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

November 14, 2013

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

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000456/2013004; 05000457/2013004

Dear Mr. Pacilio:

On September 30, 2013, 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 October 2, 2013, with Mr. M. Kanavos, 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, one NRC-identified finding of very low safety significance was identified. This finding involved a violation of NRC requirements. However, because of its very low safety significance, and because the issue was entered into your corrective action program, the NRC is treating this violation as a non-cited violation (NCV) in accordance with Section 2.3.2 of the NRC Enforcement Policy. Additionally, two licensee-identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of this NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and to 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 System (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading rm/adams.htm (the Public Electronic Reading Room).

Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000456/2013004; 05000457/2013004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2013004; 05000457/2013004
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	July 1 through September 30, 2013
Inspectors:	J. Benjamin, Senior Resident Inspector A. Garmoe, Acting Senior Resident Inspector J. Steffes, Acting Resident Inspector J. Robbins, Resident Inspector, Byron Station R. Baker, Operations Engineer M. Bielby, Senior Operations Engineer T. Go, Health Physicist M. Holmberg, Reactor Inspector V. Meghani, Reactor Inspector R. Ng, Project Engineer M. Perry, Resident Inspector Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report 05000456/2013004; 05000457/2013004; 07/01/2013 – 09/30/2013; Braidwood Station, Units 1 and 2; Other Activities.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. One Green finding was identified by the inspectors. The finding was considered a non-cited violation (NCV) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., Greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process,” dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, “Components Within the Cross-Cutting Areas,” dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy dated January 28, 2013. 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: Initiating Events

Green. The inspectors identified a finding of very low safety significance and an associated Severity Level IV NCV of 10 CFR 50.59, “Changes, Tests, and Experiments,” when licensee personnel failed to perform and maintain a written evaluation to demonstrate that a procedure change did not require a license amendment. Specifically, the licensee implemented a change to procedures 1/2BwOA SEC-4, “Loss of Instrument Air,” Revision 3, that revised the actions to address a loss of component cooling water (CC) to the reactor coolant pump (RCP) thermal barrier heat exchange such that a complete loss of seal cooling could occur, which would result in damage to the RCP seals and a subsequent loss of coolant accident (LOCA). As part of the licensee corrective actions, procedures 1/2 BwOA SEC-4 were revised to address the issue. A revised 10 CFR 50.59 evaluation was also developed and approved.

The performance deficiency was determined to be more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” because it could be reasonably viewed as a precursor to a significant event. The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 2, for the Initiating Events cornerstone. The inspectors then answered ‘No’ to all of the screening questions in Table 3. The finding was further evaluated using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” Exhibit 1. The inspectors answered ‘No’ to all of the questions contained therein. Therefore, the inspectors concluded the finding was of very low safety significance (Green). Because the associated finding was determined to be of very low safety significance in accordance with the SDP, the traditional enforcement aspect of this issue was determined to be at the Severity Level IV level. The inspectors did not identify a cross-cutting aspect associated with this finding since it was not indicative of current performance. (Section 4OA5)

B. Licensee-Identified Violations

Two 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 corrective action program. These violations and the 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 during the inspection period until September 5, 2013, when power was reduced to approximately 93 percent for main steam safety valve and auxiliary feedwater system testing. The unit was subsequently returned to full power until September 8, 2013, when the licensee began a power reduction to support a planned refueling outage that began on September 9, 2013. The reactor was started up and the main generator was synchronized to the grid on September 30, 2013. At the end of the inspection period, Unit 1 was at about 30 percent power and in power ascension.

Unit 2 began the inspection period in a planned maintenance outage to support replacement of the 2A and 2B reactor coolant pump (RCP) seals. The reactor was started up on July 4, 2013, the main generator was synchronized to the grid on July 5, 2013, and Unit 2 reached full power on July 6, 2013. Unit 2 remained at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood with a specific focus on the Unit 1 auxiliary feedwater tunnel. The evaluation included a review to check for deviations from the descriptions provided in the Updated Final Safety Analysis Report (UFSAR) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining and determined whether the barriers required to mitigate external flooding were in place and operable as appropriate for the plant conditions at the time. The inspectors also walked down underground bunkers/manholes subject to flooding that contained multiple trains or multiple-function risk-significant cables. The inspectors also reviewed abnormal operating procedures for mitigating design basis flooding events to ensure these procedures could be implemented as written. Documents reviewed are listed in the Attachment.

This inspection constituted one external flooding sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns (71111.04Q)

a. Inspection Scope

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

- 2A Essential Service Water (SX) System; and
- Unit 2 Fuel Pool Cooling (FC) System.

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, the UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), Issue Reports (IRs), 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 their corrective action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted two partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

.2 Semiannual Complete System Walkdown (71111.04S)

a. Inspection Scope

On August 23, 2013, the inspectors performed a complete system alignment inspection of the Unit 1 Direct Current (DC) system to verify the functional capability of the system. This system was selected because it was considered both safety-significant and risk-significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- 2B Emergency Diesel Generator (EDG) Room (Fire Area 9.1-2);
- Unit 1 Containment (Fire Areas 1.1-1, 1.2-1, and 1.3-1);
- Unit 1 DC Battery Rooms (Fire Areas 5.4-1 and 5.6-1); and
- Division 22 4 kilovolt (kV) Switchgear Room (Fire Area 5.1-2).

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

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

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Underground Vaults

a. Inspection Scope

The inspectors selected underground bunkers/manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors determined whether the cables were submerged, whether splices were intact, and whether appropriate cable support structures were in place. In those areas where dewatering devices, such as a sump pump were used, the inspectors determined whether the device was operable and level alarm circuits were set appropriately to ensure that the cables would not be submerged. In those areas without dewatering devices, the inspectors verified that drainage of the area was available, or that the cables were qualified for submerged conditions. The inspectors also reviewed corrective action documents associated with submerged cable issues identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following underground bunkers/manholes subject to flooding:

- 2B Circulating Water Pump Cable Vaults (Vault 2D and 2E).

Documents reviewed are listed in the Attachment.

This inspection constituted one underground vault sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Annual Operating Test administered by the licensee from July 15 through August 23, 2013, as required by 10 CFR 55.59(a). The results were compared to the thresholds established in Inspection Manual Chapter (IMC) 0609, Appendix I, “Licensed Operator Requalification Significance Determination Process (SDP)," to assess the overall adequacy of the licensee’s Licensed Operator Requalification Training (LORT) Program in meeting the requirements of 10 CFR 55.59. (02.02)

Documents reviewed are listed in the Attachment.

This inspection constituted one annual licensed operator requalification examination results sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

.2 Biennial Review (71111.11B)

a. Inspection Scope

The following inspection activities were conducted during the weeks of July 15 and 22, 2013 to assess: 1) the effectiveness and adequacy of the facility licensee's implementation and maintenance of its Systems Approach to Training (SAT) based LORT Program, put into effect to satisfy the requirements of 10 CFR 55.59; 2) conformance with the requirements of 10 CFR 55.46 for use of a plant referenced simulator to conduct operator licensing examinations and for satisfying experience requirements; and 3) conformance with the operator license conditions specified in 10 CFR 55.53.

- Licensee Requalification Examinations (10 CFR 55.59(c); Systems Approach to Training Element 4 as Defined in 10 CFR 55.4): The inspectors reviewed the licensee's program for development and administration of the LORT biennial written examination and annual operating tests to assess the licensee's ability to develop and administer examinations that are acceptable for meeting the requirements of 10 CFR 55.59(a).

  - The inspectors conducted a detailed review of two previously administered biennial requalification written examination versions to assess content, level of difficulty, and quality of the written examination materials. (02.03)

  - The inspectors conducted a detailed review of ten Job Performance Measurers (JPMs) and six dynamic simulator scenarios to assess content, level of difficulty, and quality of the operating test materials. (02.04)

  - The inspectors observed the administration of the annual operating test to assess the licensee's effectiveness in conducting the examinations, including the conduct of pre-examination briefings, evaluations of individual operator and crew performance, and post-examination analysis. The inspectors evaluated the performance of two simulator crews in parallel with the facility evaluators during four dynamic simulator scenarios and evaluated various licensed crew members concurrently with facility evaluators during the administration of several JPMs. (02.05)

  - The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the last requalification examinations and the training planned for the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans. (02.07)

- Conformance with Examination Security Requirements (10 CFR 55.49): The inspectors conducted an assessment of the licensee's processes related to examination physical security and integrity (e.g., predictability and bias) to verify compliance with 10 CFR 55.49, "Integrity of Examinations and Tests." The inspectors reviewed the facility licensee's examination security procedure, and observed the implementation of physical security controls (e.g., access restrictions and simulator Input/Output controls) and integrity measures (e.g., security agreements, sampling criteria, bank use, and test item repetition) throughout the inspection period. (02.06)

- Conformance with Operator License Conditions (10 CFR 55.53): The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators, and which control room positions were granted watch-standing credit for maintaining active operator licenses. Additionally, medical records for ten licensed operators were reviewed for compliance with 10 CFR 55.53(I). (02.08)

- Conformance with Simulator Requirements Specified in 10 CFR 55.46: The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements. The inspectors reviewed a sample of simulator performance test records (e.g., transient tests, malfunction tests, scenario-based tests, post-event tests, steady state tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy corrective action process to ensure that simulator fidelity was being maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions, as well as on nuclear and thermal hydraulic operating characteristics. (02.09)

- Problem Identification and Resolution (10 CFR 55.59(c); Systems Approach to Training Element 5 as Defined in 10 CFR 55.4): The inspectors assessed the licensee's ability to identify, evaluate, and resolve problems associated with licensed operator performance (a measure of the effectiveness of its LORT Program and their ability to implement appropriate corrective actions to maintain its LORT Program up to date). The inspectors reviewed documents related to licensed operator performance issues (e.g., recent examination and inspection reports including cited and NCVs; NRC End-of-Cycle and Mid-Cycle reports; the NRC Plant Issues Matrix (PIM); licensee event reports (LERs); licensee IRs including documentation of plant events and review of industry operating experience). The inspectors also sampled the licensee's quality assurance oversight activities, including licensee training department self-assessment reports. (02.10)

Documents reviewed are listed in the Attachment.

