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

February 9, 2009

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

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000456/2008005; 05000457/2008005

Dear Mr. Pardee:

On December 31, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Braidwood Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on January 8, 2009, with Mr. L. Coyle, and other members of your staff.

The 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, three NRC-identified findings and one self-revealed finding of very low safety significance were identified. The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section VI.A.1 of the NRC Enforcement Policy. Additionally, three licensee identified violations are listed in Section 40A7 of this report.

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

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (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/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-456; 50-457
License Nos. NPF-72; NPF-77

Enclosure: Inspection Report 05000456/2008005; 05000457/2008005
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Braidwood Station
Plant Manager - Braidwood Station
Manager Regulatory Assurance - Braidwood 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
Manager Licensing - Braidwood, Byron and LaSalle
Associate General Counsel
Document Control Desk - Licensing
Assistant Attorney General
J. Klinger, State Liaison Officer,
Illinois Emergency Management Agency
Chairman, Illinois Commerce Commission

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Associate General Counsel
Document Control Desk - Licensing
Assistant Attorney General
J. Klinger, State Liaison Officer,
Illinois Emergency Management Agency
Chairman, Illinois Commerce Commission

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Letter to C. Pardee from R. Skokowski dated February 9, 2009.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000456/2008005;
05000457/2008005

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REGION III

Docket Nos:	05000456; 05000457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2008005 and 05000457/2008005
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, Illinois
Dates:	October 1, 2008, through December 31, 2008
Inspectors:	B. Dickson, Senior Resident Inspector A. Garmoe, Resident Inspector D. McNeil, Senior Operations Engineer B. Palagi, Senior Operations Engineer M. Holmberg, Reactor Inspector G. O'Dwyer, Reactor Inspector R. Winter, Reactor Inspector M. Perry, Resident Inspector, Illinois Department of Emergency Management
Approved by:	R. Skokowski, Chief Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000456/2008-005, 05000457/2008-005; 10/01/2008 -12/31/2008; Braidwood Station, Units 1 & 2, Equipment Alignment, Operability Evaluations, Problem Identification and Resolution.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three Green findings were identified by the inspectors and one Green finding was self-revealed. The findings were considered non-cited violations (NCVs) of NRC regulations. 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-Revealed Findings

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control,' was identified by the inspectors for the failure to properly control high pressure gas cylinders in proximity to safety-related equipment. Specifically, the inspectors identified four high pressure gas cylinders in two separate locations that were restrained by a single chain less than half the height of the bottles and were in the vicinity of safety-related motor control centers. The licensee entered this issue into their corrective action program (CAP) and made the restraint of the gas cylinders seismically qualified.

  The inspectors determined that the failure to properly evaluate the installation and storage of high pressure gas cylinders in plant area AB-401 and AB-426 was contrary to the design basis and was a performance deficiency. The finding was more than minor because the finding was similar to IMC 0612, Appendix E, Example 4a, in that no engineering evaluation was performed to assess the seismic impact on the gas cylinders on multiple locations, where safety-related equipments were potentially affected. Therefore, this performance deficiency also impacted the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors performed a Phase 1 SDP screening and the finding was determined to be potentially risk-significant due to external initiating event core damage sequences. The regional senior reactor analyst (SRA) determined that the Phase 2 SDP pre-solved tables and worksheets did not clearly address the inspection finding. Therefore, the SRA performed a SDP Phase 3 analysis and determined the issue was of very low safety significance. The inspector concluded this issue did not have a cross-cutting aspect because this finding was not indicative of current performance. The licensee originally installed the gas cylinder bottles greater than 2 years ago and they recognized the error when it was bring to their attention. (Section 1R04.b)

- Green. A finding of very low safety significance and associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was self-revealed when leak-by of valve 2CS023 led to a 100 gallon sodium hydroxide (NaOH) spill that leaked into the

2A Residual Heat Removal (RH) pump room and rendered the 2A RH pump unavailable on September 30, 2008. The licensee had failed to take adequate corrective actions to address a previous identified hard-to-close valve 2CS023. The licensee entered this issue into the CAP, cleaned up the spill, and planned to replace the valve. This finding has a cross-cutting aspect in the area of human performance since the operator did not verify the closure of the valve (H.4(a)).

The inspectors determined that the failure to properly verify the adequacy of lubricating the 2CS023 valve stem for better valve operation previously was a performance deficiency. The finding was more than minor because it impacted the Mitigating Systems Cornerstone attribute to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors performed a Phase 1 SDP review of this finding and determined the issue was of very low safety significance. (Section 1R15.b.2)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified by the inspectors for failure to promptly identify and correct the auxiliary feedwater (AFW) tunnel hatch cover design deficiencies. Specifically, upon finding that the design safety factor of the concrete expansion anchor was less than the requirement, the licensee failed to evaluate and correct all deficiencies associated with the design calculation in a timely manner. The licensee entered the issue into their CAP, implemented compensatory measures using temporary modifications, and completed permanent modifications to restore design margins prior to December 31, 2008.

  The finding was more than minor because it was associated with the Barrier Integrity Cornerstone attribute of systems, structures, and components (SSC) and Barrier Performance (Containment Isolation SSC Reliability) and affected the cornerstone objective of maintaining functionality of containment. The inspectors determined the finding to be of very low safety significance using the SDP Phase 1 screening worksheets, as there was no actual open pathway in the physical integrity of the reactor containment; it did not represent a degradation of the barrier function of the control room, auxiliary building, spent fuel pool and it did not involve an actual reduction in function of the hydrogen igniters. This finding has a cross-cutting aspect in the area of problem identification and resolution because the licensee did not thoroughly evaluate the problem immediately upon identification. (P.1(c) (Section 1R15.b.1)

- Green. The inspectors identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having a very low safety significance, associated with the licensee's failure to analyze and establish an adequate quench volume within the boron recycle system holdup tanks and failure to analyze the water hammer loads on boron recycle system holdup tank inlet piping induced by relief valve discharges. Insufficient holdup tank quench volume could result in an overpressure failure of the holdup tank and the water hammer induced piping loads could damage the boron recycle system holdup tank inlet piping system. The licensee's corrective actions included changing procedures to maintain a minimum 40 percent boron recycle holdup tank level as a quench volume for system relief valves and initiating an action to perform an analysis to investigate the magnitude of the potential water hammer loads on the inlet piping.

The finding was more than minor because the finding affected the Barrier Integrity Cornerstone objective for maintaining the radiological barrier function of the containment. The finding was associated with the design control and procedure quality attributes of the Barrier Integrity Cornerstone. The inspectors determined that the failure to establish an adequate boron recycle system holdup tank quench volume and analyze the magnitude of water hammer loads on boron recycle system holdup tank inlet piping degraded the radiological barrier function of the containment but did not represent an actual open pathway from containment; therefore, the finding screened as having very low safety significance. Because the performance errors that led to this finding occurred prior to the approval of the plant operating license and the licensee recognized the error when it was brought to their attention, this issue did not reflect current plant performance and therefore, no cross-cutting aspect was identified. (Section 4OA2.5.b.1)

B. <u>Licensee-Identified Violations</u>

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's CAP. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power for the entire inspection period.

Unit 2 operated at full power until the afternoon of December 27, 2008, when the reactor automatically tripped due to a main turbine trip while above 30 percent power. A phase-to-phase fault on the Unit 2 'C' heater drain pump caused the actuation of the unit auxiliary transformer (UAT) 241-1 sudden pressure relays (SPRs). The main generator, main turbine and reactor tripped as expected upon actuation of the UAT 241-1 SPRs. The operators restarted the plant on December 28, 2008, and synchronized to the grid on December 29, 2008. Full power operation was achieved on December 30, 2008.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 2A RH System Partial Alignment;
- 1B Containment Spray (CS) during 1A CS Work Window;
- 1A Diesel Generator (DG) during 1B DG Work Window; and
- 1B RH System Partial Alignment.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Updated Final Safety Analysis Report (UFSAR), Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions 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 and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the correction action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted four partial system walkdown samples as defined in Inspection Procedure (IP) 71111.04-05.

b. Findings

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to properly control high pressure gas cylinders in proximity to safety-related equipment. Specifically, the inspectors identified four high pressure gas cylinders in two separate locations that were restrained by a single chain less than half the height of the bottles and were in the vicinity of safety-related motor control centers (MCCs). The licensee entered this into their CAP and made the restraint of the gas cylinders seismically qualified.

Description: During a plant walkdown the inspectors identified high pressure gas cylinders containing high pressure calibration gas for radiation protection monitors in the auxiliary building (AB) on the 401 and 426 elevations. The gas cylinders in both locations were in proximity to safety-related MCCs and were not seismically restrained. Each location contained two high pressure gas cylinders sitting on a metal stand with a single chain less than half the height of the cylinders. The metal stands were free standing and not attached to any structure.

The cylinders contained a high pressure, approximately 2500 pound per square inch gauge when full, proprietary calibration gas that is utilized by the personnel contamination monitors in the area. The licensee performed an engineering evaluation of the radiation protection installation on AB-401 elevation but did not include a seismic review of the high pressure gas cylinders. There was no documented engineering review performed for the gas bottles installed on AB-426 elevation. Because the gas cylinders were in constant use they did not have protective caps installed. If any of the cylinders had fallen over either the valve stem or pressure regulator could have broken off causing the cylinder to become a high energy missile.

Analysis: The inspectors determined that the failure to properly evaluate the installation and storage of high pressure gas cylinders in plant area AB-401 and AB-426 was contrary to the design basis and was a performance deficiency.

