August 8, 2007

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2007003 AND 05000455/2007003

Dear Mr. Crane:

On June 30, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 10, 2007, with Mr. Dave Hoots and other members of your staff.

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

This report documents five NRC-identified findings of very low safety significance (Green). All five findings involved violations of NRC requirements. In addition, three licensee-identified violations which were determined to be of very low safety significance are listed in this report. However, because of the very low safety significance of the violations and because they were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, 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 a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the Resident Inspector office at the Byron Station.

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Sincerely,

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

Docket Nos. 50-454; 50-455
License Nos. NPF-37; NPF-66

Enclosure: Inspection Report 05000454/2007003 and 05000455/2007003;
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Byron Station
Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing
Manager Licensing - Braidwood and Byron
Senior Counsel, Nuclear
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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Sincerely,

/RA/

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

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License Nos. NPF-37; NPF-66

Enclosure: Inspection Report 05000454/2007003 and 05000455/2007003;
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cc w/encl: Site Vice President - Byron Station
Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing
Manager Licensing - Braidwood and Byron
Senior Counsel, Nuclear
Document Control Desk - Licensing
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Illinois Emergency Management Agency
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Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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Letter to C. Crane from R. Skokowski dated August 8, 2007

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2007003; 05000455/2007003

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2007003 and 05000455/2007003
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL 61010
Dates:	March 1 through June 30, 2007
Inspectors:	B. Bartlett, Senior Resident Inspector R. Ng, Resident Inspector S. Sheldon, Acting Resident Inspector T. Bilik, Region III Reactor Inspector J. Cassidy, Health Physicist G. Hausman, Senior Engineering Inspector M. Holmberg, Region III Reactor Inspector R. Jones, Reactor Engineer D. Lords, Reactor Engineer D. Szwarc, Reactor Inspector C. Thompson, Illinois Emergency Management Agency
Approved by:	R. Skokowski, Chief Reactor Projects Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000454/2007003; 05000455/2007003; on 03/01/2007-06/30/2007; Byron Station, Units 1 and 2; Fire Protection, Inservice Inspection Activities, Operability Evaluations, and Refueling and Outage Activities.

This report covers a three-month period of baseline resident inspection and announced baseline inspections on Occupational Radiation Safety, Fire Protection (Triennial), Inservice Inspection (ISI) Activities and Temporary Instruction 2515/150 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles. These inspections were conducted by regional inspectors and the resident inspectors. Five Green findings, all of which were non-cited violations (NCVs), were identified. 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. 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. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified an NCV of Byron Station’s Operating License Condition 2.C.6 for the licensee’s failure to maintain a three-hour rated firewall in the control room heating, ventilation and air conditioning (HVAC) equipment room. Specifically, the walls between the upper cable spreading rooms and the control room HVAC equipment were not fireproofed to achieve a three-hour rating as required by the fire protection report and applicable plant drawings. The licensee entered this issue into its corrective action program for resolution and implemented compensatory measures that included hourly fire watches.

  This finding was more than minor because it was associated with the Initiating Events cornerstone attribute of “External Factor” related to fire and affected the cornerstone objective to limit the likelihood of fire that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding was of very low safety significance because there were no fire ignition source scenarios that would have caused the structural steel beams to weaken and the ceiling to collapse. (Section 1R05.1)

- Green. The inspectors identified an NCV of 10 CFR 50.55(a)(g)(4) for the licensee’s failure to perform a Magnetic Particle (MT) examination of the full required exam surface on a steam generator (SG) main feedwater nozzle weld (2RC01BA) in accordance with the American Society of Mechanical Engineers (ASME) Section XI Code. The examiners subsequently completed the MT examination of the required area and the issue was entered into the licensee’s corrective action program.

This finding was greater than minor significance because it was associated with the Initiating Events cornerstone attribute of “Equipment Performance,” and affected the cornerstone objective to limit those events (reactor coolant system barrier failure) which upset plant safety and challenge safety systems. Absent NRC intervention, the licensee would not have performed the full Code-required exam of the weld for an indefinite period of service which would have placed the reactor coolant pressure boundary at increased risk for undetected cracking, leakage, or component failure. This finding was of very low safety significance because a qualified examination was subsequently performed with no relevant indications detected. In particular, it did not result in the loss of function of the mitigating system. (Section 1R08.1)

- Green. The inspectors identified a finding of very low safety significance and associated NCV for the licensee’s failure to establish measures to assure that regulatory requirements and design basis were correctly translated into procedures as required by 10 CFR 50 Appendix B, Criterion III, Design Control.” Specifically, the procedures related to the reactor vessel head lift did not correctly reflect in a non-conservative direction the design lift height. As immediate corrective actions, the licensee implemented compensatory measures to lower reactor cavity water level during the head lift to ensure the actual airdrop distance was bounded by the analysis.

  It was more than minor because it involved the “Equipment Performance” attribute of the Initiating Events Cornerstone Objective. The finding was determined to be of very low safety significance because the licensee's subsequent calculations showed the lift height as specified in the procedure was acceptable due to the margin gained from the heavier head weight assumed in their analysis. Therefore, a head drop would not have resulted in a total loss of the core cooling safety function.

  This finding has a cross-cutting aspect in the area of Problem Identification and Resolution, operating experience, because the licensee failed to implement and institutionalize operating experience through changes to their procedures(P.2(b)). (Section 1R020)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” for failure to ensure that all testing necessary to demonstrate that the Unit 1 and 2 remote shutdown panels (RSPs) will perform satisfactorily in-service be identified and conducted. Specifically, the licensee failed to periodically test applicable (i.e., important to safety) components (e.g., control switches) on the RSPs to ensure the operability and functional performance of the RSP components and the operability of their associated systems as a whole. The licensee’s corrective actions were to immediately begin testing of the instrumentation and controls located at the RSP and to continue the testing in accordance with a schedule that would allow timely completion.

