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

November 12, 2010

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

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NRC SPECIAL INSPECTION TEAM (SIT) REPORT 05000456/2010010; 05000457/2010010

Dear Mr. Pacilio:

On September 30, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection at your Braidwood Station, Units 1 and 2, to evaluate the facts and circumstances surrounding the dual unit trip and associated equipment issues that occurred on August 16, 2010. Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and due to the equipment performance issues that occurred, a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The basis for initiating the special inspection and the focus areas for review are detailed in the Special Inspection Charter (Attachment 2).

The enclosed inspection report documents the inspection results, which were discussed at the public exit meeting on September 30, 2010, with Mr. A. Shahkarami and other members of your staff and on November 12, 2010, with Mr. R. Gaston. The determination that the inspection would be conducted was made on August 17, 2010 and the onsite inspection started the same day.

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, interviewed plant personnel, and evaluated the facts and circumstances surrounding the event, as well as the actions taken by your staff in response to the unexpected equipment conditions.

The report documents three self-revealing findings and one NRC-identified finding of very low safety significance. Two of these findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. However, because of their very low safety significance and because they are entered into your corrective action program, the NRC is treating these issues as non-cited violations (NCVs) consistent with Section 2.3.2 of the NRC Enforcement Policy, dated September 30, 2010.

If you contest the violations or the significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies 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, D.C. 20555-0001; and the NRC Resident Inspector at the Braidwood Plant. In addition, if you disagree with the cross-cutting aspect of a 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 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/
Gary L. Shear, Acting Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000456/2010010; 05000457/2010010
w/Attachments:
1. Supplemental Information
2. Special Inspection Team Charter
3. Timeline of Events for August 16, 2010, Dual Unit Reactor Trip

cc w/encl: Distribution via ListServ

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2010010 and 05000457/2010010
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	Braceville, IL
Dates:	August 17, 2010 – September 30, 2010
Inspectors:	J. Jandovitz, Senior Project Engineer DRP M. Thorpe-Kavanaugh, Reactor Engineer, DRP N. Féliz Adorno, Reactor Inspector, DRS T. Go, Health Physics Inspector, DRS
Approved by:	G. Shear, Acting Director Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000456/2010010;05000457/2010010; 08/17/2010 – 09/30/2010; 11/12/2010; Braidwood Station, Units 1 & 2; Special Inspection for the August 16, 2010, dual unit trip and subsequent equipment issues.

This report covers an 8-day period (August 17-27, 2010) of onsite inspection and in-office review through September 30, 2010. A four-person team, composed of a project engineer and three regional inspectors, conducted the inspection. Four Green findings were identified, two of them with associated non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. <u>NRC-Identified and Self-Revealed Findings</u>

Cornerstone: Mitigating Systems

- <u>Green</u>. The inspectors identified a Green finding and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to establish adequate controls to ensure that forebay inspect-and-clean activities provided assurance that systems, structures, and components would be capable of performing their safety function during inspect-and-clean intervals. Specifically, the inspectors noted that during the event on August 16, 2010, the operability margin of one train of the essential service water system decreased to zero under forebay fouling conditions that were less than the pre-established limiting conditions. The licensee entered this issue into its corrective action program (CAP).

  The finding was determined to be more than minor because, if left uncorrected, it would have the potential to lead to a more significant safety concern. Specifically, forebay conditions would have been allowed to degrade between inspect-and-clean intervals and the potential adverse impact to the essential service water system and its supported equipment was not evaluated. The finding screened as very low safety significance because it was a design deficiency that was confirmed not to result in an actual loss of operability or functionality. The inspectors determined that this finding had a cross-cutting aspect in the area of human performance, decision-making component, because the licensee did not make safety-significant or risk-significant decisions using a systematic process, especially when faced with uncertain or unexpected plant conditions, to ensure safety was maintained. [H.1(a)] (Section 4OA5.1)

- <u>Green</u>. A self-revealed finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for the failure to establish measures for the selection and review for suitability of equipment essential to the safety–related function of the component. In 2008, the safety-related 1.5 ampere (amp) control power fuses in motor control center (MCC) 131X1 were specified to be replaced with 3.0 amp fuses due to failures of other similar 1.5 amp fuses. In 2009, these fuses failed and were replaced with the same sized 1.5 amp fuses, even though the licensee's review for suitability concluded the fuses were adequate, but marginally sized. They were then scheduled to be replaced with 3.0 amp fuses in 2015. During the event on August 16, 2010, these fuses failed again at which time they were replaced with 3.0 amp fuses.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure of these fuses resulted in the loss of function for eight safety injection valves. This caused a train of emergency core cooling and containment isolation for the safety injection system to be inoperable. The inspectors answered "no" to the Mitigating Systems questions and screened the finding as having very low significance (Green). This finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee did not implement corrective actions to address safety issues in a timely manner, commensurate with their safety significance. Specifically, in 2008 these 1.5 amp fuses were specified to be replaced with 3.0 amp fuses, they failed in 2009 and were replaced with 1.5 amp fuses. They were then scheduled for replacement with the higher amp fuses in 2015. [(P.1(d)] (Section 4OA5.2)

Cornerstone: Initiating Events

- Green. A self-revealed finding of very low safety significance (Green) was identified for the failure to correct a condition that resulted in water being discharged to the turbine building floor during the reject of condensate from the condenser hotwell. Specifically, water had been observed to overflow to the turbine building floor in multiple instances in the past during hotwell condensate reject. However, the licensee did not implement corrective actions to correct this condition or evaluate its impact on plant equipment as required by the licensee’s corrective action program. The water discharged from the condensate hotwell reject during the Unit 2 trip caused a reactor trip of Unit 1 on August 16, 2010. The licensee entered this issue into its corrective action program and changed the operation of the condensate reject from an automated action to a manual action controlled by the operators.

  The finding was determined to be more than minor because it was associated with the Initiating Events Cornerstone attribute of configuration control, and affected the cornerstone objective of limiting the likelihood of those events that upset plant stability. The finding screened as very low safety significance (Green) because a Phase 3 evaluation determined that it resulted in a delta core damage frequency of 5.6E-7/year with Large Early Release Frequency (LERF) not being a risk contributor. No violation of NRC requirements was identified because the deficiencies that contributed to the reactor trip were associated with nonsafety-related components. The inspectors determined that this finding had a cross-cutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee did not have a low threshold for identifying issues and did not identify issues completely. [P.1(a)] (Section 4OA5.3)

- Green. A self-revealed finding of very low safety significance was identified for the inadequate evaluation of operating experience done in accordance with the station procedure. Specifically, the licensee evaluated an event at another plant where building material was dislodged during a steam release resulting in a loss of off-site power and concluded the event was not applicable to Braidwood station. The evaluation did not address a previous event at Braidwood where the reactor building flashing was dislodged during a steam release. It did conclude, however, that off-site power could be adversely affected by debris. During the dual unit trip on August 16, 2010, reactor building flashing was dislodged during a steam release and was found on power lines and in the vicinity of the off-site power supplies. The licensee entered this issue into its corrective action program and structurally restrained the flashing left on the reactor building.

The finding was determined to be more than minor because the finding was associated with the Initiating Events Cornerstone attribute of protection against external factors and affected the cornerstone objective of limiting the likelihood of those events that challenge critical safety functions during shutdown. Specifically, not protecting the off-site power supplies from flashing falling from the reactor building could result in a loss of off-site power and would challenge the emergency diesel generators to supply alternating current power to safety-related equipment during the plant shutdown. The finding screened as very low safety significance (Green) because it was determined not be a loss of cooling accident or External Event initiator and would not contribute to both a plant trip and the likelihood that mitigation equipment or functions would not be available. There is no cross-cutting aspect because the 2007 evaluation completed on the operating experience is not reflective of current performance. (Section 4OA5.4)

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

A violation of very low safety significance identified by the licensee has been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's CAP. This violation and corrective action tracking number are listed in Section 4OA7 of this report

REPORT DETAILS EVENT DESCRIPTION

On August 16, 2010, at 2:06 a.m., the Unit 2 reactor tripped due to a main generator lockout relay actuation. Following the reactor trip, all safety systems functioned as designed, with the exception of one auxiliary feedwater (AFW) flow control valve, which failed open. Additionally, the Unit 2 condenser hotwell rose as expected until it reached the set point to automatically actuate the hotwell condensate reject control valves. This, in combination with the actuation of AFW pumps, resulted in approximately 12,000 gallons of water being discharged from open-ended risers on the AFW suction headers to the turbine building floor on the 451' elevation, where it flowed through holes in the floor and rained down on the lower elevations. Some of this water entered a Unit 1 motor control center (MCC) that contained circuitry for two of the circulating water (CW) pumps.

At 2:19 a.m., as a result of the water in the MCC, the Unit 1 CW pumps A and C tripped, which eventually caused a Unit 1 automatic reactor trip on low condenser vacuum. The water in the same MCC also damaged the instrumentation for the condenser steam dump valves, which then could not be opened for normal decay heat removal. Therefore, operators used the steam generator (SG) power operated relief valves (PORVs) to relieve decay heat and maintain Unit 1 temperature and pressure. In addition, the main steam safety valve (MSSV) 1D opened and would not close as expected.

A detailed timeline of the dual unit trip is contained in Attachment 3.

<u>Inspection Scope</u>

A Special Inspection was initiated following the NRC's review of the deterministic and conditional risk criteria specified in Management Directive 8.3. The inspection was conducted in accordance with NRC Inspection Procedure (IP) 93812, "Special Inspection," and the "Special Inspection Charter," dated August 16, 2010 (Attachment 2). The team gathered information from the plant computer and event recorder with alarm printouts; interviewed station personnel; performed physical walkdowns of plant equipment; reviewed procedures, maintenance records and various technical documents; and reviewed corrective action documents and causal evaluations. A list of specific documents reviewed is provided in Attachment 1.

4OA5 Other Activities – Special Inspection (93812)

<u>Sequence of Events</u>

a. <u>Inspection Scope</u>

The team evaluated the licensee's initial response to the event, focusing on relevant plant conditions, system line-ups, and operator actions. This evaluation included a review of the control room operators' use of operating procedures and identification of degraded plant conditions. The team interviewed plant personnel and reviewed applicable portions of the emergency operating procedures (EOPs), control room logs, plant event recorder data, and corrective action program (CAP) documents.

A detailed sequence of events is included in Attachment 3.

b. Findings and Observations

No findings of significance were identified.

Licensee's Event Response for Unit 1 Trip

a. Inspection Scope

The team reviewed the licensee's plans and actions for assessing the impact that the event had on Unit 1 systems. The review included discussions with various site engineers, review of action plans for evaluating the condition of systems and components that did not perform as expected, review of in-process results from the licensee's reviews, and methods for tracking identified deficiencies. In addition, the team independently reviewed the licensee's post-trip review to determine the cause of the Unit 1 reactor trip and whether it was a manual or automatic reactor trip including a review of plant data and records to confirm the adequacy of the licensee's assessment and planned corrective actions. The team also reviewed the licensee's assessment of their readiness to restart Unit 1 and independently assessed the restart schedule and readiness.

b. Findings and Observations

No findings of significance were identified.

Licensee's Event Response for Unit 2 Trip

a. Inspection Scope

The team reviewed the licensee's plans and actions for assessing the impact of the event on Unit 2 systems. The review included discussions with various site engineers, review of action plans for evaluating the condition of systems and components that did not perform as expected, review of in-process results from the licensee's reviews, and methods for tracking identified deficiencies. In addition, the team independently reviewed the licensee's post-trip review to determine the cause of the Unit 2 reactor trip, whether it was a manual or automatic reactor trip, including a review of plant data and records to confirm the adequacy of the licensee's assessment and planned corrective actions. The team also reviewed the licensee's assessment of their readiness to restart Unit 2, and independently assessed the restart schedule and readiness.

b. Findings and Observations

No findings of significance were identified.

Assessment of Operator's Performance

a. Inspection Scope

The team evaluated the operators' response and performance during the events, including awareness of and response to plant conditions and shutdown activities. This evaluation included interviews of all members of the operating crew who responded to the initial event, review of the control room operators' use of EOPs, identification of degraded plant conditions, initial actions to mitigate the event, and significant limiting condition for operation (LCO) entries. Additionally, this evaluation included performing walk-downs of the plant, and reviewing operator logs, annunciator response procedures, plant drawings, plant process computer data, and CAP documents.

b. Findings and Observations

Operations response to the dual unit shutdown was considered generally good, however, the following observations were noted.

