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

August 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 05000456/2013003; 05000457/2013003 AND 07200073/2013001

Dear Mr. Pacilio:

On June 30, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Braidwood Station, Units 1 and 2. The enclosed inspection report documents the results of this inspection, which were discussed at an exit meeting on July 17, 2013, with Ms. M. Marchionda-Palmer, 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.

One self-revealed finding and five NRC-identified findings of very low safety significance were identified during this inspection. Four of these findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating these violations as Non-Cited Violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

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

If you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and 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.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosures: Inspection Report 05000456/2013003
05000457/2013003; and 07200073/2013001
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:	05000456/2013003; 05000457/2013003
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	April 1 through June 30, 2013
Inspectors:	J. Benjamin, Senior Resident Inspector A. Garmoe, Resident Inspector J. Neurauter, Senior Reactor Inspector J. Carujo-Sandin, Reactor Engineer A. Dahbur, Reactor Engineer T. Daun, Reactor Engineer A. Dunlop, Reactor Engineer R. Edwards, Reactor Inspector N. Feliz-Adorno, Reactor Engineer T. Go, Health Physicist M. Learn, Reactor Engineer V. Meghani, Reactor Inspector R. Ng, Project Engineer A. Sallman, Senior Reactor Systems Engineer, NRR J. Robbins, Resident Inspector, Byron M. Perry, Resident Inspector Illinois Emergency Management Agency
Approved by:	E. Duncan Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000456/2013003; 05000457/2013003 and 07200073/2013001; 04/01/2013 - 06/30/13; Braidwood Station, Units 1 & 2; Flood Protection Measures, Maintenance Effectiveness, Problem Identification and Resolution, and Other

This report covers a 3-month period of inspection by resident inspectors, announced baseline inspections by regional inspectors, and regional inspectors of operational activities associated with an Independent Spent Fuel Storage Installation (ISFSI). Six Green findings were identified by the inspectors. Four of these findings involved non-cited violations (NCVs) of NRC requirements. 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 (SDP)," 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 (ROP)," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance when licensee personnel failed to identify degraded Diesel Oil Storage Tank (DOST) room sump discharge check valves in 2013 and after performing periodic testing in 2005. The licensee entered this issue into their Corrective Action Program (CAP) as Issue Report (IR) 1526652, "IR Not Generated as Required – 2005 OD Check Valve UT [Ultrasonic Testing] Results." Corrective actions included the repair of the degraded DOST room sump check valves.

  The inspectors determined that the failure to identify issues associated with degraded DOST room sump pump discharge check valves was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the Protection Against External Factors attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Since the finding resulted in the potential for a loss of the emergency power function during a turbine building flooding event, and based upon an actual DOST room sump check valve failure, a detailed risk evaluation was performed, which determined that the finding was of very low safety significance. This finding had a cross-cutting aspect in the Corrective Action Program component of the Problem Identification and Resolution (PI&R) cross-cutting area because the licensee failed to take appropriate corrective actions in a timely manner to address degraded DOST room sump check valves (P.1(d)). (Section 1R06.1.b)

- Green. The inspectors identified a finding of very low safety significance and an associated non-cited violation of 10 CFR 50.65(b)(2)(ii) when licensee personnel failed to scope four Unit 1 and Unit 2 Essential Service Water (SX) pump room sump pump discharge check valves and eight Unit 1 and Unit 2 DOST room sump pump discharge check valves into the Maintenance Rule as required. The licensee entered this issue into their CAP as IR 1498897, "Review 1/2WF040A/B Valves for Inclusion Into MRule [Maintenance Rule]," and planned to scope the components into the Maintenance Rule.

The inspectors determined that the failure to scope the Unit 1 and Unit 2 SX pump room sump pump discharge check valves and Unit 1 and Unit 2 DOST room sump pump discharge check valves into the Maintenance Rule was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because, if left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern. Since a degraded SX or DOST sump check valve would degrade one or more trains of a system that supported a risk-significant system or function, a detailed risk evaluation was performed that determined the finding was of very low safety significance. This finding had a cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area because the licensee failed to use conservative assumptions readily available in the applicable guidance document to demonstrate that not scoping the components into the Maintenance Rule was in accordance with Maintenance Rule requirements and therefore maintained safety (H.1(b)). (Section 1R12.1.b)

- <u>Green</u>. A finding of very low safety significance was self-revealed when licensee personnel performed inadequate functionality evaluations after previously identifying that the Unit 1 Boric Acid Storage Tank (BAST) bladder was degraded. The licensee entered this issue into their CAP as IR 1498696, "Secured Boric Acid Tank Transfer Earlier Than Expected." Corrective actions included the replacement of the Unit 1 and Unit 2 BAST bladders.

  The inspectors determined that the failure to adequately evaluate Unit 1 BAST system functionality after identifying that the Unit 1 BAST bladder had substantially degraded was a performance deficiency. The inspectors determined the performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors screened the finding using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors answered 'No' to all of the Mitigating System Screening questions for Reactivity Control Systems, therefore the finding screened as having very low safety significance. This finding had a cross-cutting aspect in the Operating Experience component of the PI&R cross-cutting area because the licensee failed to implement and institutionalize Operating Experience that specifically discussed the potential adverse consequences that a degraded tank bladder could have on plant safety (P.2(b)). (Section 4OA2.6)

- <u>Green</u>. The inspectors identified a finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to maintain the procedural requirement to commence a reactor coolant system (RCS) cooldown within 2 hours following a design basis seismic event that included a reactor trip, failure of all nonsafety-related equipment, and limiting single active failure. The licensee entered this issue into their CAP as IR 1496506, "NRC Identified PZR [Pressurizer] PORV [Power-Operated Relief Valve] Natural Circulation Cooldown Analysis." Corrective actions included development of a revised instruction in the Emergency Operating Procedures (EOPs).

The inspectors determined that the failure to adequately revise an EOP was a performance deficiency. Specifically, the licensee removed a procedural requirement to commence an RCS natural circulation cooldown if instrument air was lost to containment, which inadvertently could adversely affect a safety-related PZR PORV function. The inspectors determined that the performance deficiency was more than minor because it was associated with the Procedural Quality attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e, core damage.) The inspectors evaluated this finding using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," and determined that this finding was of very low safety significance because the issue was determined to not be a confirmed loss of operability or functionality. This finding had a cross-cutting aspect in the Corrective Action Program component of the PI&R cross-cutting area because licensee personnel failed to thoroughly evaluate a problem and ensure that the resolution adequately addressed the cause and extent of condition, as necessary. Specifically, the licensee failed to adequately evaluate a prior NRC finding such that the corrective actions adequately addressed the problem (P.1(c)). (Section 4OA5.3)

- Green. The inspectors identified a finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to account for PZR PORV accumulator air system leakage during the assumed 2 hour time spent in hot standby following a limiting seismic event. The licensee entered this issue into their CAP as IR 1481590, "NRC Question Regarding Pressurizer PORV Accumulator Leakage." As part of their corrective actions, the licensee planned to revise procedures and seek clarification from the NRC concerning the licensing basis of the auxiliary spray system.

  The inspectors determined that the failure to ensure that the PZR PORVs could perform their credited safety function following a limiting seismic event was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the Design Control attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The inspectors evaluated this finding using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," and determined that the finding was of very low safety significance because the issue was determined to not be a confirmed loss of operability or functionality. This finding had a cross-cutting aspect in the Corrective Action Program component of the PI&R cross-cutting area because the licensee failed to thoroughly evaluate a problem such that the resolution addressed causes and extent of condition, as necessary. Specifically, the licensee failed to adequately evaluate not accounting for PZR PORV air accumulator leakage in the natural circulation cooldown current licensing basis (CLB) due to the reliance on another system to provide the credited safety function (P.1(c)). (Section 4OA5.4)

Cornerstone: Miscellaneous

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to adhere to design requirements specified for a special lifting device used to handle a transfer cask containing spent nuclear fuel in the vicinity of the spent fuel pool. The licensee entered this issue into their CAP as IR 1509204, "Required NDE [Nondestructive Examination] Not Performed on Lift Yoke," and IR 1509602, "Lift Yoke Stud Nuts Not Lock Wired." As part of their corrective actions, the licensee performed required tests and installed lock wire in accordance with design drawings prior to conducting additional lifts with the special lifting device.

The inspectors determined that the failure to adhere to design drawings and American National Standards Institute (ANSI) requirements for annual testing of a special lifting device was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it was associated with the Design Control attribute of the Barrier Integrity Cornerstone and adversely impacted the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radioactive releases caused by accidents or events. The inspectors evaluated the finding using IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions." The inspectors answered 'No' to all the screening questions in Appendix A, Exhibit 3, and therefore the finding screened as having very low safety significance. This finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area since the licensee failed to have complete, accurate, and up-to-date design documentation and procedures that ensured personnel, equipment, procedures, and other resources were available and adequate to assure nuclear safety. Specifically the licensee's procedures for annual testing of a special lifting device lacked specific guidance, and design changes were made that conflicted with design drawings (H.2(c)). (Section 4OA5.2.b)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

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

Unit 2 operated at or near full power for the entire inspection period with one exception. On June 28, 2013, Unit 2 was shut down for a planned maintenance outage to replace the 2A and 2B reactor coolant pump (RCP) seal packages. Unit 2 remained shut down at the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current (AC) Power Systems

a. Inspection Scope

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

- The coordination between the TSO and plant personnel during off-normal or emergency events;
- The explanations for the events;
- The estimates of when the offsite power system would be returned to a normal state; and
- The notifications from the TSO to plant personnel when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

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

- The communications between plant personnel and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

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

b. Findings

No findings were identified.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems, including conditions that could lead to an extended drought.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Ultimate Heat Sink (UHS); and
- Auxiliary Building Ventilation.

Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.3 Readiness for Impending Adverse Weather Condition – Severe Thunderstorm Warning

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for May 28, 2013, the inspectors reviewed the licensee's overall preparations and protection for the expected weather conditions. On May 28, 2013, the inspectors walked down the switchyard exclusion area and surrounding secured material zone area, in addition to the licensee's emergency AC power systems, because their required functions could be adversely affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power (LOOP). The inspectors compared the licensee staff's preparations with the site's procedures and determined whether the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. The inspectors also verified that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.4 Readiness For Impending Adverse Weather Condition - Heavy Rain and Local Flooding

a. Inspection Scope

On April 18, 2013, heavy rain and local flooding were forecast. The inspectors observed the licensee's preparations and planning for the potentially significant adverse weather. The inspectors reviewed licensee procedures and discussed potential compensatory measures with control room staff. The inspectors focused on plant-specific design features and implementation of the procedures for responding to or mitigating the effects of these conditions on the operation of the facility. Inspection activities included a review of the licensee's adverse weather procedures, daily monitoring of the off-normal environmental conditions, and a determination of whether operator actions specified by plant-specific procedures were appropriate to ensure safe operation of the facility.

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

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 2A Emergency Diesel Generator (EDG) with 2B EDG Out-of-Service (OOS);
- Unit 1 EDGs During Unit 1 Station Auxiliary Transformer (SAT) Outage;
- Unit 1 Boric Acid Storage Tank (BAST) with Unit 2 BAST OOS; and
- Unit 2 Train B Safety Injection System Following Maintenance.

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 CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

This inspection constituted four partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Station Auxiliary Diesel Generator - Fire Zone 8.7A-0;
- Station Auxiliary Diesel Oil Storage Tank (DOST) - Fire Zone 8.7B-0;

- Main Control Room Heating Ventilation and Air Conditioning (HVAC) Room Train A - Fire Zone 18.4-1;
- Main Control Room HVAC Room Train B - Fire Zone 18.4-2;
- Unit 2 Auxiliary Electrical Equipment Room - Fire Zone 5.5-1;
- Unit 2 Lower Cable Spreading Room - Fire Zone 3.2D-2;
- Elevation 451' Diesel Generator 2A Switchgear Room Air Shaft – Fire Zone 18.2-2;
- Elevation 451' Division 21 Miscellaneous Electrical Equipment Room (MEER) and Battery – Fire Zone 5.6-2; and
- Elevation 451' Division 22 MEER and Battery – Fire Zone 5.4-2.

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 OOS, 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.

This inspection constituted nine quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. <u>Findings</u>

No findings were identified.

1R06 <u>Flooding</u> (71111.06)

.1 <u>Internal Flooding</u>

a. <u>Inspection Scope</u>

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

- Auxiliary Building to Turbine Building Watertight “L” Wall Interface Below 401’ Grade Level.

Documents reviewed are listed in the Attachment.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

(1) Failure to Identify and Correct Degraded DOST Room Sump Pump Check Valves

Introduction: The inspectors identified a finding of very low safety significance (Green) when licensee personnel failed to identify degraded DOST room sump discharge check valves in 2013 (Issue of Concern 1) and after performing periodic testing in 2005 (Issue of Concern 2). Specifically, in February 2005, a periodic DOST room sump pump discharge check valve ultrasonic test (UT) revealed that five of the eight Unit 1 and Unit 2 DOST room sump pump discharge check valves were potentially leaking water back into their associated sumps, as evidenced by complete or partial downstream pipe voiding. The licensee failed to identify these test results as an issue and, as a result, did not initiate an IR and follow the associated CAP standards until identified by the inspectors during this inspection period. In addition, a periodic UT performed in June 2013 for Unit 2 DOST room sump check valve 2OD001D failed to identify that the check valve was degraded and leaking until questioned by the inspectors.

Description: Braidwood UFSAR Section 10.4.5, “Circulating Water System,” describes that the auxiliary building is completely watertight below grade elevation at the turbine building to auxiliary building interface with the exception of the main steam tunnel. The current licensing basis (CLB) assumes that a failure of a CW pipe or CW main condenser expansion joint (EJ) could result in flooding the turbine building to an elevation of 396’, which was only a few feet below the plant grade level of 401’.

The DOST rooms are located in the auxiliary building at about the 383’ elevation and have room sumps with sump pumps that discharge into the turbine building sump system. The DOST sump systems rely on nonsafety-related sump pump discharge check valves to provide a watertight barrier such that a CW system line break or CW EJ failure and subsequent turbine building flooding event will not adversely affect the safety-related systems in the DOST rooms (the long-term EDG fuel oil supply and fuel oil transfer system). The nonsafety-related DOST room sump pumps are not discussed in the UFSAR, are not seismically qualified, are powered by a nonsafety-related power supply, and were not scoped into the Maintenance Rule.

On June 7, 2013, based upon operating experience at Byron, Braidwood identified that the eight Unit 1 and Unit 2 DOST room sump pump discharge check valves were installed with elastomers that were not compatible with diesel fuel oil. Byron IR 1469869, “Mispositioned O-Ring Found During As-Found Inspection,” dated June 11, 2013; and Byron IR 1522293, “Expedite Work Orders to Replace OD Check Valve O-Rings,” dated June 17, 2013, documented a DOST room sump pump discharge check valve failure after performing a periodic preventative maintenance activity that involved removing the check valve from service and conducting a visual inspection of the individual check valve components. The visual examination identified that the check valve disc o-ring was swollen and had slipped out of the disc groove. As a result, the check valve was not able to prevent back leakage from the turbine building into the DOST room sump. Byron identified that the elastomers utilized in the seat o-ring were not designed for a fuel oil application and were swollen as a result of having been exposed to fuel oil. Since flow into the individual DOST room sumps included both water and fuel oil, the licensee determined that the check valve elastomers were non-conforming for their design application. Byron classified this issue as a maintenance rule functional failure.

Issue of Concern 1 - Failure to Identify an Issue in 2013

In response to this Byron operating experience, Braidwood performed a test to verify that the eight Unit 1 and Unit 2 DOST sump check valves would provide a watertight barrier in the event of a turbine building flooding event. On June 11, 2013, the licensee filled the individual DOST room sumps with water, allowed the sump pumps to run, held the configuration for a period of time, and then conducted UT examinations of the vertical sections of the discharge piping to determine if the piping remained water-solid. The licensee considered the acceptance criteria met if the discharge lines were water-solid following the hold period since a water-solid condition indicated that the check valves were not leaking back into their associated sump. The licensee completed seven of the eight tests and concluded that all check valves tested were functioning properly. However, the testing results for check valve 1OD001D were inconclusive.

On June 13 and 14, 2013, the inspectors performed a historic review of IRs related to DOST sump check valve performance and identified numerous IRs that documented 2B DOST room check valve 2OD001D was potentially leaking based upon frequent sump pump cycling. The inspectors reviewed plant computer data and interviewed plant operators and determined that the sump pump routinely ran in a predictable manner and had an abnormally high number of running hours compared to the other sump pumps. Based on this review, the inspectors questioned the licensee’s conclusion that check valve 2OD001D was not leaking following recent testing.

In response to the inspectors’ concern, the licensee performed additional testing and identified two issues. The first issue was that check valve 2OD001D was, in fact, leaking back into the sump; and the second issue was that the sump pump was cycling on a much narrower water level band than designed. The licensee determined that this was the cause for the frequent sump pump run times and high running hours. When the licensee had previously performed the UT examination, the pipe was water-solid; however, the test did not adequately account for the last time the sump pump had run. The licensee entered this issue into their CAP as IR 1526337, IR 1525363, and IR 1528154. Check valve 2OD001D was subsequently disassembled and about half of the o-ring was identified as missing with the remaining half significantly degraded. The o-ring for check valve 2OD001D also replaced using elastomers qualified for both water and fuel oil.

The licensee completed the testing of check valve 1OD001D and identified that it was also leaking. The licensee entered this issue into their CAP, disassembled the check valve, and identified that the check valve o-ring had one through-wall cut and several other minor cuts. Additionally, the o-ring was soft and swollen. This check valve o-ring was subsequently replaced with elastomers qualified for both water and fuel oil.

Issue of Concern 2 - Unacceptable 2005 DOST Sump Pump Check Valve Testing Results Accepted by the Licensee

Upon identification of non-conforming check valve elastomers, the inspectors reviewed the results of previously performed Unit 1 and Unit 2 DOST room sump check valve tests. The last UT examination was performed in 2005 and the WO task instructions directed UT examinations to verify check valve piping fluid levels. A summary of the 2005 results are as follows:

Unit 1		Unit 2	
1OD001A	piping water-solid	2OD001A	piping empty
1OD001B	piping empty	2OD001B	piping water-solid
1OD001C	piping water-solid	2OD001C	piping 50 percent full
1OD001D	piping empty	2OD001D	piping 90 percent full

The three sub-systems that were completely empty and two sub-systems that were partially empty had been erroneously determined to have a satisfactory as-found and as-left condition. Therefore, these five potential issues had not been entered into the licensee's CAP.

The licensee notified the inspectors that they had not initiated an IR in 2005 since they had not identified any issues with these results. The licensee entered this issue into their CAP as IR 1526652, "IR Not Generated as Required – 2005 OD Check Valve UT Results." The inspectors discussed this issue with licensee management who notified the inspectors that, absent NRC inquiry, they had not planned to review the previous test results. Therefore, the inspectors considered this issue NRC-Identified.

The inspectors reviewed procedure LS-AA-120, "Issue Identification and Screening Process," and identified that the licensee was required to initiate an IR upon the discovery of an issue. Specifically, the licensee defined an "Issue" as follows:

> *Issue: Includes any equipment deficiencies, equipment or documented non-conformances, programmatic deficiencies, human performance errors, enhancements, and commendable behaviors*.

Procedure LS-AA-120 also required, in part, that licensee personnel implement or initiate appropriate immediate actions upon the discovery of an issue (Section 4.3.1); verbally contact an immediate supervisor to ensure necessary immediate actions are taken and appropriate routing is applied (Section 4.3.2); initiate an IR (Section 4.3.3); route the IR to Operations Shift Management (Section 4.3.4); and perform a prompt Operations Shift Management Review and subsequent Station Ownership Committee Review (Section 4.4).

The inspectors determined that the 2005 UT examination results should have prompted an IR for follow-up. As a result of not identifying the potential failures as CAP issues, the licensee did not correct the potential deficiencies in a time frame commensurate with the CAP based upon the degraded conditions potentially existing for over 7 years. The licensee entered this issue into their CAP as IR 1526652, "IR Not Generated as Required – 2005 OD Check Valve UT Results." Corrective actions included repair of DOST room sump check valves 1OD001D and 2OD001D, and a planned inspection and repair of the remaining six check valves in 2014.

Analysis: The inspectors determined that the failure to identify numerous issues associated with degraded DOST room sump discharge check valves was a performance deficiency indicative of both historic and recent performance. Specifically, for Issue of Concern 1, in June 2013, the licensee failed to identify leaking 2B DOST room sump check valve 2OD001D after performing a test to demonstrate the functionality of the check valve. For Issue of Concern 2, in February 2005, the licensee failed to identify five unacceptable test results after performing a test to determine the functionality of the Unit 1 and Unit 2 DOST room sump check valves.