  The finding was more than minor because the finding was associated with the “Equipment Performance” attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was of very low safety significance because the finding did not represent an actual loss of the instrumentation indications and control functions at the RSP, since the 1B0A PRI-5 and 2B0A PRI-5 procedures' "Response Not Obtained" column provided an alternative shutdown capability method using local manual actions and the Fire Hazards Panel. (Section 1R05)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of Technical Specification 5.4.1 regarding procedure adherence. Specifically, the licensee failed to follow procedure when reinstalling a flood seal hatch. The seal, also served as a High Energy Line Break (HELB) barrier, was found to have been improperly reinstalled following maintenance.

  The finding was more than minor because it involved the attribute of "Procedure Adherence" and could have affected the functionality of containment isolation valves necessary to ensure isolation of the secondary side of the steam generators. As such, this finding affected the containment barrier cornerstone. The finding was of very low safety significance because the finding did not represent an actual loss of the Unit 1 Auxiliary Feedwater System Containment Isolation Valves. Subsequently, the licensee repaired the hatch to ensure a proper seal.

  This finding has a cross-cutting aspect in the area of human performance, work practices, because the licensee's supervisory oversight of planned work activities did not effectively ensure the protection of a safety system in a mild environment from the effects of a harsh environment (H.4(c)). (Section 1R015)

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

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power throughout the inspection period with minor exceptions. On May 13, 2007, the operators reduced power on the unit to about 89 percent to perform turbine control valve testing. The unit was returned to full power the next shift.

Unit 2 shut down for refueling outage B2R13 on the first day of the report period. The generator was placed in service on May 3, 2007, ending the refueling outage after 31 days. Following the refueling outage, the unit operated at or near full power with one exception. On May 23, 2007, power was reduced to 95 percent to swap operating feedwater pumps, and then the unit was returned to full power.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed the licensee's seasonal preparations for operation during the summer months. This was primarily accomplished by verifying that the licensee had completed the requirements for summer readiness as documented in Exelon Nuclear Procedure WC-AA-107, "Seasonal Readiness." The inspectors also reviewed the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS) and other design-bases documents to identify those components that were susceptible to degradation from high temperature during the summer months. The inspectors verified that the licensee had addressed these components in preparation for summer operation. In addition, the inspectors selected the following risk-significant support systems/areas for specific review:

- Unit 1 and Unit 2 Main Power Transformers; and
- Unit 1 and Unit 2 Essential Service Water Cooling Towers.

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors verified that minor issues identified by the licensee were entered into the licensee's corrective action program. This review constituted one sample of the inspection requirement for the readiness for extreme weather conditions.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04Q)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed four partial walkdown samples of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. The inspectors utilized the valve and electric breaker lineups and applicable system drawings to determine that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to determine that there were no obvious deficiencies. The inspectors used the information in the appropriate sections of the UFSAR and TS to determine the functional requirements of the systems.

The inspectors verified the alignment of the following:

- Unit 2 Train B Essential Service Water System (SX) while Unit 2 Train A SX was Out of Service (OOS);
- Unit 1 Train B Auxiliary Feedwater System (AFW) with the Train A AFW Containment Isolation Valves Inoperable;
- Unit 0 Train B SX Makeup Pump with the Train A SX Makeup Pump OOS; and
- Unit 1 Train B Containment Spray (CS) While Unit 1 Train A CS was OOS.

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Walkdowns

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of fire fighting equipment; the control of transient combustibles and ignition sources; and on the condition and operating status of installed fire barriers. The inspectors reviewed applicable portions of the Byron Station Fire Protection Report and selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events Report.

The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

The Byron Station Pre-Fire Plans, applicable for each area inspected, were used by the inspectors to determine approximate locations of firefighting equipment.

The inspectors completed seven inspection samples by examining the plant areas listed below to observe conditions related to fire protection:

- Fuel Handling Building Elevation 401' & 426' (Zone 12.1-0);
- Auxiliary Building General Area 383' (Zone 11.4-0);
- Upper Cable Spreading Room Area (Zone 3.3B-2);
- Unit 1 Auxiliary Building Landry Room (Zone 11.6C-0);
- Unit 2 Auxiliary Building General Area Elevation 346 (Zone 11.2-0);
- Unit 1 Division 11 Miscellaneous Electrical Equipment and Battery Room (Zone 5.6-1); and
- Unit 1 Division 12 Miscellaneous Electrical Equipment and Battery Room (Zone 5.4-1).

The inspectors reviewed selected issues documented in Issue Reports (IRs), to determine if they had been properly addressed in the licensee's corrective action program. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

Structural Steel Beam Missing Fire Proofing Materials

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated non-cited violation (NCV) of the Byron Operating License for the licensee's failure to fire proof structural steel beams to achieve a three-hour fire rating.

Description: On April 23, 2007, the inspectors performed a fire protection walkdown of the Unit 2 upper cable spreading room. The inspectors identified that a structural beam separating the upper cable spreading room and the neighboring control room heating, ventilation, and air conditioning (HVAC) equipment room was not fire proofed on the side of the HVAC equipment room. The beam was fireproofed inside of the upper cable spreading rooms. The inspectors confirmed that the same condition existed on Unit 1.

The inspectors determined that both the upper cable spreading room and the control room HVAC equipment room were three-hour fire rated barrier zones per Byron's Fire Protection Report. Drawing A810, Structural Steel Fireproofing Details, Revision Z, showed that the three-hour fire rating was achieved through fire proofing both sides of the structural beam. Based on visual inspection and later confirmed by the licensee, the inspectors determined that this condition existed since initial construction. The concern was that the heat generated by a fire in the control room HVAC equipment room could weaken the structural steel beam to the point that the supported ceiling might collapse and cause damage to the neighboring upper cable spreading room. This issue was entered into the licensee's corrective action program as IR 630782. The licensee implemented compensatory measures that included hourly fire watches. The licensee subsequently performed an extent of condition review and identified two other steel beams in the control room HVAC equipment rooms that lacked fireproofing material.