- Unit 1 water box isolation was not completed in accordance with the guidance provided in the alarm response procedure. Specifically, the alarm response procedure stated that boxes A and D should not be isolated if possible. However, these were the two water boxes isolated by operators. The team considered this important because the loss of condenser vacuum increased significantly and unexpectedly when the water boxes were isolated. The team verified that, during a transient, the conduct of operations procedures allowed operators to not immediately refer to the alarm response procedure. Also, the licensee used the simulator to verify that isolating water boxes A and D instead of water boxes B and C had no effect on the condenser vacuum, and therefore no real impact on the event. To better control the condenser vacuum, the licensee alarm response procedure was enhanced to not isolate any of the water boxes. Since the procedures allowed the operators to perform the actions taken, there was no violation of NRC requirements;

- Unit 1 operators missed an entry into an LCO for Technical Specification (TS) Section 3.3.9, regarding boron dilution actions for greater than the TS allowed action statement time (discussed as a licensee-identified non-cited violation in Section 4OA7); and

- The Unit 1 MSSV 1D opened and did not close as designed, causing a continuous steam release to the environment and an unexpected contribution to the cooldown rate. The team noted that the operators were not aware that the safety valve was stuck open until notified by a responder, who arrived from offsite about 40 minutes after the event started. There was no indication in the control room for the operation of the MSSVs. The team noted that the status of the safety valves was important to understanding plant conditions and controlling the plant cooldown. This issue was entered into the licensee's corrective action program as AR01101893.

Major Equipment Problems

a. Inspection Scope

The team evaluated the circumstances surrounding the following major equipment problems associated with the August 16, 2010, event:

- Unit 2 main generator lockout relay actuation;
- MCC 133V failure due to water intrusion;
- Unit 2 AFW flow control valve (FCV) (2AF005H) failure to open;
- Unit 1 MSSV failure to remain fully seated following the reactor trip;
- Unit 1 condensate/condensate booster (CD/CB) pump 'C' seal failure;

- Unit 1 essential service water (SX) high differential pressure condition following the Unit 1 reactor trip; and
- Unit 1 blown fuses identified while placing the unit on shutdown cooling.

The team performed walk-downs of these components and conducted interviews of plant personnel. In addition, the team reviewed engineering evaluations, procedures, operator logs, and equipment history. While assessing the licensee's performance in addressing these issues, the team considered cause determinations, planned corrective actions, prior similar events, adequacy of past corrective actions, adequacy of the licensee's extent of condition reviews, and adequacy of past operability reviews.

b. Findings and Observations

Unit 2 main generator lockout relay actuation: The Unit 2 trip was caused by the main generator stator ground system due to a ground fault. Complex troubleshooting was performed in accordance with Licensee Procedure MA-AA-716-004 associated with Issue Report (IR) 1101855 and concluded that the cause of the fault was from pieces of a failed de-ionizing damper. This damper provides cooling to ducting for the main generator bus work. The team reviewed the history of the dampers, including previous inspection results from 2002, performed in response to operating experience, and noted that these dampers were next scheduled for inspection during the Spring 2011 outage, in accordance with their preventive maintenance (PM) schedule. The team verified that the licensee had revised the PM schedule to perform more frequent inspections of these dampers. No findings were identified.

MCC 133V failure due to water intrusion: The Unit 2 trip caused water to be discharged from the Unit 2 auxiliary feedwater suction header stand-pipes to the turbine building floor and lower levels. Water from the 451' elevation travelled through openings in the floor to the 426' elevation landing on the MCC 133V and transformer. The water intrusion into the MCC caused breaker 1435VU to experience an overcurrent trip, resulting in the de-energizing of non-safety related buses 133U and 133V, as well as the associated MCCs 133U and 133V.

The team reviewed the licensee's immediate actions and troubleshooting activities and performed a walkdown of the affected areas. The licensee's short-term corrective actions were to install a temporary modification allowing MCC 133V to be powered from the 133Z transformer, with permanent replacement of the transformer scheduled for the next refueling outage. The inspectors reviewed the temporary modification and contingency plan for repowering MCC 133V using the MCC 133Z transformer.
The inspectors questioned the extent of condition of the water intrusion on the Unit 2 equivalent MCC 233V and verified that the licensee had completed an inspection of MCC 233V. The immediate inspections identified water in the vicinity of MCC 233V, but no damage was found after additional visual inspections into the transformer cabinet. The inspectors also reviewed the operational technical decision-making document for the continued operation of MCC 233V. Additionally, the team reviewed the results of the last performed preventative maintenance inspections for these MCCs. No findings were identified.

Unit 2 auxiliary feedwater flow control valve (2AF005H) failed open: The function of AFW flow control valve 2AF005H was to control AFW flow to the steam generator (SG). This air-operated valve was normally open and fails open in the event of a loss of air to the valve operator. The valve was designed to fail in the open position to ensure the delivery of AFW flow to the SGs to cool the reactor down safely to the temperature at which the residual heat removal system could be utilized. The consequence of this failure was an increased flow rate. To prevent SG high level, the operators throttled the AFW isolation valve to maintain the desired flow rate following alarm response procedure BwAR 1-3-B7, “AF pump discharge flow high.” The team noted that the current SG tube rupture analysis and faulted SG analysis assumed that all the AFW control valves fail open. Specifically, Section 15.2.8.2 of the Updated Final Safety Analysis Report (UFSAR) stated that the case in which the valves fail open had also been considered because air supply to these valves was not safety-related. It further stated that flow may be diverted out of the break, but more flow may be provided to the intact SGs at lower pressure. The safety analysis found this case to be less limiting and gave credit for operators to isolate the faulted generator 20 minutes after the reactor trip.

The licensee’s troubleshooting of the failure of the valve 2AF005H found that both the control loop and valve were functioning properly per their design with no anomalies noted. The licensee determined that the most likely cause of the valve failure from their troubleshooting efforts was test switch problems on a card used to defeat the control logic during calibration activities such that the valve did not stroke. The licensee determined that it was likely that the card relay contacts did not remake the normal current path following the most recent calibration. Since the failure mode was in the fail safe condition, valve fails open, operability of the system was not affected. It was also postulated that the open relay contacts subsequently made up when the card relay was cycled by placing the normal/defeat switch to defeat and then back to normal when performing the troubleshooting activities. This was the likely explanation of why no problem was found during the troubleshooting. As a result, the licensee replaced the card and sent the suspected failed card to a laboratory for further evaluation.

The team reviewed the AFW control valve health history and did not find a prior similar issue. However, when assessing the licensee’s initial extent of condition, the team noted that the licensee focused on the other AFW control valves and did not consider other applications that use similar cards. In response to the team’s observation, the licensee indicated that these other applications will be evaluated as part of the apparent cause investigation. No findings were identified.

<u>Unit 1 MSSV that did not remain fully seated following the reactor trip</u>: After the Unit 1 reactor trip, MSSV (1MS016D) opened in response to overpressure but did not reseat as designed. This event was significant in that the steam release from this MSSV contributed to the tritium release discussed later in this report. In addition, the MSSV must meet the operability requirements contained in TS Sections 3.6.3., “Containment Isolation,” and 3.7.1, “Main Steam Safety Valves.”

Following the event, the valve was replaced with a spare and the MSSV that remained open was sent to a testing facility for diagnosis. The results from the testing facility were not available when the special inspection ended. Therefore, this issue continues to be followed by the resident staff as the licensee finalizes their conclusions and resultant corrective actions. This was entered into the licensee’s corrective action program as AR01101893.

The team noted that the Unit 1 operations staff had not identified that the MSSV was open until an individual arriving from offsite to support the event mentioned it to the control room operators. This was about 40 minutes after the start of the event. There is no indication in the control room for the status of any of the MSSVs. Since the open MSSV did not adversely affect the cooldown of the unit, did not significantly contribute to the tritium release, or cause the inoperability of any safety-related equipment, no performance deficiency was identified. No findings were identified.

<u>Unit 1 'C' CD/CB pump seal failure</u>: During the Unit 1 trip, the CD/CB pump 1C automatically started as designed. Approximately 45 minutes later, operators secured the pump due to a shaft seal failure. After the pump was disassembled on August 19, 2010, the impeller wear rings were found shattered. The licensee was not successful in retrieving all the pieces from the failed wear ring and concluded that they were within the piping systems. A loose parts evaluation was completed as part of IR 1103277. The team also noted that the CD/CB pump 1B failed in the same manner on August 20, 2010. All the broken pieces were not retrieved. Engineering evaluation EACE 00789519-04 identified that all CD/CB pump impellers were susceptible to stress corrosion cracking and were scheduled for inspection and replacement. AR00837434 recommended replacement of the 'C' CD/CB pump impeller during the system outage during the week of January 3, 2011.

Regarding the unaccounted for seal pieces in the system piping, the plant is designed with screens in the FW pump suction piping that prevent loose parts from entering the SGs, which protect the integrity of the primary pressure boundary of the SG tubes. These screens are inspected periodically to ensure they are intact and to remove any parts that may have been collected. The team verified that the screens were intact through review of previous inspection results. The flows in the condensate system would not be sufficient to allow the loose parts to travel to these screens until after start-up. Therefore, additional inspection of these screens' integrity and for CD/CB wear ring pieces will be conducted by the licensee as part of their scheduled maintenance activities. No findings were identified.

<u>Unit 1 SX high differential pressure condition following the Unit 1 reactor trip</u>: The SX is designed to ensure that sufficient cooling capacity is available to provide adequate cooling during normal and accident conditions. The system includes a strainer downstream of the SX pumps to protect downstream components from fouling (e.g., heat exchanger tube blockage). Differential pressure is measured across the strainer to monitor strainer fouling conditions. The strainer is automatically backwashed when the differential pressure reaches its high setpoint.

The team determined that the backwash feature of the SX system performed as designed during the event of August 16, 2010. In addition, the team confirmed that the high differential pressure experienced during the event did not cause or indicate inoperability of the SX system. Specifically, the SX system was confirmed to have a discharge header pressure value equal to the operability limit value established by the most recent flow balance of the system. However, the team noted that the forebay conditions present during this event were less limiting than the conditions considered acceptable by the licensee and was determined to be a finding as discussed below.

.1 Forebay inspect-and-clean activities did not ensure that structure, systems, and components will be capable of performing their safety function:

Introduction: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the failure to establish adequate controls to ensure that forebay inspect-and-clean activities provide assurance that structure, systems, and components (SSCs) will be capable of performing their safety function.

Description: On August 20, 2010, the inspectors noted that the licensee had not established adequate controls to ensure that future forebay inspect-and-clean activities provide reasonable assurance that SSCs will be capable of performing their safety function during inspect-and-clean intervals. Specifically, the inspectors noted that the operability margin of the SX system decreased to zero under forebay fouling conditions that were considered less than the pre-established limiting conditions developed by the licensee.

The licensee developed and implemented a lake macro-biological program as a corrective action to NCV 05000456/2009003-07; 05000457/2009003-07 for the 2008 bryozoa infestation event at the screenhouse forebays, which are the water intake structures on the lake, documented in NRC Inspection Report 05000456/2009003; 05000457/2009003. The lake macro-biological program included alert and action levels for fouling accumulation in the forebays. If the alert level is reached, the licensee is required to notify the heat exchanger coordinator and CW system engineer to determine if cleaning efforts are necessary. If the action level is reached, the licensee is required to clean, evaluate for extent of condition, and generate an IR in the CAP.

During the 2010 Unit 1 trip, the loss of bus 133V resulted in the loss of CW pumps 1A and 1C and the failure of their associated discharge valves in the open position, causing reverse flow to the 1A and 1C forebays. The reverse flow caused high flow conditions in normally low flow areas where bryozoa and loose debris accumulate. This abnormal flow caused the bryozoa to be suspended and flow into the SX system. The amount of material entering the SX system affects the performance of the system, in particular the water pressure in the SX header. The inspectors noted that the licensee's forebay fouling program was based on the 2008 bryozoa infestation experience and that it did not consider the debris removal and transportation mechanism associated with CW reverse flow even though it was mentioned in engineering change (EC) 373358, "Bryozoan event technical evaluation supporting SX availability."