The performance deficiency was screened in accordance with IMC 0612, Appendix B, "Issue Screening." The inspectors determined that the performance deficiency did not involve a violation that impeded the regulatory process or contribute to actual safety consequences. The inspectors determined that the performance deficiency was more than minor because it was associated with the Protection Against External Factors attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, Unit 1 and Unit 2 DOST room sump discharge check valves, which were designed to prevent the backflow of water following a turbine building flooding event into the DOST rooms, were unable to perform this function as a result of a design deficiency and this was not identified for an extended period due to inadequate testing.

The inspectors evaluated this finding using the Significance Determination Process (SDP) in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings." The inspectors evaluated the finding 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 the emergency power function during a turbine building flooding event, and based upon the confirmed 2OD001D check valve failure in 2013, the inspectors answered 'Yes' to Question A.2, "Does the finding represent a loss of system and/or function?" which directed that a detailed risk evaluation be performed.

To accomplish this detailed risk evaluation, Senior Reactor Analysts (SRAs) utilized two cases that bounded the risk significance of the finding.

- Case 1: A random break in either the CW piping or the CW EJs results in a reactor trip, followed by a LOOP on the affected unit, followed by a LOOP on the unaffected unit.

- Case 2: A seismic event (earthquake) results in a LOOP on both units and a failure of either the CW piping or the CW EJs.

Case 1: Random Break in CW Piping or CW EJs Followed by a Dual Unit Loss of Offsite Power (DLOOP)

The frequency of a break in either the CW piping or the CW EJs was evaluated using Electric Power Research Institute (EPRI) Report 3002000079, “Pipe Rupture Frequencies for Internal Flooding Probabilistic Risk Assessments,” Revision 3. Using Table ES-2 in the EPRI report, the following failure rate information was obtained:

System	Description	Value
CW Piping	Frequency of Piping Break Causing a Major Flood (i.e., greater than 2000 gallon per minute (gpm) leak)	7.95E-7/yr/foot
CW EJs	Frequency of Major Flood (i.e., greater than 2000 gpm leak) with flood rate ≤ 10,000 gpm	9.17E-6/yr/EJ
	Frequency of Major Flood with Flood Rate ≥ 10,000 gpm	6.08E-6/yr/EJ
	Total Frequency of Major Flood	1.53E-5/yr/EJ

The following information and assumptions were used to obtain the frequency of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs:

- It was estimated that there was approximately 400 feet of CW piping per unit in the turbine building.
- There were four CW EJs per unit.
- A flooding event on either unit would affect both units as described in the UFSAR.

Using the above information, the initiating event frequency (IEF) of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs is given by the following:

IEF = [(7.95E-7/yr/ft) x (400 ft/unit) + (1.53E-5/yr/ EJ) x (8 EJs/unit)] x [2 units]
= 8.8E-4/year

The Braidwood Standardized Plant Analysis Risk (SPAR) model, Version 8.21, and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations, Version 8.0.9.0, software was used to obtain the probability of a DLOOP following a reactor trip. From the SPAR model, the following information was obtained:

SPAR Model Designation	Description	Value
ZT-VCF-LP-GT	Probability of a LOOP Given a Reactor Trip	5.29E-3
ZT-LOOP-SITE-SC	Probability of a Dual Unit LOOP (Switchyard-Centered)	1.94E-1

The exposure time for the finding was assessed to be 1 year since the finding duration was greater than 1 year and 1 year is the maximum exposure time per the NRC's Risk Assessment Standardization Project (RASP) Handbook. Using the above information, the probability of a DLOOP following a reactor trip was obtained as follows:

DLOOP = [ZT-VCF-LP-GT] x [ZT-LOOP-SITE-SC]
= [5.29E-3] x [1.94E-1]
= 1.0E-3

The following bounding assumptions for a turbine building flooding event with the failure of a DOST "B" sump pump room discharge check valve were used:

- The "B" EDG would fail immediately due to flooding in the "B" DOST room,
- It would take only 6 hours for water that entered the "B" DOST room to overflow into the "A" DOST room and render the "A" EDG unavailable. As a result, the probability the operators would fail to recover offsite power (OSP) during the event (in 6 hours) is 5.87E-2 per the SPAR model.

Assuming that a DLOOP with a failure of both EDGs would result in a core damage event, the delta core damage frequency (∆CDF) for Case 1 was obtained as the product of the following factors:

Case 1 ∆CDF = [IEF] x [DLOOP] x [OSP Non-Recovery]
= [8.8E-4/yr] x [1.0E-3] x [5.87E-2]
= 5.2E-8/yr

A bounding ∆CDF of 5.2E-8/yr was obtained for a random break in CW piping or CW EJs followed by a DLOOP.

<u>Case 2</u>: Seismic Event That Results in a DLOOP and a Break in CW Piping or CW EJs

A seismic event can result in the failure of either the CW piping or the CW EJs resulting in turbine building flooding. It was expected that a seismic event would also result in a DLOOP. Since DLOOP is a consequence of the initiator, the EDG function was required. To obtain a bounding estimate of the ∆CDF, the frequency of a seismic event sufficient to cause plant damage was multiplied by the probability of failure of either the CW piping or the CW EJs due to the seismic event.

Using guidance from NRC's RASP Handbook, only the "Bin 2" seismic events were assumed to represent a ∆CDF. "Bin 2" was 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 large pipe failures; and earthquakes of a larger magnitude could result in major structural damage throughout the plant, which would not be representative of a differential risk. The IEF of an earthquake in "Bin 2" was estimated to be 1.2E-5/yr using Table 4A-1 of Section 4 of the RASP Handbook. To estimate the seismic capacity of the CW piping and the CW EJs, an evaluation of the seismic capacity for CW piping and CW EJs for another Westinghouse plant was referenced. For this plant, it stated that the CW piping and the CW EJs had high seismic capacity, and a flooding assessment due to seismic concerns was screened from the assessment. However, making the conservative assumption that the high confidence of low probability of failure capacity for the CW piping and the CW EJs was 0.3g, a failure probability of 3.9E-2 was obtained for the CW system.

It was further conservatively assumed that the operators would fail to recover OSP for at least 24 hours following a seismic event.

A bounding value for the ∆CDF for Case 2 was obtained as the product of the following factors:

Case 2 ∆CDF = [IEF] x [DLOOP] x [CW Failure Probability]
= [1.2E-5/yr] x [1.0] x [3.9E-2]
= 4.7E-7/yr

A bounding ΔCDF of 4.7E-7/yr was estimated for seismically-induced flooding caused by a break in the CW piping or CW EJs.

The final ∆CDF associated with the finding was obtained as the sum of the ∆CDF for both Case 1 and Case 2:

∆CDF = [5.2E-8/yr] + [4.7E-7] = 5.2E-7/yr

Since the total estimated change in CDF was greater than 1.0E-7/yr, 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 (PWR) with a large dry containment. Sequences important to LERF include steam generator tube rupture (SGTR) events and inter-system loss-of-coolant-accident (LOCA) events. These were not the dominant core damage sequences for this finding.

Therefore, based upon the detailed risk evaluation, the inspectors determined that the finding was of very low safety-significance (Green).

This finding had a cross-cutting aspect in the Corrective Action Program component of the Problem Identification and Resolution (PI&R) cross-cutting area because the licensee failed to take appropriate corrective actions in a timely manner. Specifically, as a result of suspected 2B DOST room sump check valve 2OD001D back leakage, the licensee initiated a corrective action to perform additional troubleshooting, however, the troubleshooting was not implemented in a manner that led to the timely identification of the issue (P.1(d)).

Enforcement: This issue does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding did not involve a violation and is of very low safety significance, it is identified as a Finding (FIN).
(FIN 05000456/2013003-01, Failure to Identify and Correct Degraded DOST Room Sump Pump Discharge Check Valves)

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of Unit 2A safety injection pump room cubicle cooler thermal performance to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors compared the licensee's observations to acceptance criteria, reviewed the correlation of scheduled testing and frequency of testing, and determined whether instrument inaccuracies had an impact on test results. The inspectors also determined whether test acceptance criteria considered differences between design conditions and testing conditions. Documents reviewed are listed in the Attachment.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

On April 17, 2012, 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.

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

a. Inspection Scope

On June 27, and June 28, 2013, the inspectors observed the Unit 2 shutdown for a planned maintenance outage to replace the Unit 2A and 2B RCP seals. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of 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 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 (71111.12Q)

a. Inspection Scope

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

- SX Room Sump Pump Discharge Check Valves;
- Molded Case Circuit Breaker Replacement Plan; and
- DOST Room Sump Pump Discharge Check Valves.

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, or 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 three quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

(Closed) Unresolved Item (URI) 05000456/2013002-05; 05000457/2013002-05, Nonsafety-Related SX Pump Room Sump Design Interaction

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50.65(b)(2)(ii) when licensee personnel failed to scope four Unit 1 and Unit 2 SX pump room sump pump discharge check valves and eight Unit 1 and Unit 2 DOST room sump pump discharge check valves into the Maintenance Rule as required. Specifically, these check valves are nonsafety-related components that form part of a watertight barrier protecting safety-related equipment from plant events, including turbine building flooding events.

Description:

SX Room Sump Pump Discharge Check Valves

The SX system is designed to ensure that sufficient cooling capacity is available during normal and accident conditions. At Braidwood, the SX pumps are located in the auxiliary building basement the 330’ elevation, which is approximately 71’ below grade level. The Unit 1A and Unit 2A SX pumps are located in one compartment and the Unit 1B and Unit 2B SX pumps are located in a separate adjacent compartment. Entrance to each compartment is controlled by a watertight door. Each compartment contains an SX pump room sump and includes two nonsafety-related sump pumps. The SX pump room sump pumps are normally aligned to discharge to the turbine building drain tank, located in the turbine building.

UFSAR Section 10.4.5 states, in part:

> *"In the event of a CW line break which cannot be isolated, the turbine building could theoretically be flooded to grade level (approximately 401'). Damage to turbine building equipment will not prevent safe shutdown of the plant, because no essential equipment is located in the turbine building. The auxiliary building is completely watertight below grade at the turbine building to auxiliary building interface, except for the main steam tunnel."*

Since the normal discharge from the SX pump room sumps in the auxiliary building is to the below grade turbine building drain tank in the turbine building, the SX pump room sump check valves function as a passive barrier to assist in maintaining the auxiliary building watertight at the turbine building to auxiliary building interface.

From 2008 through 2013, the licensee identified numerous issues with the SX room sump pump check valves. Four of these issues were:

- IR 812768, "2WF040A, 2A SX Sump Pump Discharge Check Valve, Has Leak By," dated August 31, 2008;
- IR 855943, "1WF040A Does Not Seat Properly," dated December 13, 2008;
- IR 1426948, "1WF040B Check Valve Does Not Stop Back Flow," dated October 16, 2012; and
- IR 1465027, "1WF040A Not Seating Properly," dated January 21, 2013.

<u>DOST Room Sump Pump Discharge Check Valves</u>

Each EDG is provided with fuel oil capacity sufficient to operate for 7 days. The fuel oil supply for each EDG consists of a fuel oil day tank located at the 401' grade level and larger DOSTs at about the 380' elevation in individual DOST rooms. In addition to the DOSTs, the fuel oil transfer pumps are also located in the DOST rooms about 4 inches above the floor. Upon a low level condition in an EDG day tank, the safety-related fuel oil transfer pumps are designed to pump fuel oil from the safety-related DOSTs to refill the EDG day tank.

Each DOST room contains a nonsafety-related sump system that is capable of pumping to the turbine building fire and oil sump at the 369' elevation in the turbine building. The watertight barrier between the turbine building and auxiliary building DOST rooms includes the DOST sump check valves and downstream isolation valves. Both of these components are located in the DOST rooms with access through watertight doors, which would be completely underwater at some point during a design basis flooding event. Also, since the access door between the individual 'A' and 'B' train DOST rooms is not watertight, a flood impacting one DOST room could eventually affect the other DOST room.

Similar to the SX Room Sump Pump Discharge Check Valve Issue, UFSAR Section 10.4.5 states, in part:

> *"In the event of a CW line break which cannot be isolated, the turbine building could theoretically be flooded to grade level (approximately 401'). Damage to turbine building equipment will not prevent safe shutdown of the plant, because no essential equipment is located in the turbine building. The auxiliary building is*

completely watertight below grade at the turbine building to auxiliary building interface, except for the main steam tunnel."

If this event was to occur, with a failure of the nonsafety-related sump system and discharge check valves, backflow from the turbine building into the individual DOST rooms could occur. The licensee does not credit the nonsafety-related DOST sump pump capability nor are the sump pumps discussed in the UFSAR. As discussed in Section 1R06.1.b of this report, recent issues involving DOST room sump pump discharge check failures included DOST room sump check valves 1OD001D and 2OD001D, which were identified to have significantly degraded o-rings.

<u>Maintenance Rule Scoping Applicability Assessment</u>

During a review of the IRs referenced above, the inspectors identified that the SX and DOST room sump check valves were not scoped into the Maintenance Rule. The inspectors questioned the scoping applicability for these check valves and discussed this issue with the licensee. Specifically, the inspectors questioned whether the check valves could be considered, "Nonsafety-related components whose failure could prevent safety-related systems and components from fulfilling their safety-related function," as defined in 10 CFR 50.65(b)(2)(ii); and if so, they should have been scoped into the Maintenance Rule. The licensee entered this issue into their CAP as IR 1498897, "Review 1/2WF040A/B Valves for Inclusion Into MRule [Maintenance Rule]." The licensee considered the issue during a routine Maintenance Rule Expert Panel meeting and concluded that the SX sump pump discharge check valves were not within the scope of the Maintenance Rule for the following reasons:

- The function of the WF040A/B check valves to prevent backflow from the turbine building to the SX pump room was bounded by the existing Sump Leakage Detection function. Specifically, the check valves would not be required to be leak tight if the system could be isolated within the 30 minute time frame assumed in the CLB (IR 1498897, "Review 1/2WF040A/B Valves for Inclusion Into MRule," Assignment #2).

- The scope of the Maintenance Rule only included systems credited in UFSAR Chapter 6, "Engineered Safety Features," and UFSAR Chapter 15, "Accident Analysis."

- Failure of a nonsafety-related SSC must directly affect a safety-related SSC (an example given by the licensee was a nonsafety-related component failing on top of and damaging a safety-related SSCs).

The inspectors discussed this conclusion with the NRC's Maintenance Rule experts in the Office of Nuclear Reactor Regulation (NRR). Documentation reviewed included NUMARC 93-01, Revision 4A, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which is endorsed by the NRC through Regulatory Guide 1.160, Revision 3, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Section 8 of NUMARC 93-01 discusses the methodology for selecting SSCs to be incorporated into the Maintenance Rule and Section 8.2.1.4 is specific to nonsafety-related SSCs whose failure prevents safety-related SSCs from fulfilling their safety-related function without regard to whether these systems are credited in UFSAR Chapter 6 or UFSAR Chapter 15. Section 8.2.1.4 includes the statement, “A utility should rely on actual plant-specific and industry-wide operating experience, prior engineering evaluations such as PRA, IPE, IPEEE, environmental qualification (EQ), and 10 CFR 50 Appendix R analyses.” The inspectors noted existing operating experience regarding internal flooding due to sump-related issues, including Information Notice 2005-30, “Safe Shutdown Potentially Challenged by Unanalyzed Internal Flooding Events and Inadequate Design,” which specifically discussed turbine building flood waters migrating through sump systems into safety-related equipment rooms.

Section 8.2.1.4 of NUMARC 93-01 also discussed that, as used in that section of the guideline, the term “directly” applies to nonsafety-related SSCS whose failure prevents a safety function from being fulfilled or whose failure as a support SSC prevents a safety function from being fulfilled. The inspectors noted that Section 7.11.2.F of Revision 8 of the NRC’s Enforcement Manual contained examples of Maintenance Rule violations specific to 10 CFR 50.65(b)(2). Example 1 addressed this aspect of maintenance rule scoping and specifically stated the following:

> *<u>Example 1</u>:*
>
> *10 CFR 50.65(b)(2) requires, in part, that the scope of the monitoring program specified in paragraph (a)(1) include nonsafety-related SSCs whose failure can prevent safety-related SSCs from fulfilling their safety-related function.*
>
> *Contrary to the above, from (<u>date</u>) to (<u>date</u>), the Unit 2 turbine building sump system was not included in the scope of the monitoring program specified in 10 CFR 50.65(a)(1). The inclusion of the turbine building sump in the scope of the monitoring program was necessary because the failure of that system could prevent the emergency feedwater system, a safety-related system, from fulfilling its safety-related function.*

The inspectors concluded that Example 1 was applicable to the SX and DOST sump check valves at Braidwood because it addressed a nonsafety-related sump system whose failure could prevent a safety-related system from fulfilling its safety-related function.

Based upon their review of the above information, and through consultation with NRC Maintenance Rule subject matter experts in NRR, the inspectors concluded that the SX pump room sump check valves and the DOST room sump check valves were required by 10 CFR 50.65(b)(2)(ii) to be scoped into the Maintenance Rule. Specifically, check valves 1(2)WF040A(B) and 1(2)OD001A(B)(C)(D) were components whose failure could prevent safety-related SSCs from fulfilling their safety-related function during a CLB CW Pipe Break or CW EJ failure. The licensee entered this issue into their CAP as IR 1498897, “Review 1/2WF040A/B Valves for Inclusion Into MRule,” and planned to scope the check valves into the Maintenance Rule.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to include the Unit 1 and Unit 2 SX pump room sump pump discharge check valves and Unit 1 and Unit 2 DOST room sump pump discharge check valves into the scope of the Maintenance Rule was a performance deficiency indicative of both historic and recent performance. Specifically, the failure of the nonsafety-related check valve components could prevent SSCs from performing their safety-related functions because these check valves are relied upon as

a part of the leak tight barrier between the turbine building and auxiliary building SX pump rooms and DOST rooms interface.

The performance deficiency was screened in accordance with IMC 0612, Appendix B, “Issue Screening.” The inspectors determined that the performance deficiency did not involve a violation that impacted the regulatory process or contribute to actual safety consequences. The inspectors determined that the finding was more than minor because if left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern. Specifically, if left uncorrected, unacceptable check valve performance could result in backflow into the SX pump room (via the SX pump room sumps) and DOST rooms (via the DOST room sumps) if a CW EJ or CW pipe break CLB event occurred.

The inspectors performed two distinct SDP risk determinations since the performance deficiency consisted of two distinct systems. For the detailed risk evaluations documented below, the inspectors bounded the assessment by evaluating the risk of actual check failures in the open direction for each system without reliance on the sump pumps’ outflow capability.

<u>SX Pump Room Sump Pump Discharge Check Valve Stuck Open</u>

The inspectors reviewed the finding in accordance with IMC 0609, Attachment 4, “Initial Characterization of Findings.” This finding was determined to affect the External Event Mitigation Systems of the Mitigating Systems Cornerstone. Using Table 3, “SDP Appendix Router,” of IMC 0609, Attachment 4, the inspectors determined the significance of the finding could be screened using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power.” Using Section B, Exhibit 2, “Mitigating Systems Screening Questions,” of IMC 609, Appendix A for External Event Mitigation Systems (Seismic/Fire/Flood/Severe Weather Protection Degraded) the inspectors answered ‘Yes’ to the question, “Does the finding involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event (e.g., seismic snubbers, flood barriers, tornado doors)?” which directed screening through Exhibit 4, “External Events Screening Questions,” of IMC 0609, Appendix A. Specifically, 1WF040B was failed open and allowed a flow path to the “A” train SX pump room from the turbine building in the event of a turbine building internal flooding event. Utilizing Exhibit 4, the inspectors answered ‘Yes’ to Question 1 since the degraded check valve would degrade one or more trains of a system that supported a risk-significant system or function; the 1A and 2A SX pumps. Therefore, Exhibit 4 directed that a Detailed Risk Evaluation be performed by an SRA.

The SRA determined that the finding could be evaluated in accordance with IMC 0609, Appendix K, “Maintenance Risk Assessment and Risk Management Significance Determination Process.” In accordance with IMC 0609, Appendix K, the SRA performed an independent analysis of the risk deficit for the unevaluated condition of the SX room ‘A’ sump pump discharge check valve 1WF040B being in a stuck-open condition.

The SRA identified two cases that would require evaluation to determine the risk significance of the finding.

- Case 1: A random break in either the CW piping or the CW EJs results in a reactor trip with a loss of condenser heat sink.

- Case 2: A seismic event results in a failure of either the CW piping or the CW EJs.