Analysis: The inspectors determined that the licensee's failure to fireproof the structural steel beams in the control room HVAC equipment room per the Fire Protection Report was a performance deficiency warranting a significance evaluation. The inspector concluded that the finding was greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening." Specifically, it was associated with the external factor attribute, related to a fire, of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations.

The inspectors determined that the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process," Appendix F, because it was associated with or involved impairment or degradation of a fire protection barrier. The inspectors performed Phase 2 of the Fire Protection SDP because the finding was associated with a high degradation of fire confinement since fireproofing material was not present to protect the steel beams from heat generated by a fire. Based on the walkdown by the inspectors and the licensee's evaluation, this finding was determined to be of very low safety significance (Green) because there were no fire ignition source scenarios that would have caused the structural steel beams to weaken to the point that the ceiling might collapse. Therefore, no potentially challenging fire scenarios existed. The inspectors determined there was no cross-cutting aspect to this finding.

Enforcement: Byron Station's Operating License Condition 2.C.6 states, in part, that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as in the licensee's Fire Protection Report. Section 2.3.18.7, Control Room HVAC Equipment Room, of the Fire Protection Report states, in part, that "All walls carry a three-hour fire rating..." Drawing A810, Revision Z, indicated both sides of the beams must be fireproofed to achieve a three-hour fire rating. Contrary to the above, since initial construction the structural steel beams in the control room HVAC equipment room were not fireproofed to a three-hour fire rating as required by the Byron Station's Fire Protection Report. Because this violation was of very low safety significance and because it was entered into the licensee's corrective action program, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC enforcement policy (NCV 05000454/2007003-01; 05000455/2007003-01).

.2 Triennial Fire Protection (71111.05T)

a. Inspection Scope

The inspectors performed a followup inspection of the licensee's activities associated with unresolved item (URI) 05000454/2004005-04(DRS); 05000455/2004005-04(DRS) regarding alternative shutdown capability using the remote shutdown panels (RSPs).

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program.

This review does not constitute an inspection sample.

b. Findings

Introduction: The inspectors identified a NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," having very low safety significance (Green) for the licensee's failure to ensure that all testing necessary to demonstrate that the Unit 1 and 2 RSPs would perform satisfactorily in-service be identified and conducted. Specifically, the licensee failed to periodically test applicable (i.e., important to safety) components (e.g., control switches) on the RSPs to ensure the operability and functional performance of the RSP components and the operability of their associated systems as a whole.

Description: During the 2004 Triennial Fire Protection Inspection, the inspectors opened an URI due to inspectors' questions regarding:

1) the implication that the RSPs were credited for safe shutdown in the licensing bases but could not be electrically isolated from the main control room (MCR) in the event of an Appendix R fire-related MCR evacuation; and

2) the licensee's failure to periodically test applicable (i.e., important to safety) components (e.g., control switches) on the RSPs.

Item 1: The inspectors observed, for an Appendix R fire-related MCR evacuation, that the discussion for alternative shutdown capability contained in NUREG-0876, "Safety Evaluation Report Related to the Operation of Byron Station, Units 1 and 2," Supplements No. 3, and No. 5, dated November 1983, and October 1984, respectively, Section 9.5.1, "Fire Protection Program," Paragraph 9.5.1.4, "General Plant Guidelines," stated the following:

> "Section 7.4.1 of the Final Safety Analysis Report (FSAR) describes the RSPs' design and capability. The design objective of the RSPs is to provide a central point to control and monitor plant shutdown independent of the control room in the event of an evacuation of the control room. The design of the panels includes the capability to electrically isolate the instrumentation indications and control functions for the shutdown systems from the control room."

Based on the licensee's post-fire safe shutdown analysis (SSA), for an Appendix R fire-related MCR evacuation, the licensee did not take credit for the use of the RSPs' instrumentation indications and control functions. The SSA credits local manual actions (e.g., local pump starts at the switchgear breakers and local valve operation) and use of the Fire Hazards Panel (FHP) for alternative shutdown capability. The licensee stated that this was due to the fact that the RSPs do not have and never did have complete electrical independence (i.e., isolation) from the MCR.

In addition, the licensee stated that Section 7.4.1 of the FSAR (subsequently the UFSAR) was intended to describe the function of the RSPs for non-fire related events, but apparently did not make this distinction clear as evident from the quote described in NUREG-0876, Supplements No. 3 and No. 5, identified above. The FSAR/UFSAR discussion was intended to show that the RSPs were provided with the necessary instrumentation and controls for prompt shutdown to hot standby and had the ability to maintain the plant in a safe condition from outside the MCR and take the plant to cold shutdown in accordance with 10 CFR Part 50, Appendix A, General Design Criteria (GDC) for Nuclear Power Plants, Criterion 19. The statements contained in NUREG-0876, Supplements No. 3 and No. 5, although correctly stated for GDC 19 compliance, inadvertently applied the discussion contained in Section 7.4.1 to the Appendix R alternative shutdown capability.

To resolve this historical discrepancy, the licensee issued IR 625349, "UFSAR Revision Required to Clarify the Use of RSPs," dated May 4, 2007, stating that a revision to UFSAR, Section 7.4 (Systems Required for Safe Shutdown) was required. The UFSAR revision was to clarify the electrical independence and capability of the RSPs and clearly state that this section only applied to non-fire conditions and GDC 19 compliance. In addition, the licensee stated that the UFSAR revision would include a reference to the fire protection report for a discussion of the RSPs for fire-related scenarios. No violations of NRC requirements associated with Item 1 were noted.

