div 3 Damper Failure”
- AR 01596929, “Loss of EHC Causes Manual Reactor Scram”
- AR 01596987, “Manual Scram on High Water Level During Feedwater Transient in Auto”
- AR 01597120, “Post Unit Trip Level Control”
- AR 01597212, “Entered 4002.01 Due to No FW004 Response in Auto or Manual”
- Functional Failure Cause Determination Evaluation - Issue Report 1547294
- IQ Review: Hydramotors - Revision 0
- IQ Review: Hydramotors - Revision 1
- Service Request 00037765, “Chg Freq And Scope of VD Hydramotor Oil Change PM’s (See Ole),” June 20, 2005
- Service Request 00053304, “Change Frequency for Damper Inspection on 1VD01YC,” September 14, 2007
- PM Change Review Form for Service Request 80653, February 25, 2013

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
CAP	Corrective Action Program
CPS	Clinton Power Station
ΔCDF	Delta Core Damage Frequency
EC	Engineering Change
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
HPCS	High Pressure Core Spray
IN	Information Notice
IP	Inspection Procedure
IR	Issue Report
LER	Licensee Event Report
LERF	Large Early Release Frequency
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
PI	Performance Indicator
PM	Planned or Preventative Maintenance
PM	Post-Maintenance
SAPHIRE	Systems Analysis Programs for Hands-on Integrated Reliability Evaluations
SBO	Station Blackout
SDP	Significance Determination Process
SLC	Standby Liquid Control
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
WO	Work Order

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Sincerely,

/RA/

Christine A Lipa, Chief
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Division of Reactor Projects

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