In both Cases 1 and 2, the exposure time for the finding was assessed to be 153 days. The exposure time was determined from the date that the SX room A sump pump discharge check valve was determined to be leaking (i.e., October 16, 2012, per IR 1426946) until the date that the check valve on the discharge of the sump pump was repaired (i.e., March 18, 2013).

Case 1: Random Break in CW Piping or CW EJs

The frequency of a break in either the CW piping or the CW EJs was evaluated using EPRI Report 1021086, "Pipe Rupture Frequencies for Internal Flooding Probabilistic Risk Assessments," Revision 2. Using Table ES-2 in the EPRI report, the following failure rate information was obtained:

System	Description	Value
CW Piping	Frequency of Piping Break Causing a Major Flood (i.e., greater than 2000 gpm leak)	7.95E-7/yr/foot
CW EJs	Frequency of Major Flood (i.e., greater than 2000 gpm leak) with flood rate ≤ 10,000 gpm	9.17E-6/yr/EJ
	Frequency of Major Flood with flood rate ≥ 10,000 gpm	6.08E-6/yr/EJ
	Total Frequency of Major Flood	1.53E-5/yr/EJ

The following information and assumptions were used to obtain the frequency of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs:

- There is about 400 feet of CW piping per unit in the turbine building.

- There are four CW EJs per unit.
- A flooding event on either unit will affect both units.

Using the above information, the IEF of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs is given by:

IEF = [(7.95E-7/yr/ft) x (400 ft/unit) + (1.53E-5/yr/ EJ) x (4 EJs/unit)] x [2 units]
= 7.6E-4/year

It was conservatively assumed that a turbine building flooding event with the failure of the SX Room A sump pump check valve would result in the failure of SX pumps 1A and 2A due to flooding. The Braidwood SPAR model, Version 8.21, and System Analysis Programs for Hands-on Integrated Reliability Evaluation, Version 8.0.8.0, software was used to obtain the Conditional Core Damage Probability (CCDP) of a reactor trip with a loss of condenser heat sink initiating event followed by a loss of SX pumps 1A and 2A.

The result was a CCDP of 4.6E-4. For the base case (i.e., without the performance deficiency and using the zero-maintenance model), the CCDP for a reactor trip with a loss of condenser heat sink initiating event is 7.7E-6. The Delta Conditional Core Damage Probability (ΔCCDP) associated with the performance deficiency is thus:

ΔCCDP = 4.6E-4 – 7.7E-6 = 4.5E-4

The delta core damage frequency (ΔCDF) for Case 1 is obtained as the product of the following factors:

Case 1 ΔCDF = [IEF] x [ΔCCDP] x [Exposure Time]
= [7.6E-4/yr] x [4.5E-4] x [153/365]
= 1.4E-7/yr

Case 2: Seismic Event That Results in a Break in CW Piping or CW EJs

A seismic event can result in the failure of either the CW piping or the CW EJs resulting in turbine building flooding. It is expected that a seismic event will also result in a DLOOP. To obtain a bounding estimate of the ΔCDF, the frequency of a seismic event sufficient to cause plant damage is multiplied by the probability of failure of either the CW piping or the CW EJs due to the seismic event.

Using guidance from NRC's 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 large 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 IEF of an earthquake in "Bin 2" was estimated to be 1.2E-5/yr using Table 4A-1 of Section 4 of the RASP Handbook. To estimate the seismic capacity of the CW piping and the CW EJs, an evaluation of the seismic capacity for CW piping and CW EJs for another Westinghouse plant was referenced. For this plant, it stated that the CW piping and the CW EJs had high seismic capacity, and a flooding assessment due to seismic concerns was screened from the assessment. However, making the conservative assumption that the high confidence of low probability of failure capacity for the CW piping and the CW EJs was 0.3g, a failure probability of 3.9E-2 was obtained for the CW system.

Using the above information, the IEF of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs is given by:

IEF = [1.2E-5/yr] x [3.9E-2]
= 4.7E-7/year

It was conservatively assumed that a turbine building flooding event with the failure of the SX Room A sump pump check valve would result in the failure of SX pumps 1A and 2A due to flooding. The Braidwood SPAR model was used to obtain the CCDP of a reactor trip with a loss of condenser heat sink initiating event followed by a dual unit LOOP and a loss of SX pumps 1A and 2A. The result was a CCDP of 5.1E-4. For the base case (i.e., without the performance deficiency and using the zero-maintenance model), the CCDP for a reactor trip with a loss of condenser heat sink initiating event followed by a dual unit LOOP is 1.4E-5. The ΔCCDP associated with the performance deficiency is thus: ΔCCDP = 5.1E-4 – 1.4E-5 = 5.0E-4

The ΔCDF for Case 2 is obtained as the product of the following factors:

Case 2 ΔCDF = [IEF] x [ΔCCDP] x [Exposure Time]
= [4.7E-7/yr] x [5.0E-4] x [153/365]
= 9.9E-11/yr

The final ΔCDF associated with the finding is obtained as the sum of the ΔCDF for both Case 1 and Case 2:

ΔCDF = [1.4E-7/yr] + [9.9E-11] = 1.4E-7/yr

The dominant core damage sequence is a Loss of Condenser Heat Sink initiating event (caused by a failure of either the CW piping or the CW EJs) followed by a failure of the auxiliary feedwater system, failure of secondary cooling recovery, and failure of high pressure recirculation.

<u>DOST Room Sump Pump Discharge Check Valve Stuck Open</u>

The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Initial Characterization of Findings." The inspectors evaluated the finding 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 the emergency power function during a turbine building flooding event, the inspectors answered 'Yes' to Question A.2 in Exhibit 2, "Does the finding represent a loss of system and/or function?" and determined a detailed risk evaluation was required. The inspectors reached this conclusion based upon the confirmed 2OD001D check valve failure in 2013.

To evaluate this finding, the SRAs utilized two cases that bounded the risk significance of the finding.

- Case 1: A random break in either the CW piping or the CW EJs results in a reactor trip, followed by a LOOP on the affected unit, followed by a LOOP on the unaffected unit.

- Case 2: A seismic event (earthquake) results in a LOOP on both units and a failure of either the CW piping or the CW EJs.

<u>Case 1</u>: Random Break in CW Piping or CW EJs Followed by a Dual Unit Loss of Offsite Power (DLOOP)

The frequency of a break in either the CW piping or the CW EJs was evaluated using EPRI Report 3002000079, "Pipe Rupture Frequencies for Internal Flooding Probabilistic Risk Assessments," Revision 3. Using Table ES-2 in the EPRI report, the following failure rate information was obtained:

System	Description	Value
CW Piping	Frequency of Piping Break Causing a Major Flood (i.e., greater than 2000 gpm leak)	7.95E-7/yr/foot
CW EJs	Frequency of Major Flood (i.e., greater than 2000 gpm leak) with flood rate ≤ 10,000 gpm	9.17E-6/yr/EJ
	Frequency of Major Flood with Flood Rate ≥ 10,000 gpm	6.08E-6/yr/EJ
	Total Frequency of Major Flood	1.53E-5/yr/EJ

The following information and assumptions were used to obtain the frequency of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs:

- There was about 400 feet of CW piping per unit in the turbine building.
- There were four CW EJs per unit.
- A flooding event on either Unit would affect both units as described in the UFSAR.

Using the above information, the IEF of a major flooding event in the turbine building due to a break in either the CW piping or the CW EJs is given by the following:

IEF = [(7.95E-7/yr/ft) x (400 ft/unit) + (1.53E-5/yr/ EJ) x (8 EJs/unit)] x [2 units]
= 8.8E-4/year

The Braidwood SPAR model, Version 8.21, and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations, Version 8.0.9.0, software was used to obtain the probability of a DLOOP following a reactor trip. From the SPAR model, the following information was obtained:

SPAR Model Designation	Description	Value
ZT-VCF-LP-GT	Probability of a LOOP Given a Reactor Trip	5.29E-3
ZT-LOOP-SITE-SC	Probability of a Dual Unit LOOP (Switchyard-Centered)	1.94E-1

The exposure time for the finding was assessed to be 1 year, since the finding duration was greater than 1 year and 1 year is the maximum exposure time per the NRC's RASP Handbook. Using the above information, the probability of a DLOOP following a reactor trip was obtained as follows:

DLOOP = [ZT-VCF-LP-GT] x [ZT-LOOP-SITE-SC]
= [5.29E-3] x [1.94E-1]
= 1.0E-3

The following bounding assumptions for a turbine building flooding event with the failure of a DOST "B" sump pump room discharge check valve were used:

- The "B" EDG would fail immediately due to flooding in the "B" DOST room,
- It would take only 6 hours for water that enters the "B" DOST to overflow into the "A" DOST and render the "A" EDG unavailable. As a result, the probability the operators would fail to recover OSP during the event (in 6 hours) is 5.87E-2 per the SPAR model.

Assuming that a DLOOP with a failure of both EDGs would result in a core damage event, the ∆CDF for Case 1 was obtained as the product of the following factors:

Case 1 ∆CDF = [IEF] x [DLOOP] x [OSP Non-Recovery]
= [8.8E-4/yr] x [1.0E-3] x [5.87E-2]
= 5.2E-8/yr

A bounding ∆CDF of 5.2E-8/yr was obtained for a random break in CW piping or CW EJs followed by a DLOOP.

<u>Case 2</u>: Seismic Event That Results in a DLOOP and a Break in CW Piping or CW EJs

A seismic event can result in the failure of either the CW piping or the CW EJs resulting in turbine building flooding. It was expected that a seismic event would also result in a DLOOP. Since DLOOP is a consequence of the initiator, the EDG function was required. To obtain a bounding estimate of the ∆CDF, the frequency of a seismic event sufficient to cause plant damage was multiplied by the probability of failure of either the CW piping or the CW EJs due to the seismic event.

Using guidance from NRC's RASP Handbook, only the "Bin 2" seismic events were assumed to represent a ∆CDF. "Bin 2" was 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 large pipe failures and earthquakes of a larger magnitude could result in major structural damage throughout the plant, which would not be representative of a differential risk. The IEF of an earthquake in "Bin 2" was estimated to be 1.2E-5/yr using Table 4A-1 of Section 4 of the RASP handbook. To estimate the seismic capacity of the CW piping and the CW EJs, an evaluation of the seismic capacity for CW piping and CW EJs for another Westinghouse plant was referenced. For this plant, it stated that the CW piping and the CW EJs had high seismic capacity, and a flooding assessment due to seismic concerns was screened from the assessment. However, making the conservative assumption that the high confidence of low probability of failure capacity for the CW piping and the CW EJs was 0.3g, a failure probability of 3.9E-2 was obtained for the CW system.

It was further conservatively assumed that the operators would fail to recover OSP for at least 24 hours following a seismic event.

A bounding value for the ∆CDF for Case 2 was obtained as the product of the following factors:

Case 2 ΔCDF = [IEF] x [DLOOP] x [CW Failure Probability]
= [1.2E-5/yr] x [1.0] x [3.9E-2]
= 4.7E-7/yr

A bounding ΔCDF of 4.7E-7/yr was estimated for seismically-induced flooding caused by a break in the CW piping or CW EJs.

The final ΔCDF associated with the finding was obtained as the sum of the ΔCDF for both Case 1 and Case 2:

ΔCDF = [5.2E-8/yr] + [4.7E-7] = 5.2E-7/yr

Since the total estimated change in core damage frequency was greater than 1.0E-7/yr, IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," was used to determine the potential risk contribution due to LERF. Braidwood Station is a 4-loop Westinghouse PWR with a large dry containment. Sequences important to LERF include SGTR events and inter-system LOCA events. These were not the dominant core damage sequences for this finding.

Therefore, based on the detailed risk evaluation, the inspectors determined that the finding was of very low safety-significance (Green).

This finding has a cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area because the licensee failed to use conservative assumptions readily available in the applicable guidance document to demonstrate that not scoping the components into the Maintenance Rule was in accordance with Maintenance Rule requirements and therefore maintained safety (H.1(b)).

Enforcement: Title 10 CFR Part 50.65(b) requires, in part, that the scope of the monitoring program specified in (a)(1) of 10 CFR Part 50.65 shall include nonsafety-related SSCs whose failure could prevent SSCs from fulfilling their safety-related function.

Contrary to the above, during initial Maintenance Rule system scoping in 1996, the Unit 1 and Unit 2 SX pump room sump pump discharge check valves 1(2)WF040A(B), and the Unit 1 and Unit 2 DOST room sump pump discharge check valves 1(2)OD001A(B)(C)(D) were not included and maintained within the scope of the (a)(1) or (a)(2) monitoring program as required by 10 CFR Part 50.65(b) (i.e. the Maintenance Rule). Inclusion of these components was required because failure of the check valve components could prevent the safety-related SX pumps or safety-related EDG fuel oil transfer pumps from performing their safety-related functions.

Because this violation was of very low safety significance and because the issue was entered into the licensee's CAP as IR 1498897, "Review 1/2WF040A/B Valves for Inclusion Into MRule [Maintenance Rule]," this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000456/2013003-02; 05000457/2013003-02, Failure to Scope Nonsafety-Related Turbine Building to Auxiliary Building Sump Pump Discharge Check Valves into the Maintenance Rule)

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 appropriate risk assessments were performed prior to removing equipment for work:

- High Energy Line Break Operator Action Credit in Unit 1 MEER;
- Planned Yellow Risk Configuration, 2B EDG Maintenance Outage;
- Planned Yellow Risk Configuration, Unit 1 SAT Maintenance Outage;
- Unplanned Risk Configuration, Unit 0B Control Room Ventilation System (VC) Damper Failure During Unit 0A VC Surveillance; and
- Unplanned Risk Configuration, Unit 2 Solid State Protection System Circuit Card Blinking Lights.

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 five samples as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 1 BAST Bladder Degradation;
- Unit 2 BAST Bladder Degradation;
- Battery 212 With Ventilation OOS;
- ITT Grinnel Diaphragm Valves; and
- 2B DOST 2D Sump Check Valve Leakage.

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 the 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 sample 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 five samples as defined in IP 71111.15-05.

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:

- Unit 2 Main Power Transformer Cleaning, WO 131027802;
- 2B EDG Following Maintenance Window, WO 1608786;
- Unit 1 SAT Following Maintenance Window, WO 1257305, WO 1306705;
- Replace SX Room Check Valve 2WF040A, WO 1637115, WO 1623126;
- Repair Unit 1 Main Power Transformer Cooling Group #1, #3, WO 1643616;
- Replace Unit 2 Feedwater 2FW009A Pressure Switch 2PS-FW162, WO 1646770;
- Inspect and Rebuild Unit 2B RCP Seals, WO 16217170; and
- Inspect and Rebuild Unit 2A RCP Seals, WO 16512810.

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 into 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 eight post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for a Unit 2 planned maintenance outage to replace the 2A and 2B RCP seal packages that began on June 28, 2013, and continued through the end of the inspection period. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed and/or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, and identification and resolution of problems associated with the outage.

Additionally, the inspectors observed maintenance activities related to the replacement of the 2A and 2B RCP seal packages.

This inspection constituted one other outage activity 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:

- 2B EDG 24 Hour Endurance Run (Routine);
- Unit 1A Auxiliary Feedwater Pump Simulated Start on Undervoltage Signal (Routine);
- Unit 2B Solid State Protection System Bi-Monthly Surveillance (Routine);
- 2BwOS SX-1, Unit 2 Auxiliary Feedwater SX Suction Line Flush 18-Month Surveillance (Routine);
- Unit 1 RCS Leakrate (RCS); and
- 2A Containment Spray Pump American Society of Mechanical Engineers (ASME) [Inservice Testing (IST)].

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;
- 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 IST activities, was testing performed in accordance with the applicable version of Section XI of the ASME Code, and 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 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 four routine surveillance testing samples, one IST sample, and one RCS leak detection inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

Implications of Control Room Ventilation Monthly Surveillance

Introduction: The inspectors identified an Unresolved Item (URI) regarding the use of TS Limiting Condition for Operation (LCO) 3.7.10 during the monthly control room ventilation system surveillance. Specifically, the inspectors questioned whether a step in procedure 0BwOSR 3.7.10.1-1, "Control Room Ventilation Filtration Surveillance (Train A)," to realign the VC suction source, and which appeared to defeat an automatic engineered safety feature (ESF) realignment, impacted the filtration system (Condition A) or control room envelope (CRE) boundary (Condition B) of the LCO.

Description: At 4:05 p.m. on May 8, 2013, the licensee commenced a routine monthly surveillance of the 'A' VC filtration train using procedure 0BwOSR 3.7.10.1-1, "Control Room Ventilation Filtration Surveillance (Train A)." During performance of the surveillance, at 7:09 p.m., the licensee noted that 'B' VC train damper 0VC08Y was unexpectedly open when it should have been closed. Approximately 25 minutes later, the damper repositioned closed. Operators were dispatched to inspect the damper and heard an abnormal grinding noise coming from the hydramotor. Consultation with the system engineer indicated that the grinding noise was likely caused by a degraded bearing. As a result, the licensee declared the 'B' train of VC inoperable and entered LCO 3.7.10, Condition A, "One VC Filtration System Train Inoperable for Reasons Other Than Condition B." Condition B stated, "One or More VC Filtration System Trains Inoperable Due to Inoperable CRE Boundary in Mode 1, 2, 3, or 4."

The licensee elected to continue with the routine surveillance on the 'A' VC train. Step F5.1 of procedure 0BwOSR 3.7.10.1-1 directed Operations to enter LCO 3.7.10, Condition A, for the 'A' VC train while the makeup filter selector switch was repositioned from 'auto' to 'outside air' then 'turbine building' and back to 'auto' as part of a contact check. The licensee entered LCO 3.7.10, Condition A, for the 'A' VC train at 4:33 a.m.

on May 9, 2013, and exited that Condition at 4:35 a.m. For those 2 minutes, both Units also entered LCO 3.0.3, since the ‘A’ and ‘B’ VC trains were simultaneously inoperable due to LCO 3.7.10, Condition A.

During plant status activities on the morning of May 9, 2013, the inspectors noted discussions among senior plant personnel about whether LCO 3.7.10, Condition B (not Condition A) was actually the correct Condition to be entered while performing Step F5.1 of procedure 0BwOSR 3.7.10.1-1. The inspectors reviewed the TSs and discussed the system design with the VC system engineer. The VC system is designed such that when the makeup air suction is from outside air, the system would automatically realign the source air to the turbine building upon an air intake high radiation signal or a safety injection signal. When the makeup filter selector switch is not in the ‘auto’ position, this automatic realignment will not occur, and manual actions would be required for the system to perform its ESF function. Additionally, the inspectors reviewed the licensee’s Control Room Habitability Program (CRHP), which included the following definitions:

> *CONTROL ROOM ENVELOPE (CRE) BOUNDARY: A combination of walls, floor, roof, ducting, doors, penetrations, and equipment that physically form the CRE.*
>
> *CONTROL ROOM HABITABILITY SYSTEMS (CRHS): The plant systems that help ensure CRE habitability. This includes the Control Room emergency ventilation/filtration system and the Control Room HVAC systems. The CRE boundary is considered as an integral part of the CRHS, since it is critical to maintaining CRE habitability.*

The inspectors’ view was that the automatic realignment feature of the ‘A’ VC train, which was blocked at the time the switch was not in ‘auto,’ did not constitute part of the CRE boundary as defined in the CRHP. In addition, manual actions were required for the safety-related system to perform its ESF design function. As a result, the inspectors communicated to licensee management their view that Condition A was the correct Technical Specification Action Statement (TSAS) to be entered when performing the surveillance. Following this discussion, the licensee continued to believe that Condition B was the correct TSAS to enter when performing this surveillance.

The inspectors also communicated their concerns that main control room logs, as officially recorded, did not completely and accurately capture the events that occurred on the night shift from May 8 to May 9, 2013. During plant status activities on May 9, the inspectors reviewed the main control room operating logs at approximately 6:30 a.m., and noted the log entries for entering LCO 3.7.10, Condition A, for the 0A VC train, and LCO 3.0.3, at 4:33 a.m. and exiting those LCOs at 4:35 a.m. However, later that morning when the logs were reviewed again, the inspectors noted those log entries had been revised. The log entries were annotated with, “Late Entry 1030 5/9/13,” and referenced entry into LCO 3.7.10, Condition B, and made no mention of LCO 3.0.3. There was no indication that anything had been revised or that LCO 3.0.3 had been entered.

As a result of the inspectors’ concerns, the licensee generated IR 1519660, “Lack of Detail in Log Entries,” on May 30, 2013. Additionally, an Operations Noteworthy Event briefing sheet was created on June 12, 2013, and discussed with all Operating crews. The Noteworthy Event briefing sheet included the statement, “Initially, LCO 3.0.3 was entered, but was retracted on days. LCO 3.7.10, Condition B, was determined to be the correct LCO entry." On July 8, 2013, the licensee again performed the monthly VC surveillance. Upon review of the main control room logs, the inspectors noted that LCO 3.7.10, Condition A, had been entered from 11:14 a.m. to 11:33 a.m. while alternating the suction source between outside and turbine building air. When questioned why the Noteworthy Event briefing sheet instructed Operating crews to enter Condition B and yet the crews entered Condition A, the licensee stated they were waiting for a more comprehensive review of the issue before revising the surveillance procedure.