Item 2: The inspectors observed that Procedure 0B0A PRI-5, "Control Room Inaccessibility," Revision 101, would be used by the Shift Manager to determine if the MCR must be evacuated due to any condition that may render the MCR uninhabitable, such as, smoke or fire in the MCR, fire causing loss of MCR control functions, MCR Radiation monitors in alarm or a confirmed report of an airborne toxic substance at or in the vicinity of the station. Once the Shift Manager determined that a MCR evacuation was required, the Unit 1 Nuclear Station Operator (NSO) would be directed to initiate Procedure 1B0A PRI-5, "Control Room Inaccessibility Unit 1," Revision 106 and the Unit 2 NSO would be directed to initiate Procedure 2B0A PRI-5, "Control Room Inaccessibility Unit 2," Revision 109. The initiation of each procedure activates the unit's associated RSP. In addition, both procedures were written, such that an operator would utilize the RSP's instrumentation indications and control switches, to monitor and operate plant equipment to maintain the unit in a safe condition during hot shutdown and eventually take the plant to cold shutdown for any of the conditions requiring MCR evacuation.

For an Appendix R fire-related MCR evacuation, as discussed in Inspector Concern 1 above (i.e., the SSA credits local manual actions and use of the FHP for alternative shutdown capability), the design of the RSP may require the operator to taking the actions identified in the procedure's "Response Not Obtained" column due to the fire rendering the RSPs' instrumentation indications and control switches inoperative. However, the inspectors concluded that for a non-fire-related MCR evacuation, the operator would be able to utilize the RSPs' instrumentation indications and control switches without using the procedure's "Response Not Obtained" column, provided the applicable (i.e., important to safety) components (e.g., control switches) on the RSPs have been periodically tested to ensure the operability and functional performance of the RSP components and the operability of their associated systems as a whole.

As stated in the license's UFSAR, Section 7.4, initial testing of the RSPs instrumentation indications and control switches was demonstrated by Startup Test 2.63.35, "Shutdown from Outside the Control Room," dated March 26, 1985, during the station's pre-operational testing program. The UFSAR also stated that Startup Test 2.63.35 satisfied the requirements of Regulatory Guide 1.68.2 and that most of the required instrumentation and equipment to show compliance with GDC 19 were located on the RSPs. However, the inspectors determined that no subsequent periodic testing of the RSPs has been performed since the performance of the pre-operational tests. As a result of the inspector's review the licensee's corrective actions were to initiate testing of the instrumentation and controls located at the RSP.

<u>Analysis</u>: The inspectors determined that failure to periodically test applicable (i.e., important to safety) components (e.g., control switches) on the RSPs was a performance deficiency warranting a significance evaluation. The inspectors determined the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening" because the finding was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee did not ensure the operability and functional performance of the RSP components and the operability of their associated systems as a whole.

The inspectors evaluated the finding using IMC 0609, "Significance Determination Process," Appendix A, Phase 1 screening. The finding screened as Green because the inspectors answered no to all five questions in the Mitigation Systems Cornerstone Column. Specifically, the finding did not represent an actual loss of the instrumentation indications and control functions at the RSP, since the 1B0A PRI-5 and 2B0A PRI-5 procedures "Response Not Obtained" column provided an alternative shutdown capability method using local manual actions and the FHP. The inspectors determined there was no cross-cutting aspect to this finding.

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criteria XI, "Test Control," requires that a program be established to ensure that all testing necessary to demonstrate that structures, systems and components will perform satisfactorily in-service be identified and conducted.

General Design Criteria 19, requires that equipment at appropriate locations outside the MCR be provided: (1) with a design capability for prompt hot shutdown of the reactor, including the necessary instrumentation and controls to maintain the plant in a safe condition during hot shutdown and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

General Design Criteria 18, requires that electrical systems important to safety shall be designed to permit periodic inspection and testing of important areas and features. The systems shall be design with a capability to test periodically the operability and functional performance of the components of the systems and the operability of the systems as a whole.

Contrary to 10 CFR Part 50, Appendix B, Criteria XI, “Test Control,” from March 26, 1985, to June 25, 2004, the licensee’s test program failed to ensure that all testing necessary to demonstrate that the Unit 1 and 2 RSPs would perform satisfactorily in-service be identified and conducted. Specifically, the licensee failed to periodically test applicable (i.e., important to safety) components (e.g., control switches) on the RSPs to ensure the operability and functional performance of the RSP components and the operability of their associated systems as a whole. Because the finding was determined to be of very low safety significance, and because the licensee subsequently entered the finding into their corrective action program as IR 231542, “Consider Testing of RSP Switches,” dated June 25, 2004, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000454/2007003-02(DRS); 05000455/2007003-02(DRS)).

1R06 Flood Protection Measures (71111.06)

1. Internal Flooding Review

a. Inspection Scope

The inspectors evaluated the internal flooding controls for the following areas:

- Unit 1 and Unit 2 Auxiliary Feedwater Tunnels and Unit 1 and Unit 2 Main Steam Tunnels.

This review represented one inspection sample. Documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified during this inspection.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Piping Systems ISI

a. Inspection Scope

From April 7, 2006, through April 20, 2006, the inspectors conducted a review of the implementation of the licensee’s Risk-Informed Inservice Inspection Program (RI-ISI) for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. The inspectors selected the licensee's RI-ISI program components and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the on-site inspection period.

The inspectors observed the following three types of nondestructive examination (NDE) activities to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that the indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements.

- Ultrasonic Examination (UT) of pressurizer surge line weld (2R411A-14") J-08;
- Magnetic Particle Examination (MT) of main feedwater nozzle-to-vessel weld 2RC01BA; and
- Bare Metal Visual (BMV) Examination of vessel upper head penetrations (reviewed video/video home system (VHS) record).

The inspector reviewed examinations completed during the previous outage with relevant/recordable conditions/indications that were accepted for continued service to verify that the licensee's acceptance was in accordance with the Section XI of the ASME Code. Specifically, the inspector reviewed the following records:

- The inspectors reviewed MT records of a main steam integral welded attachment (E-2, FW501). During this examination, the licensee recorded a curvilinear indication that exceeded procedural limits (the indication was analyzed and found to be acceptable per ASME Code, Section XI).

