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

February 10, 2015

EA–13–209

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000456/2014005; 05000457/2014005

Dear Mr. Hanson:

On December 31, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Braidwood Station, Units 1 and 2. On January 22, 2015, the NRC inspectors discussed the results of this inspection with Ms. M. Marchionda, and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report.

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

Based on the results of this inspection, one self-revealed and two NRC-identified findings of very low safety significance were identified. The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. Additionally, a licensee-identified violation is listed in Section 4OA7 of this report.

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

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records (PARS) component of the 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/

John A. Ellegood, Acting Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
IR 05000456/2014005; 05000457/2014005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000456; 05000457
License Nos:	NPF–72; NPF–77
Report No:	05000456/2014005; 05000457/2014005
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	October 1 through December 31, 2014
Inspectors:	J. Benjamin, Senior Resident Inspector D. Betancourt, Resident Inspector B. Boston, Resident Inspector K. Barclay, Resident Inspector, Point Beach M. Holmberg, Reactor Inspector R. Jickling, Senior Emergency Preparedness Inspector J. McGhee, Senior Resident Inspector, Byron B. Palagi, Operations Engineer M. Perry, Resident Inspector Illinois Emergency Management Agency
Approved by:	J. Ellegood, Acting Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000456/2014005; 05000457/2014005; 10/01/2014–12/31/2014; Braidwood Station, Units 1 & 2; Operability Determinations and Functionality Assessments; Problem Identification and Resolution; Other Activities

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three Green findings were identified by the inspectors. These findings were considered non-cited violations (NCV) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," (SDP) dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," Revision 5, dated February 2014.

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when licensee personnel failed to adhere to Operability Determination Process standards after identifying an unanalyzed condition that had the potential to adversely impact numerous safety-related systems during a probable maximum precipitation (PMP) event. The issue was entered into the Corrective Action Program (CAP) as Issue Report (IR) 2396124. Corrective actions for this issue included performing an operability evaluation.

The performance deficiency was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening" because the issue was associated with the Protection Against External Factors 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 licensee evaluated an unanalyzed condition utilizing another power plant's licensing basis in a manner that was not accurate and was not adequate. The finding was of very low safety significance (Green) because the potentially impacted systems remained operable. The finding had a cross-cutting aspect of Avoid Complacency in the Human Performance area. Specifically, the licensee failed to recognize and plan for the possibility of mistakes and plant specific differences between Braidwood and Byron while using Byron's current licensing basis to evaluate a Braidwood condition not previously analyzed (H.12). (Section 1R15.1b)

Green. A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control" was self-revealed following the licensee's failure to design the 1B essential service water (SX) pump inboard bearing casing drain line in a manner that ensured pump operability. Specifically, the licensee had re-designed the 1B SX pump inboard bearing drain line by replacing a hard pipe drain with a flexible hose drain line consisting of fittings of a smaller diameter when compared to the previous hard pipe drain line. This design change resulted in unplanned 1B SX pump inoperability and required operator action to secure the pump to preclude pump damage. The licensee entered this issue into the CAP as IR 2413941. Corrective actions included restoring adequate drain flow by replacing the flexible hose drain line with a hard pipe of a larger diameter.

The performance deficiency was of more than minor safety significance 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 failure to adequately design the 1B SX pump inboard bearing housing drain line resulted in an inoperable 1B SX pump. The finding was of very low safety significance (Green) because the inspector answered 'No' to all of the associated Mitigating Systems screening questions within IMC 0609, Attachment 4, "Initial Characterization of Findings." The finding is associated with the cross-cutting area of Problem Identification and Resolution with an aspect of Evaluation because the licensee did not thoroughly evaluate plant design in a manner commensurate with the safety significance. Specifically, the licensee inappropriately evaluated the design of the 1B SX pump inboard bearing housing drain line after identifying that the drain line size was the contributing cause for a loss of oil inventory in December 2013 (P.2). (Section 4OA2.7b)

Green. 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," for the licensee's failure to assess the impact of plant modifications on the PMP event analysis in the plan design basis. Specifically, the licensee failed to determine if modifications to plant grading that caused higher water levels during a PMP event would adversely affect safety-related equipment. The licensee entered this issue into the CAP as IR 2413941. Corrective actions included performing an operability determination to ensure safety until a formal quality design review can be completed at a later date.

The performance deficiency was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," because the issue was associated with the Protection Against External Factors 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 licensee failed to evaluate the design to ensure that the consequences of the licensing basis PMP would be acceptable with respect to NRC regulations. The finding was of very low safety significance (Green) because it did not result in the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event. The finding had a cross-cutting aspect of Design Margins in the Human Performance area. Specifically, the licensee did not carefully guard design margins when making station grade modifications that could adversely affect safety-related equipment during a heavy rainfall event. This issue was determined to be indicative of recent performance based upon two recent major revisions to station calculation WR–BR–PF–10, Local PMP Analysis, which evaluated the acceptability of recent grade modifications at the station (H.6). (Section 4OA5.2b)

REPORT DETAILS

Summary of Plant Status

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

Unit 2 operated at or near full power for the duration of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. 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. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. 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. Documents reviewed are listed in the Attachment. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues:

- lake screen house heating systems; and
- B.5.B building heat systems.

This inspection constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 2B SX train with 2A SX train unavailable during testing;
- 1A emergency diesel generator (EDG) with 1B EDG out-of-service for maintenance; and
- 2B containment spray (CS) with 2A CS unavailable during testing.

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, UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted three partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 8.7B–0, turbine building station auxiliary diesel oil tank room;
- Fire Zone 9.2–2 and 9.3–2, 2A EDG room and day tank room;
- Fire Zone 9.2–1, 9.3–1, diesel generator (DG) 401’ 1A and day tank room;
- Fire Zone 11.3–0, AB 364’ auxiliary building general area;

- Fire Zone 11.3D–1, 1A centrifugal charging pump room; and
- Fire Zone 11.4A–2, AB 383’ 2B auxiliary feedwater pump diesel room.

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

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05–05.

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 November 2, 2014, the inspectors observed a crew of licensed operators in the plant’s simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. 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 During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On December 16, 2014, the inspectors observed the operation of Unit 2 during solid state protection system surveillance testing. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

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

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. 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.

.3 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspector reviewed the overall pass/fail results of the Annual Operating Test and Biennial Written Examination administered by the licensee from August 25, 2014, through October 9, 2014, required by 10 CFR 55.59(a). The results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee's

Licensed Operator Requalification Training program to meet the requirements of 10 CFR 55.59.

This inspection constitutes one annual licensed operator requalification inspection sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Unit 1 auxiliary feedwater;
- auxiliary building floor drains; and
- 1B SX pump.

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

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

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the 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

No findings were identified.

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

a. Inspection Scope

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

- 1B EDG out-of-service for maintenance–planned yellow risk;
- 1B SX pump out-of-service for oil leak repairs–unplanned yellow risk;
- 2A CS American Society of Mechanical Engineers (ASME) testing, valve strokes–planned yellow risk; and
- 2B CS ASME testing, valve strokes–planned yellow risk.

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

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- probable maximum flooding impact on turbine building flooding and associated safety-related equipment;
- ultimate heat sink east slope elevation below 590 foot elevation;
- 1B SX pump oil inboard bearing oil leak;
- gas voids identified in SX supply to 2A auxiliary feedwater system; and
- 2B EDG lockout test performance issues.

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

This operability inspection constituted five samples as defined in IP 71111.15–05.

b. Findings

Failure to Adequately Evaluate Operability Following the Discovery of an Unanalyzed Condition Involving the Probable Maximum Precipitation Event

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when licensee personnel failed to adhere to Operability Determination Process standards after identifying an unanalyzed condition that had the potential to adversely impact numerous safety-related systems during a PMP event.