At the end of the inspection period, the inspectors were in the process of discussing the issue with NRC staff in the Office of NRR, reviewing the licensee's determination of LCO applicability, and reviewing control room ventilation system design documentation. Pending additional information from the NRR staff, a complete understanding of the licensee's position, and a more detailed understanding of the VC system design, this issue is considered a URI.
(URI 05000456/2013003-03; 05000457/2013003-03, Implications of Control Room Ventilation Monthly Surveillance)

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency preparedness Off-Year Exercise drill on April 17, 2013, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator and Technical Support Center to determine whether the event classifications, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to determine whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment.

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

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS5 Radiation Monitoring Instrumentation (71124.05)

This inspection constituted one complete sample as defined in IP 71124.05-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the UFSAR to identify radiation instruments associated with monitoring area radiological conditions including airborne radioactivity, process streams, effluents, materials/articles, and workers. Additionally, the inspectors reviewed the instrumentation and the associated TS requirements for post-accident monitoring instrumentation including instruments used for remote emergency assessment.

The inspectors reviewed a listing of in-service survey instrumentation including air samplers and small article monitors, along with instruments used to detect and analyze workers' external contamination. Additionally, the inspectors reviewed personnel contamination monitors and portal monitors, including whole-body counters, to detect workers' internal contamination. The inspectors reviewed this list to assess whether an adequate number and type of instruments were available to support operations.

The inspectors reviewed licensee and third-party evaluation reports of the radiation monitoring program since the last inspection. These reports were reviewed for insights into the licensee's program and to aid in selecting areas for review ("smart sampling").

The inspectors reviewed procedures that govern instrument source checks and calibrations, focusing on instruments used for monitoring transient high radiological conditions, including instruments used for underwater surveys. The inspectors reviewed the calibration and source check procedures for adequacy and as an aid to smart sampling.

The inspectors reviewed the area radiation monitor alarm setpoint values and setpoint bases as provided in the TSs and the UFSAR.

The inspectors reviewed effluent monitor alarm setpoint bases and the calculation methods provided in the Offsite Dose Calculation Manual (ODCM).

b. Findings

No findings were identified.

.2 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down effluent radiation monitoring systems, including at least one liquid and one airborne system. Focus was placed on flow measurement devices and all accessible point-of-discharge liquid and gaseous effluent monitors of the selected systems. The inspectors assessed whether the effluent/process monitor configurations aligned with ODCM descriptions and observed monitors for degradation and OOS tags.

The inspectors selected portable survey instruments that were in use or available for issuance and assessed calibration and source check stickers for currency as well as instrument material condition and operability.

The inspectors observed licensee staff performance as the staff demonstrated source checks for various types of portable survey instruments. The inspectors assessed whether high-range instruments were source checked on all appropriate scales.

The inspectors walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. Selectively, the inspectors compared monitor response (via local or remote control room indications) with actual area conditions for consistency.

The inspectors selected personnel contamination monitors, portal monitors, and small article monitors and evaluated whether the periodic source checks were performed in accordance with the manufacturer's recommendations and licensee procedures.

b. Findings

No findings were identified.

.3 Calibration and Testing Program (02.03)

Process and Effluent Monitors

a. Inspection Scope

The inspectors selected effluent monitor instruments (such as gaseous and liquid) and evaluated whether channel calibration and functional tests were performed consistent with Radiological Effluent Technical Specifications (RETS)/ODCM. The inspectors assessed whether: (a) the licensee calibrated its monitors with National Institute of Standards and Technology (NIST) traceable sources; (b) the primary calibrations adequately represented the plant nuclide mix; (c) when secondary calibration sources were used, the sources were verified by the primary calibration; and (d) the licensee's channel calibrations encompassed the instrument's alarm setpoints.

The inspectors assessed whether the effluent monitor alarm setpoints were established as provided in the ODCM and station procedures.

For changes to effluent monitor setpoints, the inspectors evaluated the basis for changes to ensure that an adequate justification existed.

b. Findings

No findings were identified.

.4 Laboratory Instrumentation

a. Inspection Scope

The inspectors assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded instrument performance.

The inspectors assessed whether appropriate corrective actions were implemented in response to indications of degraded instrument performance.

b. Findings

No findings were identified.

.5 Whole Body Counter

a. Inspection Scope

The inspectors reviewed the methods and sources used to perform whole body count functional checks before daily use of the instrument and assessed whether check sources were appropriate and aligned with the plant's isotopic mix.

The inspectors reviewed whole body count calibration records since the last inspection and evaluated whether calibration sources were representative of the plant source term and that appropriate calibration phantoms were used. The inspectors looked for anomalous results or other indications of instrument performance problems.

b. Findings

No findings were identified.

.6 Post-Accident Monitoring Instrumentation

a. Inspection Scope

The inspectors selected containment high-range monitors and reviewed the calibration documentation since the last inspection.

The inspectors assessed whether electronic and source (NIST traceable) calibrations were completed for all range decades above 10 rem/hour and below 10 rem/hour.

The inspectors assessed whether calibration acceptance criteria were reasonable, accounted for the large measuring range, and the intended purpose of the instruments.

The inspectors selected two effluent/process monitors that were relied on by the licensee in its emergency operating procedures as a basis for triggering emergency action levels and subsequent emergency classifications, or to make protective action recommendations during an accident. The inspectors evaluated the calibration and availability of these instruments.

The inspectors reviewed the licensee's capability to collect high-range, post-accident iodine effluent samples.

As available, the inspectors observed and discussed electronic and radiation calibration of these instruments to assess conformity with the licensee's calibration and test protocols with technicians and system engineers.

b. Findings

No findings were identified.

.7 Portal Monitors, Personnel Contamination Monitors, and Small Article Monitors

a. Inspection Scope

For each type of these instruments used on site, the inspectors assessed whether the alarm setpoint values were reasonable under the circumstances to ensure that licensed material was not released from the site.

The inspectors reviewed the calibration documentation for each instrument selected and discussed the calibration methods with the licensee to determine consistency with the manufacturer's recommendations.

b. Findings

No findings were identified.

.8 Portable Survey Instruments, Area Radiation Monitors, Electronic Dosimetry, and Air Samplers/Continuous Air Monitors

a. Inspection Scope

The inspectors reviewed calibration documentation for at least one of each type of instrument. For portable survey instruments and area radiation monitors, the inspectors reviewed detector measurement geometry and calibration methods and had the licensee demonstrate use of its instrument calibrator as applicable. The inspectors conducted comparison of instrument readings versus an NRC survey instrument if problems were suspected.

As available, the inspectors selected portable survey instruments that did not meet acceptance criteria during calibration or source checks to assess whether the licensee had taken appropriate corrective action for instruments found significantly out of calibration (greater than 50 percent). The inspectors evaluated whether the licensee had evaluated the possible consequences of instrument use since the last successful calibration or source check.

b. Findings

No findings were identified.

.9 Instrument Calibrator Inspection Scope

As applicable, the inspectors reviewed the current output values for the licensee's portable survey and area radiation monitor instrument calibrator units. The inspectors assessed whether the licensee periodically measured calibrator output over the range of the instruments used through measurements by ion chamber/electrometer.

The inspectors assessed whether the measuring devices had been calibrated by a facility using NIST traceable sources and whether corrective factors for these measuring devices were properly applied by the licensee in its output verification.

a. Findings

No findings were identified.

.10 Calibration and Check Sources

a. Inspection Scope

The inspectors reviewed the licensee's 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," source term to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

b. Findings

No findings were identified.

.11 Problem Identification and Resolution (02.04)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involved radiation monitoring instrumentation.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

This inspection constituted one complete sample as defined in IP 71124.06-05.

.1 Inspection Planning and Program Reviews (02.01)

Event Report and Effluent Report Reviews

a. Inspection Scope

The inspectors reviewed the radiological effluent release reports issued since the last inspection to determine if the reports were submitted as required by the ODCM/TSs. The inspectors reviewed anomalous results, unexpected trends, or abnormal releases identified by the licensee for further inspection to determine if they were evaluated, were entered in the CAP, and were adequately resolved.

The inspectors identified radioactive effluent monitor operability issues reported by the licensee as provided in effluent release reports; reviewed these issues during the onsite inspection, as warranted, given their relative significance; and determined if the issues were entered into the CAP and adequately resolved.

b. Findings

No findings were identified.

.2 ODCM and UFSAR Review

a. Inspection Scope

The inspectors reviewed the UFSAR descriptions of the radioactive effluent monitoring systems, treatment systems, and effluent flow paths so they could be evaluated during inspection walkdowns.

The inspectors reviewed changes to the ODCM made by the licensee since the last inspection against the guidance in NUREG-1301, 1302 and 0133, and Regulatory Guides 1.109, 1.21 and 4.1. When differences were identified, the inspectors reviewed the technical basis or evaluations of the change during the onsite inspection to determine whether they were technically justified and maintained effluent releases as-low-as-is-reasonably-achievable.

The inspectors reviewed licensee documentation to determine if the licensee had identified any non-radioactive systems that had become contaminated as disclosed either through an event report or the ODCM since the last inspection. This review provided an intelligent sample list for the onsite inspection of any 10 CFR 50.59 evaluations and allowed a determination of whether any newly contaminated systems have an unmonitored effluent discharge path to the environment, whether any required ODCM revisions were made to incorporate these new pathways, and whether the associated effluents were reported in accordance with Regulatory Guide 1.21.

b. Findings

No findings were identified.

.3 Groundwater Protection Initiative Program

a. Inspection Scope

The inspectors reviewed reported groundwater monitoring results and changes to the licensee's written program for identifying and controlling contaminated spills/leaks to groundwater.

b. Findings

No findings were identified.

.4 Procedures, Special Reports, and Other Documents

a. Inspection Scope

The inspectors reviewed Licensee Event Reports (LERs), event reports and/or special reports related to the effluent program issued since the previous inspection to identify any additional focus areas for the inspection based on the scope/breadth of problems described in these reports.

The inspectors reviewed effluent program implementing procedures, particularly those associated with effluent sampling, effluent monitor setpoint determinations, and dose calculations.

The inspectors reviewed copies of licensee and third party (independent) evaluation reports of the effluent monitoring program since the last inspection to gather insights into the licensee's program and aid in selecting areas for inspection review (smart sampling).

b. Findings

No findings were identified.

.5 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down selected components of the gaseous and liquid discharge systems to evaluate whether equipment configurations and flow paths aligned with the documents reviewed in Section 2RS6.1 (02.01) above and to assess equipment material condition. Special attention was made to identify potential unmonitored release points, building alterations which could impact airborne or liquid effluent controls, and ventilation system leakage that communicated directly with the environment.

For equipment or areas associated with the systems selected for review that were not readily accessible due to radiological conditions, the inspectors reviewed the licensee's material condition surveillance records, as applicable.

The inspectors walked down filtered ventilation systems to assess for conditions such as degraded high efficiency particulate air/charcoal banks, improper alignment, or system installation issues that would impact the performance or the effluent monitoring capability of the effluent system.

As available, the inspectors observed selected portions of the routine processing and discharge of radioactive gaseous effluents (including sample collection and analysis) to evaluate whether appropriate treatment equipment was used and the processing activities aligned with discharge permits.

The inspectors determined if the licensee had made significant changes to their effluent release points (e.g., changes subject to a 10 CFR 50.59 review or that required NRC approval of alternate discharge points).

As available, the inspectors observed selected portions of the routine processing and discharge of liquid waste (including sample collection and analysis) to determine if appropriate effluent treatment equipment was being used and that radioactive liquid waste was being processed and discharged in accordance with procedure requirements and aligned with discharge permits.

b. Findings

No findings were identified.

.6 Sampling and Analyses (02.03)

a. Inspection Scope

The inspectors selected effluent sampling activities, consistent with smart sampling, and assessed whether adequate controls had been implemented to ensure representative samples were obtained (e.g., provisions for sample line flushing, vessel recirculation, composite samplers, etc.)

The inspectors selected effluent discharges made with inoperable (declared OOS) effluent radiation monitors to assess whether controls were in place to ensure compensatory sampling was performed consistent with the RETS/ODCM and that those controls were adequate to prevent the release of unmonitored liquid and gaseous effluents.

The inspectors determined whether the facility was routinely relying on the use of compensatory sampling in lieu of adequate system maintenance, based on the frequency of compensatory sampling since the last inspection.

The inspectors reviewed the results of the Inter-Laboratory Comparison Program to evaluate the quality of the radioactive effluent sample analyses and assessed whether the Inter-Laboratory Comparison Program included hard-to-detect isotopes as appropriate.

b. Findings

No findings were identified.

.7 Instrumentation and Equipment (02.04)

Effluent Flow Measuring Instruments

a. Inspection Scope

The inspectors reviewed the methodology the licensee used to determine the effluent stack and vent flow rates to determine if the flow rates were consistent with RETS/ODCM or UFSAR values, and that differences between assumed and actual stack and vent flow rates did not affect the results of the projected public doses.

b. Findings

No findings were identified.

.8 Air Cleaning Systems

a. Inspection Scope

The inspectors assessed whether surveillance test results since the previous inspection for TS required ventilation effluent discharge systems (high efficiency particulate air and charcoal filtration), such as the Standby Gas Treatment System and the Containment/Auxiliary Building Ventilation System, met TS acceptance criteria.

b. Findings

No findings were identified.

.9 Dose Calculations (02.05)

a. Inspection Scope

The inspectors reviewed all significant changes in reported dose values compared to the previous radiological effluent release report (e.g., a factor of five, or increases that approach Appendix I Criteria) to evaluate the factors, which may have resulted in the change.

The inspectors reviewed radioactive liquid and gaseous waste discharge permits to assess whether the projected doses to members of the public were accurate and based on representative samples of the discharge path.

The inspectors evaluated the methods used to determine the isotopes that were included in the source term to ensure all applicable radionuclides were included within detectability standards. The review included the current Part 61 analyses to ensure hard-to-detect radionuclides were included in the source term.

The inspectors reviewed changes in the licensee's offsite dose calculations since the last inspection to determine whether the changes were consistent with the ODCM and Regulatory Guide 1.109. The inspectors reviewed meteorological dispersion and deposition factors used in the ODCM and effluent dose calculations to evaluate whether appropriate factors were being used for public dose calculations.

The inspectors reviewed the latest Land Use Census to assess whether changes (e.g., significant increases or decreases to population in the plant environs, changes in critical exposure pathways, the location of the nearest member of the public or critical receptor, etc.) had been factored into the dose calculations.

For the releases reviewed above, the inspectors evaluated whether the calculated doses (monthly, quarterly, and annual dose) were within the 10 CFR 50, Appendix I, and TS dose criteria. The inspectors reviewed, as available, records of any abnormal gaseous or liquid tank discharges (e.g., discharges resulting from misaligned valves, valve leak-by, etc.) to ensure the abnormal discharge was monitored by the discharge point effluent monitor. Discharges made with inoperable effluent radiation monitors, or unmonitored leakages were reviewed to ensure that an evaluation was made of the discharge to satisfy 10 CFR 20.1501 so as to account for the source term and projected doses to the public.

b. Findings

No findings were identified.

.10 Groundwater Protection Initiative Implementation (02.06)

a. Inspection Scope

The inspectors reviewed monitoring results of the Groundwater Protection Initiative to determine if the licensee had implemented its program as intended and to identify any anomalous results. For anomalous results or missed samples, the inspectors assessed whether the licensee had identified and addressed deficiencies through its CAP.

The inspectors reviewed identified leakage or spill events and entries made into 10 CFR 50.75(g) records. The inspectors reviewed evaluations of leaks or spills and reviewed any remediation actions taken for effectiveness. The inspectors reviewed onsite contamination events involving contamination of groundwater and assessed whether the source of the leak or spill was identified and mitigated.

For unmonitored spills, leaks, or unexpected liquid or gaseous discharges, the inspectors assessed whether an evaluation was performed to determine the type and amount of radioactive material that was discharged by:

- Assessing whether sufficient radiological surveys were performed to evaluate the extent of the contamination and the radiological source term and assessing whether a survey/evaluation had been performed to include consideration of hard-to-detect radionuclides.
- Determining whether the licensee completed offsite notifications, as provided in its Groundwater Protection Initiative implementing procedures.

The inspectors reviewed the evaluation of discharges from onsite surface water bodies that contained or potentially contained radioactivity, and the potential for groundwater leakage from these onsite surface water bodies. The inspectors assessed whether the licensee was properly accounting for discharges from these surface water bodies as part of their effluent release reports.

The inspectors assessed whether onsite groundwater sample results and a description of any significant onsite leaks/spills into groundwater for each calendar year were documented in the Annual Radiological Environmental Operating Report for the Radiological Environmental Monitoring Program or the Annual Radiological Effluent Release Report for the RETS. For significant, new effluent discharge points (such as significant or continuing leakage to ground water that continued to impact the environment, if not remediated), the inspectors evaluated whether the ODCM was updated to include the new release point.

a. Findings

No findings were identified.

.11 Problem Identification and Resolution (02.07)

a. Inspection Scope

Inspectors assessed whether problems associated with the effluent monitoring and control program were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee’s CAP. In addition, the inspectors evaluated the appropriateness of the licensee’s corrective actions for a selected sample of problems documented by the licensee involving radiation monitoring and exposure controls.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

4OA1 Performance Indicator (PI) Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI for Braidwood Unit 1 and Unit 2 for the period from the fourth quarter of 2012 through the first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," definitions and guidance, were used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, IRs, event reports and NRC Integrated Inspection Reports for the period of October 1, 2012 through March 31, 2013, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two safety system functional failures samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency AC Power System PI for Braidwood Unit 1 and Unit 2 for the period from the first quarter 2012 through first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, IRs, event reports and NRC Integrated Inspection Reports for the period of January 1, 2012, through March 31, 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - High Pressure Injection Systems PI for Braidwood Unit 1 and Unit 2 for the period from the fourth quarter 2012 through first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator narrative logs, IRs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of October 1, 2012, through March 31, 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee’s IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Heat Removal System PI for Braidwood Unit 1 and Unit 2 for the period from the fourth quarter 2012 through first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator narrative logs, IRs, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of October 1, 2012, through March 31, 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee’s IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Residual Heat Removal System PI for Braidwood Unit 1 and Unit 2 for the period from the fourth quarter 2012 through first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of October 1, 2012, through March 31, 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.6 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for Braidwood Unit 1 and Unit 2 for the period from the fourth quarter 2012 through first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of October 1, 2012, through March 31, 2013, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.7 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage PI for Braidwood Unit 1 and Unit 2 for the period from the third quarter 2012 through the first quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator logs, RCS leakage tracking data, IRs, event reports and NRC Integrated Inspection Reports for the period of July 1, 2012, through March 31, 2013 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two RCS leakage samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.8 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS specific activity PI for Braidwood Station Units 1 and 2 for the period from the first quarter 2012 through the first quarter 2013. The inspectors used PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s RCS chemistry samples, TS requirements, IRs, event reports, and NRC Integrated Inspection Reports for the period of January 1, 2012, through March 31, 2013, to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s IR database to determine whether any problems had been identified with the PI data collected or transmitted for this indicator. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a RCS sample. Documents reviewed are listed in the Attachment.

This inspection constituted two RCS specific activity samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.9 RETS/ODCM Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the RETS/ODCM radiological effluent occurrences PI for the period from the first quarter 2012 through the first quarter 2013. The inspectors used PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's IR database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment.

This inspection constituted one RETS/ODCM radiological effluent occurrences sample as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

.1 Routine Review of Items Entered into the CAP

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 CAP 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 Semiannual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of January 1, 2013 through June 30, 2013, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

Based on a review of the CAP, plant performance, and inspection results over the past year, the inspectors identified a continuing adverse trend in the licensee's evaluation and quality of response to NRC questions and concerns. This trend was first discussed in Braidwood Inspection Report 05000456/2012004; 0500457/2012004, which included the below text in Section 4OA2.3.b.

The inspectors determined that there was a general weakness in the timeliness, quality, and overall adequacy of site responses to observations and concerns from external oversight. In particular, the inspectors concluded that licensee responses to NRC questions were typically narrowly focused, which challenged effective communication and resulted in additional effort for the inspectors and licensee staff to fully understand the issues such that an adequate resolution could be achieved.