- The inspectors reviewed dye penetrant examination (PT) records of a pressurizer integral welded attachment (PSL-1). During this examination, the licensee recorded a linear indication that was analyzed in accordance with ASME Code requirements prior to returning the Unit to service.

The inspectors reviewed visual examination (VT) records of a snubber (2RC01BA-2A). The examination documented that the snubber was leaking fluid. This indication was analyzed in accordance with Code requirements and found to be acceptable.

The inspectors reviewed pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage to determine if the welding acceptance and preservice examinations (e.g., VT, PT, and weld procedure qualification tensile tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed welds associated with the following work activities:

- Repair (welding) of ASME Class 2 seal weld for the 2C reactor coolant pump (RCP) seal water injection isolation check valve 2CV8368C.

- Repair (welding) of ASME Class 2 seal weld for (2A RCP) seal water injection isolation check valve 2CV8372A.

The inspectors observed welding activities associated with the structural weld overlays of the pressurizer dissimilar metal welds. Specifically the inspectors remotely observed the automated weld overlay process and ensured that the correct welding variable settings were being employed.

The documents reviewed during this inspection are listed in the Attachment to this report.

The above activities counted as one inspection sample.

b. Findings

Failure to Perform a MT Examination on the Full Exam Surface.

Introduction: Green. The inspectors identified an NCV of 10 CFR 50.55(a)(g)(4) for failure to perform a MT examination of the full exam surface on steam generator (SG) main feedwater nozzle weld 2RC01BA in accordance with ASME Section XI Code.

Description: On April 7, 2007, the inspectors identified through direct observation that a licensee contract NDE examiner was not performing a MT examination of the full required surface area of 2RC01BA. Specifically, the required MT exam surface of the SG feedwater nozzle to shell weld (2RC01BA, Code class 2) should have included the area from the toe of the weld to the tangent of the adjacent radius. However, the area covered was terminated into the radius but several inches short of the tangent.

The inspectors reviewed the Code drawing accompanying the procedure and recent operating experience regarding this type of exam, by a vendor NDE Level III during the pre-job briefing. The reviews indicated that the exam surface to be examined extended from the toe of the weld to the tangent of the radius which was a distance and resulting area substantially more than that which was being examined. The Code-required examination surface was subsequently examined and the issue was documented as a part of the licensee's corrective actions in IR 614558.

Analysis: The inspector determined that the failure to perform the MT examination of the full exam surface was a performance deficiency warranting a significance determination. The inspector concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," because the finding was associated with the Initiating Events cornerstone attribute of "Equipment Performance," and affected the cornerstone objective to limit those events (reactor coolant system (RCS) barrier failure) which upset plant safety and challenged safety systems. Absent NRC intervention, the licensee would not have performed the Code-required examination of weld 2RC01BA for an indefinite period of in-service operations which would have placed the reactor coolant pressure boundary at increased risk for undetected cracking, leakage, or component failure. The inspector was concerned that the failure to perform an examination of the complete examination surface could have allowed undetected cracks to remain in service.

The inspectors determined that this finding was of very low safety significance because the inspectors answered "No" to each of the Phase 1 screening questions from IMC 0609,"Significance Determination Process," Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." Specifically, a qualified reexamination was subsequently performed with no relevant indications detected. No cross-cutting aspects were identified with regard to this finding.

Enforcement

On April 7, 2007, the inspectors identified an NCV of 10 CFR 50.55(a)(g)(4), "Inservice Inspection Requirements."

Title 10 CFR 50.55a(g)4 requires, in part, that throughout the service life of a pressurized water-cooled nuclear power facility, components must meet the requirements set forth in the ASME Code Section XI.

ASME Code Section XI, Table IWC-2500-1, "Examination Categories," requires that surface examinations for Item No. C2.21, "Nozzle-to-Shell Weld," be examined in accordance with Figure IWC-2500-4(a).

Figure IWC-2500-4(a) indicates an exam surface "A - B," which extends around the circumference/weld from a point on the tangent of the radius beyond the toe of the weld (point "A") to a point ½ inch from the toe of the weld on the other side of the weld (point "B").

Contrary to the above, on April 7, 2007, while performing a MT examination using procedure EXE-ISI-70, on SG feedwater nozzle weld 2RC01BA, the licensee examiner failed to perform the MT examination of the full Code-required surface in accordance with ASME Section XI, Figure IWC-2500-4(a) in violation of 10 CFR 50.55(a)(g)(4).

Because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program as IR 00614558, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000455/2007003-03).

.2 Pressurized Water Reactor Vessel Upper Head Penetration Inspection Activities

Temporary Inspection 2515/TI-150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," Revision 3 was performed as described in Section 4OA5 of this report and counted as a sample for this activity.

a. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

From April 2, 2007, through April 13, 2007, the inspectors reviewed the BACC inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary.”

The inspectors conducted a direct observation of BACC visual examination activities to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements. Specifically, on April 2, 2007, following the unit shutdown, the inspectors reviewed a sample of BACC visual examination activities through direct observation. This walkdown was begun with the Unit in Mode 3 at full operating pressure and temperature. The inspectors observed the visual inspections to determine if locations where boric acid leaks can cause degradation of safety significant components were emphasized.

The inspectors also reviewed the visual examination procedures and examination records for the BACC examination to determine if degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed the engineering evaluations performed for the following corrective action documents to ensure that ASME Code wall thickness requirements were maintained:

- IR 585873; component 2S1052; Safety Injection Vent Valve Line; and
- IR 550000; component 1FC8762B; Fuel Pool Heat Exchanger Outlet Isolation Valve.

The inspectors also reviewed a number of boric acid leak corrective actions to determine if they were consistent with the requirements of the ASME code and 10 CFR Part 50, Appendix B, Criterion XVI. The documents reviewed during this inspection are listed in the Attachment to this report.