This inspection constituted one Biennial Licensed Operator Requalification Program inspection sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

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

a. Inspection Scope

On August 21, 2013, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations, procedural compliance, and successful critical task completion requirements. Documents reviewed are listed in the Attachment.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

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

a. Inspection Scope

On September 8 and September 9, 2013, the inspectors observed the Unit 1 shutdown and transition to shutdown cooling. This was an activity that required heightened awareness and was related to increased risk. The inspectors evaluated the following areas:

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

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and critical task completion requirements. Documents reviewed are listed in the Attachment.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Control Room Ventilation System.

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

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

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

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

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- 2A Main Steam Isolation Valve (MSIV) Fyrquel Leak;
- Elevated Lake Temperatures; and
- 2D Safety Injection Accumulator Troubleshooting and Associated 1 Hour Technical Specification (TS) Limiting Condition for Operation (LCO).

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 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. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- EDG Fuel Injector Pump Bolts;
- 1A EDG SX Return Line Through-Wall Leak;
- Operability Evaluation 11-12 (Diesel Driven Auxiliary Feedwater Pump SX Booster Pump); and
- Functionality Evaluation for Valves 1SI8811A and 1SI8811B.

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 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.

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

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modifications:

- 1B EDG Governor Modifications; and
- Final Modification Design to Address Recycle Holdup Tank Overpressurization Concerns.

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

This inspection constituted two permanent plant modification samples as defined in IP 71111.18-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 1SI8811A and 1SI8811B Valve Enclosure Leakage Test following Inspection Port Installation;
- Safety-Related Battery 111 following Full Battery Replacement;
- 1B EDG following Governor Modification; and
- 1D Steam Generator Power Operated Relief Valve (PORV) Battery following Replacement of Two Cells.

These activities were selected based upon the SSC's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated.

The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and applicable NRC generic communications to ensure that the test results ensured that the equipment met the licensing bases and design requirements.

In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in their CAP at the appropriate threshold and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 1 refueling outage (RFO) conducted from September 8 through October 1, 2013, to confirm that the licensee had appropriately considered risk, industry operating experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out of service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TSs;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the primary containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- licensee identification and resolution of problems related to RFO activities.

Documents reviewed are listed in the Attachment.

This inspection constituted one RFO sample as defined in IP 71111.20-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- 1BwOS RF-1, Unit 1 Containment Floor Drain Monitoring (Routine);
- Unit 1 Main Steam Safety Valve Trevitest (Routine);
- Unit 2 Elevated Identified Reactor Coolant System Leakage;
- Unit 1A Containment Spray American Society of Mechanical Engineers (ASME) Surveillance (In-Service Testing); and
- Containment Penetration 18 Local Leak Rate Test (LLRT) (Containment Isolation Valve).

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, demonstrate operational readiness, and consistent with the system design basis;
- was plant equipment calibration correct, accurate, and properly documented;
- were as left setpoints within required ranges; and was the calibration frequency in accordance with TSs, the UFSAR, plant procedures, and applicable commitments;
- was measuring and test equipment calibration current;
- was the test equipment used within the required range and accuracy and were applicable prerequisites described in the test procedures satisfied;
- did test frequencies meet TS requirements to demonstrate operability and reliability;
- were tests performed in accordance with the test procedures and other applicable procedures;
- were jumpers and lifted leads controlled and restored where used;
- were test data and results accurate, complete, within limits, and valid;
- was test equipment removed following testing;
- where applicable for in-service testing activities, was testing performed in accordance with the applicable version of Section XI of the ASME Code, and were reference values consistent with the system design basis;
- was the unavailability of the tested equipment appropriately considered in the performance indicator data;
- where applicable, were test results not meeting acceptance criteria addressed with an adequate operability evaluation, or was the system or component declared inoperable;

- where applicable for safety-related instrument control surveillance tests, was the reference setting data accurately incorporated into the test procedure;
- was equipment returned to a position or status required to support the performance of its safety function following testing;
- were all problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- where applicable, were annunciators and other alarms demonstrated to be functional and were annunciator and alarm setpoints consistent with design documents; and
- where applicable, were alarm response procedure entry points and actions consistent with the plant design and licensing documents.

Documents reviewed are listed in the Attachment.

This inspection constituted two routine surveillance testing samples, one in-service testing sample, one reactor coolant system leak detection inspection sample, and one containment isolation valve sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

To facilitate the identification of repetitive equipment failures and specific human performance issues for followup, 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 IR packages.

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

b. Findings

No findings were identified.

.3 Selected Issue Followup Inspection: Degraded Steam Generator Blowdown Panel Annunciator

a. Inspection Scope

During routine tours of the control room and plant the inspectors became aware that the steam generator blowdown panel (SGBDP) local annunciator, which is located in the chemistry lab, was unreliable and would not emit an audible tone when an alarm signal was generated. Ordinarily, this would be accompanied by a main control room alarm that would annunciate if a local alarm was not acknowledged within five minutes. However, the main control room alarm was locked in solid such that it would not annunciate when a local panel alarm went unacknowledged. Because the chemistry lab was not continuously staffed, the inspectors were concerned with the potential consequences of unrecognized SGBDP alarms.

The inspectors spoke with the Unit 1 Operations supervisor, who confirmed that the SGBDP trouble alarm in the main control room was locked in solid and would not audibly or visually annunciate in the main control room. On July 30, 2013, the inspectors observed the SGBDP and spoke with two Chemistry supervisors, both of whom confirmed that the local audible annunciator horn was unreliable and the main control room panel trouble alarm was not functioning. Both supervisors indicated there were no compensatory measures that had been established beyond routine Chemistry rounds and those rounds, which included a check of the SGBDP, were of sufficient frequency to adequately respond to any potential alarm conditions. The Chemistry supervisors also indicated that compensatory measures upon a loss of sample flow to the panel (inability to sample from the panel) were to perform grab samples every eight hours, which was equivalent to the existing shiftly rounds frequency. The inspectors subsequently validated this through a review of procedure CY-AP-120-200, "Recirculating Steam Generator Chemistry."

The inspectors also confirmed that the main steamline radiation monitors, 1PR08J and 2PR08J, were functioning and would be able to detect a steam generator tube leak. The radiation monitors alarmed in the main control room via the Unit 1 and Unit 2 RM-11 computers, which were separate from the SGBDP alarm circuitry. Additionally, the Braidwood UFSAR Chapter 15 discussion for a steam generator tube rupture event described the identification of a steam generator tube rupture through steam jet air ejector radiation monitors or other secondary radiation monitors, but did not mention the SGBDP. The licensee was required to establish and implement a Secondary Water Chemistry Program in accordance with TS 5.5.10 and Technical Requirements Manual (TRM) Appendix J, which required that sampling points be identified in station procedures. The inspectors confirmed that upon the loss of the SGBDP, alternate sampling points were specified in plant procedures.

The inspectors verified that the SGBDP trouble alarm in the main control room was repaired on August 28, 2013, which reinstated the capability of that annunciator to alarm if a SGBDP alarm was unacknowledged for 5 minutes. At the conclusion of the inspection period, WO 1656794 was open to repair the local SGBDP annunciator. Replacement of the entire SGBDP was also scheduled for early 2014.

This review constituted one in-depth Problem Identification and Resolution sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.4 Selected Issue Followup Inspection: Equipment Abandonment via Operational Configuration Change

a. Inspection Scope

On August 22, 2013, the site experienced a lightning strike on the offsite 345 kV East Frankfort transmission line. In response, the resident inspectors performed a full system alignment of the Unit 1 Direct Current (DC) system. During performance of the inspection sample, the inspectors referenced licensee procedure BwOP DC-E2, "Electrical Lineup – Unit 1 Operating – 125 volts direct current (VDC) Division 11." The inspectors noted that the breaker for Circuit 16 in 125 VDC Distribution Panel 113 Compartment ER1 was not in the required "OFF" position as specified in the licensee's procedure. The Circuit 16 breaker was associated with the boric acid recycle evaporation system and had an associated tag stating the equipment had been abandoned in place in accordance with Engineering Change 362885. In response, the licensee performed an electrical line-up and placed the breaker in the required position. The issue was entered into the licensee's CAP as IR 1549726, "DC Breaker Not Positioned Per Line-up – DC 113, ER-1, CKT 16." Through further discussions, the inspectors determined that the boric acid recycle evaporation system had been abandoned in place in 2007 as part of the licensee's interim abandonment process, which was prescribed by procedure CC-AA-109, "Equipment Abandonment via Operational Configuration Change."