The licensee uses SX discharge header pressure as the main factor in determining operability of the SX system and SX supported systems. Specifically, the SX system was flow balanced by throttling various SX valves such that the necessary flows to all post-accident SX heat loads were achieved. Operability was maintained as long as the header pressure remained at or above the recorded SX header pressure value at the time of the flow balance. The operability of the reactor containment fan coolers (RCFCs) was most sensitive to SX header pressure because it was the only SX supported system with an associated TS flowrate value (i.e., TS 3.6.6, "Containment Spray and Cooling Systems"). The SX header pressure was relied upon by the licensee as the indicator of the reactor containment fan coolers' flowrate.

The inspectors noted that the IRs that captured the as-found conditions of the 2010 inspect-and-clean activities did not adequately screen for operability and extent of condition. For example, AR0109291 identified EC 376317, “CW forebay inspection acceptance criteria for bryozoa accumulation,” as the document that established the most conservative limits. EC 376317 allowed a maximum accumulation of 30 inches of bryozoa in any location, using a 3 inch per week accumulation rate. Based on the results of the 1C forebay inspection performed on August 6, 2010 and EC 376317, the 1A forebay would have had bryozoa spots of 15 inches maximum height mostly at the walls and minimum fouling on the floor during the dual reactor trip that occurred on August 16, 2010. However, during the reverse flow conditions and amount of debris experienced during this event, Unit 1 SX discharge header pressure operability margin decreased to zero. Therefore, the inspectors concluded that 30 inches of bryozoa in any location was not an adequate criterion to ensure that SSCs will be capable of providing their safety function.

<u>Analysis</u>: The inspectors determined that the failure to establish adequate controls, which ensure that future forebay inspect-and-clean activities provide assurance that SSCs will be capable of performing their safety function during inspect-and-clean intervals, was contrary to procedure ER-AA-340, “GL 89-13 Program Implementing Procedure,” and was a performance deficiency.

The performance deficiency was determined to be more than minor because, if left uncorrected, could potentially lead to a more significant safety concern. Specifically, unacceptable forebay conditions would have been allowed between inspect-and-clean intervals and potential adverse impact to the SX system and its supported equipment would not be evaluated. Therefore, SSCs could be incorrectly determined to be operable, and appropriate corrective actions to ensure that SSCs will be capable of performing their safety function would not be implemented. The inspectors concluded that this finding was associated with the Mitigating System Cornerstone.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of findings,” Table 4a for the Mitigation Systems Cornerstone. The finding screened as very low safety significance (Green) because the finding was a design deficiency confirmed not to result in loss of operability or functionality. Specifically, it was determined that the worst case condition since implementation of the corrective actions of the 2008 event was August 2010. During the August 2010 dual reactor trip, Unit 1 lost two CW pumps, resulting in debris entrainment into the SX system, which did not cause the SX discharge header pressure value to drop below operability limits.

The inspectors determined that this finding had a cross-cutting aspect in the area of human performance decision-making component, because the licensee did not make safety-significant or risk-significant decisions using a systematic process to ensure safety was maintained, especially when faced with uncertain or unexpected plant conditions. Specifically, the licensee did not use a systematic process to ensure that SSCs would not be adversely affected by fouling at the forebays between inspect-and-clean intervals because debris removal and transport mechanisms were uncertain. [H.1(a)]

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Procedure ER-AA-340 required the licensee to perform tests or inspections at intervals that provide assurance that the equipment is capable of performing its safety function during the interval.

Contrary to the above, before August 20, 2010, the licensee did not follow Procedure ER-AA-340. Specifically, the licensee did not establish adequate controls to ensure that future forebay inspect-and-clean activities provide assurance that SSCs will be capable of performing their safety function during inspect-and-clean intervals. Because this violation was of very low safety significance and it was entered into the licensee's CAP as AR01106410, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2010010-01; 05000457/2010010-01, "Forebay inspect-and-clean activities did not ensure that SSCs will be capable of performing their safety function")**

The licensee captured this issue in their CAP and corrective actions considered at the time of this inspection were procedure changes and margin improvements.

Unit 1 blown fuses identified while placing the unit on shutdown cooling: On August 16, 2010, the plant attempted to align Unit 1 for shutdown cooling after the reactor trip. Due to blown control power fuses on MCC 131X1, eight safety injection (SI) valves could not be energized, one of which prevented the realignment to hot leg recirculation for the 1A SI train and from the 1A and 1B Residual Heat Removal (RHR) trains. Train "A" of the Emergency Core Cooling System (ECCS) was declared inoperable and LCO 3.5.2, "ECCS Operating," was entered. In addition, two of the SI valves were containment isolation valves and the blown fuse prevented closure. Therefore, LCO 3.6.3, "Containment Isolation" was entered. The fuses were replaced within time specified by the TS LCO action statement. The team reviewed the history of these control power fuses and found these fuses had been identified as undersized or marginally sized in 2007 and had failed in 2009.

.2 Failure to replace low margin fuses in MCC131X1:

Introduction: A self-revealed finding of very low safety significance (Green) and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for the failure to establish measures for the selection and review for suitability of equipment essential to its safety–related function. Specifically, in 2008, the safety-related 1.5 amp control power fuses in motor control center (MCC) 131X1 were identified to be replaced with 3.0 amp fuses due to failures of other similar 1.5 amp fuses. In 2009, these fuses failed and were replaced with the same size 1.5 amp fuses. The subsequent licensee evaluation concluded the fuses were adequate but marginally sized. During the event on August 16, 2010, these fuses failed again at which time they were replaced with 3.0 amp fuses.

Description: On August 2, 2007, apparent cause evaluation (ACE) 00664657 was performed when the 1.5 amp control power fuses in MCC 234V6 E1 failed. The ACE concluded these control power fuses were undersized/marginally sized. A review of historical data associated with MCC control circuits having 1.5 amp fuses found similar failures. The ACE determined this condition would apply to all 480Vac MCCs with primary connected size 3 NEMA contactor starters with 1.5 amp primary control power fuses. Assignment 14 of the associated AR identified the fuses in MCC 131X1 1AP21E-M2—AP, Feed to ECCS Water Supply Isolation Valves, were vulnerable to this condition.

On June 3, 2008, EC 370955 was completed and determined that it was acceptable to increase the primary side control circuit KTK-R-1-1.5 (1.5 amp) fuses, with Bussman KTK-R-3 fuses (3 amp). This would allow for operating margin while still providing protection and coordination.

AR782761 specified replacement of the 1.5 amp control power fuses in MCC 131X1 1AP21E-M2; feed to ECCS water supply isolation valves with 3.0 amp fuses. This replacement was scheduled for A1R14 (2009).

On May 28, 2009, operators noted that the indication for the 480 volt feed to Bus 131X1A/X2A (MCC 131X1/X2) was open. It was determined that this was due to the failure of the 1.5 amp control power fuses in MCC 131X1 Compartment M2. This affected the operability of eight SI valves in the A train and would have prevented the realignment to hot leg recirculation for the SI train 1A from the residual heat removal trains 1A and 1B. However, the ability to provide flow to hot leg trains 1B and 1C via the SI pump 1B was unaffected. This resulted in entry into Technical Specification LCO 3.5.2, conditions A and B, for loss of ECCS functions and also TS LCO 3.6.3, condition A, for the loss of power to two SI containment isolation valves. Operations replaced the 1.5 amp fuse with another 1.5 amp fuse to exit from the respective LCO's.

During the investigation and evaluation of the failure of the fuses on May 28, 2009, conducted under AR925143, the licensee concluded the fuses were adequate, but had low margin and did not question whether the currently installed fuses should be promptly replaced with the 3 amp fuse in accordance with the previous evaluations and recommendations. The inspectors also noted the fuses were replaced by operations personnel under their fuse replacement program, which is not mentioned in the AR. Instead, the AR referenced work order (WO) 1239369 for replacement of the fuses in 2009, but it was discovered that no work was done under this WO even though it indicated that it was completed. Also, after the fuse was sent to the laboratory for analysis, the laboratory report concluded that the fuse blew from an overload condition, which supported the view that the fuses were marginally sized. Additionally, licensee personnel indicated the failure was caused by not performing preventative maintenance (PM) activities as planned/scheduled, and referenced the EC to replace the fuses with a 3 amp fuse. In spite of this information, the licensee did not schedule the fuses to be replaced with the 3.0 amp fuses until 2015. Therefore, the inspectors concluded the licensee had not establish measures that resulted in an adequate selection and review for suitability of the 1.5 amp fuses to perform their safety-related function.

During the event on August 16, 2010, these fuses failed again, at which time they were replaced with 3.0 amp fuses.

<u>Analysis</u>: The inspectors determined that the failure to establish measures for the selection and review for suitability of equipment essential to its safety–related function was a performance deficiency. Specifically, in 2007, ACE 664657 identified that the 1.5 amp fuses in MCC 131X1 may be undersized or marginally sized and should be

replaced with 3.0 amp fuses. In 2009, these fuses failed and the licensee's review for suitability concluded the fuses were adequate but marginally sized and replaced the fuses with the same size 1.5 amp fuses. In 2010, these fuses failed again after which the 3.0 amp fuses were installed.

The finding was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of equipment performance, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure of these fuses resulted in the loss of function for eight SI valves related to ECCS and containment isolation functions.

The inspectors determined that the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Mitigation Systems Cornerstone. The inspectors answered "no" to the Mitigating Systems questions and screened the finding as having very low significance (Green). This finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee did not take corrective actions to address safety issues in a timely manner, commensurate with their safety significance. Specifically, these 1.5 amp fuses were identified in 2007 as undersized or marginally sized, they failed in 2009 and were replaced with the same size fuse, and then scheduled for replacement with the 3.0 amp fuses in 2015. [(P.1(d)].

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related function of structures, systems, and components.

Contrary to the above, on or before August 16, 2010, the licensee had not established measures that resulted in an adequate selection and review for suitability of the 1.5 amp control power fuses in MCC X1A to perform their safety-related function. Specifically, in 2008, AR782761 specified these fuses should be replaced with 3.0 amp fuses. In May 2009, the fuses failed and were not replaced with 3.0 amp fuses even though the licensee's review for suitability determined the fuses were adequate but had low margin. After the failure in 2010, the fuses were replaced with 3 amp fuses and the licensee was conducting an evaluation of the fuse replacement schedule for all similar fuses. Because this violation was of very low safety significance and it was entered into the licensee's CAP as AR1106401, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000456/2010010-02, "Failure to replace marginally sized fuses in MCC131X1").**

<u>Unit 2 Auxiliary Feedwater Suction Vent Riser</u>

a. <u>Inspection Scope</u>

The team reviewed the circumstances surrounding the water on the turbine building floor from the Unit 2 auxiliary feedwater suction header stand-pipes and assessed the licensee's performance in addressing this issue. Specifically, the team reviewed:

- measures used to control the water when it is spilled onto the floor;
- any historical issues with water spilling from this and the Unit 1 vent; and
- the adequacy of the AFW suction header stand-pipe design.