The finding was more than minor because the finding was similar to IMC 0612, Appendix E, Example 4a, in that no engineering evaluation was performed to assess the seismic impact on the gas cylinders, where safety-related equipment (MCC 2AP32 and 1AP32E) was potentially affected. Therefore, this performance deficiency impacted the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings." In accordance with Table 3b, "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstone," the finding affected the Mitigating Systems Cornerstone. In accordance with Table 4b, "Characterization Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," (seismic, flooding, and severe weather screening criteria), the finding represented a potential loss of the following risk-significant equipment for MCC 2AP32E: DG 2B fuel oil transfer pump 2CO01PD, charging pump to cold leg injection valve 2MOV-SI8801, component cooling water to reactor coolant pump valve 2CC9413B, and volume control tank outlet valve 2CV112C. Risk-significant equipment potentially affected on MCC 1AP32E: charging pump to cold leg injection valve 1MOV-SI8801, component cooling water to reactor coolant pump valve 1CC9413B, and volume control tank outlet valve 1CV112C. The finding was determined to be potentially risk-significant due to external initiating event core damage sequences.

In accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," the regional SRA determined that the Phase 2 SDP pre-solved tables and worksheets did not clearly address the inspection finding. Therefore, the SRA performed a SDP Phase 3 analysis to characterize the significance of the finding. The following conservative assumptions were made:

- the maximum exposure time used was 1 year,
- a seismic event occurs that is strong enough to cause a loss of offsite power (LOOP) event,
- given a seismic-induced LOOP, the probability of the gas cylinders launching in the correct direction of MCCs 2AP32E and 1AP32E was 1.0, and
- given a launch of the gas cylinders missiles at the MCCs, the probability of rendering the equipment listed above inoperable was 1.0.

The analyst performed a Phase 3 analysis for each plant area using the NRC Risk Assessment Standardization Project (RASP) Handbook and the Standardized Plant Analysis Risk Model for Braidwood, Revision 3P, dated July 2008. According to the RASP handbook, the seismic-induced LOOP frequency for Braidwood was 2.85E-5.

For MCCs 1AP32E and 2AP32E, the conditional core damage probability for failure of the equipment affected by the gas cylinder missiles during a LOOP event was calculated to be 1.8E-4. Considering the seismic-induced LOOP frequency, the delta core damage frequency was estimated to be 5.13E-9. Therefore, the risk associated with this performance deficiency was very low (Green).

The inspector concluded this issue did not have a cross-cutting aspect because this finding was not indicative of current performance. The licensee originally installed the gas cylinder bottles greater than 2 years ago and they recognized the error when it was bring to their attention.

<u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to check the adequacy of the design for the mounting of high pressure gas cylinders associated with the installation of personnel contamination monitors. Specifically, the licensee failed to ensure that the high pressure gas cylinders installed in proximity to safety-related motor control centers were seismically restrained. Because this violation was of very low safety significance and it was entered into the licensee's CAP as Issue Report (IR) 821957, this violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000456/2008005-01; 05000457/2008005-01).

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- 1A Safety Injection Pump Room (Fire Zone 11.3A.1);
- 2A Safety Injection Pump Room (Fire Zone 11.3A-2);
- AB General Area 346' Elevation (Fire Zone 11.2-0);
- 1A and 1B DG Rooms (Fire Zone 9.2-1 and Fire Zone 9.1-1); and
- 2B DG Room (Fire Zone 9.1-2)

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

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

b. Findings

No findings of significance were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On October 2, 2008, the inspectors observed a fire brigade activation during an unannounced off-hour fire drill. On November 10 and 17, 2008, the inspectors observed a fire brigade activation during an announced off-hour fire drill. Based on these observations, the inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

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

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined by IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07T)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed operability determinations, completed surveillances, vendor manual information, associated calculations, performance test results, and cooler inspection results associated with the 1A Essential Service Water (SX) pump lube oil cooler and the 2A RH 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 1A SX pump lube oil cooler, 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 1A SX pump lube oil cooler, 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 1A SX pump lube oil cooler and the 2A RH 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. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger.

For the 2A RHR heat exchanger, the inspectors verified the condition and operation of the 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 inspector reviewed visual inspection records to determine the structural integrity of the heat exchanger. The inspectors verified the licensee's chemical treatment programs for corrosion control were consistent with industry norms and implemented accordingly.

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

The inspectors reviewed the results of the licensee's inspection of the UHS weirs or excavations. The inspectors verified that identified settlement or movement indicating loss of structural integrity and/or capacity was appropriately evaluated and dispositioned by the licensee. 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 service water system and UHS. This included the review of licensee's procedures for a loss of the service water system or UHS and the verification that instrumentation, which is relied upon for decision making, was available and functional. In addition, the inspectors reviewed programs that monitored, trended, and controlled macrofouling by the licensee to prevent clogging. The inspectors verified that licensee's biocide treatments for biotic control were adequately conducted and the results monitored, trended, and evaluated. The inspectors also verified that the licensee maintain adequate pH, calcium hardness, etc.

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

These inspection activities constituted two heat sink inspection samples as defined in IP 71111.07-05.

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

On October 22, 2008 and October 29, 2008, the inspectors observed a crew of licensed operators (Crew 3 and Crew 5, respectively) in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

Each crews' performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Braidwood Licensed Operator Scenario #0861B "Loss of Bus 141/ATWS/Loss of Heat Sink" was observed for both crews. Other documents reviewed are listed in the Attachment to this report.

This inspection constituted two quarterly licensed operator requalification program samples as defined in IP 71111.11.

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the biennial written examination, the individual Job Performance Measure operating tests, and the simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from August 25 through October 3, 2008, as part of the licensee's operator licensing requalification cycle. These results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification SDP." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG 1021, "Operator Licensing Examination Standards for Power Reactors," and IP 71111.11, "Licensed Operator Requalification Program." The documents reviewed during this inspection are listed in the Attachment.

Completion of this section constituted one biennial licensed operator requalification inspection sample as defined in IP 71111.11B.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Service Air;
- Essential Service Water; and
- Excore Neutron Monitoring System.

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

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

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Emergent Issues during 1A CS Work Window;
- 2A Auxiliary Feedwater (AFW) pump Slave Relay Surveillance Failure; and
- Trouble Calibrating 1C Reactor Coolant Pump Seal Injection Flow Transmitter.

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

These maintenance risk assessments and emergent work control activities constituted three samples as defined in IP 71111.13-05. Documents reviewed are listed in the Attachment to this report.

b. Findings

Introduction: The inspectors identified an unresolved item (URI) related to slave relay testing for the 2A AFW system. Specifically, the licensee declared the system inoperable but available during testing. However, the process that the licensee used for risk management might be inconsistence with the NRC endorsed industry guidance.

Descriptions: On November 21, 2008, the operators performed Surveillance Test 2BwOSR 3.3.2.8-620A, “Unit Two Slave Relay Surveillance (Train A K620 and K633).” During the performance of this surveillance test the K620 and the K633 relays failed to energize. Prior to the failure of the relays to energize, the operators declared the 2A AFW system inoperable and entered TS Limiting Condition for Operation (LCO) 3.7.5, Condition A, due to the system’s test configuration. The licensee informed the inspectors that the system was considered available for on-line risk purposes due to the fact that the system could be manually realigned to the correct configuration within 41 minutes. The licensee stated that according to the plant’s probabilistic risk assessment, the AFW system was not needed until 41 minutes following design basis accident. The operators also informed the inspectors that this classification was in accordance with licensee's Procedure, WC-AA-101, "Online Work Control Process," specifically Attachment 6, Case 4. Case 4 states that the system is available if the equipment could be "promptly restored to service." Additionally, in determining whether a system is available, Case 4 also states that restoration actions need not be proceduralized but must be documented and that the assessment may take into account time needed for restoration.

Title 10 of CFR Part 50.65 (a)(4), states that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing (PMT) and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to the SSCs that a risk informed evaluation process has shown to be significant to public health and safety. The definition of SSC Unavailability, for the purposes of availability or reliability calculations in accordance with 10 CFR Part 50.65 (a)(4) requirements, is provided in Appendix B of NUMARC 93-01, Section 11, which is the Nuclear Energy Institute's (NEI) guidance for implementation of 10 CFR Part 50.65 (a)(4) requirements. The NRC endorsed NUMARC 93-01, Section 11 in Regulatory Guide 1.182.

In Section 11 of NUMARC 93-01, the unavailability definition is considered for two cases: (1) SSCs tagged out of service, and (2) SSCs not tagged out of service. In the case of 2BwOSR 3.3.2.8-620A, the SSC was out of service for surveillance testing but not be tagged out of service. In accordance with the definition of unavailability in Appendix B, of NUMARC 93-01, SSCs out of service for testing, "…not tagged out, are considered unavailable unless the plant configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose. Restoration actions must be uncomplicated (a single action or a few simple actions) and must not require diagnosis or repair. Credit can be taken only if the (operator) is positioned at the proper location throughout the duration of the test." The inspectors concluded that the intent is to allow licensees to take credit for restoration actions that are virtually certain to be successful during accident conditions.

When questioned, the licensee stated that an equipment operator, who was in constant communication with the control room, had been assigned to realign the system if needed. The inspectors asked whether this equipment operator had been assigned any other duties and whether this equipment operator had been stationed locally in the plant at the valves that needed to be realigned. The licensee told the inspectors that the equipment operator was performing other tasks as part of his normal plant tour rounds and therefore was not stationed locally at the valves.

The inspectors reviewed 2BwOSR 3.3.2.8-620A and noted that during portions of the surveillance test, contacts for both the K620 and K633 relays were jumpered to measure contact resistance. With these jumpers installed an automatic start of the 2A AFW pump would not occur on a "Lo-Lo" steam generator water level condition. Additionally, the AFW system discharge test valve 2AF004A would not open automatically on that same signal. This valve is normally open; however, it is closed as part of the test configuration. Following the resistance reading the jumpers are removed. This action restores the ability of the 2AF004A valve to automatically open on a steam generator (Lo-Lo) water level condition, if the K620 and K633 relays are functioning properly.

Prior to attempting to energizing the K620 and K633 relays, by use of a test push button, the operators entered TS LCO action statement 3.3.2 Conditions A and J for the AFW system essential service water suction valves, 2AF006A and 2AF017A. These action statements were entered because the test switch (S804) on test panel 1PAJ11, located outside the control room, was placed in TEST, which actuated a circuit blocking function. The SX suction valves would not automatically open on low water level signal coincident with a low AFW pump suction pressure signal. With test switch S804 in TEST, an automatic start of the 2A AFW pump on a steam generator “Lo-Lo” signal would also be blocked.