The licensee performed an extent of condition review of other systems that had been abandoned via the interim abandonment process. This review identified several other valves and breakers associated with the caustic storage tank and hydrogen recombiner systems that were not in their required positions, all of which had been processed through the interim abandonment program by January 2012. The licensee performed a work group evaluation and determined that there was no formal requirement in the interim abandonment process to validate that components in the field were actually in their newly required position. Coincidently, the licensee had subsequently added a requirement to the Procedure Change Desktop Guide, effective July 30, 2012, to verify the field configuration of components for revisions that changed the required position. This action addressed the gap in the interim abandonment process because equipment lineup procedures would be revised through the interim abandonment process and therefore affected equipment would be required by the Procedure Change Desktop Guide to be verified in the new correct configuration. At the conclusion of the inspection period, the licensee was in the process of repositioning the out-of-position components.

The inspectors determined that the failure to maintain equipment in the procedurally-required configuration was a performance deficiency. Specifically, procedure BwOP DC-E2 required the Circuit 16 breaker in DC Panel 113 to be in the 'OFF' position but it was found unexpectedly in the 'ON' position. The inspectors determined that the performance deficiency was minor because they answered 'No' to all of the more-than-minor questions in IMC 0612, Appendix B, "Issue Screening." Technical Specification 5.4.1.a requires, in part, that written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, shall be implemented. Section 1.c of Regulatory Guide 1.33, Revision 2, Appendix A recommends procedures for equipment control. Thus, the failure to maintain equipment in accordance with procedure BwOP DC-E2 represented a violation of TS 5.4.1.a. However, this constituted a minor violation that was not subject to enforcement action in accordance with the NRC's Enforcement Policy.

This review constituted one in-depth Problem Identification and Resolution sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.5 (Closed) Unresolved Item 05000456/2013003-04; 05000457/2013003-04 Implementation of Lake Chemistry Management Program

a. Inspection Scope

This Unresolved Item (URI) was opened in Section 4OA2.5.b of Braidwood Inspection Report 05000456/2013003; 0500457/2013003. The inspectors identified gaps in the implementation of the licensee's lake chemistry management program regarding the timeliness of the identification and follow-up to lake chemistry samples that indicated the potential for lake softening. Specifically, the inspectors identified several instances where senior site management and the Operations department were not notified at the first sign of natural lake softening, as required in procedure CY-BR-120-412, "Lake Chemistry Data Sheet," Revision 7. Upon notification, Operations was required by CY-BR-120-412 to implement procedure BwOA ENV-7, "Adverse Cooling Lake Conditions," which prescribed parameters to monitor and equipment to maintain available to minimize the impact of potential lake precipitation events. Because lake softening preceded actual consequential lake precipitation events in 2002 and 2004, the inspectors were concerned that untimely follow-up to indications of lake softening events could increase the likelihood of consequences from a potential lake precipitation event. At the conclusion of the second quarter 2013 inspection period, the inspectors were continuing to review the impact of delays in implementing procedure BwOA ENV-7 on the ability to mitigate lake precipitation events.

Subsequently, the licensee performed an apparent cause evaluation of the lake chemistry management program. The apparent cause evaluation also intended to address the inspectors' questions regarding the impact of delaying entry into BwOA ENV-7 after the identification of lake softening. The licensee performed a periodic cooling lake inhibitor optimization test to determine the margin between existing lake conditions and the conditions that would result in a lake precipitation event. The precipitation events in 2002 and 2004 were determined to be a result of high hydroxyethylidene diphosphonic acid (a scale inhibitor) levels in the lake, which was a corrective action to condenser tube scaling in 2001. These high scale inhibitor levels prevented natural softening events, which resulted in more severe precipitation events. The licensee has since placed limits on the amount of scale inhibitor in the lake such that natural softening events will occur. Results of the cooling lake inhibitor optimization tests indicated that the lake would precipitate at a pH of 9.6. The highest lake pH seen in the past five years was 9.2. Through consultation with an independent consultant and the lake chemistry vendor, NALCO, the licensee determined the lake pH value was limited to 9.2 based on the relationship between algae blooms and metabolism. Based on this information, the licensee concluded that crash precipitation events could no longer occur.

Based on the determination that crash precipitation events could no longer occur, the inspectors considered this URI closed.

4OA5 Other Activities

.1 Institute of Nuclear Power Operations Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final report for the Institute of Nuclear Power Operations plant assessment conducted in December 2012. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to determine if any significant safety issues were identified that required further NRC followup.

b. Findings

No findings were identified.

.2 Failure to Perform a Required 10 CFR 50.59 Evaluation

a. Inspection Scope

As part of routine inspection activities, the inspectors reviewed procedures 1/2BwOA SEC-4, "Loss of Instrument Air Unit 1/2."

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated Severity Level IV NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," when licensee personnel failed to perform and maintain a written evaluation to demonstrate that a procedure change did not require a license amendment. Specifically, the licensee implemented a change to procedures 1/2BwOA SEC-4, "Loss of Instrument Air Unit 1/2," Revision 3, that revised the actions to address a loss of component cooling water (CC) to the reactor coolant pump (RCP) thermal barrier heat exchanger such that a complete loss of seal cooling could occur, which could result in damage to the RCP seals and a subsequent RCP seal loss of coolant accident (LOCA).

Description: As part of their routine inspection activities, the inspectors reviewed procedures 1/2BwOA SEC-4, "Loss of Instrument Air Unit 1/2." Step 7 of these procedures directed the procedure user to monitor Volume Control Tank (VCT) level. If VCT level could not be maintained greater than 10 percent, then the user was directed to verify that CC valves to the RCPs were open and to suspend the operation of all of the safety-related centrifugal charging pumps (CCPs). The inspectors reviewed the applicable UFSAR section, which described an automatic function to transfer the CCP suction to the Residual Water Storage Tank (RWST) in a low VCT level condition. Because implementing Step 7 would result in isolating seal injection flow to the RCP seals with the plant potentially at power and was contradictory to the system description in the UFSAR, the inspectors questioned the appropriateness of this procedural step and requested any associated 10 CFR 50.59 documentation.

Step 7 was revised in Revision 3 of procedures 1/2 BwOA SEC-4. The licensee approved a 10 CFR 50.59 screening for Revision 3 on July 24, 1998, which concluded that a 10 CFR 50.59 evaluation was not required. One of the questions in the screening was whether the proposed activity would result in a change to any of the following: administrative controls as described in the Safety Analysis Report (SAR), plant operating conditions as described in the SAR, specific SAR commitments, or operation of equipment from that described or committed to in any SAR document. The inspectors questioned the response to that question since the proposed procedure change did result in operation of the chemical and volume control system in a manner that was different from that described in the UFSAR.

The licensee subsequently reviewed the 1998 procedure change in accordance with their current screening guidance in procedure LS-AA-104-1003, "50.59 Screening Form," Revision 3, and determined that the above screening question should have been answered 'Yes'. Specifically, a similar question in the current guidance, "Does the proposed activity involve a change to a procedure that adversely affects how UFSAR described SSC design functions are performed or controlled," was answered 'Yes'.

The licensee then performed a full 10 CFR 50.59 evaluation in accordance with procedure LS-AA-104-1004, "50.59 Evaluation Form," Revision 5, and determined that the procedure revision should not have been made prior to receiving NRC approval. Specifically, the licensee answered 'Yes' to the question, "Does the proposed activity create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in [the] UFSAR." The design of the RCP was such that two independent methods of cooling were available to prevent RCP bearing failure.

Section 5.4.1.3.4 of the Braidwood UFSAR stated, “Should a loss of component cooling water to the RCPs occur, the chemical and volume control system continues to provide seal injection water to the RCPs; the seal injection flow is sufficient to prevent damage to the seals with a loss of thermal barrier cooling.” The revised procedure step to secure the operation of the CCPs upon low VCT level was inconsistent with the UFSAR, which relied upon seal injection from the CCPs should thermal barrier cooling be lost. Without thermal barrier cooling or seal injection flow from the CCPs, the RCP seals would lose all cooling, potentially fail, and lead to an RCP seal LOCA.

The licensee entered this issue into their CAP as IR 1541343, “Inconsistency in 1/2BwOA SEC-4, Loss of Instrument Air,” IR 1544225, “NRC ID 50.59 Screening for 1998 Procedure Change,” and IR 1547783, “NRC ID 50.59 Evaluation of 1/2BwOA SEC 4 Revision 3.” The licensee’s corrective actions included revising Step 7 of procedures 1/2BwOA SEC-4 to the original pre-Revision 3 version of the procedure, such that if VCT level could not be maintained above 10 percent, then operators would transfer the CCP suction to the RWST and close the VCT outlet valves.

Analysis: The inspectors determined that the failure to perform an adequate 10 CFR 50.59 evaluation that revised the actions in 1/2BwOA SEC-4, “Loss of Instrument Air Unit 1/2,” to address a loss of CC event was contrary to 10 CFR 50.59(c)(2)(vi) and was a performance deficiency.

The performance deficiency was determined to be more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” because the performance deficiency could be reasonably viewed as a precursor to a significant event. Specifically, securing the operation of all CCPs with the plant at power could result in a RCP seal LOCA. The inspectors concluded this finding was associated with the Initiating Events cornerstone.