The inspectors have continued to observe these same attributes in recent inspection issues. For example, as documented in Braidwood Inspection Report 05000456/2013002; 05000457/2013002, the inspectors identified a Green finding and associated non-cited violation when licensee personnel failed to account for an allowed 15 psig/hour pressurizer PORV accumulator air leakage limit when establishing the PORV accumulator pressure operability limit. In Section 4OA5.5 of this Inspection Report, the inspectors identified a Green finding and associated non-cited violation when licensee personnel failed to incorporate the same 15 psig/hour leakage limit into design calculations for natural circulation cooldown conditions. The first non-cited violation was a missed opportunity to question whether the 15 psig/hour leakage limit was more generically not considered in design calculations.

In a second example, the inspectors identified a Green finding and associated non-cited violation in Section 1R04.2.b of Braidwood Inspection Report 05000456/2012004; 05000457/2012004 concerning the initiation of an RCS cooldown within 2 hours of a reactor trip with natural circulation conditions. The licensee corrected this non-cited violation through a revision to the EOP guidance. In Section 4OA5.4 of this Inspection Report, the inspectors identified a Green finding and an associated non-cited violation regarding the impact of the EOP revision on the licensing basis function of PZR PORVs. Upon revising the EOP guidance to correct the first non-cited violation, the licensee did not consider whether the parameter being revised was relied upon by other equipment or functions.

The inspectors determined the adverse trend, as described in Section 4OA2.3.b of NRC Inspection Report 05000456/2012004; 05000457/2012004, continued to exist and contributed to some of the findings and NCVs at Braidwood.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

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

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

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

b. Findings

No findings were identified.

.5 Selected Issue Followup Inspection: Lake Chemistry Management Program

a. Inspection Scope

On February 17, 2002, and February 2, 2004, lake precipitation events occurred. The events involved soluble calcium carbonate rapidly precipitating out of the lake water in a manner that impacted plant equipment. The licensee characterized both of these events as Significant Conditions Adverse to Quality (SCAQs) within the CAP. The February 17, 2002 lake precipitation event resulted in a partial loss of nonsafety-related service water flow due to strainer plugging and impacted CW system components, main condenser performance, and lake screen house traveling screens. The February 2, 2004 lake precipitation event adversely affected numerous safety-related and nonsafety-related systems and components due to fouling and impacted safety-related and nonsafety-related heat exchangers and room coolers, SX and non-SX water strainers, and numerous valves.

The licensee performed individual root cause evaluations following both events and identified the root cause as an abnormally high lake mineral concentration. To address this issue, the licensee decided to manage future lake softening events through the Lake Chemistry Control Program. This strategy utilized chemical treatment to adjust the timing and the rate of softening of the lake to prevent future precipitation events. In addition, the licensee established requirements to notify senior site management and Operations at the first sign of any lake softening or precipitation event and entry into an Abnormal Operating Procedure (AOP) if the lake softening rate exceeded a pre-determined threshold.

The inspectors reviewed the licensee's identification and resolution of potential lake softening events. Specifically, the inspectors evaluated whether the licensee had established an adequate process to implement AOP BwOA-ENV-7, "Adverse Cooling

Lake Conditions," at the first sign that the lake was precipitating in a manner that could have an adverse impact on safe plant operation.

This review constituted one in-depth PI&R sample as defined in IP 71152-05.

b. Findings

Unresolved Item: Implementation of Lake Chemistry Management Program

Introduction: The inspectors identified an URI associated with the licensee's implementation of station procedural standards to notify Senior Site Management and Operations at the first sign of a lake softening event, and to implement AOP BwOA-ENV-7, "Adverse Cooling Lake Conditions," when pre-determined calcium precipitation rate limits were exceeded on three occasions from March 2012 through April 2013.

Description: The licensee's root cause analysis performed following a 2004 Braidwood Lake Precipitation Event (IR 199206, "Lake Chemistry Trend Calcium Carbonate Issue," Assignment 13) identified that the Lake Chemistry Plan had not been formalized into operational procedures and, as a result, guidelines for administrative controls, actions limits and levels, and contingency actions had not been established for managing lake chemistry. As one of the corrective actions to address this issue, the licensee developed and implemented AOP BwOA-ENV-7, "Adverse Cooling Lake Conditions," to address any future adverse lake precipitation event (IR 199206, Assignment #35).

On November 10, 2004, BwOA-ENV-7, "Adverse Cooling Lake Conditions," was approved, placed within the station procedures, and was required to be followed in accordance with station standards. This AOP stated that prompt actions may be required to minimize any adverse effects on plant operation. Procedure BwOA-ENV-7 required that several actions be performed to minimize the impact of a significant lake precipitation event. For example, the procedure directed numerous actions to determine whether there had been an adverse impact on plant systems. These actions included the observation of traveling screen operation, monitoring of safety-related and nonsafety-related service water system strainer performance, trending of main condenser pressure, and the monitoring of component cooling system heat exchanger performance, fire protection jockey pump performance, and reactor containment fan cooler service water flow. Upon the identification of any adverse impact, the procedure directed notification of the Braidwood Station Duty Team to ensure appropriate actions would be taken commensurate with safety. Additionally, immediately following entry, BwOA-ENV-7 required that the Emergency Director evaluate Emergency Plan conditions. The procedure also required that the licensee minimize SX and auxiliary feedwater pump, main control room chiller, and EDG operation to preclude chemical or biological fouling.

Following issuance, BwOA-ENV-7 had been revised numerous times to modify the thresholds and standards for informing Senior Site Management and Operations of lake precipitation events and to specify the standards upon which Operations would be notified to implement the procedure. For the period of January 2012 through May 2013, CY-BR-120-412, "Lake Chemistry Data Sheet," Revision 7 was in effect and required the following:

- At the first sign of a precipitation event or natural softening, NOTIFY Senior Site Management and Operations (Reference Section 3.5).

- COMPARE Calcium Hardness and Total Alkalinity trends to determine behavior of these parameters during period of softening and non-softening. (Reference Section 4.6.5)

  - REVIEW CW Makeup and blowdown flow history, as well as recent weather precipitation.

  - If lake softening rate exceeds 15 ppm [parts per million] Calcium Hardness in a 2-3 day period, NOTIFY Operations to enter BwOA-ENV-7.

The inspectors reviewed Braidwood Lake chemistry data from January 2012 through April 2013. The inspectors identified that the licensee appeared to have not followed the standards discussed above for three of the five potential lake softening events during this period. Specifically, the inspectors identified that Senior Site Management and Operations notification and entry into procedure BwOA-ENV-7, "Adverse Cooling Lake Conditions," was delayed for up to several days after the licensee had performed lake water sampling, had analyzed the sample, and had documented the results. The following specific examples were identified:

- *2012 First Lake Softening Event (BwOA-ENV-7 Entered on March 5, 2012 – 3 Days After Entry Conditions were Present*

Date	*Calcium*	*Delta Between Prior Day Sample*
2/29/2012	*257*	
3/2/2012	*231*	*(26)*

- *2012 Third Lake Softening Event (BwOA-ENV-7 Entered on April 15, 2012 – 2 Days After Entry Conditions were Present)*

Date	*Calcium*	*Delta Between Prior Day Sample*
4/11/2012	*194*	
4/13/2012	*167*	*(27)*

- *2013 Second Lake Softening Event (BwOA-ENV-7 Entered on April 4, 2012 – 1 Day After Entry Conditions were Present)*

Date	*Calcium*	*Delta Between Prior Day Sample*
4/1/2013	*209*	
4/3/2013	*191*	*(18)*

The inspectors determined through interviews with licensee personnel and through the review of Operations logs that the licensee had not notified Senior Management and Operations at the first signs of the listed lake softening events or had implemented BwOA-ENV-7 earlier than was documented in the Operations logs.

As a result of not implementing BwOA-ENV-7, "Adverse Cooling Lake Conditions," when required, the licensee did not appear to perform the actions required by the AOP in a time frame commensurate with station standards. Therefore, the licensee failed to meet the standards that they had originally developed and modified over the years to minimize the possible adverse effects of lake precipitation events.

The inspectors discussed this issue of concern with licensee staff, management, and senior management who disagreed with the inspector's assessment. The main points of the disagreement were on the meaning of the term "at the first sign" and on the acceptability of allowing a sample to be taken and analyzed on one day but not reviewed by a supervisor through the Lake Chemistry Control Program until chemistry staff were available, potentially several days later. The inspectors inferred from the term "at the first sign" that actions were required to be performed without an undue delay and that these actions were not dependent upon readily available chemistry staff. In the past two lake precipitation events, plant equipment was adversely impacted relatively soon after the onset of the event. The inspectors recognized that the elevated differential calcium concentration samples identified during this inspection did not actually result in a lake precipitation event.

As of the end of the inspection period, the licensee planned to determine the impact of a 2-3 day delay in implementing BwOA-ENV-7 on the ability to mitigate a lake softening event. Pending a review of this information, this issue is considered a URI.
(URI 05000456/2013003-04; 05000457/2013003-04, Implementation of Lake Chemistry Management Program)

.6 <u>Selected Issue Followup Inspection: Degraded Unit 1 and Unit 2 BAST Bladder</u>

a. <u>Inspection Scope</u>

On April 7, 2013, during a maintenance activity that involved pumping down the Unit 1 BAST with the boric acid pump to replace the internal bladder, the pump lost suction and exhibited signs of cavitation with the Unit 1 BAST level at about 25 percent. The licensee had expected to be able to pump the Unit 1 BAST level down to about 10 percent based upon past experience and tank useable volume data.

In response to this event, the licensee completed a past functionality review and ACE. The inspectors reviewed these evaluations and independently reviewed historical items that had been entered into the CAP to verify that the licensee had adequately identified the cause and corrected the problem.

This review constituted one in-depth PI&R sample as defined in IP 71152-05.

b. <u>Findings</u>

<u>Inadequate Functionality Evaluations for a Degraded Unit 1 BAST Bladder</u>

<u>Introduction</u>: A finding of very low safety significance (Green) was self-revealed when licensee personnel performed inadequate functionality evaluations after previously identifying that the Unit 1 BAST bladder was degraded.

<u>Description</u>: Each Unit 1 and Unit 2 BAST houses a rubber bladder that functions to prevent oxygen in the air from being absorbed into the contents of the tank.

The function of the BAST is to provide a means for reactivity control during normal conditions and as an emergency boration source during abnormal conditions.
As identified in IR 1512602, "Recommend ACE to Investigate Unit 1 BAST Bladder Replacement," the service life for the BAST bladders is about 10 years. The Unit 1 and Unit 2 bladders at Braidwood were in service for over 20 years when problems were first detected.

Information Notice (IN) 91-82, "Problems with Diaphragms in Safety-Related Tanks," was issued by the NRC and addressed to all holders of operating licenses for nuclear power plants, including Braidwood. The purpose of IN 91-82 was to alert the addressees of problems that could occur with bladders installed in safety-related tanks. The NRC expected that recipients would review the information for applicability to their facilities and consider actions to avoid similar problems.

IN 91-82 described several bladder failures, including one at the V. C. Summer Plant in which a BAST bladder ruptured, sank to the bottom of the BAST, and partially blocked the suction line to the BAST pump. The V. C. Summer Plant licensee staff attributed the problem to the bladder having exceeded the estimated 10 year service lifetime by about 3 years. As discussed in IN 91-82, bladders in safety-related tanks have a finite service life and can cause serious safety hazards if they fail and regular inspection and replacement of these bladders can be an important and part of the plant's preventative maintenance program. As a result of this operating experience, Braidwood implemented periodic inspections to examine the BAST bladders with the first inspection occurring in 1993 in lieu of a maintenance activity to periodically replace the bladders.

On April 10, 2007, chemistry personnel documented in IR 0615367, "U1 BAS [Boric Acid System] Sulfate is Out of Goal; U2 BAST Bladder is Close to Goal," that the Unit 1 BAST sulfates were out of goal. The suspected cause was degradation of the bladder. The project to replace the bladders in both BASTs was subsequently approved by the licensee's Plant Health Committee on September 12, 2007. At that time, the Unit 1 BAST was determined to be operable since sulfate concentration was not a condition of operability. The licensee did not, however, consider the potential for blockage of the boric acid pump suction line in their operability evaluation as discussed in IN 91-82.

On October 29, 2007, the Unit 1 BAST bladder was inspected as part of the routine inspection program. As documented in IR 0691603, "Inspection Results for U1 BAST Diaphragm," water was observed on top of the bladder and the bladder was beginning to show signs of degradation. At that time, the Unit 1 BAST was determined to be operable based on the oxygen concentration being within chemistry goals. No other operability or functionality concerns were addressed in the IR. Subsequently, on January 29, 2008, the licensee initiated IRs 728334, "Create Work Order to Replace Diaphragm in 1AB03T," and 728337, "Create Work Order to Replace Diaphragm in 2AB03T," to replace the Unit 1 and Unit 2 BAST bladders in 2009.

The original April 2009 due date to replace the Unit 1 BAST bladder was re-scheduled to the fall of 2009 because a parts evaluation was not complete to support the project.
No IR was initiated to document the re-scheduling.

On March 8, 2009, IR 0904429, "Rubber Material Found in 1AB04F Filter Housing," was initiated after rubber bladder material was found in the Unit 1 boric acid filter. The IR was closed to the pending bladder replacement. Rubber bladder material was again found in the Unit 1 boric acid filter on July 3, 2011, and documented in IR 1236212, "FME [Foreign Material Exclusion] Found in AB04F Filter Housing." Again, the IR was closed to the pending bladder replacement. On March 18, 2013, and March 29, 2013, the Unit 1 boric acid filter plugged again, as documented in IRs 1488893, "FME Found During 1AB04 Filter Change," and 1494458, "Small Amounts of Debris Identified in Filter Housing 1AB04F." Common throughout these IRs was a failure to evaluate the potential adverse consequences of a degraded bladder on useable tank volume.

As documented in IR 1498696, "Secured Boric Acid Tank Transfer Earlier Than Expected," on April 7, 2013, during a maintenance activity to pump down the Unit 1 BAST to replace the bladder, the 1A boric acid pump lost suction and exhibited signs of cavitation at a BAST level of about 25 percent. The licensee had expected the boric acid pump to be able to pump the BAST down to about 10 percent consistent with past operating experience and as assumed in the licensee's useable volume assumptions. On April 16, 2013, an inspection found that there was 6 feet of water on top of the bladder and that the bladder was at the bottom of the tank partially covering the suction line causing the loss of flow and pump cavitation.

The licensee performed an ACE as prescribed in IR 1512602, "Recommend ACE to Investigate U1 BAST Bladder Replacement," Assignment 2. The licensee determined the apparent cause to be that, "station personnel did not perform thorough technical reasoning and risk assessment when characterizing the Unit 1 BAST material condition, resulting in an incomplete assessment and appreciation of the risk and potential outcomes of the condition."

The licensee performed a past functionality determination since the BAST system was a credited reactivity control system described in the Technical Requirements Manual (TRM). Specifically, for operating conditions, a flow path via a boric acid transfer pump from the boric acid storage system can satisfy one of the two required emergency boration sources. The licensee determined that for the limiting historic plant conditions, the Unit 2 BAST and Unit 1 Refueling Water Storage Tank (RWST) would be necessary to supplement the Unit 1 BAST to achieve limiting cold shutdown reactivity conditions.

The inspectors identified that the licensee failed to meet the standards of NRC Part 9900: Technical Guidance, "Operability Determinations & Functionality Assessments for Resolutions of Degraded or Nonconforming Conditions Adverse to Quality or Safety." Specifically, this standard stated the following:

> *Section 2.2 Scope of SSCs for Functionality Assessments*
>
> *Functionality assessments should be performed for SSCs not described in TSs, but which warrant programmatic controls to ensure that SSC availability and reliability are maintained. In general, these SSCs and the related controls are included in programs related to Appendix B to 10 CFR Part 50, "Quality Standards and Records," and the maintenance rule (10 CFR 50.65). Additionally, SSCs warrant functionality assessments within the processes used to address degraded and nonconforming conditions because they perform specified functions described in the Updated Final Safety Analysis Report, Technical Requirements Manual, Emergency Plan, Fire Protection Plan, regulatory commitments, or other elements of the CLB.*

Based on the above, the licensee did not perform an adequate functionality assessment for the issues described in IR 1236212, "FME Found in AB04F Filter Housing," dated

June 3 2011; IR 1488893, “FME Found During 1AB04 Filter Change,” dated March 18, 2013; and IR 1494458, “Small Amounts of Debris Identified in Filter Housing 1AB04F,” dated March 29, 2013, upon the discovery of pieces of the BAST rubber bladder in a Unit 1 boric acid filter, a condition indicative of substantial degradation.

The licensee entered this issue into their CAP as IR 1498696, “Secured Boric Acid Tank Transfer Earlier Than Expected.” Corrective actions included a replacement of the Unit 1 BAST bladder, and an inspection and replacement of the Unit 2 BAST bladder.

Analysis: The inspectors determined that the licensee’s failure to adequately evaluate Unit 1 BAST system functionality after identifying that the bladder had substantially degraded was a performance deficiency.

The performance deficiency was screened in accordance with IMC 0612, Appendix B, “Issue Screening.” The inspectors determined that the performance deficiency did not involve a violation that impacted the regulatory process or contribute to actual safety consequences. The inspectors determined the performance deficiency was more than minor because the issue was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee did not ensure that the Unit 1 BAST remained functional based upon past functionality evaluations.

The inspectors performed a significance review of the finding in accordance with IMC 0609, Attachment 4, “Initial Characterization of Findings.” Table 3, “SDP Appendix Router,” directed that the finding be screened using IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power.” The inspectors answered ‘No’ to all of the Mitigating System Screening questions for Reactivity Control Systems, therefore the finding screened as having very low safety significance (Green). Additionally, the inspectors verified that an alternative source of emergency boration was available through the RWST.

This finding had a cross-cutting aspect in the Operating Experience component of the PI&R cross-cutting area because the licensee failed to implement and institutionalize Operating Experience in NRC IN 91-82 that specifically discussed the potential adverse consequences that a degraded tank bladder could have on pump suction in a manner to support plant safety (P.2(b)).

Enforcement: This issue does not involve enforcement action because no violation of a regulatory requirement was identified. Because this finding did not involve a violation and is of very low safety significance, it is identified as a FIN.
(FIN 05000456/2013003-05; 05000457/2013003-05, Inadequate Functionality Evaluations for a Degraded Unit 1 BAST Bladder)

This review constituted one in-depth PI&R sample as defined in IP 71152-05.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) LER 05000456/2010-006-00; 05000457/2010-006-00 Technical Specifications Allowed Outage Time (AOT) Extension Request for Component Cooling Water System

Contained Inaccurate Design Information That Significantly Impacted the Technical Justification

On January 11, 2011, the licensee submitted LER 05000456/2010-006-00; 05000457/2010-006-00 in accordance with 10 CFR 50.73(a)(2)(ii)(B) and 10 CFR 50.73(a)(2)(v)(B) after identifying on November 12, 2010, that the TSs AOT extension request for the component cooling water system contained inaccurate design information that significantly impacted the technical justification. Corrective actions to address this issue included a design modification to provide a safety-related makeup capability to the component cooling water expansion tank.

The inspectors reviewed the LER. No findings or violations of NRC requirements were identified. This LER is closed

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

4OA5 Other Activities

.1 (Closed) Violation 05000457/2012008-01, Failure to Install Foam Water Sprinklers In Accordance With Sprinkler Standard

As documented in Inspection Report 05000456/2012008; 05000457/2012008 (ADAMS Accession Number ML12269A188), dated September 24, 2012, the NRC identified that the licensee had failed to ensure that two sprinklers in the 2B DOST room were free of obstructions as required by National Fire Protection Association (NFPA) 13 – 1985. In addition, the licensee failed to install a sprinkler under a deck or gallery over 4 feet wide. The licensee committed to modify the sprinklers in the 2B DOST room as documented in their response to the violation on October 23, 2012 (ADAMS Accession Number ML12297A297). In addition, the licensee committed to review the installation in the other DOST rooms and modify sprinkler locations to avoid interferences from ventilation duct obstructions accordingly. During this inspection, the inspectors reviewed the sprinkler installation in the 2B DOST room and determined whether the modified sprinkler locations for the two sprinklers described in the violation were acceptable. In addition, the inspectors determined whether the location of the sprinkler added to provide coverage under the platform described in the violation was acceptable. The inspectors also reviewed modified sprinkler installations for the remaining three DOST rooms and did not identify any concerns with respect to the sprinkler locations and obstructions. This violation is closed.