The inspectors noted that in Section E, “Limitation and Actions,” of 2BwOSR 3.3.2.8-620A, Step 5 stated that if necessary to “emergency” exit this test, perform Subsection F.3.0. This section also stated that the verifications might be delayed, but should be performed as soon as practical thereafter.

Emergency exit steps contained in Subsection F.3.0 were as following:

- Step 3.1 required the operators to verify or remove the jumpers installed in Subsection F.1.0.
- Step 3.2 required the operators the release test switch S804 to de-energize Slave Relay K620 and K633.
- Step 3.4 directs the operators to remove instrument probes from terminals 1 and 2.
- Step 3.5 directs the operators to place test switch S804 to NORMAL, at 2PA11J; and
- Step 3.6 required the operator to verify red light 081 is NOT ILLUMINATED indicating Train A Safeguards test cabinet is OUT OF TEST.

The inspectors noted that subsequent steps direct the operators to verify or return the 2AF004A, AFW Pump 2A Discharge Control Switch at local control panel to Auto and Open.

From further review of Section 11.3.2.7 of NUMARC 93-01, "prompt restoration" of the out-of-service SSC is the criterion to determine whether the SSC is available or not. In reviewing all of the procedural steps in Section F.3.0, "Restoration and Final Conditions," of the Braidwood surveillance procedure, the inspectors noted several operator actions (versus one single action) were needed to return the SSC to service. Additionally, the inspectors did not identify any discussion or considerations of risk management activities, as such stationing maintenance or operation personnel at the locations needed for prompt restoration of the system, documented in the operator logs or in the surveillance test procedure (with the exception of 41 minutes to restore).

In addressing this concern, the licensee stated that discussion of risk management activities and considerations were provided by the Unit Supervisor while conducting pre-job brief prior to the start of the surveillance activities. The licensee presented a print of an Excel spreadsheet that listed pre-job brief discussion topics for a number of TS required surveillance procedures. The inspectors reviewed this spreadsheet and noted concerns. For example, under the pre-job discussion topics of 2BwOSR 3.3.2.8-620A, Section F.2.0, instead of Section F.3.0, was listed as the procedure section to refer to if an emergency exit from the procedure is needed. The inspectors raised additional quality control and implementation issues regarding the use of the spreadsheet during pre-job briefs. The licensee documented these concerns in IR 867880.

At the conclusion of the inspection period, the inspectors were continuing their evaluation of the licensee processes and controls regarding the management of on-line risk. Therefore, this item will remain open pending further NRC review to determine the adequacy and conformance to licensing and regulatory requirements. (URI 005000456/2008005-02; 05000457/2008005-02).

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- IR 826783, “Elevated Unit 1 SI Pump Discharge Header Pressure” and IR 832975 “Rising 1A SI Accumulator Level – 1SI04TA”;
- IR 839838, “Rising Suction and Discharge Pressure in Unit 2 RH System”;
- 1A residual heat and refueling water storage tank header with 1CS011A removed;
- IR 844845, “1C Reactor Coolant Pump Seal Injection Flow Transmitter Calibration Found Out of Tolerance”;
- Operability Evaluation 07-007, “Auxiliary Feed Water Tunnel Cover Expansion Anchor Bolts”; and
- IR 826323, “Potential Chemical Intrusion to 2A Motor Windings” and IR 824756, “2A Residual Heat Pump Cleanup following Caustic Spill.”

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

These operability inspections constituted six samples as defined in IP 71111.15-05.

b. Findings

(1) Failure to Promptly Identify and Correct AFW Tunnel Hatch Cover Design Deficiencies

Introduction: A finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified by the inspectors for failure to promptly identify and correct the AFW tunnel hatch cover design deficiencies. Specifically, upon finding that the design safety factor for concrete expansion anchor was less than the requirement, the licensee failed to identify additional deficiencies associated with the same design calculation and to correct all deficiencies in a timely manner.

Description: AFW containment isolation valves (AF013 valves) are located inside the AFW tunnels and are separated from the Main Steam Isolation Valve (MSIV) rooms above by hatch covers at the 377' floor level. The hatch covers consist of steel plates supported on the concrete floor along three edges and on a steel shelf angle anchored to a concrete wall along one edge. There are four such cover plate assemblies in each unit. The steel cover plates are required to remain intact and in place to ensure that the AF013 valves are protected against the harsh environment due to flooding and High Energy Line Break (HELB) within the MSIV rooms. Failure of the cover plates in case of a HELB would subject the normally open AF013 valves to a harsh environment. Since the AF013 valves are not qualified for the harsh environment, there is no assurance that the operators will be able to close these valves to achieve containment isolation if required.

On April 18, 2007, during a review following concerns raised by the inspectors regarding adequacy of the hatch cover flood seals, the licensee identified that structural calculations for the hatch covers considered pressure due to flooding but did not take into account a more critical loading resulting from the HELB pressure (Byron IR 620080, Braidwood notified due to applicability based on design similarity). The evaluation documented in the IR indicated that stresses in the plates would remain within the acceptance limits. The evaluation failed to identify that expansion anchor were also affected by the HELB pressure.

On July 26, 2007, the licensee identified that the expansion anchors did not meet the design safety factor of four or the operability safety factor of 2 provided in the NRC Bulletin 79-02 (IR 654270). The NRC Inspection Manual Part 9900, Technical Guidance for Operability Determinations (Attachment to RIS 2005-20, Sections C.13 and C.10) does not specify a lower than the design safety factor for operability evaluation of anchor bolts for structures. However, for pipe supports, it refers to IE Bulletin 79-02 which allows a minimum safety factor of 2, a value generally used by the licensee for all anchors. The licensee procedure OP-AA-108-115 is consistent with the requirements of the NRC Part 9900 requirements. The licensee performed a comparative evaluation and accepted a very low safety factor (1.08) against the anchor ultimate strengths (average breaking strengths from tests). Despite the very low safety margin indicated, the licensee failed to correct the condition even though the plant went through refueling outages (Unit1 in October 2007, Unit 2 during April-May, 2008). The licensee also failed to perform a complete and thorough evaluation that would have identified a number of additional design deficiencies. These deficiencies were later identified as described below, however, the inspectors concluded that the licensee had opportunities to identify and correct them at around the same time when they identified the anchor safety factor problem (July, 2007).

- On June 6, 2008, the licensee had to revise their operability evaluation when the inspectors identified that a dynamic load factor further reducing the safety margin was not considered (IR 783849).
- On June 20, 2008, the licensee identified that the adverse impact of blank off plates installed near some of the MSIV blow out panel areas was not considered in the HELB pressure calculation (IR 789791).
- On June 30, 2008, the licensee discovered an error in the main steam line break energy release calculation resulting in an increase in the pressure (IR 792215).

In July, 2008, after the inspectors raised concerns about the very low safety margins, the licensee implemented compensatory measures through installation of temporary modifications to the hatch covers to increase the safety margins (Licensee Operability Evaluation # 07-007, Revision 4).

On August 14, 2008, the licensee verified past operability of the hatch covers based on calculation performed by a vendor (EC 371692). The licensee accepted a very small safety margin, approximately 10 percent, on anchors when compared to the anchor ultimate strength without adequately accounting for the uncertainties and variances. The evaluation also involved an unverified assumption regarding the number of anchors installed. A later field walk down showed that the unverified assumption was non-conservative (December 3, 2008; IR 851851). The licensee initiated corrective actions to reassess the past operability and reportability.

Based on the above observations, the inspectors concluded that the licensee failed to identify design deficiencies and correct the condition indicating inadequate safety margins for expansion anchors in a timely manner after initial identification in April, 2007. The licensee had opportunities for implementation of design modifications during the refueling outages.

The licensee completed installation of permanent modifications to restore design margins by December 31, 2008.

<u>Analysis</u>: The inspectors determined that failure to promptly identify and correct the design deficiencies associated with the AFW Hatch covers was contrary to the requirements per 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Barrier Integrity cornerstone attribute of SSC and Barrier Performance (Containment Isolation SSC Reliability) and affected the cornerstone objective of maintaining functionality of containment. Specifically, failure of the cover plates in the event of a HELB would subject the normally open AF013 valves to a harsh environment, resulting in lack of assurance that the operators will be able to close these valves to achieve containment isolation.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of findings," Table 4a for the Initiating Events, Mitigating Systems and Barrier Integrity cornerstones, because it only affected the Containment Barriers cornerstone (Tables 2 Barriers Cornerstone column and Table 3b, item 7). The inspectors answered "No," to all the questions in the Containment Barrier column of Table 4a (the finding did not represent an actual open pathway in the physical integrity of reactor containment). Based upon this Phase 1 screening, the inspectors concluded that the issue was of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Problem Identification and Resolution, because the licensee did not thoroughly evaluate the problem immediately upon identification. Specifically, after the initial discovery the licensee failed to perform thorough reviews and field inspections to identify all related design issues and to adequately evaluate them for operability. (P.1(c))

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected.

Contrary to the above, from April 18, 2007, until December 31, 2008, the licensee failed to promptly identify and correct conditions adverse to quality regarding design of AFW tunnel hatch covers. Specifically, after initial discovery of a design deficiency on April 18, 2007, the licensee failed to promptly identify all the related design issues through more detailed reviews and field inspections, and to complete corrective actions to address the design deficiencies and to restore the design margins, until December 31, 2008. Because this violation was of very low safety significance and it was entered into the licensee's CAP as IR 852425, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000456/2008005-03; 05000457/2008005-03).

(2) Inadequate Corrective Actions to Prevent Leak-By of Containment Spray Addition Tank

Introduction: A Green finding and associated NCV of 10 CFR 50, Appendix B, Criterion XVI, was self-revealed for failure to take adequate corrective actions to address degraded operation of the Unit 2 containment spray addition tank grab sample isolation valve, 2CS023. On September 30, 2008, a known leak-by of valve 2CS023 led to a 100 gallon sodium hydroxide (NaOH) spill that leaked into the 2A RH pump room and rendered the 2A RH pump unavailable for approximately 53 hours.