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 2, for the Initiating Events cornerstone. The inspectors then answered ‘No’ to all of the questions in Table 3. The finding was further evaluated using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” Exhibit 1. The inspectors also answered ‘No’ to all the questions contained therein. Therefore, the inspectors concluded the finding was of very low safety significance (Green).

Because this issue involved the failure to perform a written evaluation pursuant to 10 CFR 50.59, “Changes, Tests, and Experiments,” it, by definition, impacted the regulatory process. As a result, the traditional enforcement process was determined to be applicable. In determining the severity level of the traditional enforcement aspect of the issue, the inspectors identified that Subsection d.2 of Section 6.1, “Reactor Operations,” of the NRC Enforcement Policy listed a 10 CFR 50.59 violation that results in conditions evaluated by the SDP as having very low safety significance as an example of a Severity Level IV violation. Because the associated finding was determined to be of very low safety significance as discussed above, the traditional enforcement aspect of this issue was determined to be at the Severity Level IV level.

The inspectors determined that the performance deficiency associated with the procedural change that occurred in 1998 was of sufficient age that it did not represent current plant performance. Therefore, the inspectors did not identify a cross-cutting aspect associated with this finding.

Enforcement: Title 10 CFR 50.59(d)(1) requires, in part, that the licensee maintain records of changes in the facility, of changes in procedures, and of tests and experiments made pursuant 10 CFR 50.59(c). These records must include a written evaluation which provides the bases for the determination that the change, test, or experiment does not require a license amendment pursuant to paragraph (c)(2) of this section. Title 10 CFR 50.59(c)(2)(vi) states, in part, that a licensee shall obtain a license amendment pursuant to 10 CFR 50.90 prior to implementing a proposed change, test, or experiment if the change, test, or experiment would create a possibility for a malfunction of a SSC important to safety with a different result than any previously evaluated in the FSAR (as updated). Braidwood UFSAR Section 5.4.1.3.4 stated, "Should a loss of component cooling water to the reactor coolant pumps occur, the chemical and volume control system continues to provide seal injection water to the reactor coolant pumps; the seal injection flow is sufficient to prevent damage to the seals with a loss of thermal barrier cooling."

Contrary to the above, on July 24, 1998, the licensee failed to perform and maintain a written evaluation to demonstrate that a procedure change to procedures 1/2BwOA SEC-4 did not require a license amendment. Specifically, the procedure revision changed the result of a loss of CC to the RCP thermal barrier heat exchanger such that a complete loss of seal cooling could occur, which would result in damage to the RCP seals and a subsequent RCP seal LOCA. The licensee's corrective actions included revising Step 7 of procedures 1/2BwOA SEC-4 to the original pre-Revision 3 version of the procedure, such that if VCT level could not be maintained above 10 percent, then operators would transfer the CCP suction to the RWST and close the VCT outlet valves.

Because this violation was of very low safety significance and because the issue was entered into the licensee's CAP as IRs 1541343, 1544225, and 1547783, this violation is being treated as a Severity Level IV NCV, consistent with Section 2.3.2 of the NRC's Enforcement Policy. **(NCV 05000456/2013004-01; 05000457/2013004-01, Failure to Perform a Required 10 CFR 50.59 Evaluation)**

The associated finding for this issue was evaluated separately from the traditional enforcement violation; and therefore, the finding is being assigned a separate Tracking Number. **(FIN 05000456/2013004-02; 05000457/2013004-02, Failure to Perform a Required 10 CFR 50.59 Evaluation)**

.3 (Closed) Unresolved Item 05000456/2012005-04; 05000457/2012005-04, Functionality Evaluation of Block Walls for High Energy Line Break Loads

Introduction: During their review of URI 05000456/2012005-04; 05000457/2012005-04, "Functionality Evaluation of Block Walls for High Energy Line Break Loads," the inspectors identified additional deficiencies in the licensee's functionality evaluation of the auxiliary building safety-related block walls affected by high energy line break (HELB) pressure loading. A finding of very low safety significance (Green) was previously documented for the licensee's failure to perform an adequate technical review to determine the functionality of these walls (FIN 05000456/2012005-03; 05000457/2012005-03, Inadequate Functionality Evaluation of Block Walls for High Energy Line Break Loads). Since the deficiencies involved the same procedure, evaluation, and cross-cutting aspect as described in the previous finding, they are being treated as additional examples under the same finding.

Description: In response to questions raised by the inspectors, certain safety-related block walls in the auxiliary building were identified to be subject to pressure loads resulting from a turbine building HELB event. Turbine building HELB pressure loads were not considered in the original seismic evaluation of these walls. The licensee documented this issue in their CAP as IR 1389889, “NRC Questions on HELB Pressure Loads,” and performed Operability Evaluation 12-004, “HELB Load Not Considered in Structural Calculations,” Revision 1, in accordance with procedure OP-AA-108-115, “Operability Determinations,” to demonstrate that the walls would remain functional under seismic and HELB loads. During the review of this functionality evaluation, the inspectors identified deficiencies related to the use of appropriate load combinations and acceptance criteria.

Safety-related auxiliary building block walls at Braidwood were previously evaluated for seismic loads in accordance with the “Interim Criteria for Safety-Related Masonry Wall Evaluation,” provided in NUREG-0800 (Standard Review Plan), Attachment A, Section 3.8.4, “Other Category I Structures.” The subject walls, consisting of 12-inch thick unreinforced hollow masonry units, were divisional separation walls in the auxiliary building required to maintain the fire and ventilation barrier function while not failing in a manner that would adversely affect safety-related equipment. An overload of the wall could result in structural elements, concrete blocks, steel columns, etc., impacting the safety-related equipment. These walls were assumed to span horizontally in the evaluations and steel columns were provided for additional support along the length of the walls as needed to limit the spans. The HELB analyses at the time did not identify any pressure loading on the walls resulting from postulated pipe breaks.

During a turbine building HELB design basis reconstitution effort, the licensee identified the existence of differential pressure on certain auxiliary building safety-related block walls following postulated pipe break events. The HELB scenario involved a pipe break in the turbine building which initially communicates with the auxiliary building rooms through open fire dampers. After a period of time (200 seconds) as the temperature rises, the fire damper in one room closed while the fire damper in the other room failed to close (single active failure assumption), resulting in a buildup of a differential pressure across the block wall separating the two rooms served by the dampers. The licensee performed a functionality evaluation for the subject walls to demonstrate that the walls, while exceeding the design basis allowable stresses, would remain functional. The licensee’s evaluation used higher allowable stresses based on masonry test results documented in the UFSAR. Based on the evaluation, the licensee considered the walls to be functional and non-conforming and planned corrective actions to return the walls to conformance through more refined analyses and/or field modifications.

The inspectors noted that the functionality evaluation did not consider seismic loads acting concurrently with pressure loads due to the pipe break. The Standard Review Plan, Attachment A, Section 3.8.4, which was consistent with the design basis described in the Braidwood UFSAR, required consideration of the following load combinations:

1. *D + L + 1.5 Pa*

2. *D + L + 1.25 Pa + 1.25 E*

3. *D + L + Pa + E'*

(D = dead load, L = Live loads, E = operating basis earthquake, E' = safe shutdown earthquake, Pa = Pipe break pressure load; terms not applicable are omitted in the above load combinations)

In their evaluation, the licensee assumed that the seismic and HELB events started at the same time. However, for the scenario considered, the pressure buildup would not start until 200 seconds after the event, at the time when one fire damper closes. Since the seismic event was not assumed to last for more than 200 seconds, the licensee concluded that it was not necessary to add together the effects of seismic and HELB loads. In addition, the licensee also concluded that it was not necessary to consider any load factors for the operability evaluation. Consequently, the three load combinations noted above were reduced to the following governing combinations:

- Initial 30 seconds: Seismic activity ends within 30 seconds, pressure during this period is negligible
    - D + L + E' - condition previously evaluated in the original calculations
- After 200 seconds: The seismic activity has ended, HELB pressure starts to build
    - D + L + Pa - the operability evaluation addressed this condition

The licensee's evaluation did not provide sufficient information to justify the use of a load factor of 1.0 for the HELB pressure considering the inherent uncertainty of the calculated value based on methodologies and inputs involved in such calculations.

The inspectors further noted that the masonry allowable tensile stress used in the licensee's evaluation was equal to the modulus of rupture value based on test data documented in the UFSAR, which was about 65 percent higher than the allowable stress for the design basis safe shutdown earthquake load combination. By omitting the load factor and not considering combined effects of seismic and the HELB, the licensee also significantly reduced the design basis loads. The licensee's current evaluation showed very small margins, suggesting that applying a load factor of 1.25 or 1.5 to the pipe break pressure load, or combining a seismic event of much smaller intensity than a safe shutdown earthquake or an operating basis earthquake with HELB, could result in masonry tensile stresses exceeding the modulus of rupture of masonry.