Description: The inspectors identified that the licensee had failed to evaluate the impact of prior station grade modifications that increased the calculated amount of standing rain water outside of the turbine building from 601.35 foot elevation above mean sea level to 601.91 foot elevation above mean sea level during a maximum precipitation event that the station is licensed to protect against. Note: grade level at the station has a reference value of 601.00 feet.

UFSAR, Section 2.4 discusses the maximum Braidwood precipitation event, which forms part of the current licensing basis (CLB) for the station. In summary, the maximum precipitation event at Braidwood, based upon historic worst case meteorological data, is 31.9 inches of rainfall over a 48 hour period. At Braidwood, ground level is approximately 601 foot elevation above mean sea level, so the grade modifications raised calculated water level from about 0.35 feet outside of an area of the turbine building to approximately 0.91 feet if this postulated maximum rain fall event was to occur at the station. The consequences of increased rain water outside of the turbine building increased the hypothetical amount of turbine building flooding that would occur below grade with potential to reach and even exceed grade level. Turbine building flooding below grade could adversely affect safety-related equipment within the main steam line tunnel that openly communicates with the turbine building. Additionally, the diesel oil storage tank rooms are also located below grade and are protected from internal flooding (based on a circulating water boot rupture event) by water tight doors and a non-safety-related sump system. Because the licensee does not control the opening of flood doors when internal flooding is not possible, the increased run off, if the turbine building were to flood up completely below grade, could flow into the DG rooms that drain to the diesel oil storage tank rooms and adversely affect all four safety-related DG fuel oil transfer systems. Additionally, above grade, water could enter the auxiliary building and drain into the auxiliary building floor drain system, and ultimately could flow into the drain tank rooms that are designed to overflow into the SX pump rooms and, consequently, adversely affect all safety-related SX pumps.

The licensee entered the issue of concern into the CAP as IR 2396124, "Effect of Site Flood on Turbine Building," and determined that this aspect of plant design had not been specifically evaluated either during the establishment of the original licensing basis or following station grade modifications throughout the years. The licensee identified that another Exelon Nuclear Facility, Byron, that shares many CLB similarities, had performed a safety-related calculation in 1995 (Reference: SF–01, Effect of Postulated Site Flood on Turbine Building) to determine the potential consequences of a PMP event on safety-related structures and equipment at Byron.

The station (Braidwood) performed an initial operability determination within the issue report. The reference grade at Byron is 401 feet; this compares to 601 feet at Braidwood. Key excerpts from Braidwood's initial operability determination follow:

- 4. Summarize why there is reasonable expectation of operability.

  Byron calculation SF–01 concluded that flooding into the turbine building would not raise flood levels to the 401 foot elevation, confirming that flood water entry into the diesel generator rooms does not occur. All diesel generators remain operable and capable of performing their design safety functions.

- The body of the IR referenced the Byron turbine building calculation, which determined leakage into the turbine building would not raise flood levels to the 401 foot elevation *(flood water only filled 40 percent of the available volume on average).*

The IR discussed that Byron's equivalent to Braidwood's Zone "B" flood height was 0.78 feet above grade as compared to Braidwood's 0.91 feet above grade. Additionally, the IR discussed that Byron's equivalent to Braidwood's Zone "A" was 0.31 feet above grade as compared to Braidwood's calculated value of 0.9 feet. The IR did not provide a context of what these comparable/non-comparable flood heights implied for operability.

The inspectors reviewed the IR; the UFSAR for both Braidwood and Byron that described the plants' specific layouts (Figure 2.4–9, Subdivision of Plant Area of Local Intense Precipitation Analysis, Byron and Figure 2.4–7A, Subdivision of Plant Area of Local Intense Precipitation Analysis, Braidwood); and discussed a number of issues of concern with both plant staff and management. In summary, the inspectors could not logically determine how the licensee's operability evaluation met the Operability Determination process standards for providing the high degree of confidence that all SSCs were operable and functional. Specific concerns included application of a different station's analysis without addressing differences in the maximum precipitation event, station structural layout, plant layout orientation and grade variances. The inspectors raised the following issues of concern to the licensee following their preliminary review.

- The two station's building footprints and grading are quite different (e.g., Byron has cooling towers, Braidwood has an Independent Spent Fuel Storage pad that increases the backwater calculation, the two station's turbine buildings are oriented 180 degrees different);

- The Byron calculation assumed that large equipment rollup doors at grade level were shut as compared to the Braidwood actual configuration observed by the inspectors over the past several years being open in the warmer months. In the Byron calculation, the roll-up doors being shut provide resistance from outside rainwater getting into the turbine building where at Braidwood open rollup doors would provide little to no resistance;

- The licensee made an error in referencing how high the Byron calculation calculated turbine building would flood up (i.e., the IR referenced that, "*flood water only filled 40 percent of the available volume on average")* but upon inspector review, the inspectors determined that the Byron calculation contained a different and higher value than the 40 percent value contained in the Braidwood IR (i.e., Byron Unit 1 turbine building calculated to flood up to 44.4 percent and Byron Unit 2 turbine building calculated to flood up to 75.0 percent); and

- The inspectors identified that the licensee failed to determine the potential impact of flooding into the safety-related auxiliary building main steam line tunnels that are open to the turbine building below grade.

The inspectors discussed these issues of concern with station senior management. Following the discussion, the licensee performed a formal Operability Determination using Braidwood's specific licensing basis assumptions. In summary, the licensee concluded that the maximum water level in the turbine building would not reach grade level (specific values are 62 percent below grade flooding for Unit 1 and 42 percent below grade flooding for Unit 2) and that all TS equipment would be capable of meeting their intended safety function (i.e., all TS SSCs were operable). At the end of the inspection period, the inspectors were still in the process of reviewing this evaluation, but had not identified any significant issues that would challenge the conclusions reached in the evaluation.

The inspectors conducted a detailed review of the quality standards contained in the station's Operability Determination process (OP–108–115, Revision 15) and concluded that the Braidwood licensee had not met the standard of *"Engineering Judgment"* to reach the standard of *"Reasonable Expectation"* that all TS SSCs were operable during the initial evaluation. These standards are defined as follows in the station's Operability Determination process:

- *Engineer Judgment: A qualitative, logical, and conclusive discussion reflecting engineering knowledge, operating experience, or testing in combination with one or more of these attributes*

- *Reasonable Expectation: The supporting basis for the reasonable expectation of SSCs operability should provide a high degree of confidence that the SSCs remain operable. The standard of 'reasonable expectation' is a high standard.*

In summary, the licensee utilized another nuclear power plant's CLB without performing the necessary qualitative review to ensure that the evaluation's inputs, assumptions, and conclusions bounded the licenses basis event for Braidwood. Therefore, analysis performed by the licensee did not meet the Engineering Judgment definition to provide a conclusive discussion and therefore did not provide reasonable expectation that all TS

SSCs were operable. Additionally, the discussion used an incorrect turbine building flooding level value that was not conservative.

Analysis: The inspectors determined that the failure to perform an adequate immediate operability evaluation was a performance deficiency. Specifically, the licensee failed to use engineering judgment as defined in licensee procedures to support the conclusion that all SSCs remained operable and/or functional during the PMP event describe in the CLB.

The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," issued September 7, 2012. The issue was associated with the Protection Against External Factors 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 licensee evaluated an unanalyzed condition utilizing another power plant's licensing basis in a manner that was not accurate and was not adequate.