Description: On January 5, 2007, the licensee initiated IR 575726, which documented that Valve 2CS023 was difficult to operate while draining the Unit 2 containment spray addition tank. The corrective action assigned in the condition report was to lubricate the valve stem and stroke the valve several times to ensure proper lubrication of the valve stem. The licensee performed the stem lubrication, removed the in-field deficiency tag, and closed the condition report to the action taken. According to the work order, the valve was not stroked following application of lubrication and proper stem operation was not verified. No work or valve manipulation was performed until the event occurred on September 30, 2008.

On September 30, 2008, equipment operators began a scheduled activity to raise the NaOH concentration in the Unit 2 containment spray addition tank. This activity consisted of removing 350 gallons from the tank, then adding 330 gallons of NaOH to raise the overall NaOH concentration in the tank. The operators used Step F.8 of Procedure BwOP CS-8 for the draining and filling evolution, which required the hookup of a temporary hose and pump to the flowpath through 2CS023. Equipment operators on day shift completed the draining evolution and transferred one of six NaOH barrels into the tank. The operators closed 2CS023 in accordance with Step F.8 and turned over to the evening shift operators. The day shift operators reported 2CS023 was hard to operate and were given permission to operate the valve with a pipe wrench.

The evening shift operators completed the transfer of three additional NaOH barrels into the tank. They had to operate 2CS023 between each barrel transfer and were also given permission to use a pipe wrench after they reported the valve was hard to operate. Following the addition of the three barrels the operators closed 2CS023 and turned over to the night shift operators. The evening shift operators left the hose and pump connected with the other end in one of the empty NaOH barrels. During turnover to night shift the licensee chose to postpone the additional fill evolutions until additional resources were available on day shift.

At 8:45 p.m., the main control room received a report from a rounds operator that fluid was leaking into the 2A RH pump room on the 346' elevation from a plug in the ceiling. The operator identified the fluid coming from a 55 gallon barrel on the 364' elevation near the containment spray addition tank. The operator tightened 2CS023 and the leakage slowed to a drip. The licensee initiated their hazardous materials response procedure and commenced cleanup of the spill. The 2A RH pump was inoperable and unavailable from 12:25 a.m. on October 2 until 5:59 a.m. on October 4 to support cleanup of the spill.

The leak through the floor plug between the 364' and 346' elevations dripped on the 2A RH pump suction piping and the cubicle cooler. When the cubicle cooler ran it sprayed the caustic NaOH solution into the pump motor enclosure. Etching, deposits, and dissolved paint were visible as a result of the spill. The licensee cleaned the pump motor, motor enclosure, cubicle cooler, piping, cabling, and structural supports in the 2A pump room. The licensee performed testing of the pump motor and cubicle cooler prior to returning the pump to service. An analysis performed by the licensee in consultation with the pump vendor determined that no short-term adverse impacts are expected from the spill. However, based on concerns about the long-term integrity of the motor stator winding insulation, the licensee planned to replace to 2A RH pump motor in 2009. In addition, the licensee planned to replace the valve and revise the procedure to ensure that 2CS023 would be closed after maintenance.

Analysis: The inspectors determined that the failure to properly verify the adequacy of lubricating the 2CS023 valve stem for better valve operation as part of the corrective actions for a previously identified problem with the valve, was a performance deficiency. The inspectors reviewed IMC 0612, Appendix B, Issue Screening, and determined the finding was more than minor because it impacted the Mitigating Systems Cornerstone attribute to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings." In accordance with Table 3b, "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstone," the finding affected the Mitigating Systems Cornerstone. The inspectors answered 'no' to all of the Mitigating Systems Cornerstone questions in Table 4a of IMC 0609, Attachment 4, and determined the issue to be of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of human performance because the equipment operators left the system in a configuration that bypassed the tank berm and did not question the closure of Valve 2CS023 even though they needed a pipe wrench to operate the valve. (H.4(a))

<u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion XVI, requires that conditions adverse to quality are promptly identified and corrected. Contrary to this requirement, on January 18, 2007, the licensee failed to take adequate corrective actions to address the condition adverse to quality identified in IR 575726. Because this finding was entered into the licensee's CAP as IR 824756, this violation is being treated as a NCV in accordance with Section VI.A of the NRC Enforcement Policy.
(NCV 05000456/2008005-04; 05000457/2008005-04)

1R18 <u>Plant Modifications</u> (71111.18)

.1 <u>Temporary Plant Modifications</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the following temporary modification(s):

- EC 368874: Install Temporary Instrumentation for 1HD029A Control Loop

The inspectors compared the temporary configuration changes and associated 10 CFR 50.59 screening and evaluation information against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors also compared the licensee's information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee's decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operations, engineering, and training personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The following engineering design package was reviewed and selected aspects were discussed with engineering personnel:

- DG Monitoring Equipment Installation.

This document and related documentation were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. The modification was installed to provide more advanced monitoring of emergency DG startup and operation. The modification provides monitoring of 125 VDC relay actuations, relay contact changes in state, system pressures and temperatures, and electrical output parameters, all with better than 1-second resolution. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 1SI8821B Following Replacement of Breaker 1AP29-F1 per EC 364559;
- 1B Safety Injection Pump Cubicle Cooler Following Breaker Swap;
- 1RH610 Valve Stroke Following Planned Maintenance;
- 2B Charging Water Pump Cubicle Cooler Following Planned Maintenance;
- Unit 0 Component Cooling Water Pump Maintenance; and
- Feedwater Pump Start and Oil System Leak Following Planned Maintenance.

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

This inspection constituted six PMT samples as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- 1A DG Monthly Surveillance (Routine);
- 1B SI Pump Surveillance Test and American Society of Mechanical Engineers (ASME) Run (Routine);
- 1B AFW Pump Monthly and ASME Surveillance (Routine);
- 2B RH System Quarterly Surveillance and ASME Surveillance (IST); and
- Reactor Coolant System (RCS) Leakage Detection Surveillance Test.

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;

- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, ASME code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted three routine surveillance testing samples, one inservice testing sample, and one RCS leak detection inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on October 8, 2008, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the CAP. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This training inspection constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Heat Removal System performance indicators for Units 1 and 2 for the period from the third quarter 2007 through the third quarter 2008. To determine the accuracy of the Performance Indicator (PI) data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, were used. The inspectors reviewed the licensee’s operator narrative logs, IRs, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of October 1, 2007, through October 31, 2008, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee’s IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 MSPI - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Residual Heat Removal System PI for Units 1 and 2 for the period from the third quarter 2007 through the third quarter 2008. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of October 1, 2007, through October 31, 2008, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI residual heat removal system samples as defined in IP 71151-05.

b. <u>Findings</u>

No findings of significance were identified.

.3 <u>MSPI - Cooling Water Systems</u>

a. <u>Inspection Scope</u>

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems performance indicators for Units 1 and 2 for the period from the third quarter 2007 through the third quarter 2008. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of October 1, 2007, through October 31, 2008, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151-05.

b. <u>Findings</u>

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of items Entered Into the CAP

a. Scope

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

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

b. Findings

No findings of significance were identified.

.2 Daily CAP Reviews

a. Scope

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

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

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6 month period of July 1, 2008, through December 31, 2008, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings of significance were identified.

.4 Annual Sample: Review of Operator Workarounds (OWAs)

a. Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWAs on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one operator workaround annual inspection sample as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

.5 Selected Issue Follow-Up Inspection: Circuit Card Failures and Operators Use of TSs

a. Scope

During a review of items entered in the licensee's CAP, the inspectors recognized corrective action items documenting

- Operator Use of TS 3.6.3; and
- 2PI-515A Circuit Card Failure.

The inspectors reviewed the events surrounding recent circuit board failures. Specifically, on September 17, 2008, the 2A steam generator pressure channel, 2PI-515A, failed and resulted in a feedwater transient on Unit 2. This channel was previously entered into the CAP on June 1, 2008, and June 14, 2008, due to channel spiking. The inspectors reviewed the licensee's corrective action documents associated with the previous spiking issues and determined the response at the time was appropriate.

The licensee identified a repeatable failure mechanism on the 7300 circuit board for the 2A steam generator pressure channel. The circuit board vendor performed an independent investigation and verified the failure mechanism identified by the licensee. The failed 7300 circuit board is model NLP G05. The licensee and the vendor performed extent of condition inspections on all other model NLP G05 7300 circuit boards in stock and did not find the failure mechanism present on any other circuit boards. The licensee also added additional receipt inspections for NLP G05 circuit boards.

The inspectors reviewed the events surrounding two recent missed TS entries. On September 9, 2008, the licensee was performing Unit 2 Solid State Protection System testing, which failed. The licensee entered numerous TS action statements including TS 3.6.3 Condition A, which requires a containment penetration flowpath be isolated within 4 hours. The licensee isolated the required flowpath by closing the required valves, however they later discovered that the valves had not been deenergized and TS 3.6.3 Condition A had not been met. At this time the licensee was 1 hour and 43 minutes into Condition B, which requires a shutdown to mode 3 within 6 hours. Upon discovery, the licensee pulled the required fuses and exited the TS Action Statement.

On December 17, 2008, Valve 1PS228B failed a local leak rate test and the licensee entered TS 3.6.3 Condition A, which requires the containment penetration flowpath be isolated within 4 hours. If the flowpath is not isolated within 4 hours the licensee must shut down within 6 hours, in accordance with Condition B. The licensee determined that

Valve 1PS229B would be used to isolate the flowpath and pulled fuses to deenergize the valve. Subsequent review of the local leak rate test data determined that Valve 1PS228B was, in fact, not inoperable and the penetration could be unisolated. When the licensee reinstalled the fuses for Valve 1PS229B they identified that the valve had been deenergized open rather than deenergized closed. This meant the containment penetration flowpath was not isolated for approximately 43 hours.

The inspectors reviewed the licensee's investigation and corrective actions regarding the two missed TS entries. The licensee implemented control room oversight by senior Operations management and implemented additional peer and management checks of TS entries.