The above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.4 SG Tube Inspection Activities

a. Inspection Scope

From April 9, 2007, through April 20, 2007, the inspectors performed an on-site review of SG tube examination activities conducted pursuant to TS and the ASME Code Section XI requirements. The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documents related to the SG ISI program to determine if:

- in-situ SG tube pressure testing screening criteria and the methodologies used to derive these criteria were consistent with the Electric Power Research Institute (EPRI) TR-107620, “Steam Generator In-Situ Pressure Test Guidelines”;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee’s previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to identify tube degradation based on site and industry operating experience by confirming that the ET scope completed was consistent with the licensee’s procedures, plant TS requirements and EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6”;
- the licensee identified new tube degradation mechanisms;
- the SG tube ET examination scope included tube areas which represent ET challenges such as the tubesheet regions, expansion transitions, and support plates;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements;
- the required repair criteria are being adhered to;
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below the detection threshold during the previous operating cycle;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, “Performance Demonstration for Eddy Current Examination,” of EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines,” Revision 6;
- retrieval attempts of foreign objects were made where practicable. For those objects that were unable to be retrieved, evaluations were performed for the potential detrimental affects of the objects and appropriate repairs of the affected tubes were planned/taken; and
- the licensee identified deviations from ET data acquisition or analysis procedures.

The documents reviewed during this inspection are listed in the Attachment to this report.

The reviews, as discussed above, counted as one inspection sample.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the ISI/SG related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

The inspectors completed one inspection sample by observing and evaluating an operating crew during loss of vital alternating current (AC) power with a steam line rupture. The inspectors evaluated crew performance in the areas of:

- Clarity and formality of communications;
- Ability to take timely actions;
- Prioritization, interpretation, and verification of alarms;
- Procedure use;
- Control board manipulations;
- Supervisor's command and control;
- Management oversight; and
- Group dynamics.

The inspectors verified that the crew completed the critical tasks listed in the above simulator guide. The inspectors also compared simulator configurations with actual control board configurations. For any weaknesses identified, the inspectors observed the licensee evaluators to determine whether they also noted the issues and discussed them in the critique at the end of the session. The inspectors verified that minor issues were placed into the licensee's corrective action program.

The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors completed two inspection samples by evaluating the licensee’s implementation of the maintenance rule, 10 CFR 50.65, as it pertained to identified performance problems associated with the following structures, systems, and/or components:

- Testing of Remote Shutdown Panel Switches; and
- Unit 2 Startup Feedwater Pump Unavailable During the Refueling Outage.

The inspectors evaluated the licensee's handling of structures, systems, and components (SSC) condition problems in terms of work practices and characterization of reliability issues. Equipment problems were screened for review using a problem-oriented approach. Work practices related to the reliability of equipment maintenance were observed during the inspection period. Items chosen were risk significant and extent of condition was reviewed as applicable. Work practices were reviewed for contribution to potential degraded conditions of the affected SSCs. Related work activities were observed and corrective actions were discussed with licensee personnel. The licensee's handling of the issues being reviewed was evaluated under the requirements of the maintenance rule.

The inspectors also reviewed selected issues documented in IRs, to determine if they had been properly addressed in the licensee’s corrective action program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee’s management of plant risk during emergent maintenance activities or during activities where more than one significant system or train was unavailable. The inspectors chose activities based on their potential to increase the probability of an initiating event or impact the operation of safety-significant equipment. The inspectors verified that the evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and the work duration was minimized where practical. The inspectors also verified that contingency plans were in place where appropriate.

The inspectors reviewed configuration risk assessment records, UFSAR, TS, and Individual Plant Examination. The inspectors also observed operator turnovers, observed plan-of-the-day meetings, and reviewed other related documents to determine that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were being communicated to the necessary personnel.

The inspectors completed five inspection samples by reviewing the following activities:

- Unit 1 Degraded Grid Voltage Condition Emergent Risk;
- Unit 2 Containment Penetration P-64 Schedule Change Emergent Risk;
- Unit 1 Train A Diesel Generator Breaker Replacement while the Unit 0 Train B Essential Service Water Make-up Pump was OOS;
- Unit 2 Train A Containment Spray Pump OOS while Unit 2 Train A Residual Heat Removal Pump was OOS; and
- Unit 1 Train A Containment Spray OOS while Unit 1 Train Auxiliary Feedwater OOS, while Unit 1 Train A Component Cooling Water OOS, while Unit 1 Train A Station Air Compressor was OOS.

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated plant conditions, selected condition reports, engineering evaluations, and operability determinations for risk-significant components and systems in which operability issues were questioned. These conditions were evaluated to determine whether the operability of components was justified.

The inspectors completed four samples by reviewing the following evaluations and issues:

- Past Operability of Containment Isolation Valve 2-CC-9518;
- Unventable Voids in Containment Recirculation Sump Piping;
- Seismic Qualification of Wide Range Resistance Temperature Detectors; and
- Unsecured Flood Seal and High Energy Line Break (HELB) Barrier Hatches to the AFW Tunnel.

The inspectors compared the operability and design criteria in the appropriate section of the TS including the TS Basis, the Technical Requirements Manual (TRM) and UFSAR to the licensee's evaluations to determine that the components or systems were operable. The inspectors determined whether compensatory measures, if needed, were taken, and determined whether the evaluations were consistent with the requirements of licensee procedures. The inspectors also discussed the details of the evaluations with the shift managers and appropriate members of the licensee's engineering staff.

The inspectors also reviewed selected issues documented in IRs, to determine if they had been properly addressed in the licensee's corrective action program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

Introduction: A finding of very low safety significance (Green) and associated NCV of TS 5.4.1a was identified by the NRC inspectors. Specifically the inspectors identified that following maintenance that a flood seal hatch/High Energy Line Break barrier was not properly reinstalled.