The team performed walkdowns of the plant and conducted interviews of plant personnel. In addition, the team reviewed engineering evaluations, procedures, operator logs, drawings, and equipment health history.

b. Findings and Observations

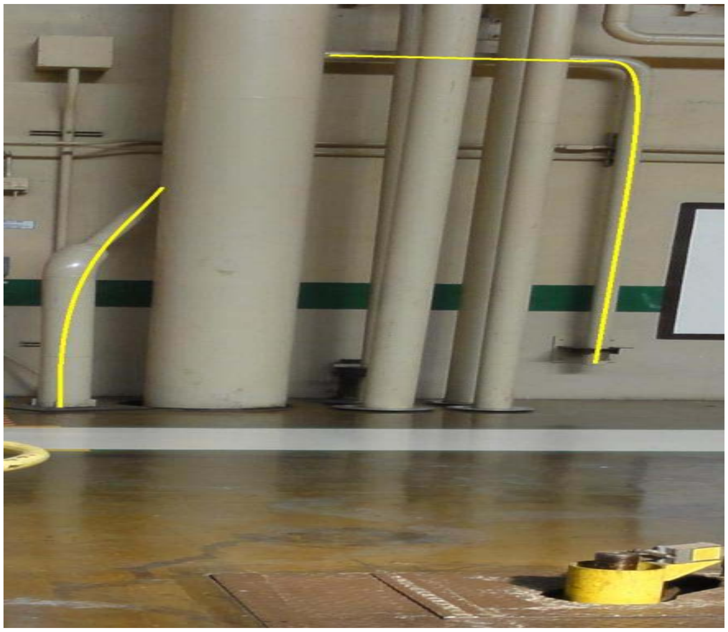
The AFW suction header includes two stand-pipes (or vent risers) used to attenuate AFW pumps suction pressure transients during pump startup by providing a source of water that is close to the pumps' suction and at a head equal to the water height in the condensate storage tank (CST). The CST is the preferred source of water to the AFW pumps. These transients occur because the motor-driven AFW pump accelerates at a higher rate than the water coming from the CST resulting in a temporary low suction pressure (assuming that the stand-pipes were isolated from the header). The high point on the stand-pipes is approximately 8.5 feet higher than the top of the CST. When the condenser hotwell high level setpoint is met, the hotwell overflow control valves open to transfer condensate reject to the CST via the condensate header using the CD/CB pumps. The condensate header communicates with the AFW suction header coming from the CST. When the flow rate of water rejected from the hotwell to the CST is greater than the discharge rate out of the AFW pumps, the level in the standpipe would increase and the conditions were great enough that water could spill onto the turbine deck, because the stand-pipes are open to the atmosphere on the common turbine building at the 451' elevation. The discharged water is able to flow through the floor and rain down the lower elevations through multiple openings in the floor. The team found that this occurrence was known to happen in multiple occasions in the past by the licensee without significant impact to the plant. However, on August 16, 2010, this occurrence caused the trip of Unit 1. As a result, one self-revealed finding of significance was identified, as discussed below.

.3 Failure to identify and correct water discharged to the turbine building floor during condensate reject

Introduction: A self-revealed finding of very low safety significance was identified following a dual unit trip on August 16, 2010. Specifically, the licensee failed to identify and correct a condition that resulted in condensate reject (i.e. water) to be discharged to the turbine building floor. This condition resulted in Unit 2 having caused a reactor trip of Unit 1.

Description: On August 25, 2010, the inspectors noted that the licensee failed to correct a condition that resulted in water to be discharged from Unit 2 to the common turbine building floor during reject of condensate from the Unit 2 condenser hotwell, which led to the reactor trip of Unit 1 on August 16, 2010.

When Unit 2 tripped on August 16, 2010, the condenser hotwell level began to rise and reached the setpoint to actuate hotwell overflow control valves. For approximately 15 minutes, the flow rate of water rejected from the hotwell to the CST was greater than the discharge rate out of the AFW pumps. Therefore, during this time, water was discharged from the two Unit 2 AFW stand-pipes to the turbine building floor at the 451' elevation. The turbine building is shared between the two units. The licensee roughly estimated that 12,000 gallons of water discharged through the stand-pipes. This volume of water flowed down onto the lower elevations of both units through nearby floor openings.



Photograph 1 – One of two Unit 2 suction header stand-pipes

Water entered MCC 133V and caused feed breaker 1435V to trip. The loss of MCC 133V resulted in the loss of 1A and 1C CW pumps, which led to a Unit 1 automatic reactor trip on low condenser vacuum approximately 13 minutes after Unit 2 tripped.

The inspectors learned through interviews and discussions with plant personnel that water had been observed to discharge through the AFW stand-pipes on multiple occasions in the past. However, this occurrence was found to be captured in the CAP only on one occasion in 2009. In addition, the inspectors noted that the resolution of the issue captured in 2009 focused only on industrial safety and did not evaluate the impact of the water on plant equipment. This condition had not caused a reactor trip prior to the 2010 event.

Procedure LS-AA-120, "Issue identification and screening process," required that conditions adverse to quality (CAQ) be captured in the CAP, evaluated for significance following the guidance contained in Attachment 2 of the procedure, and assigned an investigation class following the guidance contained in Attachment 3. Attachment 2 stated that a near-miss condition that, under different circumstances would reasonably be expected to result in a significance level 1 or 2 event, is an example of a significance level 3 CAQ. A reactor trip was identified as a significance level 2 event by this attachment. The guidance for assigning an investigation class contained in Attachment 3 considered two elements associated with the cause of the CAQ: risk and uncertainty. It stated that risk involves consequence and probability of recurrence. In determining the potential consequence, the guidance considered not only what happened but also what could have happened if the circumstances were different. That is, if under different circumstances a more significant event could have occurred, then the potential consequence may be higher. Following the guidance contained in Attachments 2 and 3 of the procedure, the inspectors determined that the condensate reject overflow observed in the past would have been screened as a high risk significance level 3 CAQ. According to Procedure LS-AA-120, a high risk CAQ receives at least an ACE and assignment of corrective actions to restore the CAQ to an acceptable condition. Procedure LSAA-125, “Corrective action program procedure,” defined corrective action as an action taken or planned that restores a CAQ to an acceptable condition. It further required creating a corrective action to restore a CAQ. However, the inspectors found that the licensee did not create a corrective action to restore the CAQ that resulted in condensate reject overflow to the turbine building floor to an acceptable condition.

The licensee captured this issue in their CAP as AR01106403. The corrective actions included changing the normal position of the manual valves downstream of the hotwell overflow control valves to the close position. In this configuration, manual action will be required to reject water from the hotwell by operating the normally closed bypass valve. The intent is to reject water in a controlled fashion. Continuous monitoring at the AFW stand-pipes will determine if water is being discharged to the turbine building while performing this action and prevent excessive discharge to the floor.

Analysis: The inspectors determined that the failure to correct a condition that resulted in water to be discharged to the turbine building floor during reject of condensate from the condenser hotwell was contrary to Procedure LS-AA-125 and was a performance deficiency. This condition led to a reactor trip.

The performance deficiency was determined to be more than minor because it was associated with the Initiating Events Cornerstone attribute of configuration control and affected the cornerstone objective of limiting the likelihood of those events that upset plant stability. Specifically, water discharged to the turbine building floor during reject of the condensate from the Unit 2 condenser hotwell caused component failures that led to a reactor trip on Unit 1.

The inspectors evaluated the finding in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 4a for the Initiating Events Cornerstone. The inspectors answered “Yes” to the screening question “Does the finding contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions will not be available?,” since the condenser steam dump valves are listed as mitigation equipment in the Phase 2 Risk-Informed Inspection Notebook for Braidwood Station. Therefore, a Phase 2 SDP evaluation was performed using IMC 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations.”

Using the SDP Phase 2 Worksheets, the performance deficiency was evaluated to increase the frequency of a transient initiating event (i.e., TRANS, Table 3.1) due to a loss of condenser heat sink. Section 1.2 of IMC 0609, Appendix A, Attachment 2, “Site Specific Risk-Informed Inspection Notebook Usage Rules,” states that if the increase in the frequency of an initiating event due to an inspection finding is not known then the Initiating Event Likelihood (IEL) for the applicable initiating event needs to be increased by one order of magnitude. Applying an increase in the IEL by one order of magnitude to the TRANS initiating event resulted in a characterization of the finding as “White” in

Phase 2. Since this characterization was considered to be conservative, a Phase 3 SDP evaluation was performed.

The Senior Reactor Analysts (SRAs) evaluated the finding using the Braidwood Standardized Plant Analysis Risk (SPAR) Model Revision 3P (Change 3.51). The SRAs increased the Loss of Condenser Heat Sink (LOCHS) IEL from its nominal value of 8.0E-2/year to account for the performance deficiency as an additional contributor to the nominal IEL. Applying an increased IEL in the Braidwood SPAR model resulted in a delta Core Damage Frequency (ΔCDF) of 5.6E-7/year due to the performance deficiency. Large Early Release Frequency (LERF) was not a risk contributor based on LERF factors in the Risk-Informed Inspection Notebook being zero for transient with loss of condenser heat sink. Based on the Phase 3 analysis, the inspectors determined that the finding was of very low safety-significance (Green).

The inspectors determined that this finding had a cross-cutting aspect in the area of problem identification and resolution because the licensee did not have a low threshold for identifying issues and did not identify issues completely. Specifically, the condition was captured in the CAP on only one occasion in 2009 while condensate reject had been observed to overflow to the turbine building floor in multiple instances in the past. In addition, the licensee did not fully evaluate the issue in 2009 because the licensee failed to recognize that the issue had the potential to cause a reactor trip. [P.1(a)]

Enforcement: No violations of NRC requirements were identified because the affected components were not safety related. Because this finding does not involve a violation and has very low safety significance, it is identified as a finding.

Corrective actions for this event included changing the normal position of the manual valves downstream of the hotwell overflow control valves to the closed position. In this configuration, manual action will be required to reject water from the hotwell by operating the normally closed bypass valve. The intent is to reject water in a controlled fashion. Continuous monitoring at the AFW stand-pipes will determine if water is being discharged to the turbine building while performing this action.
(FIN 05000456/2010010-03; 05000457/2010010-03, "Failure to identify and correct water discharged to the turbine building floor during condensate reject").

Reactor Building Flashing

a. Inspection Scope

The team reviewed the circumstances surrounding the Unit 1 reactor building flashing that was dislodged during the steam release from the MSSVs (see Photograph 2). This review included identifying the reason the flashing was dislodged, evaluation of past similar events, and assessing the impact of the falling flashing to the Unit 1 transformers, and corrective actions taken by the licensee.

Photograph 2– Area where flashing was dislodged from Unit 1 containment

b. Findings and Observations

.4 Evaluation of Operating Experience did not address potential for dislodged RB flashing affecting off-site power supply

Introduction: A finding of very low safety significance was identified by the inspectors for the inadequate evaluation of operating experience (OE). Specifically, review of an event at another plant where building material was dislodged during a steam release and caused a loss of off-site power concluded that event was not applicable to Braidwood station. During the dual unit trip on August 16, 2010, reactor building flashing was dislodged during a steam release and was found on power lines and in the vicinity of the off-site power supplies. While there was no affect on the offsite power supply, the increased risk to them should have been fully evaluated and addressed as a result of the operating experience review.

Description: On August 16, 2010, the unit 1 CW pumps 1A and 1C tripped and caused condenser vacuum to degrade. Operators initiated a turbine runback but vacuum continued to degrade until the turbine automatically tripped followed by reactor trip. The C-9 permissive, which would normally open the steam dump valves, was disabled due to failure of MCC 133V. Without the steam dump valves, the PORVs open to control temperature and pressure. In addition, two or three of the MSSVs open and subsequently close, with the exception of one which remains open. All of these valves release excess steam to the environment. The steam released from the combination of the PORVs and MSSVs caused portions of the containment flashing, located above the vent lines for these valves, to become detached and land on power lines and in the area of the off-site power transformer and equipment (See Photograph 3).

Photograph 3 – Flashing dislodged from Unit 1 containment located on main power transformer output lines

On August 11, 1994, Braidwood Unit 1 experienced a spurious train “A” main steam isolation followed by an automatic reactor trip. Unit 1 PORVs and MSSVs lifted causing some flashing and a piece of the containment roof walkway to become dislodged piercing the turbine building roof. At the time, site engineering staff visually inspected the main steel framing and flashing for the containment walkway enclosure and determined that no structural damage had occurred. All sections of sheet metal siding blown off the walkway were accounted for and were placed in storage for future evaluation. The flashing and walkway were replaced.

On June 5, 2007, Braidwood station created AR637360, “OPEX review potential vulnerability containment buttress siding,” to review OE for an industry event that described a reactor scram in which the cross-under steam piping safety valves lifted; high steam flow was released from these valves; and caused portions of the turbine building metal siding to detach and contact bus bars on two of three reserve station transformers, which led to a loss of power to station buses. In the AR’s condition description, the originator discussed the 1994 incident described above and also stated that “the potential existed that the siding could have landed on the station auxiliary transformer (SAT) (preferred power source) for the emergency bus and cause a loss of off-site power (LOOP).” It was recommended that engineering review the OE to determine if the buttress was susceptible to complicating emergency response (i.e. LOOP) during a main steam line isolation from full power. This AR was closed based on initiating a corporate AR that will track the formal reviews of the OE.