.2 Operation of an Independent Spent Fuel Storage Installation (ISFSI) at Operating Plants (60855.1)

a. Inspection Scope

The inspectors observed and evaluated select licensee loading, processing, and transfer operations of the first canister during the licensee's 2013 dry fuel storage campaign to verify compliance with the applicable Certificate of Compliance (CoC) conditions, the associated TSs, and approved ISFSI procedures. Specifically, the inspectors observed loading and independent verification of fuel assemblies placed into a multi-purpose canister (MPC); decontamination and surveying; welding and non-destructive testing of the MPC lid; draining of water; and forced helium dehydration. The licensee used the Holtec International HI-STORM 100 Cask System for this campaign.

The inspectors reviewed procedures used to perform ISFSI preparation, loading, sealing, transfer, monitoring, and storage activities. The inspectors reviewed applicable heavy loads procedures and inspection documentation to determine compliance with the site's heavy loads program. The inspectors reviewed select documents, in part, after the licensee completed certain loading activities.

The inspectors reviewed the licensee's evaluations associated with fuel characterization and selection for storage. The inspectors reviewed the licensee's evaluation to characterize fuel as intact fuel, damaged fuel, or fuel debris. The licensee did not plan to load any damaged fuel assemblies or fuel debris during this campaign. The inspectors reviewed the campaign cask fuel selection packages to verify that the licensee was loading fuel in accordance with the CoC approved contents.

The inspectors reviewed a number of IRs and the associated corrective actions since the last ISFSI inspection. The inspectors also reviewed 72.48 screenings and changes to the licensee's 10 CFR 72.212 evaluations since the last ISFSI inspection.

The inspectors performed a walk down of the ISFSI pad to assess the material condition of the pad and the loaded HI-STORM 100 storage casks. The inspectors reviewed the licensee's evaluations of flammable materials near the ISFSI and radiation monitoring program. Additionally, the inspectors performed independent radiation surveys around the ISFSI pad and storage casks and observed the licensee perform required surveillances.

b. Findings

Inadequate Control of a Special Lifting Device

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to adhere to design requirements specified for a special lifting device used to handle a transfer cask containing spent nuclear fuel in the vicinity of the spent fuel pool.

Description: The Holtec transfer cask, or HI-TRAC, is used to move a MPC containing spent nuclear fuel from a wet pit to a dry area where the fuel is processed for storage; then placed atop a storage overpack, or HI-STORM, for transfer of the MPC into the storage overpack. The HI-TRAC is connected to the single failure proof crane hook through the lift yoke to accomplish these moves.

The Holtec HI-STORM 100 CoC, Condition 5, states that each lift of the HI-TRAC must be made in accordance with the heavy loads requirements and procedures of the licensed facility at which the lift is made. Additionally the Holtec HI-STORM 100 Final Safety Analysis Report (FSAR), Table 8.1.6, designates the lift yoke as a special lifting device complying with ANSI N14.6-1993, "Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds or More for Radioactive Materials."

Section 9.1.5.4.1 of the Braidwood Station UFSAR describes the control of the heavy loads program commitment to the seven elements in Section 5.1.1 of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." NUREG-0612, Element 4, states that special lifting devices should satisfy the guidelines of ANSI N14.6, matching the designation in the Holtec FSAR.

Section 6.3.1 of ANSI N14.6 provides two options for performing annual testing on the special lifting device. To satisfy this annual testing requirement, the licensee elected to omit load testing, as permitted by Section 6.3.1.b, by performing dimensional testing, visual inspection, and nondestructive testing of major load-carrying welds and critical areas. When the inspectors requested the records of these tests, it was determined that not all the required testing had been performed on the lift yoke. Procedure BwFP FH-85, "Dry Cask Storage Special Lifting Device Annual Testing," Revision 0, was reviewed by the inspectors and was found to lack specific guidance on the specific areas of the lift yoke that required nondestructive testing. As a result, critical areas identified by the licensee were not nondestructively tested or evaluated as required by ANSI N14.6. In addition, the inspectors discovered that the design drawing for the lift yoke at Braidwood Station, Drawing No. 5894, Sheet 2, Revision 8, "HI-TRAC 125 Ton Transfer Cask Lift Yoke Ancillary #702," specified that certain bolted connections be lock wired. None of these connections appeared to be load bearing; however, the licensee had removed the lock wire and used lock nuts in their place. The inspectors noted that this change was not evaluated and was not compliant with the design drawings. Design Analysis Number HI-2094252, "Structural Analysis of 125-Ton HI-TRAC Lift Yoke," specified the safety class as safety-related.

On April 29, 2013, and again on April 30, 2013, the non-compliant lift yoke was used to conduct lifts of the HI-TRAC in the vicinity of the spent fuel pool. Upon identification, the licensee entered this issue into their CAP as IR 1509204, "Required NDE [Nondestructive Examination] Not Performed on Lift Yoke," and IR 1509602, "Lift Yoke Stud Nuts Not Lock Wired." As part of their corrective actions, the licensee performed the required tests, and installed lock wire in accordance with design drawings, prior to conducting additional lifts with the lift yoke.

Analysis: The inspectors determined that the failure to adhere to design Drawing No. 5894 specifications and ANSI N14.6 requirements for annual testing of a special lifting device was a performance deficiency.

The performance deficiency was screened in accordance with IMC 0612, Appendix B, "Issue Screening." The inspectors determined that the performance deficiency did not involve a violation that impacted the regulatory process or contribute to actual safety consequences. The inspectors determined that the performance deficiency was more than minor because the issue was associated with the Design Control attribute of the Barrier Integrity Cornerstone and adversely impacted the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radioactive releases caused by accidents or events. Specifically the lift yoke did not meet design requirements when used to conduct lifts of the HI-TRAC in the vicinity of the spent fuel pool. The inspectors evaluated the finding using IMC 0609, "Significance Determination Process," Attachment 4, "Initial Characterization of Findings." The inspectors determined that the finding affected the Barrier Integrity Cornerstone and evaluated the finding for significance using IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions." The inspectors answered 'No' to all the screening questions in Appendix A, Exhibit 3 and therefore the finding screened as having very low safety significance (Green).

This finding has a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because the licensee failed to have complete, accurate, and up-to-date design documentation and procedures that ensured personnel, equipment, procedures, and other resources were available and adequate to assure nuclear safety. Specifically the licensee's procedures for annual testing of a special lifting device lacked specific guidance and design changes were made that conflicted with design drawings (H.2(c)).

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

Contrary to the above, on April 29 and April 30, 2013, the licensee failed to ensure measures that establish the design basis for a special lifting device were correctly translated into specifications, drawings, procedures, and instructions. Specifically, a special lifting device was used to perform lifts in the vicinity of the spent fuel pool that was not compliant with the design requirements. Upon identification, the licensee performed the required tests, and installed lock wire per design drawings, prior to conducting additional lifts with the lift yoke.

Because this violation was of very low safety significance and the issue entered into the licensee's CAP as IR 1509204, "Required NDE Not Performed on Lift Yoke," and IR 1509602, "Lift Yoke Stud Nuts Not Lock Wired," this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000456/2013003-06; 05000457/2013003-06; Inadequate Control of a Special Lifting Device).**

.3 Inadvertent Removal of the Design Basis Requirement to Commence a Cooldown Within 2 Hours Following the Establishment of Natural Circulation Conditions and Loss of Air to Containment

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to maintain the procedural requirement to commence an RCS cooldown within 2 hours following a design basis seismic event that included a reactor trip, failure of all nonsafety-related equipment, and a limiting single active failure. Specifically, the natural circulation cooldown was assumed to begin within a 2 hour period from the beginning of this CLB event, however, the licensee recently modified the applicable procedure in a manner that could delay the RCS cooldown beyond the 2 hour period assumed in the original design. Commencing the RCS cooldown beyond the 2 hour time frame assumed in the design could lead to cycling the PZR PORVs beyond their 50 cycle design limit.

Description: The inspectors had previously identified and documented a Green finding in which the licensee failed to follow EOP instructions contained in the procedure 1(2)BwEP ES-0.1, "Reactor Trip Response Unit 1(2)," that required a cooldown to commence within 2 hours following a reactor trip, without RCPs running, and if steam generators PORVs were being utilized (FIN 05000456/2012004-01; 05000457/2012004-01).

Prior Instruction: *"If Steam Generator PORVs are being utilized, Natural Circulation cooldown SHOULD be initiated within 2 HOURS."*

The licensee entered this issue into the CAP and addressed the issue on December 13, 2012, by revising the SHOULD statement to a SHALL statement in the instruction. Additionally, the licensee modified the requirement to commence the cooldown within 2 hours after the condensate storage tank (CST) reached 70 percent. This modification was intended to align the instruction with minimum CST volume assumptions.

New Instruction: *"If Steam Generator PORVS are being utilized, Natural Circulation cooldown SHALL be initiated within 2 HOURS after CST level reaches 70 percent to ensure an adequate Auxiliary Feedwater supply."*

The inspectors reviewed the change to ensure that it was consistent with design assumptions. The inspectors identified that, in addition to the CST, the PZR PORVs were also dependent upon the 2 hour hot standby assumption within the same CLB and Calculation of Record (COR). However, unlike the CST, the start of the 2 hour PZR PORV time frame was assumed at the onset of the event (i.e., post-trip and upon loss of air to containment).

The PZR PORVs had a maximum 50 cycle design value in the absence of the nonsafety-related instrument air supply. This value was based upon a 1988 one-time test that cycled the PZR PORVs over a 10 minute period with an initial air pressure of 100 pounds per square inch gauge (psig) without makeup air to the PZR PORV accumulators. The limiting valve, 2RY456, cycled 66 times with a final accumulator pressure of 81 psig. For a CLB seismic event that resulted in a reactor trip, loss of all nonsafety-related systems and components, and considered the worst case single active failure, the PZR PORVs were calculated to cycle a maximum of 34 times over the assumed 2 hour hot standby period to mitigate the pressure rise as a result of the latent heat within the PZR and subsequent compression of the PZR bubble due to the assumed emergency boration necessary to maintain the shutdown margin within design assumptions. Additionally, the licensee's analysis assumed that three additional RCS depressurizations using the PZR PORVs occurred during the RCS cooldown following the 2 hour hot standby period.

The inspectors concluded that the revised instruction could extend the natural circulation cooldown time beyond the timeframe assumed within the CLB and therefore increase the number of PZR PORV cycles to a number greater than the 37 cycles previously calculated. As a result, the inspectors concluded that this change was not conservative. The licensee entered this issue into their CAP as IR 1496506, "NRC Identified PZR PORV Natural Circulation Cooldown Analysis," and discussed their evaluation with the inspectors. The licensee concluded that even if the time in hot standby was doubled to 4 hours, the number of postulated PZR PORV cycles, which was over 50, would be acceptable because the number was less than the pre-operational test limit of valve 2RY-456, which cycled 66 times over a 10 minute timeframe. Additionally, the licensee's position was that operating procedures were not required to include guidance to begin the cooldown within 2 hours because operators had demonstrated on the plant simulator that a cooldown would be initiated if instrument air was lost to the containment. The inspectors questioned the licensee's acceptance of procedural guidance that did not ensure CLB assumptions were satisfied. Additionally, the inspectors questioned and challenged the licensee's urgency to cool down without a procedural instruction that was required to be followed as evidenced by the performance issue identified in

FIN 05000456/2012004-01; 05000457/2012004-01 in which the licensee did not cool down within 2 hours.

The inspectors discussed this issue with NRC regional staff and experts in the Office of NRR and concluded that the licensee failed to maintain the design basis requirement to commence an RCS cooldown within 2 hours for the CLB event when the instruction was inappropriately revised in the Reactor Trip Recovery EOPs on December 13, 2012. The inspectors concluded that it was not appropriate to rely on the plant simulator to meet this requirement, because the instruction was a 10 CFR 50, Appendix B, Criterion III, "Design Control," requirement.

The licensee entered this issue into their CAP as IR 1496506, "NRC Identified PZR PORV Natural Circulation Cooldown Analysis." Corrective actions included development of a new instruction in the Unit 1 and Unit 2 Natural Circulation Cooldown EOPs that required an RCS cooldown to begin within 2 hours if a LOOP and loss of instrument air occurred to specifically ensure sufficient PZR PORV accumulator capacity remained available.

Analysis: The inspectors determined that the failure to adequately revise an EOP to address a prior NRC Finding was a performance deficiency. Specifically, the licensee inadvertently removed a procedural requirement to commence an RCS natural circulation cooldown if instrument air was lost to containment, which could adversely affect a safety-related PZR PORV function.

The performance deficiency was screened in accordance with IMC 0612, Appendix B, "Issue Screening." The inspectors determined that the performance deficiency did not involve a violation that impacted the regulatory process or contribute to actual safety consequences. The inspectors determined that the performance deficiency was more than minor because it was associated with the Procedural Quality attribute of the Mitigating System Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e, core damage.) Specifically, the credited PZR PORV pressure control function to maintain hot standby conditions and depressurize the RCS to facilitate a natural circulation cooldown could not be ensured without this quality instruction. The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Phase I – Initial Screening and Characterization of Findings," which directed the finding to be screened using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." Using IMC 0609, Appendix A, the inspectors determined that this finding was of very low safety significance (Green) because this issue was determined to not be a confirmed loss of operability or functionality.

This finding had a cross-cutting aspect in the Corrective Action Program component of the PI&R cross-cutting area because licensee personnel failed to thoroughly evaluate a problem and ensure that the resolution adequately addressed the cause and extent of conditions, as necessary. Specifically, the licensee failed to adequately evaluate a prior NRC finding such that the corrective actions adequately addressed the problem (P.1(c)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that the applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, and as specified in the licensee application, for those SSCs to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to the above, on December 13, 2012, the licensee removed the design requirement in procedure 1BwEP ES-0.2, "Natural Circulation Cooldown Unit 1," and 2BwEP ES-0.2, "Natural Circulation Cooldown Unit 2," to commence an RCS cooldown within 2 hours following an event consisting of a reactor trip, loss of all nonsafety-related equipment, and a limiting single active failure. As a result, the licensee failed to ensure that the applicable regulatory requirements were correctly translated into the Unit 1 and Unit 2 procedures.

Because this violation was of very low safety significance and the issue was entered into the licensee's CAP as IR 1419787, "Natural Circ [Circulation] Cooldown – NRC Question on PZR PORV Cycles," this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000456/2013003-07; 05000457/2013003-07, Inadvertent Removal of the Design Basis Requirement to Commence a Cooldown Within 2 Hours Following the Establishment of Natural Circulation Conditions and Loss of Air to Containment)

.4 Failure to Account for PZR PORV Accumulator Leakage During Hot Standby and the Subsequent Cooldown Period Following a Postulated Earthquake

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to account for PZR PORV accumulator air system leakage during the assumed 2 hour time spent in hot standby following a limiting seismic event. Specifically, the licensee did not account for designed PZR PORV accumulator leakage following a CLB postulated earthquake resulting in a LOOP and unavailability of nonsafety-related equipment.

Description: The inspectors previously identified in URI 05000456/2013002-006; 05000457/2013002-006, Issue of Concern 2, that the licensee's COR did not account for any PZR PORV accumulator air system leakage during the 34 cycles in the 2 hour hot standby period assumed with the CLB seismic event that resulted in a reactor trip, failure of all nonsafety-related systems and components, and a limiting single active failure. The licensee had established an allowable leakage value of up to 15 psig per hour during routine surveillance testing based upon the PZR PORV safety function for a SGTR and LOOP event with the final PZR PORV cycle about 1 hour following initiation of the event. In addition to accumulator air system leakage, each PZR PORV cycle could expend up to 0.29 psig per Operability Evaluation 2013-001; and, therefore, the 34 cycles assumed in hot standby during the cooldown could result in an approximate 10 psig pressure drop. The Branch Technical Position (BTP) RSB 5-1 CLB assumed that the PZR PORVs function without nonsafety-related instrument air for up to 2 hours in hot standby. The inspectors identified that the accumulator pressure could drop below the minimum PZR PORV operability value of 85 psig in less than 1 hour following this CLB event. Thus, the pre-established accumulator pressure limit was not conservative with respect to ensuring the PZR PORVs would operate under the assumptions discussed in BTP RSB 5-1 and therefore the 2 hour mission time in hot standby could not be ensured. This could require RCS pressure control using the RCS safety relief valves, which did not have the capability to be isolated if stuck open or if leak-by occurred. The inspectors discussed this issue of concern with licensee staff and management.

The licensee entered this issue into their CAP and performed an Operability Evaluation to comprehensively address this issue. The licensee determined that the PZR PORVs could fulfill their safety function for this CLB event assuming a PZR PORV air accumulator leakage commensurate with the maximum as-left testing conditions of 1 psig/hour.

The licensee evaluated this issue further and determined that the PZR PORV safety function was not required because their CLB relied on auxiliary spray as an alternative method of RCS pressure control. The licensee determined that the nonsafety-related auxiliary spray system could be credited based upon an exception in their CLB for being categorized as a Class II plant. The licensee postulated that the auxiliary spray system could be utilized using portable nitrogen bottles.

The inspectors discussed this issue with NRC regional staff and experts in the Office of NRR and concluded that the licensee was required to consider PZR PORV accumulator air leakage if leakage was permitted by the licensee's testing criteria.

The licensee entered this issue into their CAP as IR 1481590, "NRC Question Regarding Pressurizer PORV Accumulator Leakage." Regardless of whether PZR auxiliary spray can be credited, this represented an adverse impact on the ability of the PZR PORVs to perform their credited function and therefore, an adverse impact on the facility's defense in depth. At the end of the inspection period, the licensee planned to revise their procedures and seek clarification from the Office of NRR concerning the licensing basis of the auxiliary spray system.

Analysis: The inspectors determined that the failure to ensure that the PZR PORVs could perform their credited safety function following a limiting seismic event was a performance deficiency indicative of both historic and recent performance. Specifically, the licensee had established a limiting PZR PORV accumulator leakage value as high as 15 psig/hour, but failed to consider a more limiting CLB event involving a 2 hour hot standby period followed by an RCS cooldown period. When evaluated through the CAP, the licensee inappropriately evaluated the issue as acceptable based upon the use of the nonsafety-related auxiliary spray system.

The inspectors screened the performance deficiency in accordance with IMC 0612, Appendix B, "Issue Screening," and determined that the performance deficiency did not involve a violation that impacted the regulatory process or contribute to actual safety consequences. The performance deficiency was more than minor because it was associated with the Design Control attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the allowable leakage rates of 10-15 psig/hour and assumed usage values would result in an insufficient air source to the PZR PORVs.

The inspectors evaluated this finding using the SDP in accordance with IMC 0609, Attachment 4, "Phase I – Initial Screening and Characterization of Findings," which directed the finding to be screened using IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors determined that this finding was of very low safety significance (Green) because this issue was not a confirmed loss of operability or functionality based largely upon the relatively low measured leakage rates of the PZR PORV accumulators compared to the maximum design leakage rates (1 psig/hour versus 15 psig/hour).

This finding had a cross-cutting aspect in the Corrective Action Program component of the PI&R cross-cutting area since the licensee failed to thoroughly evaluate a problem such that the resolution addressed causes and extent of conditions as necessary. Specifically, the licensee failed to adequately evaluate not accounting for PZR PORV air accumulator leakage in the natural circulation cooldown CLB because the licensee inadequately relied on the auxiliary spray system to provide the credited function (P.1(c)).

Enforcement**:** Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that measures shall be established to assure that the applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, and as specified in the licensee application, for those SSCs to which the appendix applies, are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to the above, from initial plant licensing in 1987, the licensee failed to account for established PZR PORV air accumulator leakage limits during a LOOP event without the reliance on safety-related equipment.

Because this violation was of very low safety significance and because the issue was entered into the licensee's CAP as IR 1481590, "NRC Question Regarding Pressurizer PORV Accumulator Leakage," this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy. As part of their corrective actions to address this issue, the licensee planned to revise their procedures and seek clarification from the Office of NRR concerning the licensing basis of the auxiliary spray system. **(NCV 05000456/2013003-08; 05000457/2013003-08, Failure to Account for PZR PORV Accumulator Leakage During Hot Standby and Subsequent Cooldown Period Following a Postulated Earthquake)**

.5 (Closed) URI 05000456/2012003-06; 05000457/2012003-06, MSIV Hydraulic System Design

a. Inspection Scope

As discussed in NRC Integrated Inspection Report 05000456/2012003; 05000457/2012003, the inspectors questioned whether allowing one inoperable accumulator on each MSIV for an unlimited period of time had any impact on TS 3.3.2, "Engineered Safety Feature Actuation System Instrumentation," and/or Technical Specification 3.7.2, "Main Steam Isolation Valve." Additionally, the inspectors questioned if an active-side MSIV accumulator failure had any impact on the licensee's remote shutdown capability required by General Design Criteria (GDC) 19.