While the licensee's analysis may be reasonable based on its assumptions regarding the timing of HELB and seismic events, there might be other scenarios with slightly different sequence of events that might not be bounded by the current evaluation. Specifically, the possibility of a seismic event, an initial event, or an aftershock, occurring after the

HELB while the differential pressure still existed would subject the wall to combined effects. The inspectors further noted that while the probability of such occurrence could be very low, the current staff guidance precludes the use of probabilities in operability considerations. Specifically, Section C.6 of the Inspection Manual Part 9900 Technical Guidance states, in part, "the definition of operability is that the SSC must be capable of performing its specified safety function or functions, which inherently assumes that the event occurs and that the safety function or functions can be performed. Therefore, the use of PRA [Probabilistic Risk Assessment] or probabilities of occurrence of accidents or external events is not consistent with the assumption that the event occurs, and is not acceptable for making operability decisions." The inspectors also reviewed the licensee's procedure for operability determinations and found that it was consistent with Section C.6 in the NRC's Part 9900 guidance.

Due to the disagreement with the licensee regarding adequacy of the functionality evaluation, the inspectors requested the Office of Nuclear Reactor Regulation's (NRR's) support through a concurrence Task Interface Agreement (TIA). The TIA memorandum dated September 6, 2013, documented the staff evaluation and determination that the licensee: (1) did not assign and justify a wall capacity reduction factor in its functionality assessment to account for uncertainty and variability of wall strength; (2) did not provide adequate justification to demonstrate the likelihood and reasonableness of load combinations used in its assessment; and (3) did not provide adequate information to demonstrate that using a load factor of 1.0 on HELB pressure loads was adequate considering the expected uncertainties in the results of GOTHIC analysis due to modeling and variability of the input parameters.

The inspectors reviewed OP-AA-108-115 to determine whether the licensee had adequately evaluated the non-conforming condition in accordance with station standards. The inspectors concluded that Operability Evaluation 12-004, Revision 1, did not meet at least two requirements of OP-AA-108-115. First, Section 4.4.3.2 of procedure OP-AA-108-115 required the reviewer to "technically review assumptions, engineering judgment, and or numerical evaluations." The inspectors concluded that this standard was not met because the use of the non-conservative load combinations and acceptance criteria that did not include a capacity reduction factor, as identified by the inspectors and discussed above, were not identified by the reviewer. Secondly, Section 4.4.3.3 required that the operability evaluation be sufficiently detailed to be able to be "stand alone." Section 4.4.2 discussed that the operability evaluation should contain sufficient detail for a knowledgeable individual to independently reach the same conclusions as the preparer (i.e. the operability evaluation must be able to stand alone). The inspectors concluded that Operability Evaluation 12-004, Revision 1, did not "stand alone."

Prior to issuance of the TIA memorandum, the licensee installed new structural supports and HELB protective devices (dampers) to prevent failure of the divisional separation walls and associated doors. The above deficiencies therefore did not have any impact on current functionality of the walls. The licensee entered this issue in their CAP as IR 1555159, "NRC TIA Conclusion of Seismic/HELB Concurrent Loads on AB [Auxiliary Building] Walls."

Analysis: The inspectors determined that the failure to perform an adequate functionality evaluation was contrary to the requirements of OP-AA-108-115, “Operability Determinations,” Revision 11, and was a performance deficiency. Specifically, the failure to adequately justify the non-conservative load combinations and acceptance criteria used in the evaluation resulted in an inadequate operability evaluation. Section 4.4.3.2 of OP-AA-108-115 required the reviewer to technically review assumptions, engineering judgments, and/or numerical evaluations, which, if properly performed, would have identified and corrected the deficiencies identified by the inspectors.

The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability and reliability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee failed to ensure that equipment in the Miscellaneous Electrical Equipment Rooms (MEERs) and the EDG rooms would be protected following a HELB outside containment, since there was the potential that the masonry block wall separating the two divisions in the MEERs or the masonry block wall separating the EDGs would fail if a damper from these rooms to the turbine building failed to close during the HELB event.

In accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings,” Table 2, the inspectors determined the finding affected the Mitigating Systems cornerstone. As a result, the inspectors determined the finding could be evaluated using Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” Exhibit 2, for the Mitigating Systems cornerstone. Since the finding resulted in the potential for a loss of both divisions of batteries, all instrument inverters, and both EDGs, the inspectors answered ‘Yes’ to the Mitigating Systems Question A.2 in Exhibit 2 and determined a Detailed Risk Evaluation was required.

The Senior Reactor Analysts performed a bounding risk evaluation for the delta core damage frequency (ΔCDF) for the failure of the masonry block walls separating the MEERs or the walls separating the EDG rooms during a HELB event in the turbine building. A core damage event was assumed to occur if the block wall separating the MEERs was failed. In addition, a core damage event was assumed to occur if the block wall separating the EDGs failed with a loss-of-offsite-power (LOOP) event. The following inputs and assumptions were used:

- The initiating event frequency for a steamline line break outside containment for a pressurized water reactor is 7.70E-3/year (from the 2010 Standardized Plant Analysis Risk (SPAR) Initiating Event Data Parameter Estimation Update).

- The initiating event frequency for a feedwater line break outside containment for a pressurized water reactor is 1.83E-3/year (from the 2010 SPAR Initiating Event Data Parameter Estimation Update).

- To determine the failure probability of not manually tripping the reactor and closing the MSIVs during a significant HELB event, the following was performed:

- Following a HELB outside containment, the human error probability that the operators would manually trip the reactor and close the MSIVs was determined using the SPAR-H human reliability analysis method (per NUREG/CR-6883). Using SPAR-H, only the Action portion of the task was evaluated to be applicable since a significant HELB in the turbine building would very likely be heard by the control room operators, indicated via alarms or indications, and immediately reported via a local operator, and so diagnosis of the HELB event would readily occur. The performance shaping factor for "Stress" was determined to be "High," with the other performance shaping factors at a nominal value. This resulted in a human error probability to manually trip the reactor and close the MSIVs of 2E-3.

- The failure-to-close probability of a MSIV is 1.20E-3 (from the Braidwood SPAR model version 8.21). Since there are four MSIVs that need to close to isolate a HELB outside containment, the failure probability due to valve failure is 4.8E-3.

- The total failure probability of not manually tripping the reactor and closing the MSIVs during a significant HELB event is the sum of the human error probability (2E-3) and the valve failure probability (4.8E-3) or 6.8E-3.

- The probability of the failure to close for a fire or ventilation damper is 2.7E-3/demand (from NUREG/CR-4840, Table 4.4).

- The probability of a LOOP following a reactor trip is 5.29E-3 (from the Braidwood SPAR model)

Using the above inputs and assumptions, a bounding ΔCDF was calculated for the failure of the MEER masonry block wall during a HELB event:

ΔCDF (MEER) = [7.70E-3/year + 1.83E-3/year] x [6.8E-3] x [2.7E-3/damper] x [2 dampers]

= 3.5E-7/year

The ΔCDF for the failure of the EDG masonry block wall during a HELB event is the above value multiplied by the probability of a LOOP following a reactor trip:

ΔCDF (EDGs) = [3.5E-7/year] x [5.29E-3]

= 1.9E-9/year

The total internal ΔCDF is the sum of the contributions calculated above for the failure of the MEER block wall and the EDG block wall or 3.52E-7/year.

Since the total estimated change in core damage frequency was greater than 1.0E-7/year, external events were evaluated for risk significance.

Fire risk contribution was screened because the performance deficiency is associated with a HELB event outside containment initiating event. A HELB event outside containment would not be considered in conjunction with a fire.

A seismic event can result in the failure of piping in the turbine building. It is expected that a seismic event will also result in a dual unit LOOP event. Since a dual unit LOOP event is a consequence of the initiator, the EDG function is required. To obtain a bounding estimate of the ΔCDF, the frequency of a seismic event sufficient to cause plant damage is determined. This frequency is multiplied by the probability of piping failure, which is then multiplied by the probability of damper failure to a MEER or EDG room.

Using guidance from NRC's Risk Assessment Standardization Project (RASP) handbook, only the "Bin 2" seismic events were assumed to represent a ΔCDF. "Bin 2" is defined in the RASP handbook as seismic events with intensities greater than 0.3g but less than 0.5g. Earthquakes of lesser severity are unlikely to result in pipe failures and earthquakes of a larger magnitude could result in major structural damage throughout the plant which would not be representative of a delta risk. The initiating event frequency of an earthquake in "Bin 2" for Braidwood was estimated to be 1.2E-5/year using Table 4A-1 of Section 4 of the RASP handbook. To estimate the seismic capacity of the piping in the turbine building, a conservative assumption was made that the high confidence of low probability of failure capacity for the affected piping in the turbine building was 0.3g. A failure probability of 3.9E-2 was then obtained for the piping. The frequency of a HELB event in the turbine building due to a seismic event was then obtained as 4.7E-7/year (i.e., 1.2E-5/year x 3.9E-2 = 4.7E-7/year). Multiplying this value by the failure probability of a damper (2.7E-3) in either the MEER or EDG rooms, the ΔCDF is:

ΔCDF = [4.7E-7/year] x [2.7E-3/damper] x [4 dampers]

= 5.1E-9/year

The total ΔCDF is the sum of the contributions calculated above for internal events and external events or 3.6E-7/year (i.e., 3.52E-7/year + 5.1E-9/year = 3.6E-7/year].

IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," was used to determine the potential risk contribution due to large early release frequency (LERF). Braidwood Station is a 4-loop Westinghouse pressurized water reactor with a large dry containment. Sequences important to large early release frequency include steam generator tube rupture events and inter-system LOCA events. These were not the dominant core damage sequences for this finding.