Description: On March 19, the inspectors performed a routine verification that the Unit 1 AFW tunnel hatches had been properly reinstalled. The inspectors determined that hatch 1DSFS008 had not been properly reinstalled. The hatch was bent upwards along one corner resulting in a narrow opening of approximately 7 square inches. The inspectors questioned licensee personnel regarding the as-found condition of the hatch. The licensee initiated IR 605830, which stated that the flood seals were still able to protect the AFW isolation valves and that the AFW isolation valves could still perform their containment isolation function. However, this initial conclusion was based on engineering judgement, and a more detailed evaluation was needed to confirm operability. Therefore, an Unresolved Item (URI) 05000454/2007002-03 was opened pending receipt from the licensee and the inspectors' review of the detailed operability assessment of the flood seal and HELB barrier hatches to the AFW tunnel not being properly secured. Also, the licensee repaired the hatch to ensure a proper seal for the area.

The licensee performed several detailed analysis and calculations. The licensee determined:

- The original structural calculations were only performed for static loading due to the steam differential pressure and water height differential pressure. When the more appropriate dynamic calculation was performed the allowable stress was exceeded. After performing a finite element analysis of the hatch under dynamic loading the peak stress was re-calculated to be less than the allowable value.

- Due to the height of the valves above floor level and the relatively large volume contained within the AFW tunnel, the safety related motor operated valves (MOV) would not be submerged within the 20 minute mission time following a postulated steam line break, feedwater line break, or circulating water line break.

- While the safety-related motor operated valves in the AFW tunnel were not environmentally qualified for a harsh environment they were identical to MOVs designed for a harsh environment with the exception that they had motors with class B insulation instead of class H insulation. As the AFW MOV motors received appropriate preventive maintenance the licensee determined they would remain operable up to 266 °F and low pressure. Therefore, the valves would remain operable although the valves would not be qualified for the post-accident environment.

- The licensee's calculations determined that peak temperature following a postulated accident would be approximately 212°F at 34.4 psia.

Based upon the above, the licensee concluded that the as-found condition of the flood seal/HELB barrier did not challenge the operability of the safety-related MOVs.

The inspectors reviewed the licensee's calculations and with assistance from the Office of Nuclear Reactor Regulations performed an independent analysis. Although the licensee's results were slightly less conservative, the NRC inspectors' analysis agreed with the licensee's results. Therefore, the inspectors had no significant comments on the operability assessment.

Analysis: The inspectors determined that the failure to follow licensee procedures and properly reinstall a flood seal hatch/HELB barrier was a performance deficiency, warranting a significance evaluation. The inspectors concluded that the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on November 2, 2006. The finding involved the attribute of procedure adherence and could have affected containment isolation valves necessary to ensure isolation of the secondary side of the steam generators. As such, this finding affected the containment barrier cornerstone.

The inspectors utilized IMC 0609, "Significance Determination Process," Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated March 23, 2007, and determined that since the finding did not represent a degradation of the radiological barrier function provided for the control room, or auxiliary building, or spent fuel pool, did not represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere and did not represent an actual open pathway in the physical integrity of reactor containment, or involve an actual reduction in defense-in-depth for the atmospheric pressure control or hydrogen control functions of the reactor containment, this finding was of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of human performance, work practices, because the licensee's supervisory oversight of planned work activities did not effectively ensure the protection of a safety system in a mild environment from the effects of a harsh environment (H.4(c)).

Enforcement: Technical Specification 5.4.1 states that written procedures shall be established, implemented and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Section 9, "Procedures for Performing Maintenance," Subsection e requires "General procedures for the control of maintenance, repair..." Contrary to the above, on March 19, 2007, maintenance workers failed to follow work order 00695410, task 22 which required flood seal 1DSFS008 to be reinstalled. Because this violation was of very low safety significance and the issue was entered into the licensee's corrective action system (IR 606111), it was treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000454/2007003-04).

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post maintenance testing activities associated with maintenance or modification of mitigating, barrier integrity, and support systems that were identified as risk significant in the licensee's risk analysis. The inspectors reviewed these activities to determine that the post maintenance testing was performed adequately, demonstrated that the maintenance was successful, and that operability was restored. During this inspection activity, the inspectors interviewed maintenance and engineering department personnel and reviewed the completed post maintenance testing documentation. The inspectors used the appropriate sections of the TS, TRM, and UFSAR, and other related documents to evaluate this area.

The inspectors completed five inspection samples by observing and evaluating the post maintenance testing subsequent to the following maintenance activities:

- Unit 2 Train A Containment Spray Outside Containment Isolation Valve;
- Unit 2 Train B Residual Heat Removal Pump Work Windows;
- Unit 2 Pressurizer Heater Relay Calibration;
- Unit 0 Essential Service Water Cooling Tower Fan 0SX163E Testing; and
- Unit 1 Containment Spray Valve Strokes Following Routine Maintenance.

The inspectors also reviewed selected issues documented in IRs to determine if they had been properly addressed in the licensee's corrective action program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during Refueling Outage B2R13 beginning April 1, 2007. The licensee placed the main generator back in service on May 3, 2007. One inspection sample was completed for this report.

The inspectors evaluated the licensee's conduct of refueling outage activities to assess the licensee's control of plant configuration and management of shutdown risk. The inspectors reviewed configuration management to verify that the licensee maintained defense-in-depth commensurate with the shutdown risk plan; reviewed major outage work activities to ensure that correct system lineups were maintained for key mitigating systems; and observed refueling activities to verify that fuel handling operations were performed in accordance with the TS, TRM, UFSAR and approved procedures. The inspectors interviewed operations, engineering, work control, radiological protection, and maintenance department personnel during their inspection activities. The inspectors also attended outage-related status and pre-job briefings as well as Radiation Protection ALARA [As Low As Reasonably Achievable] briefings. Other major outage activities evaluated during this inspection period included evaluating the licensee's control of:

- containment penetrations in accordance with the TS;
- structures, systems or components (SSCs) which could cause unexpected reactivity changes;
- flow paths, configurations, and alternate means for reactor coolant system inventory addition;
- SSCs which could cause a loss of inventory;
- reactor coolant system pressure, level, and temperature instrumentation;
- spent fuel pool cooling during and after core offload;
- switchyard activities and the configuration of electrical power systems in accordance with the TS and shutdown risk plan.
- SSCs required for decay heat removal; and
- movement of the reactor head package.

