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

November 10, 2008

Mr. Charles G. Pardee
President and Chief Nuclear Officer (CNO), Exelon Nuclear
Chief Nuclear Officer (CNO), AmerGen Energy Company, LLC
4300 Winfield Road
Warrenville IL 60555

SUBJECT: CLINTON POWER STATION NRC INTEGRATED INSPECTION REPORT 05000461/2008-004

Dear Mr. Pardee:

On September 30, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Clinton Power Station. The enclosed report documents the inspection results, which were discussed on October 10, 2008, with Mr. F. Kearney 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, one NRC-identified and three self-revealed findings of very low safety significance were identified. One of the findings involved a violation of NRC requirements. However, because of the very low safety significance, and because the issue was entered into your corrective action program, the NRC is treating the issue as a Non-Cited Violation (NCV) in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a NCV, 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's Office at the Clinton Power Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

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

cc w/encl: Site Vice President - Clinton Power Station
Plant Manager - Clinton Power Station
Regulatory Assurance Manager - Clinton Power Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
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Associate General Counsel
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Assistant Attorney General
J. Klinger, State Liaison Officer,
Illinois Emergency Management Agency
Chairman, Illinois Commerce Commission

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Associate General Counsel
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Assistant Attorney General
J. Klinger, State Liaison Officer,
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Letter to C. Pardee from M. Ring dated November 10, 2008

SUBJECT: CLINTON POWER STATION NRC INTEGRATED INSPECTION REPORT 05000461/2008-004

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	05000461/2008-004
Licensee:	AmerGen Energy Company, LLC
Facility:	Clinton Power Station, Unit 1
Location:	Clinton, IL
Dates:	July 1 through September 30, 2008
Inspectors:	B. Kemker, Senior Resident Inspector D. Lords, Resident Inspector C. Acosta-Acevedo, Reactor Engineer E. Coffman, Reactor Engineer A. Barker, Senior Project Engineer N. Feliz-Adorno, Reactor Engineer D. Meléndez-Colón, Dresden Resident Inspector D. Reeser, Operations Engineer S. Mischke, Resident Engineer, Illinois Emergency Management Agency
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000461/2008-004; 07/01/08 – 09/30/08; Clinton Power Station, Unit 1; Maintenance Effectiveness, Operability Evaluations.

This report covers a three-month period of inspection by the resident inspectors and an announced inspection by regional inspectors. Four Green findings, one of which had an associated NCV were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance associated with a self-revealed event that resulted in a Unit 1 reactor scram. The licensee failed to perform adequate post-maintenance testing following replacement of the feedwater level control system dynamic compensator card during the Cycle 10 refueling outage that concluded in February 2006. This resulted in an ineffective response from the feedwater level control system and a subsequent reactor scram following the unexpected loss of a reactor recirculation pump. The ineffective feedwater level control system response has not been corrected; however, the licensee entered this issue into its corrective action program for evaluation. No violation of regulatory requirements was identified.

  The finding was of more than minor significance because this issue was associated with the Equipment Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Specifically, inadequate post-maintenance testing resulted in ineffective response from the feedwater level control system during a loss of a reactor recirculation pump transient and caused a reactor scram. The finding was of very low safety significance because the issue: (1) did not contribute to the likelihood of a primary or secondary system loss-of-coolant-accident initiator, (2) did not contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions would not be available, and (3) did not increase the likelihood of a fire or internal/external flooding event. The inspectors did not identify a cross-cutting area component related to this finding. (Section 1R12.b.1)

- Green. The inspectors identified a finding of very low safety significance associated with a self-revealed event that resulted in the unexpected loss of a reactor recirculation pump. The licensee failed to evaluate an unexpected and unknown cause for stray voltage in the End-of-Cycle Recirculation Pump Trip (EOC-RPT) circuit during post-modification testing during the Cycle 11 refueling outage that concluded in February 2008. This resulted in the unexpected loss of a reactor recirculation pump and the subsequent plant transient that led to a reactor scram. As an immediate and interim corrective action, the licensee implemented a design change to the EOC-RPT circuitry that should prevent inadvertent relay actuation causing recirculation pump trips due to the stray voltage problem. No violation of regulatory requirements was identified.

The finding was of more than minor significance because this issue was associated with the Equipment Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Specifically, the failure to evaluate an unexpected and unknown cause for stray voltage in the EOC-RPT circuit during post modification testing resulted in the unexpected loss of a reactor recirculation pump and the subsequent plant transient that led to a reactor scram. The finding was of very low safety significance because the issue: (1) did not contribute to the likelihood of a primary or secondary system loss-of-coolant-accident initiator, (2) did not contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions would not be available, and (3) did not increase the likelihood of a fire or internal/external flooding event. The inspectors concluded that this finding affected the cross-cutting area of human performance. Specifically, the licensee failed to appropriately incorporate risk insights in investigating and resolving an unexplained source of voltage in a circuit that had a high risk consequence (i.e., reactor recirculation pump trip). (IMC 0305 H.3(a)) (Section 1R12.b.2)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance with an associated NCV of Technical Specification (TS) 5.4.1.a was self-revealed. The licensee failed to perform adequate preventive maintenance on shutdown service water system valve 1SX014A. This resulted in significant degradation of the valve body by corrosion due to prolonged exposure to raw service water that went undetected until gross seat leakage was discovered while attempting to establish conditions for surveillance testing. The licensee replaced the valve and established a preventive maintenance schedule for internal valve inspections.

  The finding would become a more significant safety concern if left uncorrected and was therefore more than a minor concern. Specifically, the failure to adequately perform preventive maintenance could reasonably result in significantly degraded or inoperable safety-related equipment. Because the shutdown service water system was primarily associated with long term decay heat removal following certain design basis accidents, the inspectors concluded that this issue was associated with the Mitigating Systems Cornerstone. The finding was of very low safety significance because the issue: (1) was not a design or qualification deficiency; (2) did not represent an actual loss of safety function of a system; (3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; (4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and (5) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The inspectors concluded that this finding affected the cross-cutting area of human performance. Specifically, the licensee's investigation determined that internal valve inspections were not performed because the component category was incorrectly classified. (IMC 0305 H.3(b)) (Section 1R12.b.3)

- Green. The inspectors identified a finding of very low safety significance associated with the licensee's failure to recognize the safety-related system function of the 1B residual heat removal pump seal cooler when initially evaluating the past operability of the pump after unacceptable results were obtained during shutdown service water system flow balance testing. No analysis was performed to ensure that the pump's safety function would be fulfilled with less than minimum design flow to the cooler until the inspectors challenged the licensee's original conclusion. The licensee re-performed the past operability evaluation and determined that sufficient margin existed such that the pump would have been able to fulfill its safety function with significantly less than design flow to the seal cooler as measured during the test. Corrective actions for the initial unacceptable results involved re-balancing shutdown service water system flow. No violation of regulatory requirements was identified.

The finding would become a more significant safety concern if left uncorrected and was therefore more than a minor concern. Specifically, the failure to correctly recognize the safety-related functions of systems or components when performing operability or past operability evaluations could reasonably result in an unrecognized condition of a system failing to fulfill its safety-related function. In addition, based on review of examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," evaluation errors resulting in a reasonable doubt about the operability of a system or component are generally not considered to be of minor significance. Because the residual heat removal system was primarily associated with long term decay heat removal following certain design basis accidents, the inspectors concluded that this issue was associated with the Mitigating Systems Cornerstone. The finding was of very low safety significance because the issue: (1) was not a design or qualification deficiency; (2) did not represent an actual loss of safety function of a system; (3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; (4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and (5) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. Subsequent evaluation was able to determine that sufficient margin in flow existed for the time period in question. The inspectors did not identify a cross-cutting area component related to this finding. (Section 1R15.b.1)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

The unit was operated at or near full power during the inspection period with one exception.

On September 6, 2008, the licensee reduced power to about 72 percent to perform control rod pattern adjustment and main turbine control/intermediate valve and main steam isolation valve testing. The unit was returned to full power the following day upon completion of valve testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns (71111.04Q)

a. Inspection Scope

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

- Division I Emergency Diesel Generator;
- High Pressure Core Spray (HPCS) System; and
- Division I Residual Heat Removal (RHR) System.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones. The inspectors reviewed operating procedures, system diagrams, 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.

This inspection constituted three quarterly partial system walkdown inspection samples as defined in Inspection Procedure 71111.04.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown (71111.04S)

a. Inspection Scope

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

This inspection constituted one semi-annual complete system walkdown sample as defined in Inspection Procedure 71111.04.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors performed fire protection tours in the following plant areas:

- Fire Zone CB-1a, Unit 2 Diesel Generator Bays - Elevations 712'-0", 719'-0", 737'-0";
- Fire Zone A-3f, Division 2 Switchgear Room - Elevation 781'-0";
- Fire Zone CB-5a, Division 3 Switchgear Room - Elevation 781'0", and
- Fire Zone CB-5c, Division 1 and 2 Cable Risers - Elevation 781'0".

The inspectors verified that transient combustibles and ignition sources were appropriately controlled and assessed the material condition of fire suppression systems, manual fire fighting equipment, smoke detection systems, fire barriers and emergency lighting units. 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; that the licensee's fire plan was in alignment with actual conditions; and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

In addition, the inspectors verified that fire protection related 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 four quarterly fire protection inspection samples as defined in Inspection Procedure 71111.05AQ.

b. Findings

No findings of significance were identified.

.2 Fire Protection – Drill Observation (71111.05A)

a. Inspection Scope

During an announced drill on August 28, 2008, associated with the 'A' Control Building chiller (702' elevation), the inspectors assessed the timeliness of the fire brigade in arriving at the scene, the fire fighting equipment brought to the scene, the donning of fire protective clothing, the effectiveness of communications, and the exercise of command and control by the fire brigade leader. The inspectors also assessed the acceptance criteria for the drill objectives; the rigor and thoroughness of the post-drill critique; and verified that fire protection drill problems were being entered into the licensee's corrective action program with the appropriate characterization and significance.

This inspection constituted one annual fire protection drill inspection sample as defined in Inspection Procedure 71111.05AQ.

b. Findings

No findings of significance were identified.

1R06 Flooding Protection Measures (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. 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 area(s) 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:

- Divisions I, II, and III Shutdown Service Water (SX) Pump Rooms Elevation 690'-0"; and
- RHR Pump Room 'C' Elevation 707'-6".