The inspectors determined that the finding was of very low safety significance (Green) in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process For Findings At-Power," issued June 19, 2012. Using Exhibit 2, "Mitigating Systems Screening Questions," question 1, the finding screened as Green because the potentially impacted systems remained operable. The inspectors concluded that this finding had a cross-cutting aspect of Avoid Complacency in the Human Performance area. Specifically, the licensee failed to recognize and plan for the possibility of mistakes and plant specific differences between Braidwood and Byron while using Byron's CLB to evaluate a Braidwood condition not previously analyzed (H.12).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed and accomplished by instructions, procedures, and drawings appropriate to the circumstances, and shall be accomplished in accordance with these instructions, procedures, and drawings." Specifically, the licensee's Operability Determination, OP–AA–108–115, Revision 15, states:

- *Step 4.1.5, "Immediately determine operability from a detailed examination of the deficiency"*
- *Section 2, "Terms and Conditions"*
    - *Engineer Judgment: A qualitative, logical, and conclusive discussion reflecting engineering knowledge, operating experience, or testing in combination with one or more of these attributes.*
    - *Reasonable Expectation: The supporting basis for the reasonable expectation of SSC operability should provide a high degree of confidence that the SSC remain operable. The standard of 'reasonable expectation' is a high standard.*

Contrary to the above, on October 15, 2015, the licensee failed to follow OP–AA–115, Revision 15, Step 4.1.5, after the identification of the issue related to a PMP condition that had not been previously analyzed. The licensee failed to meet the definition of engineering judgment and thus did not provide reasonable expectation that all SSCs remained operable and/or functional during a hypothetical PMP event at the station (Ref: IR 2396124). Specifically, the licensee used a safety-related Byron calculation in a manner that did not provide reasonable expectation based upon the following:

- The licensee made an error in referencing how high the Byron calculation calculated the turbine building would flood up. Specifically the IR referenced that, "*flood water only filled 40 percent of the available volume on average,*" but the inspectors review determined that the Byron calculation contained a different and higher value than the 40 percent value contained in the Braidwood IR (i.e., Byron Unit 1 turbine building calculated to flood up to 44.4 percent and Byron Unit 2 turbine building calculated to flood up to 75 percent).

- The two station's building footprints and grading are quite different (e.g., Byron has cooling towers, Braidwood has an Independent Spent Fuel Storage pad that increases the backwater height calculation; and the turbine buildings are oriented 180 degrees different).

- The Byron calculation assumed that very large equipment rollup doors at grade level were shut as compared to the Braidwood actual configuration observed by the inspectors over the past several years being normally open in the warmer months. In the Byron calculation, the roll-up doors being shut provide resistance from outside rainwater getting into the turbine building.

Corrective actions for this issue included performing an operability determination that addressed the issues raised by the inspectors, which concluded potentially impacted systems remained operable. Because this violation was of very low safety significance and was entered into the licensee's CAP (as IR 2396124), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000456/2014005–01, 05000457/2014005–01, Failure to Adequately Evaluate Operability Following the Discovery of an Unanalyzed Condition Involving the Probable Maximum Precipitation Event).

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following modification:

- Unit 2 main power output line Y connection bypass jumper.

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

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

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

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

- 1B SX Pump Inboard Bearing Housing Oil Leak Repair Activity (WO 01786140);
- 1A CS Spray Additive Check Valve Repair Activity (WO 01786282);
- Unit Common Service Air Reservoir Low Pressure Troubleshooting and Associated Repair Activity (WO 01606054);
- 2C Pressurizer Variable Heater Controller Replacement Activity (WO 01781693);
- Unit 2 Instrument Air 2IA006A Valve and Actuator Replacement Activity (WO 01371392);
- Unit Common Auxiliary Building Damper 0VA438YB Repair Activity (WO 01789592);
- Unit 2 Steam Generator Wide Range Level Calibration Activity (WO 17884757); and
- Unit Common Station Diesel Battery Room Exhaust Fan Repair Activity (WO 01789753).

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

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

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

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:

- 1A auxiliary feedwater pump undervoltage simulated start (Routine);
- 2A DG hot restart surveillance (Routine);
- 2A CS slave start testing (Routine);
- 2A solid state protection system surveillance (Routine)
- 1A chemical volume ASME in-service test (IST); and
- Unit 1 and Unit 2 reactor coolant system (RCS) water inventory balance (RCS Leakage Detection).

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, sufficient to demonstrate operational readiness, and consistent with the system design basis;
- was plant equipment calibration correct, accurate, and properly documented;
- were as-left setpoints within required ranges; and was the calibration frequency in accordance with TSs, the UFSAR, plant procedures, and applicable commitments;
- was measuring and test equipment calibration current;
- was the test equipment used within the required range and accuracy and were applicable prerequisites described in the test procedures satisfied;
- did test frequencies meet TS requirements to demonstrate operability and reliability;
- were tests performed in accordance with the test procedures and other applicable procedures;
- were jumpers and lifted leads controlled and restored where used;
- were test data and results accurate, complete, within limits, and valid;
- was test equipment removed following testing;
- where applicable for inservice testing activities, was testing performed in accordance with the applicable version of Section XI of the ASME Code, and were reference values consistent with the system design basis;
- was the unavailability of the tested equipment appropriately considered in the performance indicator (PI) data;

- where applicable, were test results not meeting acceptance criteria addressed with an adequate operability evaluation, or was the system or component declared inoperable;
- where applicable for safety-related instrument control surveillance tests, was the reference setting data accurately incorporated into the test procedure;
- was equipment returned to a position or status required to support the performance of its safety function following testing;
- were all problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- where applicable, were annunciators and other alarms demonstrated to be functional and were annunciator and alarm setpoints consistent with design documents; and
- where applicable, were alarm response procedure entry points and actions consistent with the plant design and licensing documents.

Documents reviewed are listed in the Attachment.

This inspection constituted four routine surveillance testing samples, one IST sample, and one RCS leakage detection inspection sample as defined in IP 71111.22, Sections–02 and-05.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (IP 71114.04)

a. Inspection Scope

The regional inspectors performed an in-office review of the latest revisions to the Emergency Plan, Emergency Plan Annex, and Emergency Plan Implementing Procedures as listed in the Attachment.

The licensee transmitted the Emergency Plan and Emergency Action Level revisions to the NRC pursuant to the requirements of 10 CFR Part 50, Appendix E, Section V, "Implementing Procedures." The NRC review was not documented in a safety evaluation report and did not constitute approval of licensee-generated changes; therefore, this revision is subject to future inspection. The specific documents reviewed during this inspection are listed in the Attachment.

This Emergency Action Level and Emergency Plan Change inspection constituted one sample as defined in IP 71114.04–06.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on October 30, 2014, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Power Changes Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Power Changes Per 7000 Critical Hours PI (IE03) for Braidwood Unit 1 and Unit 2 from the first quarter 2014 through the fourth quarter 2014. 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 7, dated August 2013, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, maintenance rule records, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014 through December 31, 2014, 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 unplanned power changes per 7000 critical hour samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage PI (BI02) for Braidwood Unit 1 and Unit 2 for the period from the second quarter 2013 through the second quarter 2014. 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 April 1, 2013, through June 30, 2014, 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.

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of April 1, 2014 through October 17, 2014, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the 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 OWAs.

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

b. Findings

No findings were identified.

.5 Selected Issue Follow-Up Inspection: Use of the Personal Digital Assistants During Rounds

a. Inspection Scope

During the first quarter of 2014 the NRC identified that station personnel had inadequately incorporated the requirements of 0BwOS FP.7.2.D–1, “Unlocked Fire Door Daily Surveillance,” into the personal digital assistants (PDAs) utilized by operators during shift round activities. This was the subject of an NCV documented in Inspection Report 05000456/2014002–03; 05000456/2014002–03, “Failure to Identify Fire Doors that Did Not Conform to National Fire Protection Association Codes and Standards.” Specifically, the finding was related to the failure to incorporate the requirements of the procedure into the PDAs, which resulted in simply including a list of all fire doors that were required to be tested and not the required actions needed to be taken if the door did not function as specified.

As part of the corrective actions for this issue the licensee corrected the inaccuracies in the PDA regarding procedure 0BwOS FP.7.2.D–1, conducted an extent of condition review, and conducted training to emphasize the need to contact the operations shift promptly if a fire door is degraded. During this inspection period, the inspectors reviewed the corrective actions, discussed the contents of the corrective actions with operations management, and conducted an independent extent of condition review to identify if there were any additional procedures that had not been properly translated into the PDAs.

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

b. Findings

No findings were identified.