This review constituted two in-depth problem identification and resolution samples as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

.6 Selected Issue Follow-Up Inspection: Boron Recycle System Holdup Tanks (HUT)

a. Inspection Scope

On June 20, 2007, and October 4, 2007, the NRC identified a number of concerns associated with the design and operation of the Braidwood Station HUTs. From December 15, 2008, through December 16, 2008, the inspectors performed a walkdown of portions of the boron recycle system and reviewed the following IRs associated with the RH system and HUT.

- IR 649581, Potential Vulnerability with RH Suction Relief Discharge to HUT;
- IR 833241, Byron HUT PI&R Inspection Lessons Learned;
- IR 677075, Recycle Holdup Tank Level Administrative Controls; and
- IR 831252, Byron HUT NRC Inspection Issues.

The inspectors reviewed the licensee's corrective actions for the issues identified above, to verify whether: (1) the problems were accurately identified; (2) the causes were adequately ascertained; (3) extent of condition and generic implications were appropriately addressed; (4) previous occurrences were considered; and (5) corrective actions proposed/implemented were appropriately focused to address the problems and were commensurate with the safety significance of the issues.

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

b. Findings

(1) Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT Quench Volume

Introduction: The inspectors identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance (Green), associated with the licensee's failure to analyze and establish an adequate quench volume within the HUT, and failure to analyze the water hammer loads on HUT inlet piping induced by relief valve discharges. Insufficient HUT quench volume could result in an overpressure failure of the HUT, and the water hammer induced piping loads could damage the HUT inlet piping system.

Description: On June 20, 2007, the NRC identified a concern for available quench volume in the HUT, and lack of an analysis for water hammer loads on HUT inlet piping to accommodate discharges from the RH suction relief valves. The licensee's past practice of maintaining the HUT water level below the inlet piping entrance when the RH, SI, or chemical and volume control system relief valves were lined up to discharge to the HUT, provided no quench volume for the steam and hot water discharges from these relief valves to avoid pressure buildup within the HUT.

The RH suction and discharge relief valves were originally planned to discharge to the pressurizer relief tank (PRT) through a sparger pipe below the normal tank water level to ensure adequate quenching of steam for pressure suppression. This design configuration ensured that the PRT did not operate above the tank design pressure of 100 psig. Further, the PRT had a cooling system to reduce PRT water temperatures after a discharge to ensure the design temperature of 200 degrees Fahrenheit (°F) was not exceeded. During plant construction, the piping was rerouted so that the RH system’s suction relief valves discharged to the HUT instead of the PRT. In contrast with the PRT design, the HUT design and operating parameters did not ensure that an RH relief valve discharge (up to 360 psig and 350 °F) would not exceed the design pressure and temperature of the HUT (15 psig and 200 °F). Specifically, the relief valve discharge piping entered the HUT with no sparger at about 35 percent tank level; and the minimum tank level allowed by procedures was 5 percent. Further, there was not a means to cool the HUTs after a relief discharge. With this configuration, the inspectors were concerned that the licensee had not established an adequate cold water volume for quenching hot relief valve discharges into the HUT, to ensure that the tank design pressure and temperature was not exceeded.

To address this concern, the licensee established a 40 percent level in the HUT for a quench volume, and incorporated this requirement in Procedure BwOP RH-6, “Placing the RH system in Shutdown Cooling” and BwOP-AB-12, “Recycle Holdup Tank Operation.” The RH suction relief valves provided the highest capacity/volume of hot water discharge to the HUTs and therefore, the licensee believed these valves were the limiting component for evaluation of this concern. To assess the HUT response (with and without a quench volume), the licensee’s vendor completed Calculation, CN-CRA-07-50, "Byron/Braidwood RHUT [Recycle System Holdup Tank] Response to Opening of the RH Relief Valve." In the first case, with an initial tank level of five feet below the inlet nozzle, the calculation results demonstrated that the HUT would have been over-pressurized and potentially failed after 50 seconds of steam discharge. The HUT failure would release the contents of the HUT to the HUT room in the AB.

In the second case, with an initial HUT level five feet over the inlet nozzle, the water volume was sufficient to ensure that the HUT air space pressure would not exceed the HUT design pressure even if the RH suction relief valve was open for 30 minutes. The inspectors noted that this calculation did not attempt to determine the minimum acceptable tank level to ensure adequate pressure suppression occurred (e.g., quench volume).

On February 14, 2008, a licensee's contracted vendor completed Calculation, CN-CRA-08-9 "Byron/Braidwood RHUT Response to Opening of the RH Relief Valve," to provide a quantitative analysis for the licensee's previous engineering judgment that a 40 percent tank level provided sufficient quenching of hot discharges to prevent exceeding HUT design pressure. In this calculation, the vendor concluded that a 40 percent tank level would be sufficient to quench an RH relief valve discharge such that the tank design pressure would not be exceeded. The licensee completed an owner's acceptance review of this vendor calculation on September 25, 2008. The licensee entered the concerns for inadequate quench volume into the CAP (IR 649581 and IR 677075) and initiated additional actions to complete a more detailed design basis calculation for the minimum HUT quench volume.

The inspectors performed a walkdown of the Unit 1 HUT inlet pipe on December 16, 2008, and confirmed that the licensee had installed equipment status tags on inlet pipe isolation valves, 0AB8557A(B). These tags identified the need to maintain at least one HUT aligned for receiving discharges from relief valves to maintain an overpressure protection path and that a 40 percent or greater level was required for the inservice HUT. The inspectors noted that the discharge pipe routing from the RH suction side relief valves to the HUTs contained a number of loop seals created as the elevation of the piping changed. These loop seals would allow for fluid to collect in the low points. If a relief valve lifted, dynamic loads would be created as the non-condensable gases in the high points compress and the fluid columns accelerated. Although, non-condensable gases would help cushion the fluid impact on downstream fluid columns, the discharge piping was not analyzed for these transient dynamic "water hammer" loads. Therefore, the effect of these transient loads was not known.

The licensee believed that an RH relief valve discharge would likely not create a violent transient (e.g., steam bubble collapse) in the discharge piping, and if any transient "water hammer" loads did occur, the effect would be minimal. The licensee identified that the existing piping stress analysis from the RH suction relief valves to the HUT considered the reaction loads associated with actuation of the relief valves. In addition, the licensee stated that the potential for condensation-induced water hammer was low due to: (1) the approximate 30-feet elevation change in the piping between the tank and the RH relief valves, which would limit the driving pressure available to move a slug backwards in the line; and (2) an extended blow down into the tank would heat the water in the vicinity of the nozzle, thus reducing the condensation rate and limiting the reduction in void pressure, thereby, limiting the available driving pressure. Furthermore, the licensee stated that Braidwood Unit 1 had experienced a lift of the RH suction relief valve and had not experienced damage to pipe and pipe supports. Based on this operating experience, the licensee postulated that resulting transient loads would result in minimal if any damage to piping and pipe supports. Additionally, the licensee identified a vendor screening criteria which indicated that a hydraulic transient analysis was not required for this piping based on vendor test data. However, the licensee had not confirmed that this screening criterion was applicable to Braidwood Station and had not performed an owners' acceptance review of the supporting vendor analysis.

Because the HUT inlet piping contained multiple low points (loop seals) that can collect water, these loop seals create a configuration susceptible to "water hammer" induced by relief valve actuation. The licensee reported that the HUT inlet pipe supports were analyzed to include seismic loads which provided margin to accommodate dynamic "water hammer" loads in the direction of the support restraint. However, the postulated dynamic “water hammer” loads could create piping forces in directions that were not restrained by the existing pipe supports. The licensee entered the concern for relief valve induced “water hammer” loads on the HUT inlet pipe into the CAP (IR 67705). The licensee initiated an action to perform an analysis to investigate the magnitude of the potential “water hammer” loads on the inlet piping. During the walkdown of the Unit 1 HUT inlet pipe from the HUT to the RH suction relief valves, the inspectors did not identify evidence of damaged piping or movement at the piping supports.

Analysis: The inspectors determined that the failure to evaluate and establish an adequate HUT quench volume and analyze the magnitude of water hammer loads on HUT inlet piping to accommodate discharges from the RH suction relief was a performance deficiency warranting a significance evaluation. The inspectors determined the finding was more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” because the finding affected the Barrier Integrity Cornerstone objective for maintaining the Radiological Barrier Function of the Containment. The finding was associated with the design control and procedure quality attributes of the Barrier Integrity Cornerstone. Specifically, the licensee's past practice of maintaining the HUT water level below the inlet piping entrance when the RH relief valves were lined up to discharge to the HUT provided no quench volume for the steam and hot water discharges from these relief valves to avoid pressure buildup within the HUT.

The inspectors evaluated the finding using IMC 0609, Attachment 0609.04, “Phase 1 ─ Initial Screening and Characterizations of Findings.” The inspectors determined in Tables 2 and 4a of the Attachment that the failure to establish a minimum level for adequate quenching in the HUTs degraded the Radiological Barrier Function of the Containment but did not represent an actual open pathway from containment; therefore, the finding screened as having very low safety significance (Green). Because the performance errors, which led to this finding, occurred prior to the approval of the plant operating license and the licensee recognized the error when it was brought to their attention, this issue did not reflect current plant performance and therefore, no cross-cutting aspect was identified.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that design control measures shall provide for verifying the adequacy of design and that the design basis is correctly translated into procedures and instructions.

Contrary to the above, from plant construction to September 28, 2008, the licensee failed to verify the adequacy of the HUT design. Specifically, the licensee: (1) failed to evaluate and maintain the required water volume necessary to quench the RH system relief valve discharges into the HUT and incorporate appropriate minimum HUT level requirements into the HUT level control procedures; and (2) failed to evaluate the effect of dynamic "water hammer" loads on inlet from relief valve discharges to the HUT. However, because this issue was of very low safety significance, and was entered into the licensee’s CAP (IR 649581 and IR 677075), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000456/2008005-05, NCV 05000457/2008005-05).