The licensee identified that more than one inoperable MSIV accumulator on different MSIVs could result in a loss of safety function and implemented a requirement to evaluate the condition if it was to occur. Additionally, the licensee planned to submit a Licensee Amendment Request (LAR) that would include TS 3.7.2 Operability Requirements if one MSIV accumulator was inoperable.

The inspectors reviewed the licensee's evaluation and assessment and conducted an independent review. Additionally, the inspectors discussed the issue with NRC regional staff and Office of NRR experts. This URI is closed.

b. Findings

No findings were identified.

.6 (Closed) URI 05000456/2012003-07; 05000457/2012003-07, Removal of TRM 3.3.y Requirements Via a 10 CFR 50.59 Evaluation

a. Inspection Scope

As discussed in NRC Integrated Inspection Report 05000456/2012003; 05000457/2012003, the inspectors had not completed their review of a 10 CFR 50.59 evaluation that permitted the removal of TRM Section 3.3.y, Condition D, which required the individual MSIV isolation switches to be functional or required the MSIVs to be TS 3.7.2 inoperable within 48 hours. The inspectors focused their review on the indirect effect of the 10 CFR 50.59 change in that it no longer required the active side of the MSIV accumulator to be functional.

The inspectors reviewed the 10 CFR 50.59 evaluation that implemented this change and discussed the evaluation with both NRC regional staff and Office of NRR experts in 10 CFR 50.59, GDC-19, and the Fire Protection Program. This URI is closed.

b. Findings

No findings were identified.

.7 (Closed) URI 05000456/2013002-06; 05000457/2013002-06, Current Licensing Basis Requirements for RCS Pressure Control Function During Postulated Seismic Event in Reference to NRC RSB BTP 5-1

a. Inspection Scope

This URI documented three issues regarding the licensee's interpretation of their CLB requirements pertaining to the RCS Pressure Control Safety Function during a postulated seismic event and assumed 2 hour period in hot standby. Specifically, the inspectors identified three issues of concern regarding the licensee's ability to maintain RCS pressure control without the reliance on primary safety valves and in a manner that could accomplish an RCS cooldown within a timeframe required by RSB BTP 5-1.

This URI is considered closed.

b. Findings

- Issue of Concern 1: Inadvertent Removal of the Design Basis Requirement to Commence a Cooldown within 2 Hours Following the Establishment of Natural Circulations Conditions and Loss of Instrument Air to Containment. This issue of concern is closed to non-cited violation 05000456/2013003-07; 05000457/2013003-07.

- Issue of Concern 2: Failure to Account for Allowable PZR PORV Accumulator Air Leakage During 2 Hour Hot Standby Period. This issue of concern is closed to non-cited violation 05000456/2013-08; 05000457/2013-08.

- Issue of Concern 3: No Procedures for Crediting the Use of Auxiliary Spray Utilizing Portable Nitrogen Bottles. No findings were identified.

.8 Review of GOTHIC Code Used to Address High Energy Line Break (HELB) Concerns

a. Inspection Scope

On April 3, 2013, inspectors from Region III and the Office of NRR conducted a review of the GOTHIC Code that was used by the licensee to address HELB concerns at the licensee's corporate office at Cantera.

a. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 17, 2013, the inspectors presented the inspection results to Ms. M. Marchionda-Palmer, Braidwood Plant Manager, and other members of the licensee's staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the areas of radiation monitoring instrumentation; radioactive gaseous and liquid effluent treatment; and RCS specific activity and RETS/ODCM radiological effluent occurrences PI verification with Mr. D. Enright, Site Vice President, and other members of the licensee's staff on April 26, 2013.

- The results for the ISFSI operational inspection with Mr. M. Kanavos, Braidwood Plant Manager, and other members of the licensee's staff on May 3, 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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Kanavos, Site Vice President
M. Marchionda-Palmer, Plant Manager
M. Abbas, NRC Coordinator
T. Barren, Manager, Dry Cask Storage Project
P. Boyle, Director, Site Work Maintenance
E. Cieszkiewicz, Supervisor, Radiation Protection
J. Dawn, Coordinator, Dry Cask Storage Campaign
A. Ferko, Director, Site Engineering
B. Finlay, Manager, Site Security
R. Leasure, Manager, Site Radiation Protection
D. Palmer, Manager, Radiation Protection
J. Rappeport, Manager, Site Chemical Environment & Radwaste
B. Schipiour, Director, Site Maintenance
D. Stiles, Director, Site Training
T. Tierney, Acting Director, Site Operations
C. VanDenburg, Manager, Site Regulatory Assurance

Nuclear Regulatory Commission

E. Duncan, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2013003-03; 05000457/2013003-03	URI	Implications of Control Room Ventilation Monthly Surveillance (Section 1R22.1.b)
05000456/2013003-04; 05000457/2013003-04	URI	Implementation of Lake Chemistry Management Program (Section 4OA2.5b)

Opened and Closed

05000456/2013003-01; 05000457/2013003-01	FIN	Failure to Identify and Correct Degraded DOST Room Sump Pump Discharge Check Valves (Section 1R06.1.b)
05000456/2013003-02; 05000457/2013003-02	NCV	Failure to Scope Nonsafety-Related Turbine Building to Auxiliary Building Sump Pump Discharge Check Valves into the Maintenance Rule (Section 1R12.1.b)
05000456/2013003-05; 05000457/2013003-05	FIN	Inadequate Functionality Evaluations for a Degraded Unit 1 BAST Bladder (Section 4OA2.6b)
05000456/2013003-06; 05000457/2013003-06	NCV	Inadequate Control of a Special Lifting Device (Section 4OA5.2.b)
05000456/2013003-07; 05000457/2013003-07	NCV	Inadvertent Removal of the Design Basis Requirement to Commence a Cooldown Within 2 Hours Following the Establishment of Natural Circulation Conditions and Loss of Air to Containment (Section 4OA5.3)
05000456/2013003-08; 05000457/2013003-08	NCV	Failure to Account for PZR PORV Accumulator Leakage During Hot Standby and Subsequent Cooldown Period Following a Postulated Earthquake (Section 4OA5.4)

Closed

05000456/2013002-05; 05000457/2013002-05	URI	Nonsafety-Related Turbine Building Waste Disposal System to Safety-Related Essential Service Water Pump Room Sump Design Interaction (Section 1R12.1b)
05000456/2010006-00; 05000457/2010006-00	LER	Technical Specifications Allowed Outage Time Extensions Request for Component Cooling Contained Inaccurate Design Information that Significantly Impacted the Technical Justification (Section 4OA3.1)
05000457/2012008-01	VIO	Failure to Install Foam Water Sprinklers in Accordance with Sprinkler Standard (Section 4OA5.1)
05000456/2013002-06; 05000457/2013002-06	URI	Current Licensing Basis Requirements for RCS Pressure Control Function During Postulated Seismic Event in Reference to NRC RSB BTP 5-1 (Section 4OA5.7)
05000456/2012003-06; 05000457/2012003-06	URI	MSIV Hydraulic System Design (Section 4OA5.5)
05000456/2012003-07; 05000457/2012003-07	URI	Removal of TRM 3.3.y Requirements via 10 CFR 50.59 Evaluation (Section 4OA5.6)

Discussed

05000456/2012004-01; 05000457/2012004-01	FIN	Failure to Adequately Evaluate Operations Crew Performance for a Reactor Trip and Failure to Adequately Evaluate Emergency Operating Procedure Standards

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

- 0BwOA ENV-1; Adverse Weather Conditions Unit 0; Revision 116
- 1BWOA ENV-1; Adverse Weather Conditions Unit 1; Revision 5
- 2BWOA ENV-1; Adverse Weather Conditions Unit 2; Revision 5
- IR 1498474; 0/1/2 BwOA-ENV-1 Entry Due to High Winds; April 6. 2013
- IR 1498720, 2B DG Work Window Deferred Due to Weather Forecast; April 7, 2013
- IR 1503813; Relay House Cable Vault Has Water Leaking in From Cable Runs; April 18, 2013
- IR 1504169; Review of EP Effects from Local Flooding; April 19, 2013
- IR 1518716; Braidwood Units 1 and 2 Entered 0/1/2 BwOA ENV-1; May 28, 2013
- IR 1519553; 0BwOA ENV-1 Entered Due to Severe Thunderstorm Warning; May 30, 2013
- IR 1524396; Entered 0BwOA ENV-1 Due to Severe Thunderstorm Warning; June 13, 2013
- IR 1527864; 0/1/2 BwOA ENV-1 Entry Due to Severe Thunderstorm Warning; June 23, 2012
- IR 1528789; Entered 0BwOA ENV-1; June 25, 2013
- IR 1529376; Entered 0/1/2 BwOA ENV-1 Due to Severe Thunderstorm Warning; June 26, 2013
- IR 1529992; 0/1/2 BwOA ENV-1 Entry, OLR Yellow; June 27, 2013
- WC-AA-107; Seasonal Readiness, Revision 11

1R04 Equipment Alignment

- BwOP AB-8; Transfer of Boric Acid from Unit 2 Boric Acid Tank to Unit 1 Boric Acid Tank; Revision 11
- BwOP AB-9; Transfer of Boric Acid from Unit 1 Boric Acid Tank to Unit 2 Boric Acid Tank; Revision 13
- BwOP AB-23; Alignment of U-0 Boric Acid Transfer Pump For U-1 or U-2 Demands; Revision 6
- BwOP AB-29; Boric Acid Tank Drain; Revision, 4
- BwOP AB-E1; Electrical Lineup – Unit 0 Operating; Revision 5
- BwOP AB-M1; Operating Mechanical Lineup Unit 0 Boric Acid Operating; Revision 10
- BwOP DG-11T1; Diesel Generator Start/Stop Log; Revision 8
- BwOP DG-12; Diesel Generator Shutdown; Revision 28
- BwOP DG-E1; Electrical Lineup 1A Diesel Generator; Revision 7
- BwOP DG-E2; Electrical Lineup – Unit 1B Diesel Generator; Revision 6
- BwOP DG-E3; Electrical Lineup – Unit 2A Diesel Generator; Revision 7
- BwOP DG-M1; Operating Mechanical Lineup Unit 1A DG; Revision 17
- BwOP DG-M2; Operating Mechanical Lineup Unit 1B DG; Revision 17
- BwOP DG-M3; Operating Mechanical Lineup Unit 2A DG; Revision 15
- BwOP DM-E1; Electrical Lineup – Unit 0 Operating; Revision 3
- BwOP DM-M1; Operating Mechanical Lineup Unit 0; Revision 6
- BwOP DO-19; Filling the Diesel Fire Pump Fuel Oil Storage Tank; Revision 58
- BwOP DO-M11; Operating Mechanical Lineup Unit 1 DG 1A Fuel Oil; Revision 3

- BwOP DO-M12; Operating Mechanical Lineup Unit 1 DG 2A Fuel Oil; Revision 4
- BwOP SI-E2; Electrical Lineup – Unit 2 Operating; Revision 7
- BwOP SI-M2; Operating Mechanical Lineup Unit 2; Revision 22
- IR 1495814; 1A DG Adjust Fuel Linkage to Reduce Cylinder D/T – 1DG01KA; April 1, 2013
- IR 1496284; Possible U2 BAST Bladder Replacement Bundling of Work; April 2, 2013
- IR 1498776; U1 BAST X-Tie Valve Has Significant Leakby – 1A88465; April 7, 2013
- IR 1500069; Small Amount of Debris Identified in Filter Housing 2AB04F; April 10, 2013
- IR 1500436; Replace the 2B Fuel Pump DG Rod Ends – 2DG01KB; April 11, 2013
- IR 1500855; 2B DG Lube Oil FME Integrity Lost Due to Extruded Quad Ring; April 11, 2013
- IR 1502571; Inspection of Unit 1 Boric Acid Storage Tank – 1AB03T; April 16, 2013
- IR 1505775; 2B DG Crankcase Pressure Indication Higher than Expected; April 13, 2013
- IR 1506060; 2B DG Intake Air Manifold Leaks – 2DG01KB; April 24, 2013
- IR 1506868; 2B DG Intake Air Manifold Leaks at 4R, 7R, 8R and 9R Cylinders; April 25, 2013
- IR 1509323; 2A DG 6R Explosion Cover Leak – 2DG01KA; May 2, 2013
- IR 1517863; 1A DG #2 Air Compressor Running Frequently – 1DG01SA-B; May 25, 2013
- IR 1529301; NRC Id'd Housekeeping Issues in U2 SI Pp Rooms; June 26, 2013

1R05 Fire Protection

- IR 1160371; Degraded Condition for 3 Years Still Not Fixed; January 9, 2011
- IR 1500167; NRC ID Fire Protection Questions; April 10, 2013
- IR 1508505; SAT 242-1 Fire Detection Alarm Received & No Fire; April 30, 2013
- IR 1515373; Fire Door Not Latching Properly; May 18, 2013
- IR 1516704; Missing Fireproofing on Beam in LCSR U1 – 1Z1 Fire Zone; May 22, 2013
- IR 1516707; Missing Fireproofing in LCSR U1 – 1Z1 Fire Zone; May 22, 2013
- IR 1518179; Hydro Date Out of Spec - **Correction** - No Deficiency; May 27, 2013
- IR 1518928; IEMA Id'd HELB Door Installation Work Impedes Normal Access; May 28, 2013
- IR 1519922; NRC Question on DOST Sprinkler Modifications; May 30, 2013
- BwOP FP-27; Smoke Removal Plan; Revision 3
- CC-AA-102; Operations Department (Including Radwaste) Configuration Change Checklist – EC 391764, Revision 000
- CC-AA-103; Work Planning Instructions – EC 391764, Revision 001 AWA #1
- LS-AA-128; Fire Protection Change Regulatory Review (FPCRR) – EC 351562; Revision 0
- MA-AA-716-025; Scaffold Installation Modification and Removal Request Process; Revision 9
- Braidwood Pre-Fire Plan #26; FZ 3.2D-2, CSR 439' Lower Cable Spreading Room, Zone D-2
- Braidwood Pre-Fire Plan #48; FZ 5.4-2, SWGA 451' Division 22, MEER & Battery Room
- Braidwood Pre-Fire Plan #49; FZ 5.5-1, SWGA 451' Unit 1, Aux. Electrical Equip. Room
- Braidwood Pre-Fire Plan #52; FZ 5.6-2, Aux Bldg 451'-0" Elev Division 21 Misc. Electrical Equipment and Battery Room
- Braidwood Pre-Fire Plan #86; FZ 8.7A-0, TB 401' Station Aux. Diesel Generator Room
- Braidwood Pre-Fire Plan #87; FZ 8.7B-0, TB 401' Station Aux. Diesel Oil Tank Room
- Braidwood Pre-Fire Plan #202; FZ18.2-2, AB 451' DG 2A Switchgear Room Air Shaft
- Braidwood Pre-Fire Plan #205; FZ 18.4-1, AB 451' Control Room HVAC Equipment Room Train A
- Braidwood Pre-Fire Plan #206; FZ 18.4-2, AB 451' Control Room HVAC Equipment Room Train B
- National Fire Protection Association; Chapter 4 – Spacing, Location and Position of Sprinklers; 2003
- Commonwealth Edison Letter to NRR; Byron Units 1 and 2 Fire Protection Report; August 20, 1984

1R06 Flood Protection Measures

- IR 1503222; NOS ID: Simulator – EP Exercise Critique Not Focused on ERO; April 1, 2013
- IR 1503235; NOS Ids Deficiencies Not Discussed During EP OSC Critique; April 17, 2013
- IR 1503707; Braidwood EP OYE TSC Failed Objectives; April 18, 2013
- IR 1505212; GSEP – Unable to Hear Announcement or Siren; April 17, 2013
- WO 612745, Ultrasonic Verification of DOST Check Valves; February 25, 2005
- BwMP 3100-094; Removal and Installation of Flood Seal Opening Barriers; Revision 10
- 0BwOA SEC-5; WS System Malfunction; Revision 101
- 1BwOA; WS System Malfunction; Revision 101
- NUREG-0800; Standard Review Plan – 3.4.1 Flood Protection; July 1981
- NUREG-0800; Standard Review Plan – 3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment; October 1990

1R07 Heat Sink Performance

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- BwAR 0-38-A14; Turbine Bldg. Fire/Oil Sump Flood Level; Revision 53
- BwAR OPL02J-1-A8; Diesel Fuel Oil Storage Tank Sump 1B Level High High; Revision 53
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- 1BwOSR 3.3.2.8-602A; ESFAS Instrumentation Slave Relay Surveillance (Train A – K602, K647 and K648); Revision 17
- 0BwOSR 3.7.10.1-1; Control Room Ventilation (VC) Filtration Surveillance (Train A); Revision 9
- Drawing M-96; Control Room HVAC System; December 29, 1977
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- IR 1092631; 2OD01PB Running Unexpectedly; July 20, 2010
- IR 1098761; Sumps Have Sediment That Needs Cleaning; August 6, 2010
- IR 1349481; Need WO to Clean 1A DOST Room Sump; March 29, 2012
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- IR 1487763; Wrong Size WF Sump Pumps Installed in SX Pump Rooms Sumps; June 2, 2010
- IR 1487776; Need WO to Install Upgraded Impeller in 2WF06PA; November 14, 2011
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- IR 1525902; Disassemble and Inspection of 1OD001D; June 17, 2013
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- IR 1526130; 1OD001B Needs WO to Replace Elastomers; June 18, 2013
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- Braidwood Fire Protection Report Table 2.4-2; Safe Shutdown Equipment List; Amendment 25
- 1BwEP-3; Steam Generator Tube Rupture; Revision 207 WOG 2
- 1BwOA ELEC-5; Local Emergency Control of Safe Shutdown Equipment; Revision 103
- 0BwOA PRI-5; Control Room Inaccessibility; Revision 101

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- EC 391342-1 Evaluation; Units 1 & 2, Room Heat Up During HELB Damper Installation; Revision 001
- EC 391342; Unit 1 Switchgear Heat Removal (VX); Revision 003
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- PC-AA-1014; Risk Management; Revision 3
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- U-1 SAT Outage – May 2013 Protected Equipment; 480 VAC ESF Power (Div 11, 21, 22), AF Flow to SGs (B Train), SX Cooling to ESF Equipment (A Train), CS Isolation from RWST

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- IR 1188507; Daiichi: DG DOST Room Flooding Issue; March 17, 2011
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- IR 1383367; NRC Resident Questions Answer to Question #2 of Safety Eval; June 5, 2012
- IR 1395340; Torque Valve Revision for ITT Grinnell Valves; July 31, 2012
- IR 1431454; Re-torque 2RE1003 in A2R17; October 25, 2012
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- IR 1481590; PZR PORV Air Accumulator Capacity Impact on Feed and Bleed; February 26, 2013
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- IR 1500855; 2B DG Lube Oil FME Integrity Lost Due to Extruded Quad Ring; April 11, 2013
- IR 1501529; 2B DG Minor Oil Leak from Crankcase Level Gage; April 13, 2013
- IR 1501576; 2B DG Sump Level Found at -2.5 Inches (Round Min – 1 Inch); April 13, 2013
- IR 1505009; Leak from Pump Shaft Packing – 1AB03P; April 22, 2013
- IR 1505775; 2B DG Crankcase Pressure Indication Higher than Expected; April 13, 2013
- IR 1506060; 2B DG Intake Air Manifold Leaks – 2DG01KB; April 24, 2013
- IR 1506641; 2B DG – Loose/Stripped Bolt on 7L Inspection Cover – 2DG01KB; April 25, 2013
- IR 1506666; 2B DG Lower Lube Oil Cooler – Loose Bolts on Reversing Head; April 25, 2013
- IR 1506682; 2B DG – 1L Fuel Injector Pump Supply Fitting Leaking 2DG01KB; April 25, 2013
- IR 1511698; SAT 142-1 Deluge T-Fitting Cracked (Dup); May 7, 2013
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1R20 Refueling and Other Outage Activities

- BwOP RC-1; Unit 1/2 Startup of a Reactor Coolant Pump; Revision 26
- 2BwGP 100-2; Plant Startup; Revision 30
- 2BwGP 100-5; Shutdown; Revision 43
- OP-AA-101-111-1001; Operations; Revision 13

1R22 Surveillance Testing

- IR 1510933; PCRA Needed for ½ BwOSR; May 6, 2013
- BwOP CV-E1; Electrical Lineup - Unit 1 Operating; Revision 11