.6 Selected Issues for Follow-up Inspection: Large Mound of Debris Left Within Station Probable Maximum Precipitation Area

a. Inspection Scope

The inspectors conducted an in-depth review to the correct actions performed by the licensee to address an issue that was identified during flooding walkdowns performed in response to the 10 CFR 50.54(f) information request regarding the near-term task force recommendation 2.3: Flooding. Specifically, the licensee identified a 275 feet by 250 feet mound of dirt, asphalt, and concrete that partially blocked rain water from flowing north out of the plant site. The licensee noted that an approximately 85 feet by 140 feet area of the mound would cause rain water to flow back towards the plant. This configuration was contrary to and therefore non-conforming with assumptions made in the PMP calculation for Zone B (Reference: WR–BR–PF–10).

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

b. Findings and Observations

No findings were identified.

The inspectors reviewed the Engineering Change Request and the WO and found that there was no change from the analysis reviewed by the licensee in 2012. The licensee documented the inspector's questions in IR 2396747 and created an "ACIT" CAP assignment to "Add the North Spoils Pile to a Revision of Calculation WR–BR–PF–10." Since this issue was coded as an "ACIT" assignment, it was not recognized by the licensee to be a condition adverse to quality. Since the mound of dirt could adversely affect the outcome of the associated safety-related calculation and was not accounted for within the calculation, the inspectors identified that the licensee had failed to code the corrective action assignment correctly.

The inspector reviewed the actions that the licensee had taken to date to restore compliance and determined that the licensee had neither an action to remove the mound of dirt or accept the configuration within the design.

The licensee entered the inspector's issue of concern into the CAP as IR 2396747. At the end of the inspection period, the licensee had not decided upon the corrective action to restore compliance.

The licensee performed a preliminary engineering evaluation and determined that the current mound of dirt configuration would have minimum impact on the PMP analysis.

The inspectors reviewed the evaluation and did not disagree with the conclusions. The inspectors determined that the issue was of minor significance, largely in part, due to the non-conforming condition not resulting in a significant change to the margin available with the preliminary evaluation performed by the licensee.

.7 <u>Selected Issue for Follow-up Inspection: Corrective Actions Associated with December 30, 2013 1B Essential Service Water Oil Leak</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the causal analysis and corrective actions associated with an oil leak that occurred from the 1B SX pump on December 30, 2013. The oil leak was significant enough that Operations made the decision to secure the pump and enter the associated Technical Specification Action Requirements for an inoperable SX pump. The licensee remained in this condition for a number of days until the cause was adequately understood and corrective actions implemented before restoring SX pump operability.

The inspectors selected this sample to review because a similar oil leak occurred on the same pump during this quarter and appeared to be related in cause.

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

b. <u>Findings</u>

<u>Failure to Correct Undersized Essential Service Water Pump Bearing Casing Drain Line Resulted in System Inoperability</u>

<u>Introduction</u>: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control" was self-revealed following the licensee's failure to design the 1B SX pump inboard bearing casing drain line in a manner that maintained pump operability. Specifically, the licensee had re-designed the 1B SX pump inboard bearing drain line by replacing a hard pipe drain with a flexible hose drain line consisting of fittings of a smaller diameter when compared to the previous hard pipe drain line. This design change resulted in unplanned 1B SX pump inoperability and required operator action to secure the pump to preclude pump damage.

<u>Description</u>: On December 30, 2013, an equipment operator identified that the 1B SX was spraying oil from the inboard bearing housing onto the surrounding floor and wall. Additionally, the operator identified that the oil level in the associated sight glass was low. Operations secured the 1B SX pump and placed the control switch in the pull-to-lock position. Operations entered the associated TS action requirements and changed Unit 1 on-line risk from a Green to a Yellow condition. The licensee replaced the bearing isolators, and restored 1B SX pump operability on December 31, 2013, after the pump had been started and monitored for several hours.

The licensee documented the condition in IR 1601971 and performed an equipment apparent cause evaluation. The licensee concluded that the apparent cause was insufficient venting of the oil reservoir through the bearing isolators and vented inspection plugs. The licensee identified that the contributing cause was a low flow drainage restriction as a result of a non-conforming design. Specifically, the drain line coming out of the inboard bearing housing on the 1B SX pump was modified and replaced with a flex hose. The fittings associated with the metallic flexible hose were estimated to have an inside diameter of less than 0.75 inches and had certain fittings that caused further reduction to the inside diameter. These drainage restrictions had not been adequately accounted for in the design modification that installed the metallic flexible hose. The licensee concluded that this drain flow reduction could result in intermittent increase in oil level inside the bearing housing and cause subsequent leaks from the bearing isolators.

Based upon this causal analysis, the licensee developed the following corrective actions:

- IR 1601971, Assignment #12, Corrective Action: Inspect/clean vented inspection plugs and replace air release filters on all SX pumps. This corrective action was completed by April 11, 2014.

- IR 1601971, Assignment #14, Corrective Action: Evaluate the flex hose piping configuration on the lube oil drainage header for 1B, 2A and 2B SX pumps for restriction of flow and take actions to replace the fittings to the appropriate size. Although the status of this corrective action was completed on October 31, 2014, the corrective action of replacing the fittings to the appropriate size was not completed based upon the evaluation determining that the action was not necessary. The assignment was not changed because the licensee determined that the intent of the requested corrective action had been satisfied because, in part, after replacing the bearing isolators, vent plugs, and air released filters, and because there had not been any additional similar oil leaks since December 2013.

On November 18, 2014, an operator noted that the oil reservoir sight glass for the 1B SX pump was almost empty and an oil mist was spraying out from the inboard bearing. The pump was secured and declared inoperable. The licensee performed an apparent cause analysis and determined that cause of the oil spray was inadequate drainage through the flexible hose and associated fittings. Additionally, the cause evaluation determined that the corrective actions discussed in IR 1601971, Assignment #14 had not been completed as required. Specifically, the licensee had completed the assignment by performing an evaluation but did not replace any components because the evaluation concluded that the drain flow path was adequately sized.

<u>Analysis</u>: The inspectors determined that the failure to design the drain in a manner that ensured pump operability was a performance deficiency. Specifically, the licensee designed an undersized drain line that led to oil loss during pump operation.

The inspectors determined that the performance deficiency was of more than minor safety significance in accordance with IMC 0612, Appendix B, “Issue Screening,” issued September 7, 2012, 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 failure resulted in an inoperable 1B SX pump.

The inspectors performed a significance review in accordance with IMC 0609, Attachment 4, “Initial Characterization of Findings,” issued June 19, 2012. Table 3, “SDP Appendix Router,” directed that the finding be screened using IMC 0609, Appendix A, “The Significance Determination Process for At-Power Findings,” issued June 19, 2012. Using Exhibit 2, the inspector answered ‘No’ to all of the associated Mitigating Systems screening questions and therefore the finding screened as having very low safety significance (Green).

The finding is associated with the cross-cutting area of Problem Identification and Resolution with an aspect of Evaluation because the organization did not thoroughly evaluate issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, the licensee inappropriately evaluated the design of the 1B SX pump inboard bearing housing drain line after identifying that the drain line size/restrictions was the contributing cause for a loss of oil inventory in December 2013 (P.2).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that design changes shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design.

The design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

Contrary to the above, on February 6, 2003, the licensee failed to verify or check the adequacy of the design during a modification that changed the design of the 1B SX pump inboard bearing housing drain line in a manner that did not provide adequate drain flow. Ref (DCP D20–1–00–353, EC 42734)

Corrective actions performed by the licensee included restoring adequate drain flow by replacing the flexible hose drain line with a hard pipe of a larger diameter. Because this violation was of very low safety significance and was entered into the licensee’s CAP as IR 2413941 and IR 2413452 this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2014005–02; Failure to Correct Undersize Essential Service Water Pump Bearing Casing Drain Line Resulted in System Inoperability)**.