This inspection constituted one internal flooding inspection sample as defined in Inspection Procedure 71111.06.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

.1 Triennial Review of Heat Sink Performance (71111.07T)

a. Inspection Scope

The inspectors reviewed operability determinations, completed surveillance tests, vendor manual information, associated calculations, performance test results and cooler inspection results associated with the HPCS room coolers and the RHR ‘A’ heat exchanger. These heat exchangers/coolers were chosen based on their risk significance in the licensee’s probabilistic safety analysis, their important safety-related mitigating system support functions and their relatively low margin.

For the HPCS room coolers and the RHR ‘A’ heat exchanger, the inspectors verified that testing, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs were adequate to ensure proper heat transfer. This was accomplished by verifying the test method used was consistent with accepted industry practices, or equivalent, the test conditions were consistent with the selected methodology, the test acceptance criteria were consistent with the design basis values, and results of heat exchanger performance testing. The inspectors also verified that the test results appropriately considered differences between testing conditions and design conditions, the frequency of testing based on trending of test results was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values and test results considered test instrument inaccuracies and differences.

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

In addition, the inspectors verified the condition and operation of the HPCS room coolers and the RHR ‘A’ heat exchanger were consistent with design assumptions in heat transfer calculations and as described in the final safety analysis report. This included verification that the number of plugged tubes was within pre-established limits based on capacity and heat transfer assumptions. The inspectors verified the licensee evaluated the potential for water hammer and established adequate controls and operational limits to prevent heat exchanger degradation due to excessive flow induced vibration during operation. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger. Also, the inspectors verified that the licensee evaluated the effects of the Extended Power Uprate to the heat exchangers.

The inspectors verified the performance of ultimate heat sinks (UHS) and their subcomponents such as piping, intake screens, pumps, valves, etc. by tests or other equivalent methods to ensure availability and accessibility to the inplant cooling water systems.

The inspectors verified that the licensee’s inspection of the UHS was thorough and of significant depth to identify degradation of the shoreline protection or loss of structural integrity. This included verification that vegetation present along the slopes was trimmed, maintained and was not adversely impacting the embankment. In addition, the inspectors verified the licensee ensured sufficient reservoir capacity by trending and removing debris or sediment buildup in the UHS.

The inspectors reviewed the licensee’s operation of the service water system and UHS. This included the review of licensee’s procedures for a loss of the service water system or UHS. In addition, the inspectors verified that macrofouling was adequately monitored, trended, and controlled by the licensee to prevent clogging. The inspectors verified that the licensee’s biocide treatments for biotic control were adequately conducted and the results monitored, trended, and evaluated. The inspectors also verified that the licensee maintained adequate pH and calcium hardness.

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

The inspectors performed a system walkdown on service water to verify the licensee’s assessment of structural integrity. In addition, the inspectors reviewed available licensee testing and inspection results, licensee dispositions of any active thru wall pipe leaks, and the history of thru wall pipe leakage to identify any adverse trends since the last NRC inspection. For buried or inaccessible piping, the inspectors reviewed the licensee's pipe testing, inspection, or monitoring program to verify structural integrity.

The inspector performed a system walkdown of the service water intake structure to verify the licensee’s assessment of structural integrity and component functionality. This included the verification that the licensee ensured proper functioning of traveling screens and strainers, and structural integrity of component mounts. In addition, the inspectors verified that service water pump bay silt accumulation was monitored, trended, and maintained at an acceptable level by the licensee. The inspectors also verified the licensee’s ability to ensure functionality during adverse weather conditions.

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

This inspection constituted two triennial heat sink inspection samples as defined in Inspection Procedure 71111.07.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

The inspectors observed licensed operators during simulator training on August 13, 2008. The inspectors assessed the operators' response to the simulated events focusing on alarm response, command and control of crew activities, communication practices, procedural adherence, and implementation of Emergency Plan requirements. The inspectors also observed the post-training critique to assess the ability of licensee evaluators and operating crews to self-identify performance deficiencies. 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 inspection sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated the licensee's handling of selected degraded performance issues involving the following risk-significant Structures, Systems, and Components (SSCs):

- Feedwater Level Control System;
- SX System Cross-tie Valves; and
- Main Steam Isolation Valves.

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the SSCs. Specifically, the inspectors independently verified the licensee's handling of SSC performance or condition problems in terms of:

- Appropriate work practices;
- Identifying and addressing common cause failures;
- Scoping of SSCs in accordance with 10 CFR 50.65(b);
- Characterizing SSC reliability issues;
- Tracking SSC unavailability;
- Trending key parameters (condition monitoring);

- 10 CFR 50.65(a)(1) or (a)(2) classification and reclassification; and
- Appropriateness of performance criteria for SSC functions classified (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSC functions classified (a)(1).

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.

This inspection constituted three maintenance effectiveness inspection samples as defined in Inspection Procedure 71111.12.

b. Findings

(1) Failure to Perform Adequate Post Maintenance Testing Following Replacement of the Feedwater Level Control System Dynamic Compensator Card Resulted in High Reactor Vessel Water Level (Level 8) Scram

Introduction

The inspectors identified a finding of very low safety significance (Green) associated with a self-revealed event. The licensee failed to perform adequate post-maintenance testing following replacement of the feedwater level control system dynamic compensator card during the Cycle 10 refueling outage that concluded in February 2006. This resulted in ineffective response from the feedwater level control system and a subsequent reactor scram following the unexpected loss of a reactor recirculation pump. Because the feedwater level control system is not safety-related, no violation of regulatory requirements was identified.

Discussion

On February 10, 2008, Unit 1 automatically scrammed following an unexpected trip of the ‘B’ reactor recirculation pump from fast speed to off. Loss of the reactor recirculation pump resulted in a plant transient, causing reactor power to decrease and reactor vessel water level to rise. A reactor scram occurred due to ineffective response of the feedwater level control system during the plant transient.

The Clinton Power Station UFSAR, Section 15.3.1.2.1.3.1 states that no scram occurs for a trip of one reactor recirculation pump. Furthermore, Section 15.3.1.2.2.1 states that tripping a single recirculation pump requires no protection system or safeguard system operation. This analysis assumes normal functioning plant instrumentation and controls. To summarize the event results from Section 15.3.1.3.3.1, no core thermal limits are exceeded and during the transient reactor vessel level swell is not sufficient to cause a turbine trip and reactor scram.

The flow of feedwater from the two turbine driven reactor feedwater pumps to the reactor vessel is controlled by the feedwater level control system. A master level controller normally provides overall control of the individual reactor feedwater pumps’ controllers and is normally set up by plant operators to automatically maintain the desired reactor vessel water level. The master controller maintains reactor vessel water level by varying feedwater system flow based upon actual feedwater flow, steam flow, and reactor vessel water level. The master controller is designed not only to respond to actual differences in the above three parameters, but also to their rate of change in order to anticipate and limit the change in reactor vessel water level and to return it to the programmed level. The system is designed to be an “inventory dominant system,” meaning that changes in feedwater flow and steam flow predominately affect the response of the system. Level and level error provide inputs to the secondary control loop. The system should provide an integral response to changes in feedwater flow, steam flow, and reactor vessel water level, such that the master level controller output will increase with the duration and rate of change in these parameters.

Review of plant data for the event revealed that as reactor vessel water level rose in response to the recirculation pump trip, feedwater level control system output to the feedwater system decreased. However, the output of the master level controller only decreased in response to lowering steam flow. There was not an appropriate response to the increasing difference between the actual reactor vessel water level and the desired reactor vessel water level. As the transient proceeded, the reactor vessel water level remained above the desired level so that the rate of change for the master level controller output should have increased. Additionally, since the difference in the actual level and the desired level was increasing, the master level controller should have been reducing its output even more for a maximum reduction in feedwater flow.

The licensee replaced the reactor level dynamic compensator card during the Cycle 10 refueling outage that concluded in February 2006. This was the first replacement of this card since initial plant startup. The replacement card was calibrated prior to installation; however, no dynamic tuning of the feedwater level control system was performed after the card was replaced because the licensee did not believe it to be necessary. Additionally, the licensee concluded that dynamic tuning of the system would be a “production risk evolution” and would delay power ascension at the end of the refueling outage.

Dynamic tuning of the feedwater level control system was performed during initial plant startup testing. Dynamic response testing was also performed to support the plant’s extended power uprate during the Cycle 8 refueling outage in 2002. At that time, the dynamic response of the system was found to be acceptable and no adjustment was performed.

The licensee also determined that the responses of the individual feedwater pump controller cards were not matched as they should be. As the demand signal to the individual feedwater pump controllers decreased, the signal out of the ‘A’ pump’s controller decreased more than the signal out of the ‘B’ pump’s controller. The output of the ‘B’ pump’s controller then continued to lag behind the output of the ‘A’ pump’s controller as the transient continued. Both controller cards were replaced during the Cycle 10 refueling outage. The cards were calibrated prior to installation by matching their outputs to the previously installed cards. The outputs of the two new controller cards were not compared to determine similarity of response and no dynamic tuning was performed after card replacement. This was the first time either of these cards was replaced and the licensee identified no history of previously calibrating or tuning of the original cards prior to replacing them during the refueling outage.

On August 27, 2006, Unit 1 experienced a momentary loss of the safety-related Division IV nuclear system protection system inverter resulting in an automatic reactor scram on high reactor vessel water level. The event cycled the safety-related 120 volt AC nuclear system protection system bus causing the Division III emergency diesel generator, the Division III SX system, and the HPCS system pump to automatically start, and the HPCS system pump to inject water into the reactor vessel. The loss of the inverter also caused the 'A' reactor recirculation pump to trip. The loss of the reactor recirculation pump along with the HPCS system injection caused reactor vessel water level to increase, resulting in a high reactor vessel water level (Level 8) scram. Review of the plant process computer traces from the August 2006 scram revealed a similar feedwater level control system response that occurred on February 10, 2008. In retrospect, the licensee concluded that this was a missed opportunity to identify and correct the abnormal feedwater level control system response that caused the February 10th reactor scram.

The inspectors thoroughly examined the licensee's root cause evaluation for the reactor scram and concluded that the licensee had not neglected any likely factors. There were two causal factors identified by the licensee related to the feedwater level control system response:

1. less than adequate integral response of the feedwater level control dynamic compensator card to a transient reactor level change because it was not properly tuned and tested after replacement during the Cycle 10 refueling outage (equipment cause), and

2. inadequate evaluation of the feedwater level response following a similar event (i.e., reactor recirculation pump trip with HPCS injection on August 27, 2006,) because the technical team investigating the reactor recirculation pump trip in 2006 readily attributed the high reactor vessel water level scram to the HPCS system injection and did not adequately challenge the post trip response of the feedwater level control system (root cause).