On June 15, 2007, corporate AR637360 was initiated to track the formal reviews of the issues for Exelon sites. Braidwood assignment was captured in AR637360, assignments -01 and -02 with various sub-assignments. The corporate AR did not mention or seek to address the concerns or recommendations of the originator of the previous AR to evaluate the previous experience with the buttress siding being blown off and its potential effects on off-site power.

On September 18, 2007, sub-assignment 01/01 addressed the impact of the OE on the main steam reheater (MSR) system, and concluded that the Braidwood station design is different from the design of the plant discussed in the OE in that the MSR relief valve tail pipes are located adequately away from the building structure or the structure is concrete and that this configuration precludes the possibility of building structure dislodging during the relief valve lifting. The evaluation focused on the specific MSR configuration discussed in the OE and did not address main steam relief valves dislodging the buttress siding.

On September 18, 2007, sub-assignment 01/02 addressed OE with respect to the auxiliary power 480 VAC and above system/transformers, and concluded OE was not applicable to Braidwood station because the type of transformer inter-locks discussed in the OE were not used at the site. The evaluator mentioned that aluminum covers would likely protect the SATs and that debris from turbine building walls and other sources are unlikely to cause a lock-out. The evaluator did not address if debris could affect the SAT in other ways that may impact off-site power to the plant. However, the evaluator also went on to say that the primary feeds (345kv) are not protected. He noted two previous incidents where debris resulted in a lock-out of the SAT. In both events, the associated busses correctly transferred to the alternate supply or were re-energized by the emergency diesel generator (EDG). The evaluator concluded that this OE was not applicable to Braidwood station.

The Licensee's Quality Assurance Topical Report (QATR) NO-AA-10, assigns major functional responsibilities. All personnel who support nuclear generation activities shall comply with the requirements of this document. As part of a three tiered approach to accomplish the oversight of safety, the document uses collection of program elements for implementing and/or reviewing areas of quality of plant operation and nuclear safety, which includes a review of operation experience.

Licensee's Procedure LS-AA-115, "Operating Experience Procedure," implements the Quality Assurance Topical Report requirement for this element.

The stated purpose of Procedure LS-AA-115 is to screen, evaluate, and act on current incoming OE documents and information to prevent or mitigate the consequences of similar events. It requires daily screening, classification, and evaluation of OE documents, and requires an evaluation documented in accordance with Attachment 1 of the procedure.

Procedure LS-AA-115, Attachment 1, "OPEX Reviewer's Guidelines," uses 27 questions to evaluate the OE. These questions were answered by the alternating current (AC) power and the main steam system engineer for their respective systems in separate sub-assignments as discussed above. However, the inspectors determined that the answers to the following questions were not adequate to meet the purpose of the procedure

a. Question 2, is this OPEX document applicable to station SSCs? This question was answered "no" for the offsite power system. Answering this question no enables the evaluator to skip to question 25. The evaluation identified that debris had previously affected the operation of the SAT resulting in operation of the EDGs, an SSC. Since the initial AR was concerned with the reactor building flashing affecting loss of offsite power, and this evaluation concluded that offsite power could still be affected by debris, the answer should have been “yes.” Further evaluations or actions should have been done to ensure the loss of offsite power was prevented, as discussed in the OE review, to meet the purpose of the procedure.

b. Question 10, are any other plant systems affected by this OPEX? This question was answered “no” for the main steam system. The evaluator stated that there were no other similar components impacted by this OPEX. It is also stated the main steam safety relief valves are also located adequately away from building structure or the structure is concrete so it would not be affected. The evaluator did not address the previous experience at Braidwood of the reactor building flashing falling off during a steam release identified in the original AR. This evaluation did not meet the purpose of the procedure to prevent or mitigate the consequences of similar events.

c. Question 12 b., did the event described in the in the OPEX include the failure of a nonsafety-related SCC resulting in actuation of a safety-related system? This was answered “no” for the main system even though the OPEX discussed how turbine building siding was blown off, impacted the off-site power equipment, resulted in the loss of off-site power and required the EDGs to start to supply AC power to safety related equipment. It is not known how the evaluator reached this invalid conclusion.

d. Question 24, will the information in this OPEX document require that a modification be implemented? This was answered “no” for the main steam system evaluation because the Braidwood MSR relief valves are appropriately located away from the building structure. Again, the evaluation did not address the reactor building flashing and its interaction with the MSSVs. Since the licensee did not address the susceptibility of the reactor building flashing becoming debris, but did conclude that the off-site power supplies were vulnerable to debris, this question was not answered appropriately to meet the purpose of the procedure to prevent or mitigate similar events.

Analysis: The team determined that the licensee’s failure to adequately evaluate industry operating experience applicable to the reactor building flashing being dislodged during a steam release and its affects and risk related to off-site power supplies was contrary to Procedure LS-AA-115, “Operating Experience Program” and was a performance deficiency. The finding was determined to be more than minor because the finding was associated with the Initiating Events Cornerstone attribute of protection against external factors, and affected the cornerstone objective of limiting the likelihood of those events that challenge critical safety functions during shutdown. Specifically, not protecting the off-site power supplies from flashing falling from the reactor building which could result in a loss of off-site power would challenge the EDG to supply AC power during the plant shutdown.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of findings,” Table 4a for the Initiating Events Cornerstone. The inspectors answered "no" to the Initiating Events questions and screened the finding as having very low significance (Green).

The inspectors did not identify a cross-cutting aspect associated with this finding since it is not considered to reflect current performance.

Enforcement: This finding does not involve enforcement action because no regulatory requirement violation was identified. Because this finding does not involve a violation and has very low safety significance, it is identified as a finding.

The licensee entered this issue into their CAP as condition report (CR) 01102706 and 01106404; inspected the flashing structures on both Unit 1 and Unit 2 reactor buildings; and installed temporary structural modifications to prevent the reactor building flashing from falling off during a future steam release until a permanent structural evaluation could be completed. **(FIN 05000456/2010010-04, Evaluation of Operating Experience did not address potential for dislodged RB flashing affecting off-site power supply).**

Dose Calculations for Release of Tritiated Steam

a. Inspection Scope

The team reviewed the licensee's monitoring results for the August 16, 2010, steam discharge contaminated with tritium from the Unit 1 PORVs and unseated MSSV event.

The team assessed whether the licensee's methods for quantifying the dose to the public from the contaminated steam discharge involved critical receptors.

The team reviewed whether the identified steam discharge occurrence was entered into 10 CFR 50.75 (g) records or will be reported on the 2010 Annual Radioactive Effluent Release Report or the Annual Radiological Effluent Release Report for the radiological effluent technical specifications.

The team assessed whether the licensee evaluated the steam condensate that spilled to the ground and reviewed whether there were remediation actions taken on the area. The team assessed whether the tritium-contaminated discharge was monitored through the licensee's groundwater protection initiative program.

For the unmonitored steam discharge, the team assessed whether an evaluation was performed to determine the type and amount of radioactive material that was discharged by: (1) assessing whether sufficient radiological surveys/evaluations were performed to evaluate the extent of the contamination; (2) assessing whether a survey/evaluation had been performed to include consideration of hard-to-detect radionuclides; (3) determining whether the licensee completed offsite notifications, in accordance with the licensee's Groundwater Protection Initiative implementing procedures; and (4) assessing whether the licensee identified and addressed discrepancies through the licensee's CAP Findings and Observations.

b. Findings and Observations

No findings were identified.

Following the Unit 1 trip on August 16, 2010, steam, containing tritium, was released to the atmosphere. The steam release occurred at 02:05 and ended on August 17, 2010, at 05:00 Central Time. There were approximately 312,500 gallons of steam discharged. A portion of the saturated steam also condensed to water from the turbine building downspouts. The condensing steam was analyzed and found to contain 25,835 picocuries per liter (pCi/L) of tritium. The total tritium activity of the condensing steam on the ground inside the protected area was found to be less than approximately 1E-1 millicuries (mCi).

The team reviewed the licensee's initial dose calculation to the public and noted that the licensee calculated a dose to a critical organ using a sampled tritium concentration data that was 8 hours post-steam discharge. This concentration may have been diluted by the make-up water from the condensate storage tank that contained a lesser concentration of tritium. In response to the team's observation, the licensee conservatively recalculated the dose to the public using a tritium concentration that was sampled and analyzed on August 9, 2010, 7 days prior to the event.

The licensee analyzed and calculated that the steam discharge in the environment contained approximately 43 mCi of tritium as a gaseous release. Specifically, the critical receptor dose (i.e., child critical organ) was 4.59E-6 mrem. The dose to the public due to gaseous effluents for both units was currently less than 1E-1 mrem. Therefore, the additional dose impact to the public from the steam discharge was minimal (1E-1mrem + 4.56E-6 mrem= 1E-1 mrem), and was less than the regulatory limits.

The licensee had not completed files for the requirements of 10 CFR Part 50.75(g) at the time of the inspection. However, the licensee generated AR01102248 to the Radiation Protection Department to make the appropriate entry into the 10 CFR Part 50.75(g) files for information that the NRC considers important for decommissioning.

Additionally, the licensee will document the unplanned release on the licensee's 2010 Annual Radioactive Effluent Release Report as required by the station's effluent monitoring program.

The condensation to the ground from the steam discharge will not be reported because the condensation did not leave the site as an effluent, but rather was recaptured. The licensee analyzed the concentration of tritium in the steam condensation to be 25,835 pCi/L.

The licensee will monitor the groundwater protection initiative monitoring wells at the site for any indication of tritium concentration anomalies as required by the station's groundwater monitoring program.

The licensee had not experienced primary to secondary leakage of the reactor coolant system (RCS) due to an SG tube rupture or a fuel failure in the recent past. Therefore, the only nuclide of significance was tritium because tritium leaches through stainless SG tubing and contaminates the secondary system. The licensee performs routine sampling at the secondary system for tritium on a weekly basis. The last chemistry surveillance was conducted on August 9, 2010. The tritium concentration on the Unit 1 secondary system was 3.64E-5 uCi/ml (36,400 pCi/L), with no indication of other radio-nuclides. This activity was used to calculate the dose to the critical receptor (child critical organ).

The team reviewed that the licensee's voluntary notification to the State of Illinois for the condensing steam that reached the ground. This voluntary notification was made by the licensee to the Local and State Government under Procedure LS-AA-1120, "Reportable Event RAD 1.34," on August 16, 2010. No findings were identified.

4OA6 Management Meetings

Exit Meeting Summary

On September 30, 2010, the team presented the inspection results to Mr. A. Shahkarami and other members of the licensee staff at a public exit meeting held at Braidwood, IL (NRC presentation materials - ADAMS Accession Nos. ML 102730329 and meeting summary ML 102950118) and on November 12, 2010, with Mr. R. Gaston. The team confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements, which meets the criteria of Section 2.3 of the NRC Enforcement Policy for being dispositioned as an NCV.