4OA5 Other Activities

.1 (Closed) Severity Level IV Violation 05000457/2013008–01; Inaccurate and Incomplete Information for Exemption Request from 10 CFR 50.60 (IP 92702)

The NRC issued a Severity Level IV Violation (VIO) on November 14, 2013, for the licensee’s failure to provide information to the NRC that was complete and accurate in all material respects. Specifically, in Letter RS–05–103, “License Amendment Request Regarding Reactor Coolant System Pressure and Temperature Limits Report and Request for Exemption from Title 10 CFR 50.60,” the licensee stated that a vendor analysis (WCAP–16143–P, Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2, Revision 0) provided a valid basis for changing the reactor pressure vessel closure head flange limit and maintained the relative margin of safety commensurate with that which existed at the time the 10 CFR 50, Appendix G requirement was issued. However, the licensee’s vendor analysis had demonstrated adequate vessel margins based upon the original Unit 2 closure head flange configuration with 54 fully-tensioned head studs, which did not represent the modified Unit 2 closure head configuration with a missing head stud (e.g., 53 head studs). Therefore, the licensee’s submittal was not complete or accurate, because the supporting vendor analysis did not provide a valid basis for changing the Unit 2 reactor pressure vessel closure head flange limits in 10 CFR 50, Appendix G.

The licensee responded to the VIO in letter BW130109, dated December 13, 2013, which described the reasons for the violation, corrective actions and when full compliance would be achieved. The inspectors reviewed the licensee's corrective actions and supporting documents to evaluate the adequacy of corrective actions and to verify that the corrective actions were completed. This review included: (1) Operability Evaluation No. 13–005, which documented the basis for operability of the Braidwood Station Unit 2 Reactor Pressure Vessel; (2) Revision 1 to WCAP–16143–P which reflected the current Braidwood Station Unit 2 configuration of 53 reactor pressure vessel head bolts; and (3) Letter RS–14–284, "License Amendment Request to Utilize WCAP–16143, Revision 1, as an Analytical Method to Determine the RCS Pressure and Temperature Limits," submitted to the NRC on October 16, 2014. Full compliance with NRC regulations would be achieved following NRC approval of the Licensee Amendment Request containing the revised vendor analysis (Revision 1 of WCAP–16143–P). The inspectors did not identify any issues of concern. This Severity Level IV Violation, VIO 05000457/2013008–01 and the associated finding, FIN 05000457/2013008–02, are closed.

.2 <u>(Closed) NRC Temporary Instruction 2515/190, Inspection of the Proposed Interim Actions Associated with Near–Term Task Force Recommendation 2.1 Flood Hazard Evaluations.</u>

a. <u>Inspection Scope</u>

The inspectors verified that the licensee's interim actions will perform their intended functions for flooding mitigation.

The inspectors independently verified that the licensee's proposed interim actions would perform their intended function for flooding mitigation.

- Visual inspection of the flood protection feature was performed if the flood protection feature was relevant. External visual inspection for indications of degradation that would prevent its credited function from being performed was performed.

- Reasonable simulation, as applicable.

- Flood protection feature functionality was determined using either visual observation or by review of other documents.

The inspectors verified that issues identified were entered into the licensee's corrective action program.

b. <u>Findings</u>

<u>Failure to Evaluate Impact of PMP Event on Turbine Building Flooding and Associated Safety-Related Systems, Structures, and Components</u>

<u>Introduction</u>: 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," for the licensee's failure to assure that regulatory requirements were translated into specifications, drawings and procedures. Specifically, modifications to plant grade levels

did not assure that safety-related equipment would remain operable following a PMP event.

Description: The licensee's UFSAR describes how the plant is designed to protect safety-related systems and components from the postulated worst case heavy rain fall event, called the PMP event. In summary the maximum precipitation event at Braidwood was based upon historic worst case meteorological data and estimated to amount to 31.9 inches of rainfall over a 48 hour period.

The UFSAR discusses that flooding resulting from the PMP event could result in a short-term maximum standing water level at the 601.85 foot elevation above mean sea level. To prevent this water from entering areas where essential equipment/systems are located, reinforced concrete curbs or steel barriers are provided at the following locations described in subsection 2.4.2.3. These areas include:

- external hatches to the refueling water storage tank tunnel;
- the radwaste building access to the transfer tunnel;
- the main steam isolation valve (MSIV) rooms adjacent to grade level elevation exterior access doors; and
- personnel access locations to the auxiliary building from grade level.

During the performance of this temporary instruction, the inspectors identified an additional external flooding flow path that the licensee had not previously analyzed. Specifically, since the turbine building contains numerous open grade level flow paths to below grade levels, then the turbine building itself could be a source of runoff during the PMP event. In this hypothetical scenario, rainwater runoff into the turbine building could result in flooding within the turbine building and begin flooding the turbine building below grade. Since the turbine building shares a wall with the auxiliary building both below and above grade, this event could potential adversely affect safety-related equipment. Specifically:

- Below Grade Flooding
    - Could result in a flooded MSIV tunnel and adversely affect the ability of the MSIVs to shut since the turbine building openly communicates with the main steam line tunnel below grade.
    - Could make all the safety-related diesel generator fuel oil transfer pumps inoperable since the diesel oil storage tank rooms are located below grade. While the rooms have watertight doors and a nonsafety-related sump system that provide protection from an internal flooding event, the room would still be vulnerable to an external flooding event because licensee controls permitted relaxation of the flood door controls when internal flooding could not occur (e.g., when circulating water pumps were secured). The safety-related fuel oil transfer pumps are located in the DOST rooms and are not qualified for submergence.
- Grade Level Flooding

- Could result in water entering the safety-related DG rooms. Water entering the DG rooms can adversely affect safety because the DG rooms have floor drains that drain to the below-grade diesel oil storage tank room sumps.

- Could lead to water entering the auxiliary building through grade level equipment and personnel access doors that are not credited flood barriers and have less than a 1–inch floor threshold.

The licensee performed an operability determination and determined that adequate margin still existed within the design to accommodate a PMP event and have no adverse effect on any safety-related equipment. In summary, the licensee concluded that the maximum water level in the turbine building would result in Unit 1 flooding 62 percent of the available volume below grade and Unit 2 flooding 42 percent of the available volume below grade based upon conservative assumptions. These flood levels could result in flooding in the MSIV rooms but not to the level that would adversely affect MSIV operation.

The inspectors reviewed the current PMP analysis as well as recent revisions to the analysis. As a result of numerous plant modifications that have changed station grading and credited rainwater runoff flow paths, the PMP event calculated standing water depth has increased approximately 7 inches outside of an area of the turbine building (i.e., from 4 inches to 11 inches). For example, during the construction of the Independent Spent Fuel Storage Installation (ISFSI) pad, rain water potentially standing in an area outside of the turbine building increased because the ISFSI pad elevation was increased to support ISFSI design requirements. The inspectors identified that modifications did not evaluate the potential impact that this increase would have on flooding into the turbine building. (Ref: Braidwood Calculation WR–BR–PF–10, Local PMP Analysis).

<u>Analysis</u>: The inspectors determined that the failure to assess the impact of plant modifications on the PMP analysis in the plant design basis was contrary to 10 CFR 50, Appendix B, Criterion III, “Design Control,” and was a performance deficiency. Specifically, the licensee failed to determine if modifications to plant grading that caused higher water levels during a PMP event would adversely affect safety-related equipment.

The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” issued September 7, 2012. The issue was associated with the Protection Against External Factors 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 licensee failed to evaluate the design to ensure that the consequence of the licensing basis PMP would be acceptable with respect to NRC regulations.

The inspectors determined that the finding was of very low safety significance (Green) in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings,” and Appendix A, “The Significance Determination Process For Findings At-Power,” issued June 19, 2012. Using Exhibit 2, Section B, “External Event Mitigation Systems,” the inspectors determined the finding was of very low safety significance (Green) because it did not result in the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event.