The licensee determined that the first causal factor was the fundamental equipment cause and that the second causal factor was the root cause for the reactor scram. While investigating the cause for the reactor recirculation pump trip, the licensee found that its organization had a low risk perception in investigating and resolving an unexplained voltage in the protection circuit. For a discussion of the reactor recirculation pump trip, refer to Section 1R12.b.2 of this inspection report. This root cause was determined to be the overall root cause for the event. The licensee considered that it applied as well to the reactor scram due to similar missed barriers - specifically, the lack of engineering technical rigor demonstrated by not defining appropriate post-maintenance testing following the dynamic compensator card replacement and by not adequately evaluating the feedwater level control system response during the August 2006 event. The licensee identified one corrective action to prevent recurrence related to this root cause. The action was for the Engineering, Maintenance and Work Management Directors to present a briefing of the root cause evaluation from this event yearly (for the next four years) to their staffs, with emphasis on risk, consequences, application of human performance fundamentals and lessons learned.

The licensee identified the following additional corrective actions:

1. establish a comprehensive troubleshooting team to find the cause for the inadequate integral response of the feedwater level control system,

2. initiate an action request to create a work order to support troubleshooting,

3. evaluate results of troubleshooting to determine further actions and create additional actions as necessary, and

4. issue an action request to perform dynamic tuning on feedwater pump flow controller cards.

The licensee had not yet completed corrective actions at the conclusion of this inspection. The feedwater level control system response has not been corrected and is currently considered by the licensee to be an "operator workaround." Refer to a discussion of this operator workaround in Section 4OA2.3 of this inspection report. Refer to Section 4OA3.1 of this inspection report for a review and closure of the Licensee Event Report (LER) associated with the reactor scram.

Analysis

The inspectors determined that the failure to perform adequate post-maintenance testing following replacement of the feedwater level control system dynamic compensator card during the Cycle 10 refueling outage that concluded in February 2006 was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the Significance Determination Process (SDP). The inspectors reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance because this issue was associated with the Equipment Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Specifically, inadequate post-maintenance testing resulted in ineffective response from the feedwater level control system and a subsequent reactor scram following the unexpected loss of a reactor recirculation pump. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." In accordance with Table 4a, "Characterization Worksheet for IE [Initiating Events], MS [Mitigating Systems], and BI [Barrier Integrity] Cornerstones," the inspectors determined that that this finding was a licensee performance deficiency of very low safety significance (Green) because the finding: (1) did not contribute to the likelihood of a loss-of-coolant-accident initiator, (2) did not contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions would not be available, and (3) did not increase the likelihood of a fire or internal/external flooding event.

Cross-cutting Aspects

The inspectors concluded that because the licensee's failure to perform adequate post-maintenance testing following replacement of the feedwater level control system dynamic compensator card was during the Cycle 10 refueling outage that concluded in February 2006, it did not necessarily reflect current licensee performance and no cross-cutting aspect was identified.

Enforcement

No violation of regulatory requirements was identified because the work activity was not directly associated with the safety-related function of an SSC. This issue is considered to be a finding **(FIN 05000461/2008004-01)**. The licensee entered this finding into its corrective action program as Action Request (AR) 00734254.

(2) Failure to Evaluate an Unexpected and Unknown Cause for Stray Voltage in the End-of-Cycle Recirculation Pump Trip (EOC-RPT) Circuit During Post Modification Testing Resulted in a Reactor Recirculation Pump Trip

Introduction

The inspectors identified a finding of very low safety significance (Green) associated with a self-revealed event. The licensee failed to evaluate an unexpected and unknown cause for stray voltage in the EOC-RPT circuit during post modification testing during the Cycle 11 refueling outage that concluded in February 2008. This resulted in the unexpected loss of a reactor recirculation pump and the subsequent plant transient that led to a reactor scram. Because the reactor recirculation system is not safety-related, no violation of regulatory requirements was identified.

Discussion

On February 10, 2008, Unit 1 automatically scrammed following an unexpected trip of the 'B' reactor recirculation pump from fast speed to off. The 'A' reactor recirculation pump remained running in fast speed. Loss of the reactor recirculation pump resulted in a plant transient, causing reactor power to decrease and reactor vessel water level to rise. A reactor scram occurred due to ineffective response of the feedwater level control system during the plant transient. For a discussion of the reactor scram, refer to Section 1R12.b.1 of this inspection report.

There are two two-speed reactor recirculation pumps in separate loops that provide driving coolant flow inside the reactor vessel. The reactor protection system contains a feature that shifts the pumps from high speed to low speed in response to a closure signal from the main turbine stop valves or control valves. This EOC-RPT feature acts to mitigate the severity of a main turbine trip late in the operating cycle, when all reactor control rods are fully withdrawn. Having the reactor recirculation pumps turn off, or alternatively downshifting the pumps to low speed, causes a prompt decrease in reactor power, minimizing the transient in reactor steam pressure that will occur in response to the turbine trip. The EOC-RPT circuitry is arranged in two independent channels, and contains redundant optical isolator cards that provide isolation of non-safety-related circuitry from the safety-related reactor protection system. The safety-related portion of the EOC-RPT circuitry trips the high speed recirculation pump breakers, while the non-safety-related portion of the EOC-RPT circuitry causes the pumps to auto start in low speed after a trip from high speed. The shift to low speed feature provides an operational convenience to avoid scram recovery delays due to reactor vessel bottom head fluid stratification.

Initial troubleshooting determined that the ‘B’ reactor recirculation pump tripped due to actuation of the non-safety-related portion of the Division III EOC-RPT trip circuit due to induced noise in circuit cabling. All four divisions of the EOC-RPT non-safety-related circuitry had been modified during the Cycle 11 refueling outage that concluded in February 2008 to resolve Operating Experience concerning spurious actuations of this circuit at other BWR/6 plants. Unsatisfactory post modification testing results on Divisions II and III led the licensee to restore those circuits to the original configuration.

In March 2005, General Electric issued 10 CFR 21 Communication Safety Information Communication SC05-02, “Potential Spurious Recirculation Pump Trips or Downshifts from High to Low Speed; High Level Optical Isolator Cards.” The communication was to inform Boiling Water Reactor (BWR)/5/6 plants of a recent BWR/6 plant that experienced spurious recirculation pump downshift events. Analysis of these events identified an inadequate surge protection network across relay coils driven by General Electric high level optical isolator cards. The solution provided by General Electric was to replace the resistor/capacitor network with a diode.

The licensee’s modification was essentially the same as what was recommended by General Electric. Other BWR/6 licensees had already installed modifications that went beyond the General Electric design. The River Bend Plant licensee reported in LER 05000458/2004-004-00, “Automatic Reactor Scram Following Recirculation Pump Downshift Due to Failed Optical Isolator Card,” that the design provided by General Electric “was not sufficient to correct the condition.” The River Bend Plant licensee then installed an interposing relay into the circuit similar to the design implemented at another BWR/6 plant. The purpose of the interposing relay was to mitigate the effects of a higher than expected voltage measured in the circuit downstream of the high level optical isolator card. The postulated cause of the higher than expected voltage measured in the circuit was that voltages were being induced by the long length of cabling between the high level optical isolator and the EOC-RPT relays.

The inspectors thoroughly examined the licensee’s root cause evaluation for the reactor scram and concluded that the licensee had not neglected any likely factors. There were three causal factors identified by the licensee related to the ‘B’ recirculation pump trip:

1. the technical team did not rigorously evaluate an unexpected and unknown cause for stray voltage in the EOC-RPT circuit (root cause),

2. both the post-maintenance test and post modification test did not specify final acceptance criteria for the maintenance activity in correcting degraded high level optical isolator card leakage current (contributing cause), and

3. the spurious actuation of the optical isolator output card apparently from “noise” later identified on all four non-safety-related EOC-RPT circuits (equipment cause).

The licensee determined that the first causal factor was the overall root cause for the event and attributed it to a low risk perception in investigating and resolving the condition. The licensee further concluded that numerous barriers existed through procedures that could have prevented the event, but they were not applied due to less than assertive and rigorous behaviors that resulted in accepting an unknown condition. This included not incorporating lessons from operating experience identified at other BWR/6 plants that had scrams as a result of the "degraded" high level optical isolator cards with circuit voltages similar to those measured at Clinton Power Station. Spurious actuations of EOC-RPT optical isolator cards and stray voltages in the EOC-RPT circuits were already encountered and addressed by other plants as described in the operating experience. The licensee determined that the second causal factor was a significant contributing cause because the lack of appropriate acceptance criteria allowed post-maintenance/modification testing to be judged as satisfactory and did not trigger the generation of an action request identifying the elevated voltages in the circuit during installation. The licensee concluded that this was not the root cause because an action request was written sometime afterwards and decisions made by the licensee's staff failed to correctly address the issue then. The licensee determined that the third causal factor was the fundamental equipment cause.

As an immediate and interim corrective action, the licensee implemented a design change to the EOC-RPT circuitry to remove relays that initiate the auto start of the low frequency motor generators, resulting in the reactor recirculation pumps transferring from high speed to off instead of high speed to low speed. This should prevent inadvertent relay actuation due to the stray voltage problem. Other auto transfers of the reactor recirculation pumps to low speed operation were not affected by the design change. The design change affected only the non-safety-related portion of the reactor recirculation pump logic and not the safety-related portions of the reactor protection system that remove power to the pumps during a main turbine trip or main generator load rejection event.

The licensee identified the following three corrective actions to prevent recurrence related to this root cause:

1. issue revisions of appropriate Exelon Nuclear procedures to have all appropriate degraded plant conditions put into one centralized database and presented periodically to the Plant Health Committee, with the Plant Health Committee to perform a review and challenge of the list of backlog and degraded critical components;

2. Engineering, Maintenance and Work Management Directors present a briefing of the root cause evaluation from this event yearly (for the next four years) to their staffs, with emphasis on risk, consequences, application of human performance fundamentals and lessons learned; and

3. develop a design that will allow the restoration of the EOC-RPT relays while minimizing the risk of the reactor recirculation pump tripping to off on a single optical isolator actuation.

The licensee identified additional corrective actions, including:

1. create one list of site performance monitoring adverse trends or degraded conditions on critical components;

2. perform a review and challenge backlog of degraded critical components and expedite actions to correct the conditions or implement risk mitigation strategies as needed;

3. revise the procedure governing the conduct of troubleshooting for complex troubleshooting to require documentation to describe how a definitive problem has been identified and verified with the physical evidence, or conduct a formal risk evaluation; and

4. revise the procedure governing the conduct of post-maintenance testing to provide detailed instructions for post-maintenance testing activities that ensures that the originally identified degraded condition has been corrected or satisfactorily mitigated, and that appropriate acceptance criteria is specified to use as the basis for determining satisfactory completion of maintenance.