Based on this detailed risk evaluation, the senior reactor analysts determined that the finding was of very low safety significance (Green).

The cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area documented for the previous finding applied to this performance deficiency also because the licensee used non-conservative assumptions in an operability evaluation of auxiliary building block walls. Specifically, the licensee used non-conservative assumptions regarding the seismic/HELB load combinations and the allowable stress acceptance criteria in the evaluation of safety-related walls without providing adequate justification (H.1(b)).

<u>Enforcement</u>: The performance deficiency described above is an additional example of the previously issued finding (FIN 05000456/2012005-03; 05000457/2012005-03, Inadequate Functionality Evaluation of Block Walls for High Energy Line Break Loads) and does not involve enforcement action because no regulatory requirement was violated.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 2, 2013, the inspectors presented the inspection results to Mr. M. Kanavos, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that proprietary material received during the inspection was returned to the licensee and none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The Licensed Operator Requalification Program with Mr. M. Kanavos, Site Vice President, and other members of the licensee staff on July 26, 2013;

- The Licensed Operator Requalification Training annual operating test results with the Licensed Operator Requalification Lead Instructor, Mr. J. Taff, via telephone on August 29, 2013; and

- The inspection results of the follow-up inspection to support review and closure of High Energy Line Break concerns with Mr. M. Abbas, via telephone on October 25, 2013.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee or destroyed.

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 the NRC Enforcement Policy for being dispositioned as NCVs.

- Braidwood License Condition 2.E requires, in part, that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR, as supplemented and amended. Section 2.3.5.2 of the approved fire protection report describes the Division 22 engineered safety feature (ESF) switchgear room and refers to the description contained in Section 2.3.5.1. Section 2.3.5.1 describes the Division 12 ESF switchgear room and states that the floor is a 5-inch clear cover of structural reinforced concrete with a 3-inch concrete topping over 3-inch fluted steel decking formwork. The floor is supported by structural steel beams protected with a fire resistant covering and carries a 3-hour fire rating.

  Contrary to the above, on July 28, 2013, a licensee individual performing a routine firewatch activity in the Division 22 ESF switchgear room identified a 25-inch long by 6.5-inch wide section of the poured concrete floor missing and a small nickel-sized hole in the metal floor plate that opened into the 2B EDG room. The un-poured portion of the floor and the hole were previously hidden from view and were recently revealed during installation of an unrelated plant modification. The inspectors screened the issue in accordance with IMC 0612, Appendix B, "Issue Screening," and IMC 0609, Appendix F, "Fire Protection Significance Determination Process," and determined the finding was of very low safety significance (Green). This issue was entered into the licensee's CAP as IR 1540434, "GOCAR Un-poured Hole in Floor 426 L-30."

- Braidwood TS 5.4.1.a requires that the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, shall be established, implemented, and maintained. Section 1.I of Regulatory Guide 1.33 recommends procedures covering the plant fire protection program.

  Contrary to the above, on July 30, 2013, the licensee identified that hourly firewatches in the 2A EDG room required by procedure BwAP 1110-1A1, "GOCAR Required Compensatory Measures Action Response Fire Detection Instrumentation," Revision 8, had not been completed between 10:24 p.m. on July 29, 2013 and 3:30 p.m. on July 30, 2013, a span of approximately 17 hours. The inspectors screened the issue in accordance with IMC 0612, Appendix B, and IMC 0609, Appendix A, and determined the finding was of very low safety significance (Green). This issue was entered into the licensee's CAP as IR 1541347, "Missed Firewatches for 2A EDG Room.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Kanavos, Site Vice President
M. Marchionda, Plant Manager
J. Bashor, Engineering Director
P. Boyle, Site Work Management Director
A. Ferko, Operations Manager
B. Finlay, Site Security Manager
R. Leisure, Radiation Protection Manager
R. Radulovich, Nuclear Oversight Manager
J. Rappeport, Site Chemical Environment & Radwaste Manager
B. Schipiour, Site Maintenance Director
D. Stiles, Site Training Director
C. VanDenburg, Regulatory Assurance Manager

Nuclear Regulatory Commission

E. Duncan, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000456/2013004-01; 05000457/2013004-01	NCV	Failure to Perform a Required 10 CFR 50.59 Evaluation (Section 4OA5)
05000456/2013004-02; 05000457/2013004-02	FIN	Failure to Perform a Required 10 CFR 50.59 Evaluation (Section 4OA5)

Closed

05000456/2013003-04; 05000457/2013003-04	URI	Implementation of Lake Chemistry Management Program (Section 4OA2.5)
05000456/2012005-04; 05000457/2012005-04	URI	Functionality Evaluation of Block Walls for High Energy Line Break Loads (Section 4OA5)

Discussed

05000456/2012005-03; 05000457/2012005-03	FIN	Inadequate Functionality Evaluation of Block Walls for High Energy Line Break Loads (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

- IR 1555147; (OSP) 1AFFS01-8 AF Tunnel Flood Seal Gasket Found in UNSAT; September 6, 2013
- IR 1555152; (OSP) AF Tunnel Flood Seal Fasteners UNSAT; September 6, 2013
- IR 1559488; NRC Inspector Walkthrough Comment; September 16, 2013

1R04 Equipment Alignment

- IR 1549464; Lightning Strike on 345KV Line 2001; August 22, 2013
- BwOP DC-E2; Electrical Lineup – Unit 1 Operating 125V DC Division 11; Revision 8
- BwOP DC-E2; A1R12 Startup; April 28, 2006
- BwOP DC-E2; Restore 1DC05EB-ER I-13; May 16, 2013
- BwOP DC-E2; Position Breaker Per Lineup DC113, ER-1, CKT 16; August 22, 103
- BwOP DC-E3; Electrical Lineup – Unit 1 Operating 125V DC Division 12; Revision 7
- BwOP FC-M1; Valve 0FC012; Operating Mechanical Lineup Unit 1; Revision 9
- BwOP SX-E2; Electrical Lineup – Unit 2 Essential Service Water System; Revision 12
- BwOP SX-M2; Operating Mechanical Lineup Unit 2; Revision 31
- Drawing M-42 Sheet 1B; Essential Service Water Units 1 & 2; July 23, 1975
- Drawing M-42 Sheet 6; Essential Service Water; February 3, 1976
- Drawing M-42A; Essential Service Water (Composite) Units 1 & 2; December 1, 1978
- Drawing M-63; Fuel Pool Cooling and Clean-up Units 1 & 2 – Sheets 1A, 1B & 1C; July 23, 1975
- Drawing M-122; Auxiliary Feed Water Unit 2; June 9, 1975
- Drawing M-126 Sheet 1; Essential Service Water Unit 2; July 23, 1975
- Drawing M-126 Sheet 2; Essential Service Water Unit 2; December 23, 1976

1R05 Fire Protection

- IR 1540434; GOCAR Un-poured Hole in Floor 426 L-30; July 28, 2013
- IR 1541347; Missed Firewatches for 2A DG Room; July 29, 2013
- BwAP 1110-1A1; GOCAR Required Compensatory Measures Action Response Fire Detection Instrumentation – 1 Hour; Revision 8
- Braidwood Fire Protection Report Sections 2.3.1.1, 2.3.1.3, 2.3.1.5, 2.3.5.1, 2.3.5.2, 2.3.5.7, 2.3.5.11, 2.3.9.1, and 2.3.9.2

1R06 Flood Protection Measures

- IR 1449644, NRC Question Regarding BwAP 1110-3 and DOST Water Tight Door, December 7, 2012
- IR 1544196; Cable Vault 1F Constant Recirculation – 1DM03J, August 7, 2013
- IR 1546265; 2B CW Pump Low Insulation Resistance Measurement Obtained, August 13, 2013
- IR 1547823; Cable Vault 2G Sump Pump Needs Repair, August 17, 2013

- IR 1549132; Lessons Learned From 2B CW Pump Motor Work, August 21, 2013
- EC 393714, Turbine Building Flooding Analysis, Revision 0
- BRW-13-0102-M, Circulating Water Piping Seismic Analysis, Revision 0