The licensee violated TS Section 3.3.9, "Boron Dilution Protection System," when they failed to enter the LCO Conditions A and C, which required 1-hour actions to close non-borated water source isolation valves and to verify that shutdown margins were within their limits. Unit 1 entered LCO 3.0.3 due to not completing the required actions. Upon discovery, the licensee lowered the water volume in the volume control tank to clear the alarms and exit all the LCOs. This violation was not greater than green since the shutdown margin was verified within 1 hour and no significant change in reactivity occurred. The licensee entered this issue into the CAP as AR01101873 and has submitted LER 2010-002-00.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

A. Shakarami, Station Vice President
L. Coyle, Plant Manager
M. Marchionda-Palmer, Director, Site Operations
P. Simpson, Response Team Lead
D. Riedinger, Engineering
D. Stroh, Relief Valve Subject Matter Expert
W. Smith, Operations
M. Boyle, Maintenance
S. Butler, Operations

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000456/2010010-01; 05000457/2010010-01	NCV	Forebay inspect-and-clean activities did not ensure that SSCs will be capable of performing their safety function (Section 4OA5.1)
05000456/2010010-02	NCV	Failure to replace low margin fuses in MCC131X1 (Section 4OA5.2)
05000456/2010010-03; 05000457/2010010-03	FIN	Failure to identify and correct water discharged to the turbine building floor during condensate reject (Section 4OA5.3)
05000456/2010010-04	FIN	Evaluation of Operating Experience concerning Reactor Building Flashing (Section 4OA5.4)

LIST OF DOCUMENTS REVIEWED

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

Corrective Action Program Documents:

AR00318048; 2AF005H failed full open in MCR after Unit 2 trip
AR01101954; 2AF005H failed open after unit trip
AR01103188; No problem found during troubleshoot of 2AF005H failure to open
AR01103207; 2AF005H troubleshooting results and follow up
AR01065023; B train SX pump suction pressure issue
AR01094398; Bryozoa exceeds action level in 1B CW bay
AR01070346; 1A CW pump forebay inspection and cleaning
AR01092591; Bryozoa exceeds action level in 2B CW bay
AR01102204; Water discharged from vent line after U2 trip
AR01101901; Water pooled on top and sides of 233V transformer
AR00987252; Operator slips and falls from water on floor
AR00987196; Condensate reject water on turbine building floor
AR01102118; UFSAR change needed to support procedure change
AR01101980; SX transient during U1 RX trip
AR01098969; As found findings 1CW01PC forebay inspection
AR01102108; Inspect unit 2 Iso-Phase Bus Ducts
AR01101855; U-2 Main Generator Relay Actuations – Generator Trip
AR00092366; OPEX Review of NOAN PB-2002.01; ISOPHASE Bus Damper Failure;
AR00837434; Current 1C CB Pump Wear Rings Susceptible to SCC
AR01101926; 1C CB Pump Seal Failure Sprayed MCC 133Y1
AR01102254; Leak on 1B Condensate Booster Pump Inboard Seal
AR01102905; Found Condensate Booster Pump Impeller Wear Rings Broken
AR01103277; FME Failure of 1CB01PC
AR01104020; Low NPSH on CD/CB PPS Post U-2 Trip Due To Loss of Vacuum
AR01104135; Increased Vibration of 1CB01PB
AR01104462; MMD Found Damaged Impeller Wear Rings
AR00677337; Pre A1R13 MSSV Trevitest Results
AR00677963; Rebuild 1MS016D
AR01101893; Main Steam Safety 1MS016D Stuck Open
AR01102324; Unplanned Release of Unit-1 Steam /Tritium Condensing to Ground
AR00664657; 1AP58E Comp E1 Control Power Transformer Primary Fuse Blowing
AR00782761; 1AP21E Replace MCC 131X1 Control Power Fuse per EC 370955
AR00925143; Unusual Light Indication at 1PM06J
AR01102278; Unable to Energize Train A SVAG Valves on U-1
AR01103523; Statement In IR 925143 Determined to Be not Accurate
AR01103789; NOS IDs Issues with Post Transient Review
AR01101893; Main Steam Safety 1MS016D Stuck Open
AR01102713; Provide Alternate Power to 133V Substation
AR01102715; Provide Alternate Source of Power to 1CW08P
AR01102716; Isolate Input Power to 133V
AR01102195; 0WX362A Cooling Water to 0WS01PA Failed Closed

AR01101889; Sub Bus 133V CI
AR01101887; Sub 133V Trans C/I, Troubleshooting and Repair
AR01101858; Unit 1 Trip Due To Loss of Circulating Water
AR01102137; Sub 133V Trans Lighting Arrestor Testing
AR01102143; Indications of Insulator Flashover on Sub Trans 133V
AR01102135; Contingency Replacement of Substation Trans 133V
AR01101895; ACB1435VU Breaker PM
AR01101899; Perform 1AP07ER Cubicle PM
AR01103228; 4.0 Critique for Dual Unit Trip
AR01102032; Valve, 2CV121, Not Controlling Properly in Auto During Trip
AR01102706; Assessment of Dome Siding Damage and Addt'l Actions
AR01102694; Large Piece of Siding on 1A/1D MSIV Room Roof
AR01102153; Unit 1 Buttress Received Some Damage Following Trip
AR01102252; Sheet Metal on Middle Phase of U-1 MPT Output Lines

Logs and Computer Print Outs:

Station Event Recorder Unit 1 dated August 16-18, 2010
Station Event Recorder Unit 2 dated August 16-18, 2010
OP-AA-108-114; Post Transient Review for Unit 1 dated August 16, 2010
OP-AA-108-114; Post Transient Review for Unit 2 dated August 16, 2010
Operations Logs dated August 16, 2010
Operations Logs dated August 17, 2010
Operations Logs dated August 18, 2010
Operations Logs dated August 19, 2010
Simulator Data for 2 CW pump Trip Isolating 1B&1C Waterboxes; dated August 25, 2010
Simulator Data for 2 CW pump Trip Isolating 1A&1D Waterboxes; dated August 25, 2010

Drawings:

M-39; Diagram of Condensate System; August 5, 1976
3NC008; Spec L-2761 for 6" x 10" 1500# - 300# Safety Valve, Rev 12
M-2037, Sheet 1; Auxiliary Feedwater System; Revision P
M-828; Instrument Locations Elevation 365'-0' Auxiliary Building; October 18, 1978
20E-1-4030AN008; Schematic Diagram Annunciator Window Engraving 1UL-AN011, 012, 013 & 014 at 1PM06J; March 25, 1983
20E-1-4031AF02; Loop Schematic Diagram Auxiliary Feedwater Steam Generator 1A Flow Cont. System ESF-12 PNL 1PA34J; May 2, 1979
20E-1-4156A; Internal-External Wiring Diagram Annunciator Input Cabinet (ESF 12) 1PA32J Part 1; December 13, 1978
20E-1-4156C; Internal-External Wiring Diagram Annunciator Input Cabinet (ESF 12) 1PA32J Part 3; November 13, 1978
20E-0-4001; Station One Line Diagram; February 20, 1977
20E-4006C; Key Diagram 4160V Switchgear Bus 143 (1AP07E); July 12, 1976
20E-1-4007AC; Key Diagram 480V Turbine Building Substation Bus 133V (1AP72E); April 24, 1978
20E-1-4008CY; Key Diagram 480V Lake Screen House MCC 133U1 (1AP97E); February 15, 1977
A-2; North Elevation Units 1 & 2; December 21, 1976
A-365; Buttress & Walkway Sections and Details Units 1 & 2; February 7, 1977
Procedures:

BwAR 1-3-B7; AF pump discharge flow high; Revision 5
BwAR 1-2-A2; SX pump discharge header pressure low; Revision 7a
BwAR 1-17-A12; Condenser hotwell level high low; Revision 7BwAR 1-17-A12; Condenser hotwell level high low; Revision 10
BwAR 2-17-A12; Condenser hotwell level high low; Revision 11
ER-AA-340; GL89-13 program implementing procedure; Revision 6
ER-AA-340-1001; GL89-13 program implementation instructional guide; Revision 7
CY-BR-120-4130; Braidwood lake macrobiological strategic plan; Revision 1
OP-AA-106-101-1005; Quarantine of Areas, Equipment, and Records; Revision 7
BwMP 3300-091; Lake screen house diver related inspections; Revision 21
LS-AA-1120; Industry Groundwater Protection Initiative (GPI) Voluntary Communication; Section: Reportable Event RAS 1.34; Revision 12
CY-AP-120-2000; Secondary Strategic Water Chemistry Plan for Recirculating Steam Generator Plants; Revision 10
BwOP SI-100; Energizing and De-Energizing SVAG Valve MCCs and SI Accumulator Outlet Valves in Modes One Through Four, Revision 3
1BwEP ES-1.3; Transfer to Cold Leg Recirculation Unit 1, Revision 200
1BwOSR 5.5.8 SI-1B; Train B Safety Injection System Valve Stroke Surveillance, Revision 8
MA-AA-716-026; Station Housekeeping/Material Condition Program; Revision 9
OP-AA-108-114; Post Transient Review; Revision 5
OP-AA-108-108; Unit Restart Review; Revision 10
1BwOSR 3.7.5.1-2; Unit 1 Train B Auxiliary Feedwater Flowpath Verification; Revision 1
1BwOSR 3.7.5.5-2; Unit 1 Train B Auxiliary Feedwater Valve Emergency Actuation Signal Verification Test; Revision 3
OP-AA-103-012; Watch-Standing Practices; Revision 8
BwAR 1-17-A13; CW Pump Trip; Revision 19
BwAR 1-17-A13; CW Pump Trip; Revision 20
1BwOA SEC-3; Loss of Condenser Vacuum Unit 1; Revision 104
1BwEP-0; Reactor Trip or Safety Injection Unit 1; Revision 202
2BwGP 100-5; Plant Shutdown and Cooldown; Revision 36
1BwEP ES-0.1; Reactor Trip Response Unit 1; Revision 200
2BwEP ES-0.1; Reactor Trip Response Unit 2; Revision 200
BwOP AF-6; Motor Driven Auxiliary Feedwater Pump A Shutdown; Revision 13
BwOp AF-8; Auxiliary Feedwater Pump (Diesel) Shutdown; Revision 26
BwISR 3.3.4.2-202; Surveillance Calibration of Aux. Feedwater to S.G. _A. _B, _C, _D Flow Control Loop
LS-AA-120; Issue Identification and Screening Process; Revision 7
LS-AA-125; Corrective Action Program (CAP) Procedure; Revision 11
LS-AA-115-1001; Processing Significance Level 1 OPEX Evaluations; Revision 2
LS-AA-115-1002; Processing of Significance Level 2 OPEX Evaluations; Revision 0
LS-AA-115-1002; Processing of Significance Level 2 OPEX Evaluations; Revision 1
LS-AA-115-1002; Processing of Significance Level 2 OPEX Evaluations; Revision 2
LS-AA-115-1003; Processing of Significance Level 3 OPEX Evaluations; Revision 1
LS-AA-115-1004; Processing of NERs and NNOEs; Revision 1
OP-AA-108-115; Operability Determinations (CM-1); Revision 9
OP-AA-108-101; Control of Equipment and System Status
0BwOA ENV-1; Adverse Weather Conditions Unit 0; Revision 109
1BwOA ENV-1; Adverse Weather Conditions Unit 1; Revision 5
2BwOA ENV-1; Adverse Weather Conditions Unit 2; Revision 5
LS-AA-125-1001; Root Cause Investigation Charter for IR01101873; Revision 7; dated August 16, 2010

LS-AA-125-1001; Root Cause Investigation Charter for IR01101855; Revision 7; dated August 16, 2010
OP-AA-106-101-1006; Issue Resolution Documentation Form for IR1101954; Revision 7; dated August 21, 2010
AD-AA-101-F-01; Procedure Approval Form for BwAR 1-17-A13; dated August 26, 2010
OP-AA-108-108; Unit Restart Review for Unit 1; Revision 10; dated August 18, 2010
OP-AA-108-108; Unit Restart Review for Unit 2; Revision 10; dated August 19, 2010
OP-AA-106-101-1006; Issue Resolution Documentation Form for IR1101901; Revision 7; dated August 21, 2010
OP-BR-108-101-1002; Crew Review of Noteworthy Event; Revision 15; dated August 20, 2010
MA-AA-716-004; Complex Troubleshooting for IR1101858; Revision 10; dated August 18, 2010
MA-SS-716-004, Attachment 2; Complex Troubleshooting Data Sheet for IR 1101855, Revision 10

Engineering Documents:

EC381096; Condensate reject configuration change; August 19, 2010
EC373358; Bryozoan event technical evaluation supporting SX availability; January 20, 2009
EC376317; CW forebay inspection acceptance criteria for Bryozoa; August 5, 2009
EC Evaluation 381118; Lost Parts Evaluation, 1CB01PC Condensate Booster Pump Rotation Assembly Has Missing Pieces; Revision 0
EC Evaluation 370955; Evaluate A Larger Fuse Size for the Control Transformer Primary Circuit in MCC Cubicles with Size 3 Starters, June 3, 2008
BRW-03-0122-M; Evaluation of CST TS; November 24, 2003
E20-2-96-209-001; Extend AF header stand-pipes; January 27, 1998
M20-1-90-008; Loop seal/vent for AF pump suction line; May 2, 1991
Exempt Change No. E20-1-95-219; Braidwood Unit 1
Engineering Change Notice 000695S; Braidwood Unit 1
Standard Specification for Metal Siding Work Braidwood Station – Units 1and 2; April 19, 1976
Calculation No. 5.7.1.11; Replacement of Metal Siding Panels at the top of Unit 1 Containment Building; September 8, 1995
EC381134; Evaluate Unit 1 Containment Buttress Siding Repaired During A1F36; August 20, 2010