The licensee had not yet completed all of the above corrective actions at the conclusion of this inspection.

Analysis

The inspectors determined that the failure to evaluate an unexpected and unknown cause for stray voltage in the EOC-RPT circuit during post modification testing during the Cycle 11 refueling outage that concluded in February 2008 was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance because this issue was associated with the Equipment Performance attribute of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Specifically, the failure to evaluate an unexpected and unknown cause for stray voltage in the EOC-RPT circuit during post modification testing resulted in the unexpected loss of a reactor recirculation pump and the subsequent plant transient that led to a reactor scram. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." In accordance with Table 4a, "Characterization Worksheet for IE [Initiating Events], MS [Mitigating Systems], and BI [Barrier Integrity] Cornerstones," the inspectors determined that that this finding was a licensee performance deficiency of very low safety significance (Green) because the finding: (1) did not contribute to the likelihood of a loss-of-coolant-accident initiator, (2) did not contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions would not be available, and (3) did not increase the likelihood of a fire or internal/external flooding event.

Cross-cutting Aspects

The inspectors concluded that this finding affected the cross-cutting area of human performance. Specifically, the licensee failed to appropriately incorporate risk insights in investigating and resolving an unexplained source of voltage in a circuit that had a high risk consequence (i.e., reactor recirculation pump trip). Consequently, the licensee's staff failed to recognize that they were in a high risk situation in investigating a complex problem that was not well understood. (IMC 0305 H.3(a))

Enforcement

No violation of regulatory requirements was identified because the work activity was not directly associated with the safety-related function of an SSC. This issue is considered to be a finding **(FIN 05000461/2008004-02)**. The licensee entered this finding into its corrective action program as AR 00734254.

(3) Failure to Perform Adequate Preventive Maintenance on Shutdown Service Water Valve 1SX014A Resulted in Significant Degradation and Gross Seat Leakage

(Closed) Unresolved Item (URI) 05000461/2008002-01, "As-Found Leakage Through Shutdown Service Water (SX) Valve 1SX014A."

Introduction

A finding of very low safety significance (Green) with an associated NCV of TS 5.4.1.a was self-revealed. The licensee failed to perform adequate preventive maintenance on SX system valve 1SX014A. This resulted in significant degradation of the valve body by corrosion due to prolonged exposure to raw service water that went undetected until gross seat leakage was discovered while attempting to establish conditions for surveillance testing.

Discussion

On January 22, 2008, operators identified gross seat leakage from 1SX014A while attempting to establish system conditions for a leakage test on the valve. The inspectors documented an initial review of this issue in NRC Inspection Report 05000461/2008002. An Unresolved Item was opened pending further review to determine whether the licensee's past operability evaluation accurately bounded 1SX014A leakage. During this inspection period, the inspectors reviewed the equipment apparent cause evaluation, past operability evaluation, corrective actions, and component failure history.

1SX014A is the Division 1 SX to normal plant service water isolation valve. During normal plant operation, the valve is open. The valve closes automatically when the SX pump starts. This valve was installed to ensure the SX system remains capable of performing its design function without being compromised by the less stringent design requirements of the normal plant service water system. 1SX014A is a 20-inch motor-operated Posi-Seal butterfly valve. The extent of condition includes the Division II and Division III SX to normal plant service water isolation valves (1SX014B and 1SX014C). 1SX014B is an identical 20-inch motor-operated Posi-Seal butterfly valve and 1SX014C is a similar but smaller 8-inch motor-operated Posi-Seal butterfly valve.

The inspectors reviewed the licensee's equipment apparent cause evaluation in detail. The failure mechanism was general corrosion of the valve body due to prolonged exposure to raw service water and possibly some contribution from microbiologically induced corrosion. The licensee's investigation also concluded that galvanic effects might have played a role due to the interaction between the Type 316 stainless steel valve disc and the carbon steel valve body. Valve inspection revealed that the valve body had corroded such that the disc was not in full contact with the valve seat allowing the valve to leak by the seat (majority of seal ring detached). In addition, the licensee's investigation determined that the apparent cause of the failure was inadequate preventive maintenance. The licensee had performed no internal valve inspections because the valve was not correctly categorized according to its Performance Centered Maintenance Template. The valve was classified as a Category 4 (no required inspection interval) component based on a designation of Critical–YES / Duty Cycle-LOW / Service Condition-MILD. The licensee's review of its Performance Centered Maintenance Template and the application of this valve in raw water conditions led to the conclusion that the Service Condition should be SEVERE based on the corrosive conditions to which the valve is exposed. This would result in a classification of Category 2, which would require valve internal inspections every eight years.

The licensee completed the following corrective actions:

1. review and revise the Performance Centered Maintenance Template classification of 1SX014A, 1SX014B, and 1SX014C as Critical, Low Duty Cycle, Severe Service Condition (Category 2);

2. create service requests for preventive maintenance tasks to perform valve inspection / replacement (for 1SX014A, 1SX014B, and 1SX014C) every six years;

3. review and revise the Performance Centered Maintenance Template classification of other SX system motor operated valves as Critical, Low Duty Cycle, Severe Service Condition (Category 2); and

4. review and revise the Performance Centered Maintenance Template classification of motor operated valves in other plant systems using raw water (i.e., normal plant service water, circulating water, and fire protection) as Critical, Low Duty Cycle, Severe Service Condition (Category 2).

The inspectors found that the licensee had missed previous opportunities to implement an effective preventive maintenance activity for 1SX014A. Prior to this recent failure, the licensee replaced 1SX014A in 1990 and 1997 because it was found to be degraded and leaking by its seat during testing. In addition, the licensee replaced the Division II SX to normal plant service water isolation valve (1SX014B) in 1990, 1997, and 2006 because it was found to be degraded and leaking by its seat during testing. The licensee replaced the Division III SX to normal plant service water isolation valve (1SX014C) in 1997, 2002, and 2008 because it was found to be degraded and leaking by its seat during testing.

The inspectors previously reviewed the maintenance history of 1SX014A, 1SX014B, and 1SX014C during an inspection in July 1997 (NRC Inspection Report 05000461/1997011) and concluded that "...Posi-Seal butterfly valves had a history of in service failure at

Clinton, were known to degrade rapidly once seat leakage developed, and were capable of rendering the SX system inoperable due to inter-system leakage. The inspectors also determined that the licensee had not evaluated whether the maintenance, testing, and planned replacement programs for these valves provided reasonable assurance of SX system operability during future operating cycles." In February 1999, the licensee's Independent Safety Engineering Group (ISEG) reviewed actions for the 1SX014A and 1SX014B butterfly valves. The ISEG report noted that a maintenance history investigation had been performed by the licensee's System Design and Functional Validation Group in 1998, which "...supports the NRC concerns and concluded that seat leakage problems with valves, particularly butterfly valves in the SX system, was an ongoing problem and did not appear to have received prompt and/or adequate attention." The ISEG concluded in its report that the corrective actions proposed and completed thus far concerning leakage issues related to Posi-Seal butterfly valves 1SX014A and 1SX014B adequately addressed the problems identified. The inspectors noted, however, that implementation of a preventive maintenance task for periodic internal valve inspections was not one of the corrective actions proposed or taken at that time.

The inspectors reviewed the licensee's past operability evaluation and resolved the open questions concerning it. Unresolved Item 05000461/2008002-01 is closed.

<u>Analysis</u>

The inspectors determined that the failure to perform adequate preventive maintenance on SX system valve 1SX014A was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, Appendix B, "Issue Screening," the inspectors determined that the failure to perform adequate preventive maintenance on 1SX014A would become a more significant safety concern if left uncorrected and was therefore more than a minor concern. Specifically, the failure to adequately perform preventive maintenance could reasonably result in significantly degraded or inoperable safety-related equipment. Because the SX system was primarily associated with long term decay heat removal following certain design basis accidents, the inspectors concluded that this issue was associated with the Mitigating Systems Cornerstone. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." In accordance with Table 4a, "Characterization Worksheet for IE [Initiating Events], MS [Mitigating Systems], and BI [Barrier Integrity] Cornerstones," the inspectors determined that that this finding was a licensee performance deficiency of very low safety significance (Green) because the finding: (1) was not a design or qualification deficiency; (2) did not represent an actual loss of safety function of a system; (3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; (4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and (5) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

Cross-cutting Aspects

The inspectors concluded that this finding affected the cross-cutting area of human performance. Specifically, the licensee’s investigation determined that internal valve inspections were not performed because the component category was incorrectly classified. While this may be considered a latent issue, the inspectors concluded that the licensee’s programs and processes had not changed sufficiently before the event based on multiple recent and current material condition issues affecting plant systems using raw water. (IMC 0305 H.3(b))

Enforcement

Unit 1 TS 5.4.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Appendix A of Regulatory Guide 1.33, Revision 2, recommends procedures for performing maintenance, including preventive maintenance schedules for safety-related SSCs. Contrary to the above, prior to January 22, 2008, the licensee failed to establish an adequate preventive maintenance schedule for SX system valve 1SX014A, an activity referenced in Appendix A of Regulatory Guide 1.33. Specifically, the licensee failed to perform appropriate internal valve inspections of the valve to identify degradation. Because of the very low safety significance, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy **(NCV 05000461/2008004-03)**. The licensee entered this violation into its corrective action program as AR 00725079.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for 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:

- emergent maintenance on June 24th causing the HPCS suction auto swap to suppression pool during troubleshooting (risk significant single train system);
- planned maintenance during the week of September 22nd on the HPCS system (risk significant single train system);
- planned maintenance during the week of August 18th to conduct ultra-sonic testing on the HPCS system piping (risk significant single train system);
- emergent maintenance on 1SX03MA to repair an expansion bellows leak on the SX supply to the Division III emergency diesel generator; and
- planned maintenance during the week of September 15th on Train ‘B’ of the RHR system.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each of the above activities, the inspectors reviewed the scope of maintenance work in the plant’s daily schedule, reviewed control room logs, verified that plant risk assessments were completed as required by 10 CFR 50.65(a)(4) prior to commencing maintenance activities, discussed the results of the assessment with the licensee's Probabilistic Risk Analyst and/or Shift Technical Advisor, and verified that plant conditions were consistent with the risk assessment assumptions. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify that risk analysis assumptions were valid, that redundant safety-related plant equipment necessary to minimize risk was available for use, and that applicable requirements were met.