1R11 Licensed Operator Requalification Program

- IR 1373856, Emergent Tech Spec 1AR12J Due to Non-Conservative Setpoint; June 3, 2012
- IR 1379674, NRC Walkdown for AF (Auxiliary Feedwater) Battery Blocks; June 19, 2012
- IR 1383554, PI&R: Action to Address Previous Issue Not Adequate; June 29, 2012
- IR 1442262, NRC Green Finding – SG (Steam Generator) PORV (Power Operated Relief Valve) Operability Evaluation; November 19, 2012
- IR 1450616, Trend In DEP Failures; December 10, 2012
- TQ-AA-150; Operator Training Programs; Revision 8
- TQ-AA-150-F03A; JPM Evaluation Results Crew 2 RO; Revision 3, September 6, 2012
- TQ-AA-150-F03A; JPM Evaluation Results Crew 2 SRO; Revision 3, September 6, 2012
- TQ-AA-150-F03A; JPM Evaluation Results Crew 3 RO; Revision 3, July 25, 2013
- TQ-AA-150-F03A; JPM Evaluation Results Crew 3 SRO; Revision 3, July 25, 2013
- TQ-AA-155-F05; Simulator Evaluation-Crew 3; Revision 1, Cycle 13-05
- TQ-AA-155-F04; Simulator Evaluation-Crew 3 Individuals; Revision 1, Cycle 13-05
- TQ-AA-155-F02; Simulator Evaluation-Shift Manager; Revision 1, Cycle 13-05
- TQ-AA-201; Examination Security and Administration; Revision 15
- TQ-AA-224-F090; Braidwood LORT NRC Biennial Written Examinations; 2012
- TQ-AA-306; Simulator Management; Revision 5
- TQ-AA-306-F-10; PWR Moderator Temperature Coefficient of Reactivity; Revision 2
- TQ-AA-306-F-11; PWR Rod Worth Coefficient of Reactivity; Revision 3
- TQ-AA-306-F-12; PWR Boron Coefficient of Reactivity; Revision 3
- TQ-AA-306-F-13; PWR Xenon Worths; Revision 3
- TQ-AA-306-F-16; PWR Approach to Criticality Using Boric Acid; Revision 3
- TQ-AA-306-F-17; PWR Approach to Criticality Using Control Rods; Revision 3
- TQ-BR-302-0103; Braidwood Simulator Steady State Testing; Revision 3
- TQ-BR-302-TR-2 Simulator Transient Test; Simultaneous Trip of All Main Feed Pumps; Revision 3
- OP-AA-105-102; Qualified Shifts Worked; 1st and 2nd Quarter 2013
- OP-AA-105-102; Attachment 2, Reactivation of License Log; Revision 9
- OP-BR-102-106; Operator Response Time Program at Braidwood Station; Revision 1
- OP-AA-102-106; Operator Response Time; Revision 1
- OP-AA-105-101; Administrative Process for NRC License and Medical Requirements; Revision14
- NOSA-BRW-12-06 (AR 1299940); Training and Staffing Audit Report Braidwood Station; May 21-June 6, 2012
- NOSA-BRW-11-08 (AR1141015); Operations Functional Area Audit Report Braidwood Station; October 17-27, 2011
- LS-AA-126-001; Focused Area Self-Assessment (FASA); Revision 7
- Simulator Work Request (SWR) 07730, EC 350253; Containment Sump Level Mod/GEMS; April 13, 2005
- SWR 14515, EC 390213; Loss of Phase Protection; Revision 1, January 25, 2013
- SWR 14725, MSXFNET (modeling code); Error Stops Simulation; May 9, 2013
- SWR 14841, EC 392851; Degraded Voltage Five Minute Timer Resolution; July 8, 2013
- Braidwood Station Open Simulator Work Requests; Multiple; Various Dates

- Braidwood Station Closed Simulator Work Requests; Multiple; Various Dates
- Differences Between Braidwood Simulator and Unit 1; Approved by Simulator Review Board Cycle 12-02
- 1 RO and 1 SRO Remediation Training and Evaluation Package; 2013
- 2013 Annual Operating Test; 2 Dynamic Simulator Scenarios; Week 1
- 2013 Annual Operating Test; 10 JPMs, Week 1
- 2013 Annual Operating Test; 2 Dynamic Simulator Scenarios; Week 3
- 2013 Annual Operating Test; 2 Dynamic Simulator Scenarios; Week 5
- Medical Records for 10 Licensed Operators

1R12 Maintenance Effectiveness

- IR 1514638, Non-ESF SWGR Ventilation Effects Control Room Envelope, May 16, 2013
- IR 1536133, Control Room Ventilation Train B Emergency Makeup Damper 0VC08Y Failed Open, July 16, 2013
- IR 1538889, VC System Maintenance Rule (a)(1) Determination, July 23, 2013
- IR 1534406, 0BwOSR5.5.18.D-1/2, Procedure Revision Required, July 11, 2013
- IR 1535355, B-Train VC EMU Flow High, July 14, 2013
- IR 1542972, 0VC24Y Failed Open – 0FZ-VC005B, August 3, 2013
- IR 1543050, Adverse Trend IR: VC System NH91 Damper Actuators, August 3, 2013
- IR 1553206, Sporadic Main Control Room Pressure Low Alarms – 0PDI-VC038D, September 1, 2013
- IR 1557140, Ventilation Effects on the MCR Envelope during Mod Testing, September 11, 2013
- Maintenance Rule Evaluation, Main Control Room HVAC, April to June, 2013

1R13 Maintenance Risk Assessments and Emergent Work Control

- IR 1511847; 0VC08Y Opened Unexpectedly; May 8, 2013
- IR 1512369; Requirements for Aligning VC Makeup Suction; May 9, 2013
- IR 1519660; Lack of Detail in Log Entries; May 5, 2013
- IR 1528059; 0PDI-VC-38B Indication Suspect; June 26, 2013
- IR 1529906; Valve Indicated Dual When Fully Open – 0VC25Y; June 27, 2013
- IR 1530080; Contingency Action for Upcoming Control Room Envelp DP Test; June 28, 2013
- IR 1530416; Transmitter Failed Calibration – 0PDT-VC038B; June 28, 2013
- IR 1533140; 0TI-VC171 and/or 0TI-VC170 Read 5 Degrees Off; July 8, 2013
- IR 1534406; 0BwOSR 5.5.18.D-1/2 Procedure Revision Required; July 11, 2013
- IR 1534859; 2A MSIV Fyrquel Leak – 2MS001A-B; July 12, 2013
- IR 1535331; MCR B-Train VC EMU HI Flow Alarm; July 13, 2013
- IR 1535355; B-Train VC EMU Flow High; July 13, 2013
- IR 1535415; MCR M/U Fan 0B Low Flow Alarm on Startup – 0FY-VC235; July 14, 2013
- IR 1535430; MCR Low Pressure Alarm Toggling; July 14, 2013
- IR 1535434; VC Sys Eng to Evaluate Test Results of 0BwOSR 55.18.D-2; July 14, 2013
- IR 1545807; Rollup IR for Calcium Carbonate Scaling; August 12, 2013
- IR 1554294; 2A13 – NRC URI – Implementation of Lake Chem Mgmt Program; August 14, 2013
- Apparent Cause Report #02; Calcium Carbonate Scaling – IR 1545807
- BwOP CW-2; Circulating Water Pump/System Shutdown; Revision 31
- 1BwOSR 3.3.2.8-602A; U1 ESFAS Instrumentation Slave Relay Surveillance (Train A – KL602, K647, and K648); Revision 17

- 0BwOSR 3.7.10.1-1; Control Room Ventilation Filtration Surveillance – Train A; Revision 8, 9, and 10
- 0BwOSR 5.5.18.d-1; Control Room Envelope Pressurization Surveillance (Train A); Revision 6
- CY-BR-120-412; Braidwood Station Lake Chemistry Control; Revision 10
- EC 389634; MCR VC HELB Pressure Sensor to Control Emergency Intake Dampers (U0); Revisions 001 and 002
- EC 393868; Lake Model – Impact of Shutting Down CW Pump(s) on UHS Temperature; July 7, 2013
- EN-BR-401-0005; Extreme Heat Implementation Plan; July 18, 2013
- EP-AA-1001; Recognition Category Hazards and Other Conditions Affecting Plant Safety; Revision 31
- ER-AA-390-1001; Mitigating Actions or Compensatory Measures Allowable on an Interim Basis and Corrective Actions for Inoperable CRE Boundary; Revision 6
- ER-AA-600-1042; On-Line Risk Management; Revision 7
- HU-AA-104-101; Procedure Use and Adherence; Revision 4
- OP-AA-102-104; Crew Review of Noteworthy Event/Near Miss/Change; Incorrect Log Entries; June 12, 2013
- OP-AA-108-117; Protected Equipment Program; Revision 3
- OP-AA-111-101; Operating Narrative Logs and Records; Revision 8
- WO 01632143 01; U0 CR Vent Train A Monthly Surveillance; May 9, 2013
- 50.59 BRW-E-2012-194; MCR VC HELB Pressure Sensor to Control Emergency Intake Dampers Modification (U0); Revision 0
- Reg Guide 1.183; Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors; July 2000
- Night Shift Logs; May 9, 2013; Control Room Ventilation
- Night Shift Logs; July 11 and 12, 2013; 2A MSIV
- Letter from NRC to Exelon; Byron U1 & U2 and Braidwood U1 and U2 – Issuance of Amendments Re: Alternative Source Term; September 8, 2006
- Letter from AmerGen to NRC Sites; Exelon/AmerGen Application to Revise TS Re Control Room Envelope Habitability in Accordance with TSTF-448, Revision 3, Using Consolidated Line Item Improvement Process; April 12, 2007
- Drawing M-96; Control Room HVAC System

<u>1R15 Operability Evaluations</u>

- IR 0628474; Through Wall Leakage Line 2SX27DA-10:; May 11, 2007
- IR 0633391; SX System Piping Corrosion; August 15, 2007
- IR 1536573; 2A EDG Failed Monthly Run and is Inoperable; July 17, 2013
- IR 1536832; Initial EOC Inspection Based on Byron DG Event; July 17, 2013
- IR 1542372; SX Piping Leak; August 1, 2013
- IR 1542390; Indicator Conduit Impacted From SX Piping Leak; August 1, 2012
- Op Eval 11-010; Auxiliary Feed Pumps 1/2AF01PA/B (IR 1202772); Revision 2
- Op Eval 11-012; Flow Circulation Issue of 1SX04P During Loss of All AC Scenario (IR 1265614); Revision 01
- BYR13-026/BRW-13-0031-M; Transient Analysis of SX System Following Loss of AC Power (EC#393571); Revision 0
- Drawing KSV-18-3; Fuel Injection Pump; December 15, 1976
- Drawing M-42A; Essential Service Water (Composite) Units 1 & 2; Sheets 1A, 1B, 2A, 2B, 3, 4, 5A, 5B, and 6