The inspectors determined that the finding had a cross-cutting aspect of Design Margins in the Human Performance area. Specifically, the licensee did not carefully guard design margins when making station grade modifications that could adversely affect safety-related equipment during a heavy rainfall event (H.6). This issue was determined to be indicative of recent performance based upon two recent changes to station calculations (Ref: Braidwood Calculation WR–BR–PF–10, Local PMP Analysis; Major Revision 14 approved on November 11, 2012, Braidwood Calculation WR–BR–PF–10, Local PMP Analysis; Major Revision 15 approved on March 28, 2014).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that:

- Measures shall be established to assure that applicable regulatory requirements and design basis, as defined in Part 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions…

- The design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

- Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design...

Contrary to the above, on March 28, 2014 (Ref: WR–BR–PF–10, Effect of Service Building on the Local Probable Maximum Precipitation, Revision 15, Major Revision), and on November 11, 2012 (Ref: Effect of Local Probable Maximum Precipitation at Plant Site, Revision 14, Major Revision), the licensee failed to establish design control measures to ensure that changes made to station grading would not adversely impact systems and components important to safety as required by 10 CFR Part 50, Appendix A, General Design Criteria 2, "Design Basis for Protection Against Natural Phenomena," as specified in the license application and Updated Final Safety Analysis Report. Specifically, the licensee failed to have adequate design control measures to ensure that a PMP event at the station would not adversely affect the emergency diesel generators, main steam isolation valves, and essential service water systems and components.

Corrective actions included performing an Operability Determination to ensure safety until a formal quality design review can be completed at a later date. Because this violation was of very low safety significance and was entered into the licensee's corrective action program as IR 2396124, this violation is being treated as an NCV, consistent with section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000456/2014005–03; 05000457/2014005–03, Failure to Evaluate Impact of PMP Event on Turbine Building Flooding and Associated Safety–Related SSCs.)

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 22, 2015, the inspectors presented the inspection results to Ms. M. Marchionda, Plant Manager, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that proprietary material received during the inspection period that was no longer under review was returned to the licensee and none of the potential input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- On November 19, 2014, the inspectors presented the preliminary inspection results regarding the review of VIO 05000457/2013008–01 and the associated FIN 05000457/2013008–02 to Mr. M. Kanavos, Braidwood Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented.
- The annual review of Emergency Action Level and Emergency Plan changes with the licensee's Emergency Preparedness Coordinator, Ms. D. Poi, via telephone on December 3, 2014.
- The inspector discussed the licensed operator requalification training biennial operating test results with Mr. J. Taff, Operations Requalification Lead, on December 16, 2014.

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, Plant Manager
J. Bashor, Engineering Director
P. Boyle, Maintenance Manager
A. Ferko, Operations Director
B. Finlay, Site Security Manager
M. Gorge, Chemistry Supervisor
R. Leisure, Radiation Protection Manager
G. Panici, Design Engineering
D. Poi, Emergency Preparedness Manager
P. Raush, Regulatory Assurance Manager
B. Schipiour, Site Maintenance Director
R. Schliessman, Regulatory Assurance
D. Stiles, Training Director
J. Taff, Operations Requalification Lead

Nuclear Regulatory Commission

J. Ellegood, Acting Branch Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000456/2014005–01 05000457/2014005–01	NCV	Failure to Adequately Evaluate Operability Following the Discovery of an Unanalyzed Condition Involving the Probable Maximum Precipitation Event (Section 1R15.1b)
05000456/2014005–02	NCV	Failure to Correct Undersize Essential Service Water Pump Bearing Casing Drain Line Resulted in System Inoperability (Section 4OA2.7b)
05000456/2014005–03 05000457/2014005–03	NCV	Failure To Evaluate Impact Of PMP Event On Turbine Building Flooding and Associated Safety-Related SSCs (Section 4OA5.2b)

Closed

05000457/2013008–01	VIO	Inaccurate/Incomplete Information Provided for NRC Approved Exemption Request (Section 4OA5)
05000457/2013008–02	FIN	Inaccurate/Incomplete Information Provided for NRC Approved Exemption Request (Section 4OA5)

Discussed

05000456/2014002–03 05000457/2014002–03	NCV	Failure to Identify Fire Doors that Did Not Conform to NFPA Codes and Standards (Section 4OA2.5b)

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.

<u>1R01 Adverse Weather Protection</u>

- WC-AA-10; Seasonal Readiness
- 0BWOS FP.B.5.W-1; B.5.b Pump and Diesel Weekly Readiness Check; Revision 2

<u>1R04 Equipment Alignment</u>

- 2BwOSR 5.5.8.SX-3A; Group A IST Requirements For 2A Essential Service Water Pump (2SX01PA); Revision 8
- BwOP CS-M2; Operating Mechanical Lineup Unit ; Revision 8
- BwOP SX-E2; Electrical Lineup – Unit 2 Essential Service Water System; Revision 12
- BwOP SX-M2; Mechanical Lineup – Operating Mechanical Lineup Unit 2; Revision 33
- M-126; Sheet 1; Diagram of Essential Service Water Unit 2; May 3, 1976
- M-126; Sheet 2; Diagram of Essential Service Water Unit 2; December 23, 1976
- M-126; Sheet 3; Diagram of Essential Service Water Unit 2; May 3, 1976
- M-42; Sheet 1A; Diagram of Essential Service Water Units 1 & 2; July 23, 1975
- M-42; Sheet 1B; Diagram of Essential Service Water; February 3, 1976
- M-42; Sheet 2A; Diagram of Essential Service Water Units 1 & 2; July 23, 1975
- SX-1; Training Handout; Essential Service Water; April 16, 2013
- M-152; Manufacturer's Supplemental Diagram of Diesel Generator Oil Schematic Unit 1 and 2
- M-50; Diagram of Diesel Generator Fuel Oil Unit 1

<u>1R05 Fire Protection</u>

- Braidwood Pre-Fire Plan Fire Zones 9.2-1, 9.3-1; DG 401' Diesel Generator Room 1A and Day Tank Room
- Braidwood Pre-Fire Plan #91; 2A Diesel Generator and Day Tank Room; Fire Zone 3; Revision 1
- Braidwood Pre-Fire Plan #11; Auxiliary Building General Area South; Revision 0
- Braidwood Pre-Fire Plan #124; 1A Centrifugal Charging Pump Room; Revision 0
- Braidwood Pre-Fire Plan Fire Zone 8.7B-0; TB Station Auxiliary Diesel Oil Tank Room
- Braidwood Pre-Fire Plan Fire Zone 11.4A-2; AB 383' U2 Auxiliary Feedwater Pump Diesel Room
- OP-AA-201-006; Control of Temporary Heat Sources; Revision 6
- BwAP 1110-1A6; Required Compensatory Measures Action Response Fire Hose Stations; Revision 4

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

- 2BwOSR 3.3.1.4-1; U2 SSPS, Reactor Trip Breaker and Reactor Trip Bypass Breaker Surveillance
- LORT Annual Exam Status Report; Braidwood Generating Station 2014
- OP-AA-1; Conduct of Operations; Revision 0