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

This inspection constituted five maintenance risk assessment inspection samples as defined in Inspection Procedure 71111.13.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- AR 00783772, "Non-conforming Condition Identified for Control Room Ventilation Chiller Condenser Temperature Control Valve 1SX019B";
- AR 00755304-02, "Full Load Capability for Emergency Diesel Generator May Not Be Available For Three Minutes Following Start With Air Temperature Greater Than 90 ºF";
- AR 00812163, "NRC GL 08-01 Inspection Results at Pipe 1RH03AA";
- AR 797055, "Spent Fuel Pool Cooling Components Incorrectly Removed from IST [Inservice Testing] Program";
- ARs 813502, 813552, 814620, "Division I Shutdown Service Water Flow Balance Test Results";
- AR 00814948, "Received 5004-3H STS [Self-Test System] Failure"; and
- AR 00797672, "Division 2 Shutdown Service Water System Flow Balance Residual Heat Removal Pump 1B Seal Cooler Did Not Meet Acceptance Criteria".

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors verified that the conditions did not render the associated equipment inoperable or result in an unrecognized increase in plant risk. When applicable, the inspectors verified that the licensee appropriately applied TS limitations, appropriately returned the affected equipment to an operable status, and reviewed the licensee's evaluation of the issues with respect to the regulatory reporting requirements. 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 evaluation.

In addition, the inspectors verified that problems related to the operability of safety-related plant equipment 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 seven operability evaluation inspection samples as defined in Inspection Procedure 71111.15.

b. Findings

(1) Failure to Recognize the Safety-related System Function of the 1B RHR Pump Seal Cooler When Evaluating Past Operability of the Pump

Introduction

The inspectors identified a finding of very low safety significance (Green) associated with the licensee's failure to recognize the safety-related system function of the 1B RHR pump seal cooler when evaluating past operability of the pump after unacceptable results were obtained during SX system flow balance testing. In its initial past operability evaluation, the licensee incorrectly concluded that the pump seal cooler did not perform a safety-related function. Consequently, no analysis was performed to ensure that the pump's safety function would be fulfilled with less than minimum design flow to the cooler until the inspectors challenged the licensee's original conclusion. No violation of regulatory requirements was identified because subsequent evaluation by the licensee determined that sufficient margin existed in the cooler's design flow for the time period of concern.

Description

On June 17, 2008, the licensee performed flow balance testing for the Division II SX system train. Three system heat loads were found with less than the minimum design flow (the 1B RHR pump seal cooler, the 1B spent fuel pool cooling heat exchanger, and the 'B' control room heating/air conditioning chiller). Measured flow for the 1B RHR pump seal cooler was 5.9 gallons-per-minute (gpm) and the minimum design flow was 9.5 gpm. At the completion of this flow verification test, the system was adjusted so that flow values through each of the system loads met their associated minimum design criteria.

The licensee initiated AR 00787454, in which the basis for operability of the 1B RHR pump seal cooler was evaluated. The evaluation stated that with the measured flow rate, the temperature on the pump's seal would exceed its limit of 160 degrees Fahrenheit during shutdown Modes 4 and 5. The evaluation also concluded that there was no TS impact as long as the 1B RHR pump discharge temperature was maintained less than 150 degrees Fahrenheit. On June 20th, the Site Ownership Committee referred action to Engineering for the evaluation of past operability/reportability.

On July 1st, the licensee completed the past operability/reportability evaluation. In that evaluation the licensee concluded that the 1B RHR pump seal cooler did not perform a safety-related function; therefore, less than design flow was not reportable.

The inspectors challenged the licensee's conclusion that the pump seal cooler did not perform a safety-related function. The inspectors noted that the Clinton Power Station UFSAR, Section 5.4.7.1.1.1, stated that the RHR system provides a means for bringing the reactor to cold shutdown using only safety-grade systems. Based on the inspectors' questions before and during the Triennial Heat Sink Inspection, the licensee wrote AR 00797672 stating that the past operability/reportability evaluation for the Division II SX train flow balance test was incorrect and re-performed the past operability evaluation. Based on the revised past operability evaluation, in which the licensee re-performed the heat load calculation for the cooler by eliminating existing design margin, the licensee determined that sufficient margin existed and the pump would have been able to fulfill its safety function with significantly less than design flow to its seal cooler as measured during the test.

Analysis

The inspectors determined that the licensee's failure to recognize that the 1B RHR pump seal cooler performed a safety-related function when evaluating past operability of the pump was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and found two examples related to this issue. Examples 3j and 3k described situations where evaluation errors resulting in a reasonable doubt about the operability of a system or component are generally not considered to be of minor significance. In addition, consistent with the guidance in IMC 0612, Appendix B, "Issue Screening," the inspectors determined that the failure to correctly recognize the safety-related functions of SSCs when performing operability or past operability evaluations would become a more significant safety concern if left uncorrected and was therefore more than a minor concern because it could reasonably result in an unrecognized condition of a system failing to fulfill its safety-related function. Because the RHR system was primarily associated with long term decay heat removal following certain design basis accidents, the inspectors concluded that this issue was associated with the Mitigating Systems Cornerstone. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings." In accordance with Table 4a, "Characterization Worksheet for IE [Initiating Events], MS [Mitigating Systems], and BI [Barrier Integrity] Cornerstones," the inspectors determined that that this finding was a licensee performance deficiency of very low safety significance (Green) because the finding: (1) was not a design or qualification deficiency; (2) did not represent an actual loss of safety function of a system; (3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; (4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and (5) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

Cross-cutting Aspects

The inspectors did not identify a cross-cutting aspect related to this finding.

Enforcement

No violation of regulatory requirements was identified. This issue is considered to be a finding **(FIN 05000461/2008004-04)**. The licensee entered this finding into its corrective action program as AR 00787454.

1R18 Plant Modifications (71111.18)

.1 Temporary Modifications

a. Inspection Scope

The inspectors reviewed the following temporary plant modifications:

- EC 361430, "Eliminate LFMG [Low Frequency Motor Generator Set] Auto Start for EOC-RPT," Revision III; and
- TSP 2008-181, "Temporary Shielding in Fuel Building Crane Cab".

The inspectors reviewed the temporary modifications and the associated 10 CFR 50.59 screening/evaluations against applicable system design basis documents, including the UFSAR and the TS to verify whether applicable design basis requirements were satisfied. The inspectors reviewed the operator logs and interviewed engineering and operations department personnel to understand the impact that implementation of the temporary modifications had on operability and availability of the affected plant SSCs.

The inspectors also reviewed a sample of action requests pertaining to temporary modifications to verify that problems were entered into the licensee's corrective action program with the appropriate significance characterization and that corrective actions were appropriate.

This inspection constituted two temporary modification inspection samples as defined in Inspection Procedure 71111.18.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

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

- replacement of compensator for bypass electro hydraulic control pump 'B';
- planned maintenance on spent fuel pool cooling 'B' heat exchanger SX outlet valve 1SX062B;
- refurbishment of hydraulic control unit for control rod 2-17;
- disassemble/clean/inspect RHR pump 'C' seal cooler; and
- overhaul actuator on SX valve 1SX029C.

The inspectors reviewed the scope of the work performed and evaluated the adequacy of the specified post-maintenance testing. The inspectors verified that the post-maintenance testing was performed in accordance with approved procedures; that the procedures contained clear acceptance criteria, which demonstrated operational readiness and that the acceptance criteria was met; that appropriate test instrumentation was used; the equipment was returned to its operational status following testing, 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 five post-maintenance testing inspection samples as defined in Inspection Procedure 71111.19.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- CPS 9080.03, "Diesel Generator 1C Operability - Manual and Quick Start Operability;" (Routine)
- CPS 9015.01, "Standby Liquid Control System Operability;" (IST)
- CPS 9069.01, "Shutdown Service Water Pump Operability Test;" (IST)
- CPS 9170.02, “Control Room HVAC 'A' Chill Water Valve Operability Test;” and (Routine)
- CPS 2700.12, “Division I SX System Flow Balance Verification.” (Routine)

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 two in-service tests and three routine surveillance tests for a total of five inspection samples as defined in Inspection Procedure 71111.22.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of the licensee’s annual emergency preparedness exercise on September 19, 2008, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. This exercise was planned to be evaluated and was included in performance indicator data regarding drill and exercise performance. The inspectors observed emergency response operations in the Operations 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’s drill critique to compare any inspector-observed weaknesses with those identified by the licensee’s staff in order to evaluate the critique and to verify whether the licensee’s staff was properly identifying weaknesses and entering them into the corrective action program.

This inspection constituted one emergency preparedness simulator-based training evolution inspection sample as defined in Inspection Procedure 71114.06.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator 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 Second Quarter 2008 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 Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - Emergency AC [Alternating Current] Power System

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported Mitigating Systems Performance Index (MSPI) - Emergency AC Power System Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule data base, event reports, and maintenance and test data from July 2007 through March 2008, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constituted one MSPI Emergency AC Power System sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported MSPI - High Pressure Injection Systems Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule data base, event reports, and maintenance and test data from July 2007 through March 2008, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constituted one MSPI High Pressure Injection System sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.4 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported MSPI - Heat Removal System Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule data base, event reports, and maintenance and test data from July 2007 through March 2008, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constitutes one MSPI Heat Removal System sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.5 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported MSPI - Residual Heat Removal System Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule data base, event reports, and maintenance and test data from July 2007 through March 2008, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constitutes one MSPI Residual Heat Removal System sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.6 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors reviewed a sample of plant records and data against the reported MSPI - Cooling Water Systems Performance Indicator. To determine the accuracy of the performance indicator data reported, performance indicator definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, were used. The inspectors reviewed the MSPI derivation reports, Control Room logs, Maintenance Rule data base, event reports, and maintenance and test data from July 2007 through March 2008, to validate the accuracy of the performance indicator data reported. 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 corrective action program database to determine if any problems had been identified with the performance indicator data collected or transmitted for this performance indicator.

This inspection constitutes one MSPI Cooling Water System sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that 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. Some minor issues were entered into the licensee’s corrective action program as a result of the inspectors’ observations; however, they are not discussed in this report.

This inspection was not considered to be an inspection sample as defined in Inspection Procedure 71152.

b. Findings

No findings of significance were identified.

.2 Annual In-Depth Review Sample

a. Inspection Scope

The inspectors selected the following action request for in-depth review:

- Apparent Cause Evaluation Report, "Last Three Secondary Containment Drawdown Tests Exceed 4400 CFM [Cubic Feet per Minute]," (AR 00777784).