1R18 Plant Modifications

- IR 1440257; Pressurizer Spray Line Temp Low Alarm Received – 2RY455B; November 14, 2012
- IR 1460458; WR Needed for Simple Troubleshooter for 2RY455B; January 9, 2013
- IR 1462344; Results of Unit 2 Pressurizer Heater Trouble Shooting; January 14, 2013
- IR 1462637; A2R17 or Forced Outage PZR Spray Bypass BwVP 200-27; January 15, 2013
- IR 1466130; A2R17 Check Calibration of RTD Loop 2RY-1451, PZR Spray; January 23, 2013
- EC 392178 000; PZR Spray Flow Bias for 2PC-0455B Controller Valve 2RY455B (IR 1462344); Revision 0
- CC-AA-102; Design Considerations Summary EC 392178 000; Revision 26
- CC-MW-112-1001; TCP Installation and Removal Authorizations; Revision 11
- 50.59 Screening - TCCP EC 392178/BwAR 2-12-B6/2BwGP 100-1A1; Pressurizer Spray Flow Bias for 2PC-0455B Controller – Temporary Configuration Change; Revision 0/7A-14A
- EC 393552, Changes to Unit 1 AB System due to Transient Analyses, Revision 0

1R19 Post-Maintenance Testing

- IR 1018119; CDBI FASA Additional Actions Required to Address EDG Frequency Variation; January 19, 2010
- IR 1408821; NRC ID: DG MCB Frequency Meter Banding Discrepancy; September 4, 2012
- IR 1428765; Abnormal Trace Indications for 2B DG Sequence Test; October 19, 2012
- IR 1445997; 2B DG Engine Analysis Data Lost Due to Computer Problems; November 20, 2012
- IR 1467778; Braidwood and Byron DG Vulnerability Review Gaps; January 28, 2013
- IR 1484171; 2A DG Monitoring System Frequency Channel – 2DGA013; March 6, 2013
- IR 1507042; Class 3 Bolting Replaced Without Section XI R/R Plan; December 14, 2012
- IR 1557852; (OSP) Unexpected Breaker Trip – U1 ESF Battery Modified Perform Test; September 12, 2013
- IR 1558466; A1R17 Lessons Learned – DC Testing and Maintenance; September 13, 2012
- IR 1558634; 1A EDG Emergency Trip Lever Further Degradation – 1DG01KA; September 14, 2013
- IR 1559548; 1B EDG DRU Bench Setup Discrepancies; September 15, 2013
- IR 1560143; (OSP) 1B DG Butterfly Valve Didn't Close During Overspeed Test; September 17, 2013
- IR 1560712; 1B EDG Idle Timer Needs Adjustment; September 17, 2013
- IR 1560714; 1B EDG Idle Operation Needs Tuning; September 18, 2013
- IR 1560718; 1B EDG Operates 60.25 HZ No Load Isochronous Mode; September 18, 2013
- BwAP 500-17; Guidance for Routing of Temporary Cables and Hoses; Revision 0
- BwHP 384-1; Operation of the BCT-2000; Revision 1 (September 12, 2013)
- EC 179481; 125 VDC Battery Charger Assembly (1DC03E); Revision 0
- WC-AA-104; 1DC01E Modified Performance Test – WO 01580852-01; Revision 18
- WO 01580852 01; Unit 1 125 Bolt Battery Modified Performance Test; September 12, 2013
- IEEE Standard 450-1995; IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications; January 24, 1995
- Maintenance Turnover Notes From Shift 2; WR/O 1580852-01, EPN 1DC01E; September 12, 2013
- Diagram of ESF 125VDC Battery Service Test and Modified Performance Test Set-Up (Typical for 111 and 212)

1R20 Refueling and Other Outage Activities

- IR 1557143; (OSP) 1RY455A Failed Accumulator IA Check Valve Test; September 11, 2013
- IR 1557145; (OSP) 1RY456 Failed Accumulator IA Check Valve Test; September 11, 2013
- EC 392231 000; Pressurizer PORV Cycles During Natural Circulation Cooldown; February 6, 2013
- 1BwGP 100-4; Power Descension; Revision 34
- BwVS 500-6; Low Power Physics Test Program; Revision 34
- 0BwOS MP-A1; Units 1 and 2 Main Generators Maximum VARs Surveillance; Revision 4
- 0BOSR MP-1; Unit One and Unit Two Main Generator VAR Surveillance; Revision 7
- EN #49371; 1RH01Sa and 1RH01SB for SI ECCS Sump CIVs (1SI8811A and 1SI8811B) Determined to Not be Leak Tight; September 9, 2013
- OP-AA-108-115; Op Eval 13-001 Revision 0, Capacity of Pressurizer PORV Air Accumulators during Natural Circulation Cooldown (IR 1459353 and 1468044); Revision 11
- OP-AA-108-117; Protected Equipment Program; Revision 2 and 3
- Operations Log; MP-A1 from May 9, 2004 to September 9, 2013
- Exelon Letter RS-13-234 to NRC; Relief Request 13R-11 Associated with Alternative Requirements for Repair/Replacement of CRDM Canopy Seal Welds; September 19, 2013

1R22 Surveillance Testing

- BwMSR 3.7.1.1; Main Steam Safety Valves Operability Test (Setpoint Verification Using the Furmanite Trevitest System; Revision 10
- BwOP CS-5; Containment Spray System Recirculation to the RWST; Revision 20
  BwOP PC-1; Local Leak Rate Flow Meter Monitor Operation; Revision 18
- 1BwOSR 3.6.1.1-9; Primary Containment Type C Local Leakage Rate Tests of Chemical and Volume Control System; Revision 14
- 1BwOSR 5.5.8.CS-3A; Comprehensive Full Flow Test for 1A Containment Spray Pump (1CS01PA) and Check Valves 1CS003A, 1CS011A; Revision 11
- WO 01538355 01; IST-LT-U1-LLRT CV 8100/8112/8113 P28 Seal Return; September 17, 2013
- WO -1653471 01; IST For 1CS003A/11A-U1 ASME Surveillance Requirements For 1CS01PA and Check Valve; September 4, 2013
- Drawing M-64; Unit 1 Chemical & Volume Control & Boron Thermal Regeneration

4OA2 Problem Identification and Resolution

- IR 1533215; 0PS01J SGBD Panel Annunciator Alarm Not Working, July 8, 2013
- CC-AA-109; Interim Abandoned Equipment Identification, Evaluation and control; Revisions 3, 4, and 6
- EC 362885; Boric Acid Recycle Evaporator System
- Steam Generator Blowdown Replacement Sample Panel Specification # 19-6-001, Revision 0
- CY-AP-120-200; Recirculating Steam Generator Chemistry, Revision 10
- BwCP PD-4T1; Chemistry Rounds Sheet, Revision 20
- BwAR 0PS01J-1-C1; Primary Cooling Water Pump Trip, Revision 6
- BwAR 0PS01J-1-C2; PH Steam Generator Blowdown Sample 1A7B/C Low Alarm, Revision 11
- BwAR 0PS01J-1-D3; Temperature Finish and Rough Cooling High Alarm, Revision 7
- BwAR 0PS01J-1-D6; Sodium Steam Generator Blowdown Sample 1A7/B/C High Alarm, Revision 9
- 1BwOA SEC-2; Abnormal Secondary Chemistry Unit 1, Revision 103

4OA5 Other

- IR 1555159; NRC TIA Conclusion on Seismic/HELB Concurrent loads on AB Walls, September 6, 2013
- 10 CFR 50.59 Evaluation for 1/2BwOA SEC-4, Revision 3; August 16, 2013
- 10 CFR 50.59 Screening for 0/1/2BwOA SEC-4, Revision 3; July 16, 1998
- 1BwOA SEC-4; Loss of Instrument Air Unit 1, Revision 103

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access Management System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CC	Component Cooling Water
CFR	Code of Federal Regulations
ΔCDF	Delta Core Damage Frequency
DC	Direct Current
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FC	Fuel Pool Cooling System
FIN	Finding
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report/Inspection Report
JPM	Job Performance Measure
kV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LORT	Licensed Operator Requalification Training
MEER	Miscellaneous Electrical Equipment Room
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PIM	Plant Issues Matrix
PORV	Power Operated Relief Valve
RASP	Risk Assessment Standardized Project
RCP	Reactor Coolant Pump
RFO	Refueling Outage
RWST	Refueling Water Storage Tank
SAT	Systems Approach to Training
SDP	Significance Determination Process
SGBDP	Steam Generator Blowdown Panel
SAR	Safety Analysis Report
SPAR	Standardized Plant Analysis Risk
SSC	Structure, System, or Component
SX	Essential Service Water
TIA	Task Interface Agreement
TRM	Technical Requirements Manual
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VCT	Volume Control Tank

VDC	Volt Direct Current
WO	Work Order

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Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-456; 50-457
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Letter to Michael J. Pacilio from Eric R. Duncan dated November 14, 2013

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000456/2013004; 05000457/2013004

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