(2) <u>Radiological Release Analysis Did Not Include Normal HUT Configurations</u>

On June 20, 2007, the NRC identified a concern that the UFSAR analysis for rupture of a HUT failed to recognize that the gas spaces of the HUTs are normally cross-connected and that a gas decay tank normally had open communication with at least one HUT.

Section 15.7.2 of the UFSAR included the results of an analysis for the worst case radioactive atmospheric release from the HUT and assumed that the postulated event was initiated by cracks in the HUT and operator error. The analysis assumed that only one HUT would fail, and a failure of both HUTs was beyond what was analyzed. The inspectors noted that the existing UFSAR analysis for the rupture of a recycle holdup tank failed to recognize that the gas spaces of the HUTs were normally cross-connected and that a gas decay tank normally had open communication with at least one HUT. The licensee stated that based on conservative assumptions in the analysis, the actual plant configuration (the gas decay tank providing cover gas to two HUTs) was bounded. Specifically, the calculated dose for a postulated recycle HUT failure was based on the following:

- The assumed inventory of noble gases in the HUT was based on transferring the total inventory of primary coolant from one unit at maximum purification letdown flow;
- No removal of noble gas was assumed in the purification letdown flow; and
- When the tank failure occurred, a portion of the iodine in the water and all of the noble gas activity was assumed to become airborne and released to the environment.

The inspectors reviewed Calculation CN-CRA-00-47, "Braidwood/Byron Doses from Recycle Holdup Tanks and Spent Resin Tank Failures," and noted that Calculation CN-CRA-00-47 assumed the HUT was initially filled to 80 percent capacity, the water contents of the tank would be released in 5-minutes, and the HUT was isolated from the other HUT and Gas Decay tank. These assumptions were consistent with those in UFSAR Section 15.7.2, which stated that the postulated events that could cause the worst case radionuclide inventory were cracks in the HUT and operator error. The inspectors identified that the calculation of record, CN-CRA-00-47, did not account for the actual plant conditions or the failure mechanism described in Section 4OA2.5.b.2 of this report. Specifically, the initial level of 80 percent was not consistent with current operation because HUT level could be as high as 95 percent or as low as 5 percent. A crack in the HUT and subsequent 5-minute release of water content was not consistent with the expected rupture of the HUT with water level below the relief valve discharge line.

Although the calculation contained conservative assumptions with respect to gaseous releases, it did not specifically address how these assumptions bound the actual plant configuration and/or operation of the waste gas systems. The inspectors reviewed the calculation and determined these discrepancies (i.e., quicker release rate, lower initial volume, and cross-connected gas systems) would have an impact on the calculated release rates; however, the margin for radiological release contained in the calculation was sufficient that the limit was not exceeded.

The inspectors concluded that the failure to account for actual plant configurations in an accident analysis was a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design

Control." The inspectors assessed this violation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," and determined that the finding was minor because the available margin and other conservative assumptions were sufficient to compensate for identified discrepancies. The licensee entered this issue into the CAP (IR 833241 and IR 67705). The licensee planned to revise the HUT rupture analysis to correct inputs and assumptions and update the UFSAR to reflect the revised analysis. Therefore, in accordance with IMC 0612, this violation of minor significance was not subject to enforcement action.

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

.1 Unit 2 Manual Reactor Trip Due to Electrical Fault on 2C Heater Drain Pump: Event Follow-up

a. Inspection Scope

On the afternoon of December 27, 2008, the Unit 2 reactor automatically tripped due to a main turbine trip while above 30 percent power. At the same time as the turbine and reactor trips, the 2C heater drain pump tripped on overcurrent and the UAT 241-1 sudden pressure relays actuated. No fire or smoke was observed at the 2C heater drain pump or UAT 241-1 but physical damage was identified on the 2C heater drain pump motor terminal box. One NRC inspector responded to the plant a short time after the reactor trip. The inspector verified that the expected automatic actions had taken place and that operators performed the actions required by their procedures.

The electrical fault on the 2C heater drain pump was determined to be a phase A to phase C fault, which caused the UAT sudden pressure relays to actuate. These relays are timed to respond quicker than the 2C heater drain pump breaker or overcurrent relays. Actuation of the UAT 241-1 sudden pressure relays resulted in a trip of the main generator, which resulted in a trip of the main turbine and reactor. The main generator, main turbine, and reactor trips occurred as expected upon actuation of the UAT 241-1 sudden pressure relays.

There were no significant complications associated with the automatic reactor trip. The 2A and 2B AFW pumps automatically started as expected. In accordance with 10 CFR 50.72, the licensee reported the automatic reactor protection system actuation and the automatic actuation of the AFW system (Event Notification 44743). Documents reviewed in this inspection are listed in the Attachment.

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

b. Findings

No findings of significance were identified.

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 and included:

- multiple tours of operations within the central and secondary security alarm stations;
- owner controlled area and protected area access control posts;
- other security officer posts including the ready room and compensatory posts; and
- security equipment log review.

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 surveys were conducted in a manner that encouraged candid and honest feedback. The results were reviewed to determine whether adequate number of staff responded to the survey. The inspectors also reviewed Exelon's self-assessment of the survey results and verified that any issues or areas for improvement were entered into the CAP for resolution.

These 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.

.2 Implementation of Temporary Instruction (TI) 2515/176, "Emergency Diesel Generator Technical Specification Surveillance Requirements Regarding Endurance and Margin Testing"

a. The objective of TI 2515/176 was to gather information to assess the adequacy of nuclear power plant emergency diesel generator endurance and margin testing as prescribed in plant-specific TS. The inspectors reviewed the licensee's TS, procedures, and calculations and interviewed licensee personnel to complete the TI. The information gathered for this TI was forwarded to the Office of Nuclear Reactor Regulation for further review and evaluation on December 17, 2008. This TI is complete at Braidwood Station; however, this TI 2515/176 will not expire until August 31, 2009. Additional information may be required after review by the Office of Nuclear Reactor Regulation.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 8, 2009, the inspectors presented the inspection results to Mr. L. Coyle and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Licensed Operator Requalification (71111.11B), with Mr. D. Burton, Licensed Operator Requalification Training Group Lead, on October 29, 2008, via telephone;
- "Emergency Diesel generator Technical Specification Surveillance Requirements Regarding Endurance and Margin testing" (TI 2515/176): A telephone exit was conducted with George Golwitzer, Acting Regulatory Assurance manager, and other licensee staff on November 25, 2008
- Identification and Resolution of Problems (71152): HUT inspection results with Mr. L. Coyle and others of the licensee's staff on December 16, 2008.
- Heat Sink Performance (71111.7T): Triennial heat sink inspection with Mr. L. Coyle, Plant Manager, and other members of the licensee's staff on December 19, 2008.

The inspectors confirmed that potential report input discussed was either not considered proprietary, or, if there was proprietary input, licensee personnel identified any documents, materials, or information provided during the inspection that were considered proprietary. Proprietary materials reviewed during the inspection were returned to the licensee.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program. Contrary to this, on December 4, 1987, the licensee failed to ensure design measures were in place for verifying or checking the adequacy of AFW hatch cover plate design. Specifically, in Calculation 5.6.3.9, the licensee failed to insure that a safety factor in accordance with the station design criteria was applied in the design of expansion anchors. This finding was of very low safety significance because it did not represent an actual open pathway in the physical integrity of reactor containment. The issue was identified in the licensee's CAP as IR 654270.

- Title 10 CFR 50.71(e) requires, in part, that licensees periodically update the UFSAR originally submitted as part of the application for the operating license to assure that the information included in the UFSAR contains the latest information developed. Contrary to this requirement, from the original plant operating license through December 16, 2008, the licensee failed to update the UFSAR: (1) description of the boron recycle system (UFSAR Section 9.3.4) to identify that it was designed or capable of handling discharges from the safety injection and RH system relief valves, which are directed into this system; and (2) description of the RH system (UFSAR Section 5.4.7.2.7) to identify deviations from the RH system design standard with respect to the suction pipe relief valve single failure analysis and collection of relief valve discharges outside containment. The finding was determined to be of very low safety significance because the design deviations associated with the RH system and boron recycle system did not impact system operability. This issue was identified in the licensee's CAP in response to a prior NRC inspection at the Byron Station, as IR 833241.

- On December 27, 2008, the licensee was performing a local leak rate test (LLRT) using Containment Isolation Valve 1PS228B as a boundary. During the test, excessive leakage past Valve 1PS228B going into containment was identified, and the licensee entered LCO 3.6.3.A, which required the flow path to be isolated within 4 hours. The licensee pulled fuses to de-energize the associated Containment Isolation Valve 1PS229B in the closed position, with the intent to isolate the flow path to meet the LCO. Subsequently, the licensee re-performed the LLRT using the appropriate test method for Valve 1PS228B and determined that the leakage did not exceed the acceptance criteria. However, when the fuses for Valve 1PS229B were reinstalled on December 29, 2008, the licensee identified that the valve was opened rather than fail-closed. Therefore, while the fuses were removed, Valve 1PS229B was inoperable and the valve was opened for approximately 43 hours. As a result, the licensee did not meet LCO 3.6.3.A and did not meet the subsequent required action to be in Mode 3 within 6 hours for inoperable Valve 1PS229B. The finding was of very low safety significance because there was no actual open pathway in the physical integrity of the reactor containment; it did not represent a degradation of the barrier function of the control room, auxiliary building, spent fuel pool; and id did not involve an actual reduction in function of the hydrogen igniters as Valve 1PS228B was closed during that period. The licensee has entered this issue into their CAP as IR 858652 and is performing a Root Cause Evaluation.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

B. Hanson, Site Vice President
L. Coyle, Plant Manager
K. Aleshire, Emergency Preparedness Manager
G. Dudek, Site Training Director
R. Gadbois, Maintenance Director
D. Gullott, Regulatory Assurance Manager
J. Knight, Nuclear Oversight Manager
T. McCool, Operations Director
J. Moser, Radiation Protection Manager
T. Schuster, Chemistry Manager
M. Smith, Engineering Director

Nuclear Regulatory Commission

R. Skokowski, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2008005-01; 05000457/2008005-01	NCV	Inadequate Control of High Pressure Gas Cylinders.
05000456/2008005-02; 05000457/2008005-02	URI	Evaluation of the licensee processes and controls regarding the management of on-line risk.
05000456/2008005-03; 05000457/2008005-03	NCV	Inadequate Corrective Action for Failure to Promptly Correct Auxiliary Tunnel Feedwater Tunnel Hatch Cover Design Deficiencies.
05000456/2008005-04; 05000457/2008005-04	NCV	Inadequate Corrective Action for Containment Spray Add Tank Drain Valve.
05000456/2008005-05; 05000457/2008005-05	NCV	Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT Quench Volume.