The inspectors verified the following attributes during review of the licensee's corrective actions for the above action request and other related action requests:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause and previous occurrences;
- evaluation and disposition of operability/reportability issues;
- classification and prioritization of the resolution of the problem, commensurate with safety significance;
- identification of the root and contributing causes of the problem; and
- identification of corrective actions, which were appropriately focused to correct the problem.

The inspectors discussed the corrective actions and associated action request evaluations with licensee personnel.

This inspection constituted one annual in-depth review sample as defined in Inspection Procedure 71152.

b. Findings and Observations

No findings of significance were identified.

.3 Annual Review of Operator Workarounds

a. Inspection Scope

The inspectors performed an in-depth review of operator workarounds and assessed the cumulative effect of existing workarounds and other operator burdens. The inspectors reviewed operator workarounds, control room deficiencies, temporary modifications and lit annunciators. The inspectors verified that operator workarounds were being identified at an appropriate threshold; that the workarounds did not adversely impact operators' ability to implement abnormal and emergency operating procedures; and, that the cumulative effect of operator burdens did not adversely impact mitigating system functions. The inspectors also reviewed action requests to verify that appropriate corrective actions were proposed or implemented in a timely manner commensurate with the significance of the issue.

This inspection constituted one annual operator workaround review inspection sample as defined in Inspection Procedure 71152.

b. Findings and Observations

Introduction

No findings of significance were identified.

Observations

The inspectors met with the site Operator Challenge/Work-around Coordinator, reviewed documents, and attended a Workaround Review Board. In general, the inspectors found that documents and action request items were well maintained and tracked with a good awareness of timelines and milestones. The Workaround Review Board itself was well organized and conducted with a thorough review of potential work around issues. Board participants were well prepared and knowledgeable of the concerns associated with each of the items discussed.

In Section 1R12.b.1 of this inspection report, the inspectors discussed an operator workaround that resulted in a reactor scram on February 10, 2008. According to the UFSAR, Chapter 15 analyses, no scram should occur for a trip of one reactor recirculation pump. This analysis assumes normal functioning plant instrumentation and controls. The feedwater level control system response has not been corrected and is currently considered by the licensee to be an operator workaround. The licensee has been evaluating this problem with the vendor and has been working on a plan to correct it. Until it is corrected, the unit is susceptible to reactor scrams from transient conditions that should not otherwise result in a reactor scram (e.g., loss of a single reactor recirculation pump or feedwater pump, inadvertent HPCS pump injection). During this inspection period, the inspectors discussed a concern with licensee management regarding an apparent lack of technical rigor in evaluating the plant start up after the February 2008 reactor scram and continued operation of the unit with this non-conforming condition because very little was documented regarding its impact on the plant and on the operators' ability to respond to reactor vessel water level transients. There was no formal evaluation of the non-conforming condition performed and there was no justification documented for starting up the unit and operating for a 2-year cycle with the non-conforming condition. The inspectors discussed this issue with the plant manager and AR 00807670 was written for the engineering staff to perform an evaluation. The inspectors concluded that this issue was not a significant safety concern because it was bounded by the UFSAR, Chapter 15 safety analyses that include a reactor scram from the trip of both reactor recirculation pumps.

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

.1 (Closed) LER 05000461/2008-001-00, "Automatic Scram on High RPV [Reactor Pressure Vessel] Water Level Due to Recirc [Recirculation] Pump Trip"

(Closed) LER 05000461/2008-001-01, "Reactor Recirc Pump Trip Initiates Automatic Scram on High RPV Water Level," Supplement 1

On February 10, 2008, Unit 1 automatically scrammed following an unexpected trip of the 'B' reactor recirculation pump. The licensee reported this event as a condition that resulted in the automatic actuation of the reactor protection system in accordance with 10 CFR 50.73(a)(2)(iv)(A). The licensee submitted Supplement 1 to the original LER to include the cause, safety analysis, corrective actions, previous occurrences, and component failure data for the event. The performance issues related to this event are discussed in Sections 1R12.b.1 and 1R12.b.2 of this inspection report. The inspectors concluded that the licensee's failure to perform adequate post-maintenance testing following the replacement of a feedwater level control system dynamic compensator card during the Cycle 10 refueling outage in February 2006 was a finding of very low safety significance. The inspectors also concluded that the licensee's failure to evaluate an unexpected and unknown cause for stray voltage in the EOC-RPT circuit discovered during post modification testing during the Cycle 11 refueling outage in February 2008 was a finding of very low safety significance. LER 05000461/2008-001-00 and LER 05000461/2008-001-01 are closed.

This inspection constituted one event follow-up inspection sample as defined in Inspection Procedure 71153.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

The inspectors also reviewed a report of the results of a survey of the site security organization relative to its safety conscious work environment. The inspectors considered whether the survey was conducted in a manner that encouraged candid and honest feedback. The results were reviewed to determine whether an adequate number of staff responded to the survey. The inspectors also discussed Exelon's self-assessment of the survey results with the site security operations manager and verified that any issues or areas for improvement were entered into the corrective action program for resolution. This review was performed by interview because the written self-assessment was not yet completed at the end of this inspection period.

The quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Resident Inspectors' Exit Meeting

The inspectors presented the inspection results to Mr. F. Kearney and other members of the licensee's staff at the conclusion of the inspection on October 10, 2008. The licensee acknowledged the findings presented. Proprietary information was examined during this inspection, but is not specifically discussed in this report.

.2 Interim Exit Meetings

An interim exit meeting was conducted for:

- Triennial Heat Sink Inspection with Mr. F. Kearney and other members of the licensee's staff on July 18, 2008. 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. Brendley, Corrective Action Program Administrator
T. Chalmers, Shift Operations Superintendent
S. Clary, Engineering Programs Manager
J. Conner, Operations Director
B. Davis, Plant Engineering Manager
S. Deal, Fire Marshall
J. Domitrovich, Maintenance Director
R. Frantz, Regulatory Assurance
J. Gackstetter, Training Director
M. Kanavos, Plant Manager
F. Kearney, Site Vice President
D. Kemper, Regulatory Assurance Manager
J. Peterson, Acting Regulatory Assurance Manager
J. Stovall, Radiation Protection Manager
C. VanDenburgh, Nuclear Oversight Manager
J. Waddell, Security Operations Manager
R. Weber, Engineering Director
C. Williamson, Security Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000461/2008004-01	FIN	Failure to Perform Adequate Post-Maintenance Testing Resulted in High Reactor Vessel Water Level (Level 8) Scram (Section 1R12.b.1)
05000461/2008004-02	FIN	Failure to Evaluate an Unexpected and Unknown Cause for Stray Voltage in the End-of-Cycle Recirculation Pump Trip Circuit During Post Modification Testing Resulted in a Reactor Recirculation Pump Trip (Section 1R12.b.2)
05000461/2008004-03	NCV	Failure to Perform Adequate Preventive Maintenance on Shutdown Service Water Valve 1SX014A Resulted in Significant Degradation and Gross Seat Leakage (Section 1R12.b.3)
05000461/2008004-04	FIN	Failure to Recognize the Safety-related System Function of the 1B Residual Heat Removal Pump Seal Cooler When Evaluating Past Operability of the Pump (Section 1R15.b.1)

Closed

05000461/2008004-01	FIN	Failure to Perform Adequate Post-Maintenance Testing Resulted in High Reactor Vessel Water Level (Level 8) Scram (Section 1R12.b.1)
05000461/2008004-02	FIN	Failure to Evaluate an Unexpected and Unknown Cause for Stray Voltage in the End-of-Cycle Recirculation Pump Trip Circuit During Post Modification Testing Resulted in a Reactor Recirculation Pump Trip (Section 1R12.b.2)
05000461/2008004-03	NCV	Failure to Perform Adequate Preventive Maintenance on Shutdown Service Water Valve 1SX014A Resulted in Significant Degradation and Gross Seat Leakage (Section 1R12.b.3)
05000461/2008002-01	URI	As-Found Leakage Through Shutdown Service (SX) Valve 1SX014A (Section 1R12.b.3)
05000461/2008004-04	FIN	Failure to Recognize the Safety-related System Function of the 1B Residual Heat Removal Pump Seal Cooler When Evaluating Past Operability of the Pump (Section 1R15.b.1)
05000461/2008001-00	LER	Automatic Scram on High RPV [Reactor Pressure Vessel] Water Level Due to Recirc [Recirculation] Pump Trip (Section 4OA3.1)
05000461/2008001-01	LER	Reactor Recirc Pump Trip Initiates Automatic Scram on High RPV Water Level," Supplement 1 (Section 4OA3.1)

Discussed

None

LIST OF DOCUMENTS REVIEWED

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

1R04 Equipment Alignment

- CPS 3309.01, “High Pressure Core Spray (HPCS),” Revision 15f
- CPS 3309.01E001, “High Pressure Core Spray Electrical Lineup,” Revision 7
- CPS 3309.01V001, “High Pressure Core Spray Valve Lineup,” Revision 11a
- CPS 3309.01V002, “High Pressure Core Spray Instrument Valve Lineup,” Revision 9
- M05-1074, “P&ID High Pressure Core Spray (HP) - Clinton Power Station Unit 1,” Revision AG
- CPS 3312.01, “Residual Heat Removal (RHR),” Revision 38
- CPS 3312.01V001, “Residual Heat Removal Valve Lineup,” Revision 16b
- CPS 3312.01V002, “Residual Heat Removal Instrument Valve Lineup,” Revision 9
- M05-1075, “P&ID Residual Heat Removal (RH) – Clinton Power Station Unit 1,” Revision AW
- CPS 3506.01, “Diesel Generator and Support Systems,” Revision 33,
- CPS 3506.01V001, “Diesel Generator and Support Systems Valve Line Up,” Revision 13A
- CPS 3506.01P001, “Diesel Generator Operations,” Revision 2
- Drawing M05-1035 Sheets 1-8, “Diesel Aux System Starting Air Exhaust and Combustion System,” Revision AE
- AR 814248, “1DG01CA: Water in Oil”
- CPS 3312.01, “Residual Heat Removal (RHR),” Revision 38
- CPS 3312.03, “Shutdown Cooling,” Revision 6
- CPS 3312.01E001, “Residual Heat Removal Electrical Lineup,” Revision 14
- CPS 3312.01V001, “Residual Heat Removal Valve Lineup,” Revision 16b
- CPS 3312.01V002, “Residual Heat Removal Instrument Valve Lineup,” Revision 9
- CPS 3001.01V001, “Locked Valve Lineup (Outside the Drywell),”
- OP-AA-108-101, “Control of Equipment and System Status,” Revision 5
- OP-AA-108-103, “Locked Equipment Program,” Revision 2