1R12 Maintenance Effectiveness

- IR 1310669; 2AF01PA – Small Leak From Inboard Mechanical Seal
- IR 1329822; AF MSPI Unavailability Reporting Enhancement Identified; February 21, 2012
- IR 1344861; Procedure Enhancement for AF Valve Strokes
- IR 1353298; Potential Procedure Error with Unit 1 AF Full Flow Test; April 12, 2012
- IR 1353682; 1AF005B Flow Oscillations; April 13, 2012
- IR 1359324; Wiped Outboard Bearing on 1AF Motor – A1R16; April 27, 2012
- IR 1359878; Valves 1AF004A and B Incorrectly Installed; April 23, 2012
- IR 1363688; A1R16: 1AF01PA Response Time Failed; May 7, 2013
- IR 1389345; MSPI AF Crosstie Removal from PRA; July 11, 2012
- IR 1391811; Evaluate LCO 3.7.5 Retraction; July 10, 2012
- IR 1411080; Abnormal SX Booster Pump Test Results During 1B AF Pump Run; September 10, 2012
- IR 1423999; 2BwOSR 3.3.2.12 Has No PRA Actions; October 8, 2012
- IR 1468482; Revise Calculations BRW-10-0146/BYR110-103 Rev. 1; April 8, 2011
- IR 1508042; AF MSPI Low Margin; April 29, 2013
- IR 1542417; CDBI-Revise Calculation BRW-03-0122-M, Rev 01 – 1CD01T; March 3, 2013
- IR 1629792; B4 Trend Code: 1FY-AF017B; March 6, 2014
- IR 1633160; Troubleshooter for 1A AF PP; March 13, 2014
- IR 2413452; Oil Leak From 1B SX Pump – 1SX01PB; November 18, 2014
- IR 2413941; CAS Identified in EACE 1601971 (1B SX Oil Leak) Not Complete; November 18, 2014
- IR 2414869; Requesting WO to Correct Lube Oil Header Slope; November 20, 2014
- MRSBD AF-01; Maintain System Pressure Boundary Integrity
- MRSBD AF-02; Prevent System Diversionary flow and Isolate AF Flow to SGs
- MRSBD AF-03; Provide Air, Water, Oil and Oil Cooling for AFW PP, Engine & Motor
- MRSBD AF-04; Provide Automatic & Manual Flow Control
- MRSBD AF-05; Provide Control & Interlock Signals
- MRSBD AF-06; Provide CW Flow to SGs on Demand
- MRSBD AF-07; Provide Fuel Oil to AFW PP Engine
- MRSBD AF-08; Post Accident Monitoring Instrumentation as Defined by TS
- MRSBD AF-09; Provide Local Indication & Alarms
- MRSBD AF-10; Provide Recirculation Flow
- WO 01733156 01; Air Filter Breathers Not Installed on 1B SX Oil Pump; November 19, 2014
- WO 01786140 01; Oil Leak from 1B SX Pump (5); November 18, 2014

1R13 Maintenance Risk Assessments and Emergent Work Control

- WC-AA-104; Integrate Risk Management; Revision 22
- IR 2413452; Oil Leak From 1B SX Pump – 1SX01PB; November 18, 2014
- Unit 0/1 Risk Assessment for the Week of 11/17/2014
- 1B EDG Protected Equipment Installation Checklist
- WO 01786140 01; Oil Leak from 1B SX Pump (5); November 18, 2014

1R15 Operability Determinations and Functionality Assessments

- Calculation No. ATD-0109; Revision 3; Thermal Performance of UHS During Postulated Loss of Coolant Accident
- Braidwood Operability Evaluation 14-005; Turbine Building Flooding During PMP; Revision 0
- Braidwood Operability Evaluation 14-006; UHS East Slop Less than 590'; Revision 0

- IR 2396124; Effect of Site Flood on Turbine Building; October 15, 2014
- IR 2396590; NRC Question on PMP Impact on DG Rollup Doors; October 16, 2014
- IR 2396747; Questions Dirt Pile Impacting PMP; October 16, 2014
- IR 2397321; Questions on PMP Event Impact to MSIV Rooms; October 17, 2014
- IR 2400901; Voids in 2A SX Supply; October 24, 2014
- IR 2400960; The UHS Elevation at Top of East Slope Found Less than 590 ft; October 24, 2014
- IR 2413452; Oil Leak from 1B SX Pump 1SX01PB; November 18, 2014
- IR 2427901; 2DG5212B (PV-2) Failed to Operate Automatically Per Design; December 19, 2014
- WO 01651911; Starting System Lockout Test for 2B Gen; December 18, 2014

1R18 Plant Modifications

- EC 399116; Revision 0; Install Jumper to Bypass Degraded Unit 2 Main Power Output Line Y Connection (Phase 'A')

1R19 Post Maintenance Testing

- IR 2413452; Oil Leak From 1B SX Pump – 1SX01PB
- WO 01733156 01; Air Filter Breathers Not Installed on 1B SX Oil Pump
- WO 01786140 01; Oil Leak from 1B SX Pump (5)
- WO 01786140; 1B SX Pump Inboard Bearing Housing Oil Leak Repair
- WO 01786282; 1A CS Spray Additive Check Valve Repair
- WO 01606054; Unit Common Service Air Reservoir Low Pressure Troubleshooting and Associated Repair Work
- WO 01781693; 2C Pressurizer Variable Heater Controller Replacement
- WO 01371392; SSC Valve and Actuator Replacement
- WO 01789592; Unit Common Auxiliary Building Damper 0VA438YB Repair Activity
- WO 17884757; Unit 2 Steam Generator Wide Range Level Calibration
- WO 01789753 Unit Common Station Diesel Battery Room Exhaust Fan Repair

1R22 Surveillance Testing

- 2BwOSR 3.3.1.4-1; U2 SSPS, Reactor Trip Breaker and Reactor Trip Bypass Breaker Surveillance (Train A); Revision 37
- 1BwOSR 3.3.2.3; Unit One Undervoltage Simulated Start of 1A Auxiliary Feedwater Pump Surveillance; Revision 6
- 2BwOSR 3.3.2.3; Unit Two Undervoltage Simulated Start of 2A Auxiliary Feedwater Pump Surveillance; Revision 6
- 1BwOSR 3.4.13.1; RCS Water Inventory Balance Surveillance Data Sheets; Revision 34
- 2BwOSR 3.4.13.1; RCS Water Inventory Balance Surveillance Data Sheets; Revision 35
- 1BwOSR 5.5.8.CV-4A; Group A IST Requirements for 1A Centrifugal Charging Pump (1CV01PA) and Check Valve 1CV8480A Stroke Test; Revision 4
- WC-AA-111; Unit One Reactor Coolant System Water Inventory Balance Surveillance; Revision 4
- WC-AA-111; Unit Two Reactor Coolant System Water Inventory Balance Surveillance; Revision 4
- WO 01761521 01; IST For 1CV8481B/8480A/8480B ASME Surveillance Requirements for 1CV01PA; October 17, 2014
- WO 01775520 01; Undervoltage Simulated Start of 1A Auxiliary FW Pump Monthly

- WO 01775522 01; Undervoltage Simulated Start of 2A Auxiliary FW Pump Monthly
- Drawing 20E-1-4030EF01; Schematic Diagram ESF Sequencing & Actuation Cabinet Train A 1PA13J; January 6, 1982
- Drawing 20E-1-4030AF14; Schematic Diagram Auxiliary Feedwater Pump 1A & 1B Discharge Test Valves 1AF004A & 1AF004B; December 10, 1991
- Drawing 20E-1-4030AF01; Schematic Diagram Auxiliary Feedwater Pump; December 10, 1991

1EP4 Emergency Action Level and Emergency Plan Changes

EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan; Revisions 24 and 25
EP-AA-1001; Radiological Emergency Plan Annex for Braidwood Station; Revisions 31 and 32
EP-AA-110-200; Dose Assessment; Revisions 4, 5, 6, and 7
EP-AA-110-200-F-01; Dose Assessment Input Form; Revision B
EP-AA-110-201-F-01; On-Shift Dose Assessment Input Sheet; Revision B
EP-AA-112-100-F-02; Shift Dose Assessor; Revision F

1EP6 Drill Evaluation

- Licensee Drill Scenario #1 for Braidwood Drill Performed on October 30, 2014

4OA1 Performance Indicator Verification

- LS-AA-2030; Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours; Revision 4
- LS-AA-2100; Monthly Data Elements for NRC Reactor Coolant System Leakage (October 2013 thru June 2014); Revision 5