Closed

05000456/2008005-01; 05000457/2008005-01	NCV	Inadequate Control of High Pressure Gas Cylinders.
05000456/2008005-03; 05000457/2008005-03	NCV	Inadequate Corrective Action for Failure to Promptly Correct Auxiliary Tunnel Feedwater Tunnel Hatch Cover Design Deficiencies.
05000456/2008005-04; 05000457/2008005-04	NCV	Inadequate Correction was Containment Spray Add Tank Drain Valve.
05000456/2008005-05; 05000457/2008005-05	NCV	Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT Quench Volume.

Discussed

None.

LIST OF DOCUMENTS REVIEWED

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

1R04 Equipment Alignment

PROCEDURES

Number	Description or Title	Date or Revision
BwOP CS-E1	Electrical Lineup Unit 1	Revision 2
BwOP CS-M1	Operating Mechanical Lineup Unit 1	Revision 8
BwOP DG-E1	Electrical Lineup Unit 1 1A DG	Revision 6
BwOP DG-M1	Operating Mechanical Lineup Unit 1 1A DG	Revision 14

CAP DOCUMENTS

Number	Description or Title	Date or Revision
IR 843145	NRC Identified Two Potential Concerns	November 10, 2008

1R05 Fire Protection

PROCEDURES

Number	Description or Title	Date or Revision
BwAP 1100-5	Fire Department Response, Notification, and Mutual Aid Agreement and Expected Chain of Events During a Fire	Revision 10
OP-AA-201-003	Fire Drill Scenario for November 17, 2008	Revision 9
OP-AA-201-003	Fire Drill Record for November 17, 2008	Revision 10

1R07 Heat Sink Performance

PROCEDURES

Number	Description or Title	Date or Revision
BWAR 2–2-C5	“CC Hx Outlet Temperature High“ Annunciator Response	Revision 9
BwMP 3300–091	Lake Screen House Diver Related Inspections	Revision 14
BwOP CF-36	Operation of the Essential Service Water Chemical Injection System	Revision 11b
BWOSR 0.1–1, 2, 3	"Unit One Modes 1, 2, 3 Shiftly Rounds"	Revision 51
BwVP 850–15	Essential Service Water System Performance Monitoring Program	Revision 6
BwVSR 3.7.9.3	Braidwood Cooling Lake Hydrographic	Revision 2

PROCEDURES

Number	Description or Title	Date or Revision
CY-AA-120–400	Closed Cooling Water Chemistry	Revision 10
CY-AA-120–410	Circulating/Service Water Chemistry	Revision 1
CY-BR-120–4120	Braidwood Station Lake Chemistry Strategic Plan	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
ER-AA-340–1003	GL 89–13 Program Performance Indicators	Revision 2
MAD 83–239	Ultimate Heat Sink Update	Revision 1

CAP DOCUMENTS

Number	Description or Title	Date or Revision
IR 368450	Need WR to replace 1SX01AA Oil Cooler at next PM Work	August 30, 2005
IR 493440	2SX01AA: 2A SX PP Lube Oil Cooler Piping Leak	May 17, 2006
AR 00754916	Considerable Silting Identified on 2B Essential Service Water Pump Lube Oil Cooler	March 26, 2008

WORK ORDERS

Number	Description or Title	Date or Revision
WO 1112480–01	ASME Surveillance Requirements for 1B Essential Service Water Pump	May 27, 2008
WO 1113992-01	IST-- For 2SX002B -- ASME Surveillance Requirements for 2B Essential Service Water Pump	June 2, 2008
WO 1141838–01	IST-- For 1SX002B -- ASME Surveillance Requirements for Essential Service Water Pump	August 25, 2008
WO 1145101–01	IST-- For 1SX002A -- ASME Surveillance Requirements for 1A Essential Service Water Pump	September 2, 2008
WO 1A-1014959–01	Lake Screen House Forebay Inspection Report	September 11, 2007
WO 1B-1009126–01	Lake Screen House Forebay Inspection Report	September 11, 2007
WO 1C-881692–01	Lake Screen House Forebay Inspection Report	September 11, 2007
WO 2A-883681–01	Lake Screen House Forebay Inspection Report	September 11, 2007

WORK ORDERS

Number	Description or Title	Date or Revision
WO 2B-1005761–01	Lake Screen House Forebay Inspection Report	September 11, 2007
WO 2C-883707–01	Lake Screen House Forebay Inspection Report	September 11, 2007
WO 539131	Heat Exchanger As-Found Inspection and Work Report	August 30, 2005
WO 590895–01	Circulating Water Intake Bay Level Control Loop	October 8, 2004
WR 98082726	Heat Exchanger As-Found Inspection and Work Report	July 24, 2004

AUDITS, ACCESSMENTS AND SELF-ASSESSMENTS

Number	Description or Title	Date or Revision
194739–05	Self Assessment Check-In Report for the GL 89–13 Essential Service Water System Performance Monitoring Program	August 2004
441886-02	Self-Assessment Check-In report for the Generic Letter 89–13 Program: NRC Heat Sink Inspection	September 2006

DRAWINGS

Number	Description or Title
M-42	Diagram of Essential Service Water Unit 1 and 2
M-137	Diagram of Residual Heat Removal Unit 2

CALCULATIONS

Number	Description or Title	Date or Revision
200042(CQD)	Essential Service Water Pump Oil Coolers for Pumps 1/2SX01PA/PB, Specification F/L-2758A	
ATD-0054	Performance Analysis for Essential Service Water Cooled Lubricating Oil Heat Exchangers for the CV, SX, SI, and AF Lube Oil Heat Exchangers and CV and AF DD Gear Heat Exchangers	Revision 3
ATD-0063	Heat Load to the Ultimate Heat Sink During a Loss of Coolant Accident	
ATD-0109	Thermal Performance of Ultimate Heat Sink During Postulated Loss of Coolant Accident	
BRW-00-0017-M	Byron/Braidwood Uprate Project Post LOCA	Revision 1

CALCULATIONS

Number	Description or Title	Date or Revision
	Component Cooling Water System Temperature Analysis	
BRW-00–0018-M	Ultimate Heat Sink Evaluation for Power Uprate Heat Load Conditions Revision 0A	
BRW-95-218	Evaluation of Essential Service Water Pump Operation with Degraded Lube Oil Coolers	
EC 357161	ATI 349059-2 Acceptance Criteria for As Found Heat Exchanger Tube Blockage of the Clean-Only GL 89–13 Coolers at Braidwood	July 10, 2006

1R11 Licensed Operator Requalification Program

PROCEDURES

Number	Description or Title	Date or Revision
OP-AA-1	Conduct of Operations (No site Approval)	Revision 0
OP-AA-100	Description of the Exelon Nuclear Conduct of Operations Manual	Revision 0
OP-AA-101-111-1001	Operations Philosophy Handbook	Revision 5
OP-AA-101-112	Roles and Responsibilities of Off-shift Personnel	Revision 5
OP-AA-101-113-1006	4.0 Crew Critique Guidelines	Revision 0

1R13 Maintenance Risk and Emergent Work

CAP DOCUMENTS

Number	Description or Title	Date or Revision
842881	Return to Service of 1A CS Pump has Potential to Result in All ECCS Inoperable	November 10, 2008
843097	Protected Equipment not Identified on Risk Assessment	November 10, 2008
861686	Potential Inadequate Risk Review Per 10CFR50.65(A)(4)	December 31, 2008

1R15 Operability Evaluations

PROCEDURES

Number	Description or Title	Date or Revision
BwOP CS-8	Filling the Containment Spray Additive Tank	Revision 9
OP-AA-108-115	Operability Determinations (CM-1)	Revision 6
OP-AA-108-115-1002	Supplemental Consideration for On-Shift Immediate Operability Determinations	

OPERABILITY EVALUATIONS

Number	Description or Title	Date or Revision
EC 371281	Evaluation – Temporary Modification to Install AFW Tunnel Seal Cover Plate Structural Support / Bracing	Revision 2
EC 371283	Evaluation – Temporary Modification to Install AFW Tunnel Seal Cover Plate Structural Support / Bracing	Revision 2
EC 371692	Review of Auxiliary Feedwater Tunnel Access Covers for Past Operability Associated with a Postulated MSLB	August 14, 2008
OpEval 07-007	AFW Tunnel Cover Bolt Evaluation Uses Non-standard Safety Factor	Revisions 0 through 4

CAP DOCUMENTS

Number	Description or Title	Date or Revision
Byron IR 620080	AFW Tunnel FSO Structural Cal Error	April 21, 2007
Byron IR 653093	The AFW tunnel Covers do not meet expected safety factors	July 24, 2007
Byron IR 851828	Unverified Assumption Used in Technical Evaluation Not Met	December 3, 2008
Byron IR 857487	Resolution of NRC URI Concerning AFW Tunnel Hatch Covers	December 17, 2008
575726	2CS023 Valve Hard to Operate	January 5, 20007
654270	The AFW Tunnel Cover Bolt Eval. Uses Non-Standard Safety Factor	July 26, 2007
783849	Load Factor Not Used For Evaluation of AFW Tunnel Cover	June 6, 2008
789791	Potential Loss of Margin in MS Pressurization Calc	June 24, 2008
790428	Creeping Margin Reduction in AF013 Operability	June 26, 2008
792215	MSLB Calc Energy Release Error	June 30, 2008
824756	Sodium Hydroxide Spill in Unit 2 CWA and 2A RH Pump Room	September 30, 2008
826323	Potential Chemical Intrusion to 2A RH Motor Windings	October 3, 2008
826559	2A RH Pump Cleaning Activities	October 4, 2008
826783	Elevated U-1 SI PP Discharge Header Pressure	October 5, 2008
829488	Replace 2A RH Pump Motor	October 10, 2008
832975	Rising 1A SI Accumulator Level – 1SI04TA	October 19, 2008
833003	2CS023 Difficult to Operate	October 19, 2008
840380	NRC Raised Concern that the Rising RH Pressure could be CC	November 4, 2008
843113	NOS Identified No Piping Evaluation to	November 10, 2008