1R05 Fire Protection

- Clinton Power Station Updated Final Safety Analysis Report, Appendix E, “Fire Protection Evaluation Report – Clinton Power Station Unit 1,” Revision 11
- AR 802634, “Hour Fire Watch Patrols Not Performed for B Fire Pump Room
- OP-AA-101-113-1004, “Guidelines for the Morning Plant Status Reports,” Revision 12
- CPS 1893.01, “Fire Protection Impairment Reporting,” Revision 17
- CPS 1893.04M513, “737 Control: Unit 2 Diesel Generator Storage Bays,” Revision 5
- AR 804217, “Fire Impairment Tracking Enhancement Needed”
- UFSAR Appendix E, “Fire Protection Evaluation Report – Clinton Power Station Unit 1,” Revision 11
- OP-AA-201-003, “Fire Drill Performance,” Revision 9
- CPS 1893.04M300, “702 Control: Basement Prefire Plan,” Revision 6

1R06 Flood Protection

- CPS 4303.02, “Abnormal Lake Level,” Revision 9C
- AR 782251, “Screenhouse SX Pit Potential Flooding Problems”
- AR 789611, “De-Watering of Cable Vaults”
- AR 808891, “Floor Drain Covers Painted to Floor 737 TB”

1R07 Heat Sink Performance

- WO 00514890, “Inspect Screenhouse Intake Bays per CPS 2400.01,” February 26, 2007
- WO 01107614, “9052.01S21 OP LPCS/RHR A Water Leg Pump Operability,” May 1, 2008
- WO 01107259, “9052.01A21 OP LPCS/RHR A Water Leg Pump Operability,” April 29, 2008
- WO 01081454, “9052.01R21 OP LPCS/RHR A Water Leg Pump Operability,” February 15, 2008
- WO 00004017, “Inspect, Clean, and Perform Eddy Current – RHR A Heat Exchanger,” January 30, 2004
- WO 00576787, “1VY08SB Remove Inspect/Hydrolaze/Eddy Current Test Coils,” October 21, 2003
- WO 00510205, “1VY08SA Remove Inspect/Hydrolaze/Eddy Current Test Coils,” October 17, 2003
- WO 00394608, “HPCS Room Coolers Test HX Performance,” July 26, 2006
- WO 00418338, “Performed Div III SX System Testing,” August 25, 2006
- WO 00910503, “SX Boundary Valve Leak Testing (1SX011B),” January 16, 2008
- WO 00668783, “SX Boundary Valve Leak Testing (1SX011B),” February 3, 2006
- WO 00669315, “SX Boundary Valve Leak Testing (1SX011A),” February 3, 2006
- WO 00019130, “Clean 1CC01AA HX,” November 28, 2001
- WO 00852025, “Disassemble/Inspect/Clean RHR Pump Seal Cooler,” February 26, 2007
- EC 358633, “Document Tube Plugging Criteria and the Number of Tubes Plugged in the 1E12B001B,” Revision 0
- EC 363679, “Credit RHR A Heat Exchanger Test with C1R09 A Heat Exchanger Inspection,” Revision 0
- CPS 2700.20, “RHR A(B) Heat Exchanger, 1E12B001A(B) Thermal Performance Test Covered by NRC GL 89-13,” Revision 3
- CPS 1003.10, “CPS Program for GL 89-13,” Revision 6
- CPS 6001.01, “Sampling and Analysis Requirements,” Revision 34d
- CPS 1830.00, “CCW Corrosion Control Program,” Revision 2c
- CPS 3209.01, “Raw Water Treatment System,” Revision 17e
- CPS 3211.01, “Shutdown Service Water,” Revision 24e
- CPS 2700.13D001, “SX System Flow Verification Data Sheet – Division 2,” Revision 4
- ER-AA-340, “GL 89-13 Program Implementing Procedure,” Revision 4
- ER-AA-340-1001, “GL 89-13 Program Implementation Instructional Guide,” Revision 6
- ER-AA-340-1002, “Service Water Heat Exchanger and Component Inspection Guide,” Revision 3
- EN-CL-402-0005, “Extreme Heat Implementation Plan,” Revision 3
- CY-AA-120-4110, “Raw Water Chemistry Strategic Plan,” Revision 2
- CY-AA-120-400, “Closed Cooling Water Chemistry,” Revision 10
- NES-G-14.01, “Summary Report Clinton GL 89-13 Program Report,” Revision 3
- 3C10-1070-001, “Secondary Containment Functional Design,” Revision 8
- VY-45, “Performance Evaluation of VY System Cooling Coils Under SX Flow Acceptance Limits,” Revision 4
- GEK-75664, “Operation and Maintenance Instructions – RHR,” Revision B

- GE-NE-0000-0010-6516-01, “RHR Heat Transfer Tube Plugging,” Revision 0
- IP-M-0457, “Waterhammer potential of SX System Division 3,” Revision 0
- 01SX20, “Pressure Setpoints for Automatic Initiation of SSW Pumps 1SX01PA B&C,” October 22, 1986
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- AR 00787454, “Division II SX System Flow Balance Data not per Design,” June 17, 2008
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- IR 00797796, “Inconsistency Found in Use of LOCA Room Temperatures in VY-45 and VY-01,” July 17, 2008
- IR 00797806, “Calculation Improvement Needed,” July 17, 2008
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- Inspection of HPCS Room Coolers 1VY08SA and 1VY08SB Cooling Coils, November 7, 2003
- Division 3 SX to VY (HPCS) Post Transient Walkdown Results, October 22, 2007
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1R12 Maintenance Effectiveness

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- Engineering Evaluation EC#00370201, “Seat Leakage Across WS/SX Cross-tie Valve 1SX014A,” no date
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- AR 00734254, "Reactor Scram Caused by Trip RR 'B' Pump"
- AR 00734457, "Reactor Scram Resulting from Single RR Loop"
- AR 00796718, "NRC Identified RR Pump Trip on 2/10/08 as Maintenance Rule Failure"
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- AR 00796872, "Corrosion and Degradation of Expansion Bellows"
- AR 00796446, "Water Found Under Insulation Around 1SX03MA"
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- AR 818718, "EACE to Investigate Cause for MSIV Seat Cracking"
- AR 736646, "C1R11 Leak Rate Test (LRT) Failures for Maintenance Rule System 97 Need Evaluated
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- AR 724415, "1B21-F022D Failed C1R11 Local Leak Rate Test"
- HU-AA-1212, "Technical Task Risk Rigor Assessment, Pre-Job Brief, Independent Third Party Reviewing, and Post-Job Brief," Revision 2
- ER-AA-380, "Primary Containment Leak Rate Testing Program," Revision 5
- CPS 9861.04D001, "MSIV A LLRT Data Sheet," Revision 25C
- CPS 9861.04D004, "MSIV D LLRT Data Sheet," Revision 25C

<u>1R13 Maintenance Risk Assessments and Emergent Work Control</u>

- AR 00790019, "HPCS Suction Auto Swap to Suppression Pool During Troubleshooting"
- Root Cause Investigation (AR 00790019), "High Pressure Core Spray Suction Auto Swap to Suppression Pool During Troubleshooting," July 9, 2008
- MA-AA-716-004, "Conduct of Troubleshooting," Revision 7
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- AR 008101112, "UT Inspections Performed Contrary to Management Decision"
- WC-AA-104, "Review and Screening for Production Risk," Revision 12
- WC-AA-101, "Online Work Control Process," Revision 14
- WC-AA-101-1002, "On Line Scheduling Process," Revision 5
- ER-AA-310-600, "Risk Management," Revision 6
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- Engineering Evaluation EC 371532, “Replacement of Division III Expansion Joints 1SX01MC and 1SX02MC with Carbon Steel Pipe,” September 24, 2008
- Drawing M05-1052, Sheet 003, “Shutdown Service Water,” Revision AI
- Drawing M06-1052, Sheet 032, “Shutdown Service Water Piping,” Revision U

1R15 Operability Evaluations

- Clinton Power Station Updated Final Safety Analysis Report, Revision 11
- Operability Evaluation (AR 00783772-02), “Low Analytical Margin Found on 1SX019B Mounting Hardware,” Revision 0
- Operability Evaluation (AR 00812163-02), “NRC GL 08-01 Inspection Results at Pipe 1RH03AA,” Revision 0
- CPS 9052.04, “LPCS/RHR A Discharge Header Filled and Flow Path Verification,” Revision 27b
- Calculation FAI/08-70, “Investigate the Waterhammer Pressures and Axial Forces for Different Length High Points,” Revision 0
- RH-17, “Piping Isometric Drawing – Residual Heat Clinton Power Station Unit 1,” Revision 8H
- CPS 2700.12, “Division 1 SX System Flow Balance Verification,” Revision 5A
- AR 813502, “Below Spec Flow Reading on 1VY04S”
- AR 813552, “Below Spec Flow Reading on 1E12B001A”
- AR 814620, “Lineup Revision Needed, Update Valve Position from SX Flow Balance”
- AR 815711, “Valve 1SX027A Needs Re-Baseline Test Performed”
- AR 783772, “Low Analytical Margin Found on 1SX019B Mounting Hardware”
- AR 797055, “FC Components Incorrectly Removed from IST Program”
- RM Documentation No. CL-SURV-02 Revision 0
- ER-AA-600-1045, “Risk Evaluation of Missed or Deficient Surveillances,” Revision 2
- ER-AA-600-1012, “Deficient Surveillances Risk Management Documentation,” Revision 7
- Engineering Change Notice (ECN30634), "Heat Exchanger Specification Sheet," June 20, 1978
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- Engineering Textbook, "The Internal-Combustion Engine in Theory and Practice," 2nd Edition, March 2005
- Nuclear Service Engine Rating, "EMD 645 Engine Nuclear Service Engine Rating Graph with Curves A, B, C," February 28, 1978
- AR 810116, “Risk Review Document for FC Missed Surveillance Needs Improvement”
- AR 797672, “Division 2 Shutdown Service Water System Flow Balance Residual Heat Removal Pump 1B Seal Cooler Did Not Meet Acceptance Criteria”
- CPS 2700.13, “Division 2 SX System Flow Balance Verification,” Revision 5D
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- Engineering Calculation IP-M-0486, Revision 6E
- Engineering Calculation VC-86, “Evaluation of Control Room Chillers for SX Acceptance Criteria,” Revision 1