4OA2 Problem Identification and Resolution

- IR 941298; EH&S Compliance Audit Concern: Clean Construction Debris Man; July 9, 2009
- IR 1383021; Excavation Soil Storage Locations Running Out of Capacity; June 28, 1012
- IR 1401170; During Fukushima Walkdowns Topography Changes Identified; August 15, 2012
- IR 1629689; Unclear Direction in 0BwOS FP.7.2.D-1; March 5, 2014
- IR 1657266; Increased Trend Developing for “At Risk” Behavior; May 7, 2014
- IR 1657276; A2R17 STD Team ID: Adverse Trend in PPE; May 7, 2014
- IR 1658555; NOS ID Adverse Trend in A2R17 Industrial Safety Behaviors; May 10, 2014
- IR 1663472; Review of Issues for Potential Trend, April 2014
- IR 1668160; Trend in HU Errors Associated with Contracted Groups; June 6, 2014
- IR 1675136; May-14 OPS EOS/CAP Trend Review; June 25, 2014
- IR 1676019; Engineering May 2014 Monthly EOS/CAP Trending Results; June 27, 2014
- IR 1689510; June-14 Monthly EOS/CAP Trend Roll-up Deviations; August 5, 2014
- IR 1689511; June-14 Monthly EOS-CAP Trend Roll-up; August 5, 2014
- IR 1690196; Potential Trend in Drill and Exercise Performance (DEP); August 7, 2014
- IR 1692430; Potential Trend in Material Condition of DM System; August 14, 2014
- IR 1999856; Replace Run Time Meter for 0WO01CA (Bus 142 CUB 10); September 7, 2014
- IR 2057067; Door D-849 Latch Fingers Sticking Inside Door; September 8, 2014
- IR 2344817; WM Aug-14 EOS/CAP Trend Roll-up; September 12, 2014
- IR 2382353; Trend Review of M&TE Issues; September 17, 2014

- IR 2382593; August 2014 Supply Review of Issues for Potential Trend; August 18, 2014
- IR 2392611; Adverse Trend – OPS Compliance with M&TE Usage; October 8, 2014
- IR 2396747; NRC Questions Dirt Pile Impacting PMP; October 6, 2014
- BwAP 380-4; Process Computer Point Alteration; Revision 5
- 1BwOS RC-S1; Reactor Coolant Pump Vibration Monitoring Shiftly Surveillance; Revision 13
- 1BwOS TRM 3.4.c.1; Pressurizer Temperature Limit Surveillance; Revision 3
- 1BwOSR 3.1.1.1-1; Shutdown Margin Daily Verification During Shutdown; Revision 11
- 1BwOSR 3.2.4.1; Quadrant Power Tilt Ration (QPTR) Calculation; Revision 9
- 1BwOSR 3.3.2.2-1; Power Range High Flux Setpoint Daily Channel Calibration (Computer Calorimetric); Revision 17
- 1BwOSR 3.3.1.2-2; Power Range High Flux Setpoint Daily Channel Calibration (Hand Calculated Calorimetric); Revision 8
- 1BwOSR 3.4.13.1; Reactor Coolant System Water Inventory Balance Surveillance; Revision 34
- OP-AA-102-103; Operator Work-Around Program; Revision 3
- OP-AA-102-103-1001;Operator Burden and Plant Significant Decisions Impact Assessment Program (CM-1); Revision 5
- OP-AA-102-103-1001, Attachment 1; Operator Burden/Degraded Equipment Aggregate Assessment; Revision 4
- U1 Operations Imported Tours; Fire Door 451 M-8; Reference 0BwOS FP.7.2.D-1
- U1 Operations Imported Tours; Fire Door 451 M-10; Reference 0BwOS FP.7.2.D-1
- U1 Operations Imported Tours; Fire Door 451 M-8; Reference 0BwOS FP.7.2.D-1
- WO 1254693; MM – Placement of Clean Debris Currently on Site

<u>4OA5 Other Activities</u>

- IR 0941298; EH&S Compliance Audit Concern: Clean Construction Debris Man; July 9, 2009
- IR 1290617; Inaccuracies in Flood Level Calculation for Flood Zone G9-1; November 14, 2011
- IR 1383021; Excavation Soil Storage Locations Running Out of Capacity; June 28, 2012
- IR 1390831; Fukushima: Potential Unit 1 RWST Hatch Leakage; July 19, 2012
- IR 1401170; During Fukushima Walkdowns Topography Changes Identified; August 15, 2012
- IR 1404810; Fukushima Effect of Local Probable Maximum Precipitation; August 24, 2012
- IR 1427443; PMP Calculation Issue Discovered During Fukushima Review; October 16, 2012
- IR 1558067; Potential NRC Violation of 10 CFR 50.9 for PTLR; September 12, 2013
- IR 1585416; Receipt of NRC NOV-Unit 2 PTLR; November 14, 2013
- IR 1589725; PTLR Analysis Not Revised for Reactor Head Stud Configuration Change; August 22, 2012
- IR 2396124; Effect of Site Flood on Turbine Building; October 15, 2014
- IR 2396590; NRC Question on PMP Impact to DG Roll-Up Doors; October 16, 2014
- IR 2396747; NRC Questions Dirt Pile Impacting PMP; October 16, 2014
- IR 2397321; NRC Question on PMP Event Impact to MSIV Doors; October 17, 2014
- IR 2411287; Fukushima Flooding Evaluation 50.54(f), Rec. 2.1: Flooding; November 13, 2014
- IR 2413755; NOV Inspection Identified Need for Licensing Tailgate; November 18, 2014
- IR 2413780; Need Action to Document ITPR Recommendation; November 18, 2014
- WO 1254693; MM – Placement of Clean Debris Currently on Site
- EC 399675; Evaluation for WCAP-16143; Revision 1
- OP-AA-108-115; Operability Determinations (CM-1); Revision 15
- 0BwOA; PRI-8 Auxiliary Building Flooding; Revision 6
- 0BwOA; PRI-8 Auxiliary Building Flooding; Revision 7
- 0BwOA; SEC-5 WS System Malfunction; Revision 101
- 1BwOA; PRI-8 Essential Service Water Malfunction; Revision 105

- 2BwOA; SEC-5 WE System Malfunction Unit 2; Revision 101
- Letter BW130109; Reply to Notice of Violation; December 13, 2013
- Letter RS-14-284; License Amendment Request to Utilize WCAP-16143 Revision 1 As an Analytical Method to Determine the Reactor Coolant System Pressure and Temperature Limits; October 16, 2014
- Operability Evaluation 13-005; Unit 2 Reactor Vessel; Revision 2
- Procedure LS-AA-117; Written Communications; Revision 11
- Procedure HV-AA-1212; Technical Task/Rigor Assessment Pre-Job Briefs Independent Third Party Review, and Post-Job Review; Revision 4
- Report FAI/14-0865; Independent Third Party Review (ITPR) of WCAP-16143; Revision 0
- WCAP-16143-P; Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2; Revision 1
- Braidwood UFSAR Change Request Form DRP-13-060, Ref: EC 369359
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 0
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 1
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 8
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 9
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 11
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 13
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 14
- Braidwood Calculation WR-BR-PF-10; Local PHP Analysis; Revision 15
- Byron Calculation SF-01, Effect of Postulated Site Flood on Turbine Building; Revision 1
- EC 397620; Updated Calculation WR-BR-PF-10 to Reflect Installation of Service Building Annex; Revision 0

Flood Hazard Reevaluation Report in Response to the 50.54 (f) Information Request Regarding Near-Term Task Force Recommendation 2.1: Flooding for the Braidwood Generating Station; Submitted February 20, 2014

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CS	Containment Spray
DG	Diesel Generator
EDG	Emergency Diesel Generator
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISFSI	Independent Spent Fuel Storage Installation
IST	Inservice Testing
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OWA	Operator Workaround
PARS	Publicly Available Records System
PDA	Personal Digital Assistance
PI	Performance Indicator
PMP	Probable Maximum Precipitation
RCS	Reactor Coolant System
SDP	Significance Determination Process
SSC	Systems, Structures, and Components
SX	Essential Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
VIO	Violation
WO	Work Order

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

John A. Ellegood, Acting Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
IR 05000456/2014005; 05000457/2014005
w/Attachment: Supplemental Information

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