CAP DOCUMENTS

Number	Description or Title	Date or Revision
	Support Removal of Cs Check Valve	
843145	NRC Identified Two Potential Concerns	November 10, 2008
844176	Future On-Line Work Windows For 1B, 2A, and 2B CS In Question	November 12, 2008
844415	Possible Missed Technical Specification LCO Entry	November 12, 2008
849208	Operability Evaluation Needed for SX Strainer Questions	November 24, 2008
851851	Unverified Assumption Used in Technical Evaluation Not Met	December 3, 2008
852425	NRC-Potential Inadequate OP EVAL for AFW Tunnel Hatches	December 4, 2008

CALCULATIONS

Number	Description or Title	Date or Revision
Calc 3101-0025-01	Structural Analysis of Auxiliary Feedwater Flood Plates, Supporting Channels, and Expansion Anchors (by MPR Associates Inc.)	Revision 1
Calc 5.6.3.9	Investigation of Det – 156, 157	Revision 4

DRAWINGS

Number	Description or Title	Date or Revision
Drawing M-46	Diagram of Containment Spray	Revision AZ
Drawing M-61	Diagram of Safety Injection Unit 1	Revision BC

1R18 Plant Modifications

PROCEDURES

Number	Description or Title	Date or Revision
LS-AA-104-1003	10 CFR 50.59 Screening Form for EC 370519	Revision 1
LS-AA-128	Fire Protection Change Regulatory Review for EC 370519	Revision 0

MODIFICATION PACKAGES

Number	Description or Title	Date or Revision
EC 370519	Install a Performance Monitoring System for the 1A EDG	Revision 0

1R19 Post Maintenance Testing

PROCEDURES

Number	Description or Title	Date or Revision
1BwOSR 5.5.8.SI-10B	Group A IST Requirements for 1B Safety Injection Pump (1SI01PB)	Revision 0

1R22 Surveillance Testing

PROCEDURES

Number	Description or Title	Date or Revision
1BwOSR 5.5.8.SI-10B	Group A IST Requirements for 1B Safety Injection Pump (1SI01PB)	Revision 0
BwIP 2000-T24	Calibration Test Report Form for Calibration of 2FI-SX130 – 2B Auxiliary Feedwater Pump Cubicle Cooler Flow Instrument	Revision 0
2BwOSR 3.7.5.4-2	Unit Two Diesel Driven Auxiliary Feedwater Pump Surveillance	Revision 18
2BwOSR 3.7.5.AFW-3B	Group A IST Requirements For Unit Two Diesel Driven Auxiliary Feedwater Pump	Revision 0
BwOP AFW-7	Auxiliary Feedwater Pump B Startup on Recirc	Revision 30

1EP6 Drill Evaluation

DOCUMENTS

Number	Description or Title	Date or Revision
	Scenario Plan: OBE Earthquake Following by Faulted and Ruptured Steam Generator	October 8, 2008

4OA1 Performance Indicator Verification

PROCEDURES

Number	Description or Title	Date or Revision
LS-AA-2001	Collection Report of NRC Performance Indicator Data	
LS-AA-2002	Significance Determination Process Evaluation	Revision 6
LS-AA-2003	Use of the INPO Consolidated Data Entry Database for NRC and WANA Entry	
LS-AA-2200	Completed LS-AA-2200 Procedures for Heat Removal System	Revision 1

PROCEDURES

Number	Description or Title	Date or Revision
LS-AA-2200	Completed LS-AA-2200 Procedures for Residual Heat Removal System	Revision 1
LS-AA-2200	Completed LS-AA-2200 Procedures for Cooling Water System	Revision 1

MISCELLANEOUS

Number	Description or Title	Date or Revision
NEI 99-02	Regulatory Assessment Performance Indicator Guideline	

4OA2 Identification and Resolution of Problems

PROCEDURES

Number	Description or Title	Date or Revision
Braidwood Procedure 1BwGP 100-5	Plant Shutdown and Cooldown	Revision 34
BOP RH-6	Placing the RH system in Shutdown Cooling	Revision 36
BWOP-AB-12	Recycle Holdup Tank Operation	Revision 11

CAP DOCUMENTS REVIEWED

Number	Description or Title	Date or Revision
649581	Potential Vulnerability with RH Suction Relief Discharge to HUT	July 12, 2007
649581	Potential Vulnerability with RH Suction Relief Discharge to HUT	July 12,2007
677075	Recycle Holdup Tank Level Administrative Controls	September 28, 2007
677075	Recycle Hold Up Tank Level Administrative Controls	September 28, 2007
694300	Inconsistent Use of Min Level for Relief Work	November 4, 2007
781601	2A SG Pressure Alarm	June 1, 2008
786494	2A Steam Generator Pressure Channel 2P-515 Spiking Low	June 14, 2008
816500	0A RHUT Placard Needs Changing	September 11, 2008
816501	0B RHUT Placard Needs Changing	September 11, 2008
819001	Steam Generator 2A Pressure Channel Failure 2PI-515A	September 17, 2008
820140	Unplanned Entry Into a 6 Hour Shutdown LCO Action Statement	September 19, 2008

CAP DOCUMENTS REVIEWED

Number	Description or Title	Date or Revision
831252	Byron RHUT NRC Inspection Issues	October 15, 2008
831252	BYRON RHUT NRC Inspection Issues	October 15, 2008
833241	Byron RHUT PI&R Inspection Lessons Learned	October 28, 2008
833241	BYRON RHUT P&IR Inspection Lessons Learned	October 20, 2008
850880	NRC P&IR RHUT Inspection Procedure Enhancement	December 1, 2008
858652	Containment Isolation Valve Found De-energized Open	December 19, 2008

DRAWINGS

Number	Description or Title	Date or Revision
Chicago Bridge and Iron Drawing 62603	General Plan 27' X 24'-9" High Elliptical Roof Tank	April 1, 1977
Drawing M-65	Diagram of Boric Acid Processing Sheet 2A	Revision AO
Drawing M-65	Diagram of Boric Acid Processing Sheet 2B	Revision BA
Drawing M-65	Diagram of Boric Acid Processing Sheet 2C	Revision AW

MISCELLANEOUS

Number	Description or Title	Date or Revision
CN-CRA-00-47	Braidwood/Byron Doses from Recycle Holdup Tanks and Spent Resin Tank Failures	June 7, 2000
CN-CRA-08-9	Byron/Braidwood RHUT Response to Opening of the RH Relief Valve	September 25, 2008
CN-CRA-07-50	Byron/Braidwood RHUT Response to Opening of the RH Relief Valve	September 25, 2007

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

DRAWINGS

Number	Description or Title	Date or Revision
AC-7	AC One Line Diagram	Revision 6

MISCELLANEOUS

Number	Description or Title	Date or Revision
Event Notification 44743	Braidwood Unit 2 Automatic Reactor Trip	December 27, 2008
Operator Logs	Control Room Operator Logs	December 27, 2008

CORRECTIVE ACTION DOCUMENTS

Number	Description or Title	Date or Revision
IR 860458	Unit 2 Reactor Trip	December 27, 2008

4OA5 Other Activities

PROCEDURES

Number	Description or Title	Date or Revision
1BwOSR 3.8.1.14-1	Unit 1 1A Diesel Generator 24 Hour Endurance Run	Revision 1
1BwOSR 3.8.1.14-2	Unit 1 1B Diesel Generator 24 Hour Endurance Run	Revision 1
2BwOSR 3.8.1.14-1	Unit 2 2A Diesel Generator 24 Hour Endurance Run	Revision 1
2BwOSR 3.8.1.14-2	Unit 2 2B Diesel Generator 24 Hour Endurance Run	Revision 0

CALCULATIONS

Number	Description or Title	Date or Revision
Calculation 19-T-6;	Diesel Generator Loading During LOOP/LOCA	Revision 6

4OA7 Licensee Identified Violations

CAP DOCUMENTS

Number	Description or Title	Date or Revision
IR 653093 (Byron)	The AFW Tunnel Covers Do Not Meet Expected Safety Factors	July 24, 2007
IR 654270	The AFW Tunnel Cover Bolt Eval. Uses Non-Standard Safety Factor	July 26, 2007

CALCULATIONS

Number	Description or Title	Date or Revision
Calc 5.6.3.9	Investigation of Det – 156, 157	Revision 4

LIST OF ACRONYMS USED

AB	Auxiliary Building
ADAMS	Agencywide Document Access Management System
AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CS	Containment Spray
°F	Degrees Fahrenheit
DG	Diesel Generator
HELB	High Energy Line Break
HUT	Boron Recycle System Holdup Tank
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
IST	Inservice Testing
LLRT	Local Leak Rate Test
LCO	Limiting Condition for Operation
LOOP	Loss of Off-site Power
MCC	Motor Control Center
MSIV	Main Steam Isolation Valve
MSPI	Mitigating Systems Performance Index
NaOH	Sodium Hydroxide
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OWA	Operator Workaround
PARS	Publicly Available Records
PI	Performance Indicator
psig	Pounds Per Square Inch Gauge
PMT	Post-Maintenance Testing
PRT	Pressurizer Relief Tank
RASP	Risk Assessment Standardization Project
RCS	Reactor Coolant System
RH	Residual Heat Removal
SDP	Significance Determination Process
SPR	Sudden Pressure Relay
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
SX	Essential Service Water
TS	Technical Specification
UAT	Unit Auxiliary Transformer
UHS	Ultimate Heat Sink
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order