Other:

WO01362533-01; 2AF005H troubleshoot; August 17, 2010
WO00630201-01; 2FSV-AF005H troubleshoot and replace solenoid valve; June 20, 2006
WO01363546; 2AF005H troubleshooting results and follow up; August 20, 2010
WO01361122; U2 SX system flow balance surveillance; August 20, 2010
WO00388570; Bus Duct Damper Inspection; April 19, 2002
WO00446425; MM-1MP03YB, Replace Old Damper with New Damper During A1R10; September 20, 2002
WO00446426; MM-1MP03YA, Replace Old Damper with New Damper During A1R10; September 20, 2002
WO00446392; MM-1MP04YA, Replace Old Damper with New Damper During A1R10; September 20, 2002
WO00446393; MM-1MP04YB, Replace Old Damper with New Damper During A1R10; September 20, 2002
WO01042212; Remove 6 Inch Flange From Drain Pipe and Clean Strainers; June 27, 2007
WO01043040; 1CB01MC PM Clean and Inspect FW PP Suction Strainer; October 5, 2007

WO01067976; 1CB01MB PM Clean and Inspect FW PP Suction Strainer; October 5, 2007
WO01067977; 1CB06M PM Clean and Inspect S/U FW PP Suction Strainer; October 5, 2007
WO01089694; Replace S/U FW Pump Suction Strainer Internals; February 23, 2008
WO01089718; Inspect For and Replace CGI Gaskets; October 4, 2008
WO01138753; 2CB01MC PM Clean and Inspect FW PP Suction Strainer; March 17, 2009
WO01159484; 1CB01MA PM Clean and Inspect FW PP Suction Strainer; March 23, 2009
WO01159487; 2CB01MB PM Clean and Inspect FW PP Suction Strainer; March 21, 2009
WO01363958; Disassemble and Rebuild 1CB01PB; August 19, 2010
WO01066978; Rebuild 1MS016D; October 3, 2007
WO01362511; 1MS016D Remove/Send Valve Out For Rebuilding; August 16, 2010
WO01141645; 1AP21E-M2 –Replace MCC 131X1 Control Power Fuses Per EC 370955; August 18, 2010
WO01065217; 1F-AF012+32 AF to SG 1A Flow Calibration; August 16, 2010
WO00733932; 1AP72E C/I Unit Sub 133V XFMR; April 24, 2006
WO00795237; C/I Unit Sub 233V XMFR; October 23, 2006
WO01362581; Repair/Fix Flashing on U-1 Cont. Building; August 17, 2010
PM174016; SX system flow balance surveillance; June 11, 2010
Bryozoan monitoring monthly report; August 13, 2010
Bryozoan monitoring monthly report; July 24, 2010
Unit 1 Braidwood MSSV Rebuild History Spreadsheet, revised June 21, 2010
Braidwood Unit 1 – Proposed IST Testing Plan for MSSV's (Spreadsheet); Updated March 9, 2010
RETDAS Version 3.6.3; Gaseous Release and Dose Summary Report – By Unit Composite Critical Receptor – Limited Analysis); dated August 20, 2010
RETDAS Version 3.6.3; Gaseous Release and Dose Summary Report – By Unit Composite Critical Receptor – Limited Analysis); dated August 18, 2010
Braidwood Station Wind Direction Data; from Andy Lotz, Murray and Trettel; dated September 23, 2010
Apparent Cause Evaluation 00664657; 2AP58E Comp E1 Control Power Transformer Primary Fuses Blowing; February 11, 2008

NRC Identified Corrective Action Program Documents:

AR01106410; Evaluation process for forebay inspection results needs review
AR01106403; NRC ID'D unit 2 vent overflow not corrected in timely manner
AR01106401; NRC Identified Installation of Marginally Sized Fuses Not Replaced

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
AFW	Auxiliary Feedwater
AR	Action Request
BDPS	Boron Dilution Protection System
CAP	Corrective Action Program
CAQ	Condition Adverse to Quality
CCDP	Conditional Core Damage Probability
CD/CB	Condensate/Condensate Booster
CFR	Code of Federal Regulations
CNO	Chief Nuclear Officer
CR	Condition Report
CST	Condensate Storage Tank
CW	Circulating Water
EC	Engineering Change
ECCS	Emergency Core Cooling Systems
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
IEL	Initiating Event Likelihood
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
LCO	Limiting Condition for Operation
LERF	Large Early Release Frequency
LOCHS	Loss of Condenser Heat Sink
LOOP	Loss of Offsite Power
MCC	Motor Control Center
MSR	Main Steam Reheater
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
OE	Operating Experience
PARS	Publicly Available Records System
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
QATR	Quality assurance Topical Report
RCFC	Reactor Containment Fan Cooler
RHR	Residual Heat Removal System
SAT	Station Auxiliary Transformer
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection System
SIT	Special Inspection Team
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SRV	Safety Relief Valve
SSC	Structure, System or Component
SX	Essential Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report

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

August 18, 2010

MEMORANDUM TO: John A. Jandovitz, Project Engineer
Branch 5
Division of Reactor Projects

FROM: Steven West, Director ***/RA by G. Shear Acting for/***
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION CHARTER FOR BRAIDWOOD STATION DUAL UNIT REACTOR TRIPS ON AUGUST 16, 2010

On August 16, 2010, at 2:06 a.m. CDT the Unit 2 reactor tripped due to a main generator lockout relay actuation. Following the trip, one auxiliary feedwater flow control valve failed open. At this time the cause of the main generator lockout is unknown and under investigation.

Following the Unit 2 reactor trip, at 2:19 a.m. CDT, the Unit 1 A and C circulating water pumps tripped, which caused a Unit 1 automatic reactor trip on low condenser vacuum. Due to loss of the condenser, operators maintained Unit 1 temperature and pressure using steam generator power operated relief valves. Following the Unit 1 reactor trip, the 1D steam generator safety relief valve stuck partially open. The cause of the circulating water pump trips remains under investigation but appears to be related to water intrusion into a motor control center. The water appears to have come from an open-ended vent riser on the Unit 2 auxiliary feedwater suction piping.

The sequence of events and the cause of the problem are being investigated by the licensee. Based on the deterministic criteria provided in Management Directive 8.3, "NRC Incident Investigation Program, " the incident met MD 8.3 criterion f, "Involved significant unexpected system interactions." A Region III senior reactor analyst completed a SPAR model event assessment for each Unit. Unit 1 was modeled with a loss of condenser heat sink initiating event. Unit 2 was modeled with a transient initiating event and failure of auxiliary feedwater flow control valve 2AF005H. The assessment resulted in a preliminary Conditional Core Damage Probability (CCDP) value of approximately 1.2E-5 for Unit 1 and 3.1E-6 for Unit 2.

CONTACT: Richard Skokowski
630-829-9620

Accordingly, based on the deterministic and risk criteria in MD 8.3, and as provided in Regional Procedure 8.31, "Special Inspections at Licensed Facility," a Special Inspection Team will commence an inspection on August 17, 2010. The Special Inspection Team will be led by you and will include Meghan Thorpe-Kavanaugh, Reactor Engineer, Branch 3, Division of Reactor Projects; Néstor Féliz Adorno, Reactor Inspector, Engineering Branch 2, Division of Reactor Safety, and Tony Go, Health Physics Inspector, Division of Reactor Safety, supporting from the Regional office.

The special inspection will determine the sequence of events, and will evaluate the facts, circumstances, and the licensee's actions surrounding the August 16, 2010 incident. The specific charter for the Team is enclosed.

Enclosure:
As stated

Accordingly, based on the deterministic and risk criteria in MD 8.3, and as provided in Regional Procedure 8.31, "Special Inspections at Licensed Facility," a Special Inspection Team will commence an inspection on August 17, 2010. The Special Inspection Team will be led by you and will include Meghan Thorpe-Kavanaugh, Reactor Engineer, Branch 3, Division of Reactor Projects; Néstor Féliz Adorno, Reactor Inspector, Engineering Branch 2, Division of Reactor Safety, and Tony Go, Health Physics Inspector, Division of Reactor Safety, supporting from the Regional office.

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Enclosure: As stated

DISTRIBUTION W/ENCL:
See next page

Memo to J. Jandovitz from S. West dated August 18, 2010

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DATE	08/18/10		08/18/10		08/18/10			

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BRAIDWOOD SPECIAL INSPECTION CHARTER

This Special Inspection Team is chartered to assess the circumstances surrounding the dual unit reactor trips and subsequent equipment issues on August 16, 2010. The Special Inspection will be conducted in accordance with Inspection Procedure 93812, "Special Inspection," and will include, but not be limited to, the items listed below.

1. Identify the time-line for the event. Include relevant plant conditions, system line ups, and operator actions.

2. Review the licensee's post-trip review to determine the cause of the Unit 1 reactor trip and whether it was a manual or automatic reactor trip. Independently review plant data and records to confirm the adequacy of the licensee's assessment and planned corrective actions.

3. Review the licensee's post-trip review to determine the cause of the Unit 2 reactor trip. Independently review plant data and records to confirm the adequacy of the licensee's assessment and planned corrective actions.

4. Assess the operators' performance in responses to the August 16, 2010, events.

5. Review the circumstances surrounding major equipment problems associated with the August 16, 2010, event. Include in this review an assessment of the licensee's performance in addressing these issues. Consider cause determination, planned corrective actions, prior similar events, adequacy of past corrective actions if applicable, adequacy of the licensee's extent of condition review, and adequacy of past operability reviews if applicable. Review at least the following issues:

- Unit 2 main generator lockout relay actuation;
- Water intrusion into motor control center 133V;
- Unit 2 flow control valve (2AF005H) failed open;
- Unit 1 safety relief valve that did not remain fully seated following the reactor trip;
- Unit 1 'C' condensate/condensate booster pump seal failure;
- Unit 1 essential service water high differential pressure condition following the Unit 1 reactor trip:
- Unit 1 blown fuses identified while placing the unit on shutdown cooling.

6. Review the circumstances surrounding the water on the turbine building floor from the Unit 2 auxiliary feedwater suction vent riser. Include in this review an assessment of the licensee's performance in addressing these issues. Review at least the following:

a. Measures used to control the water when it is spilled onto the floor;
b. Any historical issues with water spilling from this and the Unit 1 vent;
c. Assess the adequacy of the auxiliary feedwater suction vent riser design.

7. Review the circumstances surrounding the Unit 1 reactor building flashing that was dislodged during the safety valve release. Include in this review the reason the flashing was dislodged, look into past similar events, and assess the impact of the falling flashing to the Unit 1 transformers. Include in this review an assessment of the licensee's performance in addressing these issues.

8. Review the licensee's dose calculations for the release of tritiated steam from the Unit 1 power operated relief valves and unseated safety relief valve.

Charter Approval

________***/RA/***_________________
Richard A. Skokowski, Chief
Branch 3
Division of Reactor Projects

___***/RA by G. Shear Acting for/***_____
Steven West, Director
Division of Reactor Projects

Timeline of Events for August 16, 2010 Dual Unit Reactor Trip

Prior to the start of events, both units are operating at full power with no major activities planned for either unit. It is the operating crew's last shift from the weekend before time off. The "1A" and "2B" essential service water pumps are running.

Unit 1 is in the process of preparing to perform the auxiliary flow loop calibration. As part of this calibration, the "B" train 1AF005E-H air-operated valves are failed open with air unavailable to them.

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02:06:13 Unit 2 receives six consecutive generator ground relay alarms (GIX-104) in a period of 5 seconds followed by a generator lockout relay trip. **(Unit 2, T=0)**

02:06:19 Unit 2 experiences a turbine trip. All rods insert, offsite power remains available, and no safety injection occurs.

02:06:19 The Unit 2 "2A" and "2B" auxiliary feedwater (AFW) pumps automatically start due to shrink effects on the steam generators.