- Engineering Calculation VC-07, “System Analysis for Control Room Heating Ventilation and Air Conditioning (HVAC) System,” Revision 4-C
- Engineering Calculation VC-5, “Control Room HVAC System Cooling and Heating Load,” Revision 4
- Service Request (SR) 57471, “Defer Division II SX System Testing,” May 16, 2008
- Service Request 57710, “Defer Division II SX System Testing,” June 5, 2008
- AR 763764, “Division II SX Flow Balance Test Could Not Be Performed As Planned”
- CPS 9069.01, “Shutdown Service Water Operability Test,” Revision 45e
- AR 814948, “Self Test System and ADS”
- Work Order (WO) # 1166090 “IM Replace ADS DSC Card 1H13P662 D-A12-A104,” September 24, 2008
- Drawing E03-1P662, Sheet 602, “NSPS Division II Cabinet 1H13-P662,” Revision C
- Drawing E03-1P662, Sheet 606, “NSPS Division II Cabinet 1H13-P662,” Revision C
- Drawing E03-1P662, Sheet 640, “NSPS Division II Cabinet 1H13-P662,” Revision B
- Drawing E03-1P662, Sheet 706, “NSPS Division II Cabinet 1H13-P662,” Revision B
- Drawing E03-1P662, Sheet 707, “NSPS Division II Cabinet 1H13-P662,” Revision B
- Drawing E03-1P662, Sheet 708, “NSPS Division II Cabinet 1H13-P662,” Revision B

<u>1R18 Plant Modifications</u>

- EC 361430, “Eliminate LFMG [Low Frequency Motor Generator] Auto Start for EOC-RPT [End-of-Cycle Recirculation Pump Trip],” Revision 3
- Work Order 01104939, “Replace RC Network with Resistor for A & B Reactor Recirculation Pumps,” February 13, 2008
- 50.59 Evaluation No. CL-2008-E-010, “EC 361430 R/3 and USAR Log 2008-004 Revision Number, 3/0,” Revision 0
- Temporary Shielding Package 2008-181, “Temporary Shielding in Fuel Building Crane Cab”
- 50.59 Evaluation CL-2008-SO14, “TSP 2008-181”
- CC-AA-101, "Attachment 6 Shielding (Shadow) Component Permit," Revision 8
- 50.59 Screening Number: CL-2008-S-014, "Activity: Installation of Temporary Shield – TSP 2008-181," Revision 0

<u>1R19 Post-Maintenance Testing</u>

- CPS 8221.01, “Control Rod Drive CRD Hydraulic Control Unit HCU,” Revision 16
- CPS 9813.01, “Control Rod Scram Time Testing,” Revision 38A
- CPS 3304.02, “Rod Control and Information System (RCIS),” Revision 17A
- CPS 9813.01C001, “Control Rod Scram Timing Checklist,” Revision 32C
- CPS 9813.01D001, “Control Rod Scram Time Testing,” Revision 30A
- AR 814941, “CPS Attains Rated Power 2 Hours Behind Original Profile”
- CPS 9431.10, “RPS Main Steamline Isolation Valve Channed Calibration,” Revision 39
- WO #1145279, “Perfrom CRD HCU Overhaul and Replace Accumulator 24-17”
- AR 819118, “1E12-F063C RHR C Surv 9053.07 Invalid Test on Water Leg Pump”
- WO #1014846, “Disassemble/Inspect/Clean RHR Pump Seal Cooler”
- CPS 9843.02D001, “Generic Class 1, 2, and 3 Operational Pressure Test”
- Drawing M05-1052 Sheet 004, “Shutdown Service Water,” Revision V
- CPS 9843.02, “Operational Pressure Testing Of Class 1, 2, and 3,” Revision 40
- WO # 986669, “Overhaul Actuator and Replace Accessories 1SX029C”
- AR 459099, “1RIX-PR039 Not In Service During RHR B Pump Run”
- CPS 3211.01, “Shutdown Service Water (SX),” Revision 32B
- CPS 3211.01V001, “Shutdown Service Water Valve Lineup,” Revision 18E

- AR 737322, “CC Leakage Increase After Aligning CC to ‘B’ FC Heat Exchanger”
- OP-AA-103-105, “Limitorque MOV Operations,” Revision 1
- WO #1107218, “CC Leakage Increase After Aligning CC to ‘B’ FC Heat Exchanger”
- CPS 9061.06, “Containment Drywell Isolation Valve 24 Month Operability,” Revision 38
- CPS 9381.01, “MOV Thermal Overload Bypass Verification,” Revision 36
- AR 800061, “Bypass EHC Pump ‘B’ Pump Oscillations”
- AR 798798, “Bypass EHC ‘B’ Pump Compensator Found Degraded”
- OP-AA-109-101, “Clearance and Tagging,” Revision 2
- CPS 3105.04, “Steam Bypass and Pressure Regulator,” Revision 12C
- WO#1153123, “Bypass EHC Header Pressure Oscillations”

1R22 Surveillance Testing

- Clinton Power Station Technical Specifications
- CPS 3506.01C003, “Diesel Generator 1C Pre-start Checklist,” Revision 3f
- CPS 9080.03, “Diesel Generator 1C Operability – Manual and Quick Start Operability,” Revision 29
- CPS 9015.01, “Standby Liquid Control System Operability,” Revision 39d
- CPS 9015.01D001, “SLC Pump and Valve Data Sheet,” Revision 34
- IST-CPS-BDOC-V-28, “Clinton Inservice Testing Program Bases Document – Standby Liquid Control,” Revision 0
- Illinois Power Company, Clinton Power Station, “IST Program Plan - Second Ten-Year Interval Plan,” April 24, 2008
- AR 00811346, “Procedure Enhancement Opportunity”
- CPS 9069.01, “Shutdown Service Water Pump Operability Test,” Revision 46
- CPS 9170.02, “Control Room HVAC ‘A’ Chill Water Valve Operability Test,” Revision 31a
- AR 801621, “New VC ‘A’ Capacity Controller Failed to Operate”
- AR 802113, “OVC13CA Failed to Load After Replacement of 0TCVC622A”

1EP6 Drill Evaluation

- EP-MW-114-100-F-01, “Nuclear Accident Reporting System (NARS) Form,” Revision B
- HU-AA-1081-F-05, “Operations Fundamentals,” Revision 2
- EP-AA-1003, “Radiological Emergency Plan Annex for Clinton Station,” Revision 12

4OA1 Performance Indicator Verification

- Reactor Oversight Program MSPI Basis Document Clinton Power Station, March 23, 2007, Revision 2
- MSPI Deviation Report, Residual Heat Removal System, Unavailability Index, March 2008
- MSPI Deviation Report, Residual Heat Removal System, Unreliability Index, March 2008
- MSPI Deviation Report, Cooling Water System, Unavailability Index, March 2008
- MSPI Deviation Report, Cooling Water System, Unreliability Index, March 2008
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- MSPI Deviation Report, Heat Removal System, Unreliability Index, March 2008
- MSPI Deviation Report, High Pressure Injection System, Unavailability Index, March 2008
- MSPI Deviation Report, High Pressure Injection System, Unreliability Index, March 2008
- NEI 99-02, “Regulatory Assessment Indicator Guideline,” Revision 5

- AR 625478, “Site MSPI Determinations,”
- AR 00801947, “NRC Identified Error Counting NRC Unplanned Power Changes Performance Indicator”

4OA2 Identification and Resolution of Problems

- AR 00807670, “NRC Identified No Evaluation for 2/08 Scram from 1 RR Pump not per UFSAR”
- IR 109620, “VG A train Sec CT Drawndown Surv 9065.02,” May 28, 2002
- IR 194046, “Procedure 9065.02 Step 8.8 Figure 1 Data Unacceptable,” January 8, 2004
- IR 194272, “Flowrate exceeded 4400 cfm,” January 9, 2004
- IR 194448, “VG Secondary Containment Drawdown Test Fails,” January 10, 2004
- IR 774553, “Procedure 9065.02 Step 8.8 Figure 1 Data Off Scale,” May 12, 2008
- IR 777784, “Last Three (3) Secondary Containment Drawdown Tests Exceed 4400 cfm,” May 20, 2008
- CPS 9065.02, “Secondary Containment Integrity Data Sheet”
- CPS 9065.02D001, “Secondary Containment Integrity Data Sheet”
- AR 812299, “Recurrence of RFP Suction Pressure Perturbation”
- OP-AA-102-103, “Operator Work-Around Program,” Revision 2
- AR 757612, “MOV Manually Operation Results in 5 MREM Emergent Dose”
- AR 765687, “TRNG 1C Feedpump Susceptible to Damage”
- AR 739611, “RR Problems Need Screened As Operator Work-Around”
- AR 738545, “1B21N032 Computer PNT B21ND001 Core Plate D/P Reads 0 MLB/HR”
- AR 763115, “Rod Position Difficult To Determine During Scram”
- AR 784216, “Operations Tool Boxes In Containment 755 Need Decontamination”
- AR 791399, “3104.01P001 Section 8.7.1.10 Contains Op Challenge”
- AR 756259, “Feedwater Level Control Needs Troubleshooting/Tuning”
- AR 755205, “1UAY-TG502H Energized and Occasionally Chattering”

4OA3 Follow-up of Events and Notices of Enforcement Discretion

- Licensee Event Report 05000461/2008-001-00, “Automatic Scram on High RPV Water Level Due to Recirc Pump Trip,” April 9, 2008
- Licensee Event Report 05000461/2008-001-01, “Reactor Recirc Pump Trip Initiates Automatic Scram on High RPV Water Level,” Supplement 1, June 9, 2008
- Plant Operations Review Committee Meeting 08-005 (C1F50) Discussion Minutes, Subject: OP-AA-108-114, “SCRAM Report,” March 12, 2008
- AR 00734254, “Reactor Scram Caused by Trip RR ‘B’ Pump”
- AR 00734457, “Reactor Scram Resulting from Single RR Loop”

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agency-wide Documents and Management System
AR	Action Request
BI	Barrier Integrity
BWR	Boiling Water Reactor
CFM	Cubic Feet Per Minute
CPS	Clinton Power Station
EOC	End-Of-Cycle
FIN	Finding
GPM	Gallons Per Minute
HPCS	High Pressure Core Spray
IE	Initiating Events
IMC	Inspection Manual Chapter
ISEG	Independent Safety Engineering Group
IST	Inservice Testing
LER	Licensee Event Report
LFMG	Low Frequency Motor Generator
MS	Mitigating Systems
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records
RHR	Reactor Heat Removal
RPT	Recirculation Pump Trip
RPV	Reactor Pressure Vessel
SDP	Significant Determination Process
SSCs	Structures, Systems and Components
STS	Self Test System
SX	Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item