- BwOP DG-E4; Electrical Lineup - Unit 2B Diesel Generator; Revision 7
- BwOP DG-11; Diesel Generator Startup and Operation; Revision 42
- BwOP DG-11T2; Diesel Generator Operating Log; Revision 27
- BwOP DG-M3; Operating Mechanical Lineup Unit 2A Diesel Generator; Revision 15
- BwOP DO-7; Filling Unit 1 Diesel Generator Storage Tank From the 50,000 or 125,000 Gallon Fuel Oil Storage Tank; Revision 21
- 2BwOSR 3.1.4.1; Movable Control Assemblies Surveillance; Revision 20
- 2BwOSR 3.3.1.13-3; Reactor Trip Bypass Breaker Surveillance; Revision 1
- 1BwOSR 3.3.2.3; Undervoltage Simulated Start of 1A Auxiliary Feedwater Pump Surveillance; Revision 5
- 1BwOSR 3.4.13.1; Unit One Reactor Coolant System Water Inventory Balance Surveillance, Revision 32
- 1BwOSR 3.7.5.4-1; Motor Driven Auxiliary Feedwater Pump Surveillance; Revision 12
- 2BwOSR 3.8.1.14-2; Unit 2B Diesel Generator 24 Hour Endurance Run; Revision 5
- 2BwOSR 5.5.8.CS-1B; B Train Containment Spray System Valve Stroke Surveillance; Revision 16
- 1BwOS SX-1, Unit One AF Pump SX Suction Line Flush 18 Month Surveillance, Revision 2
- 2BwOS SX-1, Unit Two AF Pump SX Suction Line Flush 18 Month Surveillance, Revision 2
- BwVP 800-9T5; Clean and Dirty Turbine Oil Storage Tank 0TO01T and 0TO02T; Revision 0
- Drawing M-48; Diagram of Waste Disposal Turbine Building Floor Drains; Sheet 16
- Drawing M-48; Miscellaneous Sumps and Pumps; Sheet 19
- Drawing M-48; Diagram of Turbine Building Waste Oil Collection System; Sheet 24
- Drawing M-75; Diagram of Turbine Oil Units 1 and 2; Sheet 1
- Schematic RW-5; Liquid Radwaste PT II; February 16, 2009, Revision 0
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- BYR-BRD-103; Byron Generating Station (Units 1 and 2) and Braidwood Generating Station (Units 1and 2) Plant Process Computer Replacement Project, Combined Software Requirements Specification & Software Design Description for Calorimetric, Revision 14
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- Night Shift Log; Started Scheduled Performance of 1BwOSR 3.3.2.3, Undervoltage Simulated Start of 1A AFW Pump Surveillance; May 6, 2013
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1EP6 Drill Evaluation

- Braidwood 2013 Off-Year Exercise: U1 at 1252 MWe & U2 at 1233 MWe; 1A CS OOS, Failed Fuel Radiation Monitor 1PR06J OOS; April 17, 2013

2RS5 Radiation Monitoring Instrumentation

- 0010722727; Certificate; Bicron RSO-50E No. 076048
- 0010722805; Certificate; Bicron RSO-50E No. 079908
- 0010722797; Certificate; Bicron RSO-50E No. 076482
- 0010645472; Certificate; MGP Telepole No. 077790
- 0010687210; Certificate; MGP Telepole No. 078423
- 0010734860; Certificate; MGP Telepole No. 0012458
- 6008500; LSC SNS QC; Certificate of Radioactivity Traceability Unquenched
- 6007600; LSC H3 Ultima Gold Quenched Standard Set
- 80637-139; Proportional Counter Certificate of Calibration Standard Radionuclide Source
- 81806-139; Proportional Counter Certificate of Calibration Standard Radionuclide Source

- 20750; HpGe QC Eckert and Ziegler Analytics Certificate of Conformance
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- CY-AA-130-201-F-01; Instrument Calibration and Performance Check Quality Control Schedule: LSC 1/Perkin Elmer Tri-Carb 250 OTR; September 28, 2011
- CY-AA-130-205-F-02; Radiochemistry Method Development PC-101 Alpha/Beta Counter; April 10, 2013
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- RP-AA-229; Fast Scan ABACOS Plus Whole Body Counter Calibration; Revision 0
- RP-AA-700-1101; Calibration Data Sheet RSO-50 Ion Chamber No. 075694
- RP-AA-700-1242; Teletector Calibration Data Sheet; No. 95047; October 11, 2012
- RP-AA-700-1209; Calibration Shepherd Box Irradiators; Revision 0
- RP-AA-220; Intake Investigation Form; Revision 7
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- 96-4712; Calibration of Canberra Fast Scan A-3 Whole Body Counter System at Braidwood Nuclear Power Station; August 1, 2012
- RP-HA-700-1209; 2013 Shepherd Model 89 Calibration; March 1, 2013
- 96-4709; Calibration of the Canberra Fastscan A1 WBC System; August 2, 2012
- RP-AA-222; Methods for Estimating Internal Exposure from In-Vivo and In-Vitro Bioassay Data; Revision 3
- WO 01570434; Inventory and Leak Testing of Radioactive Sources at Braidwood Station; December 12, 2012
- RP-BR-903; Response to Radiation Monitor Out of Service; Revision 1
- IR 1506931; NRC:ID: Enhancement to Procedures for GM-Type Calibrations; April 26, 2013
- IR 1409794; 2AR11J Spiking Caused a Containment Isolation; September 6, 2012
- IR 1299133; 2PR27J Process Monitor Spiked Several Times into Alarm; December 7, 2011
- IR 1503848; Four Instrument Records for Calibration Not Found; April 18, 2013
- IR 1506939; NRC ID in Enhancement of Data Storage of Area and Process Monitor Set-Points; April 26, 2013
- IR 1297376; Issue Identified with Inside Whole Body Counter; December 2, 2011
- IR 1199647; Adverse Trend In Radiation Monitor Issues

<u>2RS6 Radioactive Gaseous and Liquid Effluent Treatment</u>

- Braidwood Nuclear Power Station Radioactive Effluent Release Report for 2012, Unit 1 and 2; January - December 2012
- CY-BR-170-301; Offsite Dose Calculation Manual; Revision 7
- WO-01402996; 1PR28J Calibration of Effluent Gaseous Vent Stack Radiation Monitor System; December 13, 2012
- WO 01200860; 0PR01J Decon Liquid Radwaste Effluent Rad Monitor Calibration; September 8, 2009
- WO 01321369; OR-PR001 Calibration of Liquid Effluent Rad Monitor; April 8, 2011
- WO 01218330; 1PR11J Replace All Electrolytic Capacitors or Entire Power Supply on Containment Purge Effluent Rad monitor; January 5, 2013
- BwIP-2505-004; Calibration of GA Particulate, Iodine, and Gas Radiation Monitor; Revision 15
- BwISR 3.3.3.2-212; Surveillance Calibration of Main Steam Radiation Monitors; Revision 12
- VA-ABVS-0VA05FC; Nucon International, Inc. Radioiodine Test Result Report; March 14, 2013
- VA-ABVS-0VA05FB; Nucon International, Inc. Radioiodine Test Result Report; March 14, 2013

- VA-ABVS-0VA05FA; Nucon International, Inc. Radioiodine Test Result Report; March 14, 2013
- 2012 Radiological Groundwater Protection Plan Summary Reports for 2012; AMO Environmental Decisions Consultant
- RPBR-920; AR Setpoint Changes; Revision 6
- RP-BR-904; Response to High Radiation Monitor Alarms; Revision 0
- WO 01423050; Aux Building Filter Plenum Ventilation System Total Bypass Leakage Test of Charcoal Adsorbed; January 17, 2013
- IR 1481656; Effluent Process Monitors Setpoint Calculations Transfer to Chemistry; February 28, 2013
- IR 1394592; 1AR11J; Containment Radiation Monitor Trended Upward and Spiking High on 12 Hour Shift; July 30, 2012
- IR 0397329; 1AR12J; Containment Fuel Handling Received Unexpected Alarm; March 23, 2012
- AR 1447618; Filter Media Utilized in 1/2PR029 and 1/2PR030; December 12, 2013
- AR 1487802; Loss of Sample Flow to OPR05J Turbine Building Fire and Oil Sump Process Monitor; March 14
- IR 1373673; EXELON Pond Level Indicator Not Working; June 2, 2012
- IR 1448745; Unable to Start the EXELON Remediation Pond Pump; December 6, 2012
- IR 1457442; Unable to Start the Pond Pump Due to No Commands; January 1, 2013
- IR 1478824; EXELON Pond Pump Will Not Run; February 22, 2013

4OA1 Performance Indicator Verification

- LS-AA-2090; Monthly Data Elements for NRC Reactor Coolant System Specific Activity; Revision 4
- Monthly Data Elements of RCS Activity from January 2012 through March 2013
- LS-AA-2150; Monthly Data Elements for NRC RETS/ODCM Radiological Effluent Occurrences; Revision 5
- Monthly Data Elements for NRC RETS/ODCM Radiological Effluent Occurrences from January 2012 through March 2013

4OA2 Problem Identification and Resolution

- IR 0199206; Lake Chemistry Trend Calcium Carbonate Issue; February 3, 2004
- IR 1295357; Evaluation of FP Operator Challenge Schedule Dates; November 29, 2011
- IR 1233019; OWA – BwOS FP-Q7 Has Become an Operator Burden; June 26, 2011
- IR 1419787; Natural Circulation Cooldown – NRC Question on PZR PORV Cycles (AR 1472162); September 28, 2012
- IR 1496506; NRC ID’d PZR PORV Natural Circulation Cool Down Analysis; April 2, 2013
- IR 1503707; Braidwood EP OYE TSC Failed Objectives; April 18, 2013
- IR 1510125; Security Computer Intermittently Freezing; May 3, 2013
- IR 1510165; Failed ERO Assembly and Accountability Objective; May 3, 2013
- IR 1516410; Change 2B RCFC Perf Test PM 49407-02 Freq From 4Y to 5Y; May 21, 2013
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- EC 393408; Evaluation of Reduced Available Inventory in U1 BAST Natural Circulation Cooldown Historical SERs References to Boration Capability
- EC 394168; Op Eval 13-005, GDC 5 Concern with Sharing of SX System; June 18, 2013
- 1BwEP-0; Reactor Trip or Safety Injection; Revision 204 WOG 2
- 1BwEP ES-0.1; Reactor Trip Response; Revision 203 and 204 WOG 2
- 2BwEP ES-0.1; Reactor Trip Response; Revision 204 WOG 2

- 2BwEP ES-0.2; Natural Circulation Cooldown; Revision 203 and 204 WOG 2
- 1BwGP 100-5; Plant Shutdown and Cooldown; Revision 46
- 1BwOA ELEC-4; Loss of Offsite Power; Revision 105
- 1BwOA PRI-2; Emergency Boration; Revision 101
- 2BwOA PRI-2; Emergency Boration; Revision 101
- BwOP SA-1; Startup and Operation of Station Air Compressors; Revision 40
- CY-BR-120-412; Braidwood Station Lake Chemistry Control; Revision 10
- ER-AA-340; GL 89-13 Program Implementing Procedure; Revision 6
- LS-AA-125-1003; Apparent Cause Report – Six Buried FP Pipe Leaks Have Occurred at Braidwood Station Since September 2011; Revision 10
- OP-AA-102-103; Operator Work-Around Program; Revision 3
- OP-AA-102-103-1001; Operator Burden and Plant Significant Decisions Impact Assessment Program; Revision 4
- OP-AA-108-101; Control of Equipment and System Status; Revision 10
- OP-AA-108-115; Operability Evaluation 13-001, Revision 0; Capacity of PZR PORV Air Accumulators During Natural Circulation Cooldown (IR 1459353 & 1468044); Revision 11
- OWA/OC 511; Temporary Hose Installed to Pump the North Oils Separator; July 5, 2011
- OWA/OC 516; Radwaste Grid is Degraded; July 5, 2001
- OWA/OC 523; Surveillance Requires Multiple Actions to Perform Based on Equipment Condition; August 25, 2011
- OWA/OC 533; Unit 1 SAT Single Phase LOOP; January 31, 2012
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- Reg Guide 1.33; Quality Assurance Program Requirements (Operation); Revision 2
- Reg Guide 1.139; Guidance for Residual Heat Removal; May 1978
- Letter from Commonwealth Edison to NRR; Byron/Braidwood Units 1 and 2 Request for Additional Information Response; October 14, 1987
- M. Richter Letter to NRC; CECO Response to GL 89-13; January 29, 1990
- Letter from Exelon to Braidwood Units 1 and 2; Regulatory Commitment Change Summary Report; February 6, 2004
- NRC Regulatory Issue Summary 2012-10; NRC Staff Position on Applying Surveillance Requirements 3.0.2 and 3.0.3 to Administrative Controls Program Tests; August 23, 2012
- Exelon Fire Protection Leak (0FP296A-14”) LTA Manager #BWR-13-0032
- Drawing M-52; Fire Protection Units 1 & 2 - Background and Extent of Condition; All Leaks Associated with Same FP Ring Header – OOS Since July 2012; March 6, 2013
- Drawing M-900; Outdoor Piping Arrangement

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- IR 1296583; Procedure Adherence Observation During MGMT Observation; December 1, 2011
- IR 1301446; ISFSI Lessons Learned – OPS Guidance on Closing Breaker; December 12, 2011
- IR 1318452; PC-AA-1016 Lessons Learned – Dry Cask Storage; January 26, 2012
- IR 1326180; NRC Severity Level 4 NCV – ISFSI Design Issues; February 13, 2012
- IR 1326203; NRC Severity LVL 4 NCV – ISFSI Procedure Adherence; February 13, 2012
- IR 1334821; Trailers on Pad Exclusively for ISFSI; March 1, 2012
- IR 1339810; NOS ID An Adverse Trend Regarding the Conduct of Briefs; March 12, 2012
- IR 1397648; NRC Identified Combustible Material at the ISFSI Pad; August 6, 2012
- IR 1406839; Questions Regarding ANSI vs UFSAR Requirements for EC380050; August 30, 2012
- IR 1424672; Braidwood Calculation 11Q3981-CAL-006 Has Minor Error; October 10, 2012

- IR 1431457; DCS Transporter Lift Brackets Inspection Issues; October 25, 2012
- IR 1433317; DCS Haul Path and Pad Failure Due to Trailers; October 30, 2012
- IR 1434191; Error in Braidwood ISFSI Pad Design Analysis; November 1, 2012
- IR 1440168; NOS ID Enhancement to Remove Extra Equipment from ISFSI Pad; November 14, 2012
- IR 1440709; BWCY1 Spent Fuel and Dummy Potential Top Nozzle Separation; November 15, 2012
- IR 1440913; NOS Finding: ISFSI/DCS M&TE Use Issues; November 15, 2012
- IR 1440920; NOS ID: Materials Segregation Issues in ISFSI/DCS Building; November 15, 2012
- IR 1442566; DCS Monthly Walkdown of Haul Path and Pad Failed; November 20, 2012
- IR 1473718; Dry Cask Storage VCT Non-Operational; February 11, 2013
- IR 1483639; REMP Sample Locations Require Correction in ODCM; March 5, 2013
- IR 1484050; IEMA Identified Seismic Housekeeping Non Compliance; March 6, 2013
- IR 1491339; Legacy Issue: Error in FHB Foundation Calculation; March 22, 2012
- IR 1492219; Dry Cask Transporter Worst Case Fire Not Addressed in 72.212; March 25, 2012
- IR 1495026; Safety: Dry Casks are Too Close to the Edge of the ISFSI Pad; March 30, 2013
- IR 1509204; Required NDE Not Performed on Lift Yoke; May 1, 2013
- IR 1509602; Lift Yoke Stud Nuts Not Lock Wired; May 2, 2013
- IR 1509609; MPC & HI-STORM Lid Lifts Not ID as Yellow Risk Activities; May 2, 2013
- HI-2094252; Structural Analysis of 125-Ton HI-TRAC Lift Yoke; Revision 0
- Drawing No. 5894; HI-TRAC 125 Ton Transfer Cask Lift Yoke Ancillary #702; Revision 8
- WO 01510238; Lift Yoke Inspection; November 4, 2012
- WO 01505816; MPC Lift Cleat Inspection; November 4, 2012
- WO 01505817; HI-TRAC Trunnion Inspect; November 4, 2012
- WO 01525669; Support DCS Mobilization; October 15, 2012
- LS-AA-114; Exelon 72.48 Review Process; Revision 0
- OU-AA-630; Dry Cask Storage Program Implementation; Revision 3
- OU-AA-630-1000; Spent Fuel Loading Campaign Management; Revision 3
- NF-AP-622 Attachment 1; Cask Loading Requirements Memorandum; March 20, 2013
- BRW-13-0004-N; Fuel Selection Package BWD-0004 for MPC0150; January 31, 2013
- BRW-13-0005-N; Fuel Selection Package BWD-0005 for MPC0151; January 31, 2013
- BRW-13-0006-N; Fuel Selection Package BWD-0006 for MPC0152; January 31, 2013
- BRW-13-0007-N; Fuel Selection Package BWD-0007 for MPC0188; March 21, 2013
- RP-BR-304-1001; HI-TRAC Radiation Survey; Revision 2
- 0BDCSR 3.2.2.1; MPC Surface Contamination Verification; Revision 1
- 0BDCSR3.3.1.1; Wet Cask Pit/MPC Boron Concentration Verification; Revision 1
- 0BDCSR3.1.1.1; Multi-Purpose Canister (MPC) Integrity Verification; Revision 2
- 0BDCSR3.1.3.1; Multi-Purpose Canister (MPC) Cavity Pressure Verification; Revision 1
- 0BDCSR3.1.4.1; Supplemental Cooling System (SCS) Operability Verification; Revision 5
- BWFP FH-70; HI-TRAC Loading Operations; Revision 5
- BWFP FH-71; MPC Processing; Revision 12
- BWFP FH-83; Spent Fuel Cask Contingency Actions; Revision 7
- BWFP FH-85; Dry Cask Storage Special Lifting Device Annual Testing; Revision 1
- PI-CNSTR-T-OP-220; Closure Welding of Holtec Multi-Purpose Canisters at Exelon Facilities; Revision 5

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
ADAMS	Agencywide Document Access Management System
ANSI	American National Standards Institute
AOP	Abnormal Operating Procedure
AOT	Allowed Outage Time
ASME	American Society of Mechanical Engineers
BAST	Boric Acid Storage Tank
BTP	Branch Technical Position
CAP	Corrective Action Program
CCDP	Conditional Core Damage Probability
∆CCDP	Delta Conditional Core Damage Probability
∆CDF	Delta Core Damage Frequency
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CoC	Certificate of Compliance
COR	Calculation of Record
CRE	Control Room Envelope
CRHP	Control Room Habitability Program
CRHS	Control Room Habitability System
CSR	Cable Spreading Room
CST	Condensate Storage Tank
CW	Circulating Water
DC	Direct Current
DLOOP	Dual Unit Loss of Offsite Power
DOST	Diesel Oil Storage Tank
EDG	Emergency Diesel Generator
EJ	Expansion Joint
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
FME	Foreign Material Exclusion
FIN	Finding
FSAR	Final Safety Analysis Report
FW	Feedwater
GDC	General Design Criteria
gpm	gallons per minute
HELB	High Energy Line Break
HVAC	Heating Ventilation and Air Conditioning
IEF	Initiating Event Frequency
IMC	Inspection Manual Chapter
IN	Information Notice
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
ISFSI	Independent Spent Fuel Storage Installation
IST	Inservice Testing
LAR	License Amendment Request
LOCA	Loss-of-Coolant-Accident

LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOOP	Loss of Off-site Power
MEER	Miscellaneous Electrical Equipment Room
MPC	Multi-Purpose Canister
MSIV	Main Steam Isolation Valve
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NIST	National Institute of Standards and Technology
NRC	U.S. Nuclear Regulatory Commission
NRR	U.S. Nuclear Reactor Regulation
NUMARC	Nuclear Management and Resources Council
ODCM	Offsite Dose Calculation Manual
OOS	Out-of-Service
OSP	Offsite Power
OWA	Operator Workaround
PARS	Publicly Available Records System
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Planned or Preventative Maintenance
PORV	Power Operated Relief Valves
ppm	parts per million
psig	Pounds Per Square Inch Gauge
PWR	Pressurized Water Reactor
PZR	Pressurizer
RASP	Risk Assessment Standardization Project
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RETS	Radiological Effluent Technical Specification
RP	Radiation Protection
RWST	Refueling Water Storage Tank
SAT	Station Auxiliary Transformer
SCAQ	Significant Condition Adverse to Quality
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SRV	Safety Relief Valve
SSC	Systems, Structures, and Components
STGR	Steam Generator Tube Rupture
SX	Essential Service Water
TRM	Technical Requirements Manual
TS	Technical Specification
TSAS	Technical Specification Action Statement
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink on May 3, 2013
URI	Unresolved Item

UT	Ultrasonic Testing
VC	Control Room Ventilation System
WF	Auxiliary Building Floor Drain
WO	Work Order

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Sincerely,

/RA/

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

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

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Letter to M. Pacilio from E. Duncan dated August 14, 2013.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000456/2013003; 05000457/2013003 AND 07200073/2013001

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