02:06:20 The Unit 2 steam dumps open to control reactor coolant system temperature. This causes steam to be sent directly to the main condenser instead of through the turbine generator. As a result, the turbine exhaust hood sprays and steam dump sprays open inside main condenser to start condensing steam from steam dumps.

02:06:21 The Unit 2 "2B" and "2C" feedwater pumps automatically trip, steam generators are now being fed from AFW pumps.

02:06:29 The Unit 2 "2F" and "2H" AFW flow control valve (2AF005F/H) high flow alarms are received. These are air operated valves that control the supply water to the "2B" and "2D" steam generators from the "2B" AFW pump.

02:06:31 The "2F" AFW flow control valve high flow alarm resets, however the "2H" alarm remains in due to the 2AF005H valve failing open.

02:06(approx) The Unit 2 reactor operators enter 2BwEP-0, "Reactor Trip or Safety Injection Unit 2" procedure in response to the reactor trip and take immediate action steps including verify reactor trip, verify turbine trip, verify power to 4KV ESF buses, and check SI status.

02:08:29 The Unit 2 condensate emergency overflow valve opens. This valve opening causes approximately 12,000 gallons of water to be discharged from the two vent lines, spilling water on the 451' elevation of turbine building. **(Unit 1, T=0)**

02:09:28 Unit 2 reactor operators transition from 2BwEP-0 to 2BwEP-ES 0.1, "Reactor Trip Response Unit 2," due to no safety injection signal received.

02:11:45 The Unit 2 condensate emergency overflow valve closes, thus stopping the water discharge onto the 451' elevation of the turbine building. From operator eyewitness accounts, the water was approximately 1.5” to 2” deep running north/south almost from the Unit 2 moisture separator reheaters to the Unit 1 “1A” feedwater pump opening and east/west from outside the work execution center to the centerline of the turbine building.

02:11:46 Unit 1 receives three consecutive Bus 133V control power alarms over a period of 26 seconds. This is a symptom of water falling onto the 426’ elevation from the 451’ elevation. Water is traveling from holes for “1A” and “2A” FW pump suction valves handwheels and plate openings in turbine deck floor to the lower level.

02:14:30 Unit 1 Bus 133U and133V feed breaker, 1435VU, trips causing a loss of power to the associated buses. Numerous alarms are received regarding the loss of power to numerous secondary side components.

02:14:32 Unit 1 loses power to the lake screen house bus 133U1. This bus supplies power to the “1A” and “1C” circulating water (CW) pumps and their associated discharge valves.

02:14:44 Unit 1 “1A” and “1C” circulating water pumps trip. The “1B” circulating water pump remains running but the discharge valves for “1A” and “1C” do not close due to the loss of power. Operators are dispatched to locally close these valves.

02:14(approx) Unit 2 reactor operators take manual control of 2CV121 due to an observed pressurizer level deviation. Also at this time, the Unit 2 Unit Supervisor performs a turnover with the WEC SRO and then assumes the role as Shift Technical Advisor.

02:16:38 Unit 1 receives a condenser vacuum low alarm. Reactor operators take action to control condenser vacuum using 1BwOA SEC-3, “Loss of Condenser Vacuum.”

02:16:56 The Unit 1 standby “1C” condensate/condensate booster pump automatically starts due to net positive suction head low alarms on the feedwater pumps because Exhaust hood sprays and steam dump sprays actuated due to loss of power from Bus 133U, which reduces the water supply to the feedwater pumps.

02:17:00 Unit 1 receives steam generator flow mismatch steam flow alarms. Reactor operators initiate a turbine runback in accordance with 1BwOA SEC-3, decreasing power at rate of 250 Mwt/min, but condenser vacuum is still degrading.

02:17:02 Unit 1 receives T_{ave} control deviation high alarm, control rods automatically step in to compensate for temperature deviation.

02:17(approx) Unit 1 reactor operators recall a “what if” brief regarding loss of a circulating water pump and (without use of procedures) take manual action to isolate “1A” and “1D” waterboxes. Operators observed condenser vacuum degrading at increasing rate over that previously noted. In addition, about this time a reactor operator adds 100 gallons boric acid based on the reactivity management book to try to compensate for control rods stepping in as a response to the turbine runback. At this point, the Shift Manager orders a reactor trip.

02:19:17 Unit 1 receives a condenser vacuum low turbine trip followed by an automatic reactor trip from approximately 55.5 percent reactor power. All rods insert, offsite power remains available, no safety injection occurs.

02:19:18 Unit 1 receives steam generator pressure high alarms on all four steam generators. The C-9 permissive, which would normally open the steam dumps, is disabled due to loss of power to transformer 133V. Without steam dumps, steam generator pressure continues rising until the Unit 1 steam generator PORVs open to control pressure. PORVs remain open until pressure lowers to below setpoint of PORVs (approximately 20 minutes later PORVs close).

02:19:21 Manual Reactor Trip is initiated by operators.

02:19:31 Unit 1 “1B” feedwater pump automatically trips.

02:19:45 Unit 1 “1C” feedwater pump automatically trips.

02:19(approx) The Unit 1 reactor operators enter 1BwEP-0, “Reactor Trip or Safety Injection Unit 1” procedure in response to the reactor trip and take immediate action steps including verify reactor trip, verify turbine trip, verify power to 4KV ESF buses, and check SI status.

02:20(approx) The Unit 1 reactor Operators transition from 1BwEP-0 to 1BwEP-ES 0.1, “Reactor Trip Response Unit 1,” due to no safety injection signal received.

02:21:40 Unit 2 enters LCO 3.7.5, “AFW System,” Condition A due to 2AF005H failing open. In accordance with alarm response procedure BwAR 2-3-B7, “AF Pump Discharge Flow High,” operators determined cause of indicated high flow (2AF005H) and take manual action to control flow to 2D steam generator by throttling/closing the 2AF013H downstream motor-operated valve. Because of the throttling of the 2AF013H valve out of its normal position of open it couldn’t perform its ESF function and therefore entered LCO.

02:22:19 The Unit 2 “2H” AFW flow control valve high flow alarm resets because flow to the “2D” steam generator is being controlled using the 2AF013H.

02:23(approx) Unit 1 reactor operators take manual action to start the “1A” AFW pump. Reactor operators take this action because IMD is preparing to perform the AFW flow loop calibration on the “B” train and the 1AF005E-H air-operated valves are failed open with air unavailable to them. Operators take action to stop IMD from performing the calibration and take action to restore air to valves. If the “1B” AFW pump would get a demand to start on lo-lo steam generator level, with these valves failed open it would cause an additional transient, therefore to avoid the steam generators reaching the lo-lo level operators started the “1A” AFW pump.

02:25:51 Unit 1 “1B” AFW pump automatically starts due to shrink effects on the steam generators (steam generator lo-lo level alarm reached).

02:26:18 Unit 1 “1B” AFW pump alarm resets because the steam generator lo-lo level alarm clears as additional water is being fed to the steam generators.

02:29:47 Unit 1 receives a “1A” essential service water pump strainer differential pressure high alarm.

02:38:11 Unit 1 reactor operator starts the “1B” essential service water pump because discharge pressure on the “1A” pump was at the operability limit of 85psig.

02:39(approx) Unit 1 reactor operators take manual action to secure the “1B” AFW pump because pump is not needed.

02:41:44 Unit 1 receives the boron dilution system blocked alarm followed by the “spare” PN0904 alarm representing the VCT high level alarm. Based on these alarms, Unit 1 should have entered LCO 3.3.9, “Boron Dilution Protection System (BDPS),” Condition A and C due to both train of BDPS inoperable due to high volume control tank level. However, this TS LCO entry was missed by the reactor operators and a late entry condition was made for this condition at 05:46.

02:45:54 The Unit 2 reactor operators start performing 2BwOSR 3.1.1.1-1, “Unit 2 Shutdown Margin Daily Verification During Shutdown” Surveillance in accordance with 2BwEP-ES 0.1.

02:58:59 The Unit 2 reactor operators completed 2BwOSR 3.1.1.1-1.

03:00(approx) Unit 1 reactor operators are informed from the shift operations superintendent responding to the site that the unit is still releasing steam. Reactor operators had seen the PORVS close approximately 15 minutes earlier. Based on this new information, operators are sent to determine if a main steam safety valve is leaking steam. Reports back from field operators indicate that the MSSV 1MS016D valve is open.

A report is received from a field operator that the “1C” condensate booster pump seal has failed and is spraying water onto the 133Y1 motor control center. The operators take action to close the suction and discharge valves isolating the pump.

03:00:00 Unit 1 Enters LCO 3.7.1, “Main Steam Safety Valves (MSSVs),” Condition A, and LCO 3.6.3, “Containment Isolation Valves,” Condition C, for 1MS016D unexpectedly leaking causing steam release to environment and therefore being considered inoperable.

03:31:42 The Unit 2 reactor operators start the Unit 2 startup feedwater pump in accordance with 2BwEP-ES 0.1.

03:37:04 The Unit 2 reactor operators secure the “2B” AFW pump in accordance with BwOP AF-8, “Auxiliary Feedwater Pump B (Diesel) Shutdown.”

03:39:04 Unit 2 exits LCO 3.7.5 as 2AF013H is now open and in its required ESF position.

03:41:44 Based on the previous alarms for the boron dilution system received for the Unit 1, the unit enters LCO 3.0.3 due to not completing the required actions of LCO 3.3.9, Condition C, to verify the unborated water source isolation valves are closed, within one hour. This TS LCO entry was missed by the reactor operators and a late entry condition was made for this condition at 05:46.

03:45:41 The Unit 2 reactor operators secure the “2A” AFW pump in accordance with BwOP AF-6, “Motor Driven Auxiliary Feedwater Pump A Shutdown.”

03:49:42 The Unit 2 reactor operators transitioned from 2BwEP-ES 0.1 to 2BwGP 100-5, “Plant Shutdown and Cooldown” procedure.

04:03(approx) Operators close the Unit 1 “1A” circulating water pump discharge valve (1CW001A).

04:06(approx) The Unit 1 reactor operators take action to manually start to the Startup Feedwater pump and secure the 1A AFW pump.

04:31(approx) Operators close the Unit 1 “1C” circulating water pump discharge valve (1CW001C).

05:30(approx) During shift turnover control board walkdowns on Unit 1, the oncoming shift manager asked whether Unit 1 was in the LCO 3.3.9. The shift stated that this was not entered and the missed LCO was recognized and reactor operators took action to address the inoperability by opening the VCT divert valve (1CV112A) to lower VCT level below the alarm setpoint.

05:45:45 Unit 1 exits LCO 3.0.3 and LCO 3.3.9, Condition C due to 1B train of BDPS operable with VCT level below the 1B BPDS level alarm setpoint.

05:46:45 Unit 1 exits LCO 3.3.9, Condition A, due to VCT level being restored to less than the 1A BDPS high level alarm setpoint.

18:25(approx) Unit 1 enters LCO 3.5.2, “Emergency Core Cooling Systems (ECCS),” Condition A and B, and LCO 3.6.3, Condition A and E, for Train “A” SVAG valves not being able to be energized as valves are controlled by MCC 131x1 which is not able to be energized. (21:37:22 and 22:08:00 according to operator logs)

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20:00:00 Unit 1 exits LCO 3.7.1 and LCO 3.6.3 for 1MS016D, because the unit is no longer in the TS mode of applicability.

20:00:00 Unit 1 exits LCO 3.6.3 for train “A” SVAG valves because the unit is no longer in the TS mode of applicability. Also, Unit 1 exits LCO 3.5.2 for train “A” SVAG valves as control power fuse for MCC 131x1 has been replaced.

If you contest the violations or the significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies 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, D.C. 20555-0001; and the NRC Resident Inspector at the Braidwood Plant. In addition, if you disagree with the cross-cutting aspect of a 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 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/
Gary L. Shear, Acting Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000456/2010010; 05000457/2010010
w/Attachments:
1. Supplemental Information
2. Special Inspection Team Charter
3. Timeline of Events for August 16, 2010, Dual Unit Reactor Trip

cc w/encl: Distribution via ListServ

<u>See Previous Concurrences</u>
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Letter to M. Pacilio from G. Shear dated November 12, 2010.

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, NRC SPECIAL INSPECTION TEAM (SIT) REPORT 05000456/2010010; 05000457/2010010

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