The inspectors observed portions of the plant startup, including the approach to criticality and power ascension, to verify that the licensee controlled the plant startup in accordance with the TS and established procedures. In addition, the inspectors completed numerous visual inspections inside the Unit 2 containment. The inspection included a tour of the Unit 2 containment shortly after plant shutdown to verify that there were no previously unidentified reactor coolant system leakage. The inspector also walkdown containment at Mode 4 before plant startup to assess the material condition of equipment inside containment before containment closure. During the visual inspections the inspectors focused on the material condition of the equipment and housekeeping.

In addition, the inspectors evaluated portions of the restart preparation activities to verify that requirements of the TS and administrative procedure requirements were met prior to changing operational modes or plant configurations. Major restart inspection activities performed included:

- Inspection of the containment building to assess material condition and search for loose debris, which if present, could be transported to the containment recirculation sumps and cause restriction of flow to the emergency core cooling system pump suctions during loss-of-coolant accident conditions.

- Inspection of the licensee’s approach to initial criticality, initial criticality, core reload physics testing, and turbine generator rolling and tie into the off-site grid.

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and associated NCV for a failure to establish measures to assure that regulatory requirements and the design basis were correctly translated into procedures as required by 10 CFR 50 Appendix B Criterion III. Specifically, the procedures related to the reactor vessel head lift did not correctly reflect in a non conservative direction the design lift height.

Description: Due to recent problems identified at other stations associated with the adequacy of licensees' reactor vessel head drop analysis, the inspectors compared the licensee's head drop analysis to the applicable procedures to ensure that the procedures appropriately reflect the design basis as determined by the analysis. The licensee had not provided a load drop analysis for the containment polar crane but had referenced Westinghouse Topical Report WCAP 9198 dated January 23, 1978, as applicable. The WCAP accident analysis included the consequences of a reactor vessel head drop through air from a height of 14 feet. This condition did not bound the 18 feet head lift condition which was specified in the licensee's Procedure BMP 3118-1, Revision 23. Particularly, Step 4.8.20 directed lifting the vessel head above 18 feet high grade studs using the containment polar crane. The inspectors, concluded that the licensee failed to correctly translate these design basis analysis information into their procedure.

On Saturday, April 28, 2007, the licensee performed a Unit 2 Reactor Vessel Head Lift in accordance with Procedure BMP 3118-1, Revision 23, lifting the vessel head above 18 feet high grade studs using the containment polar crane. Based on the inspectors' identification of the disagreement between the analysis and the procedure, the licensee took compensatory actions to lower reactor cavity water level during the head lift to ensure the actual airdrop distance was bounded by the analysis. Prior to the lift, these compensatory actions were discussed with the Region III and the Office Nuclear Reactor Regulation (NRR) management. These compensatory measures were found to be appropriate for this one-time head lift. However, re-analysis of the reactor vessel head drop analysis would need to be preformed by the licensee prior to future head lifts. The lift on April 28, 2007,was safety completed. As additional corrective actions, the licensee performed subsequent calculations that showed the actual lift height specified in the procedure was acceptable due to margin gained from the heavier load weight assumed in the original analysis.

Analysis: The inspectors determined that the licensee's failure to properly reflect into operating procedures the reactor vessel head lift height, as determined by the licensee's analysis was a performance deficiency, warranting a significance evaluation. The inspectors concluded that the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on November 2, 2006. The finding involved the attribute of equipment performance and could have affected the Initiating Events Cornerstone Objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was determined to be of very low safety significance (Green) because the licensee's subsequent calculations showed the lift height as specified in the procedure was acceptable due to the margin gained from the heavier head weight assumed in their analysis. Therefore, a head drop would not have resulted in a total loss of the core cooling safety function.

This finding has a cross-cutting aspect in the area of Problem Identification and Resolution, operating experience, because the licensee failed to implement and institutionalize operating experience through changes to their procedures (P.2(b)).

Enforcement: Appendix B of 10 CFR 50, Criterion III, requires that a licensee establish measures to assure that regulatory requirements and the design basis were correctly translated into procedures. Contrary to the above, on or before April 28, 2007, the licensee failed to correctly translate into procedures in a conservative direction the reactor vessel head lift height. Because this violation was determined to be of very low safety significance and it was entered into the licensee's corrective action program (IR 623891), it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000455/2007003-05)

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed selected surveillance tests and/or reviewed test data to determine that the equipment tested using the surveillance procedures met the TS, the TRM, the UFSAR and licensee procedural requirements. The inspectors also reviewed applicable design documents including plant drawings, to verify that the surveillance tests demonstrated that the equipment was capable of performing its intended safety functions. The activities were selected based on their importance in ensuring mitigating systems capability and barrier integrity.

These activities represented one inservice testing activity of a containment isolation valve and six routine samples. The following surveillance tests were selected:

- Unit 2 Train A Emergency Diesel Generator Sequencer Test;
- Unit 2 Containment Isolation Valve 2-CC-9518 Local Leak Rate Test;
- Unit 2 Safety Injection System Cold Leg Flow Balance;
- Unit 2 Rod Drop Timing Test;
- Unit 1 Train B AFW Diesel Battery Charger 1AF01EB Test;
- Unit 2 Train B Solid State Protection System Bi-Monthly Surveillance; and
- Unit 2 Undervoltage Simulated Start of Train A Auxiliary Feedwater Pump.

Additionally the inspectors used the documents listed in the Attachment to this report to determine that the testing met the frequency requirements; that the tests were conducted in accordance with procedures, that the test acceptance criteria were met; and that the results of the tests were properly reviewed and recorded. The inspectors verified that the individuals performing the tests were qualified to perform the test in accordance with the licensee's requirements, and that the test equipment used during the test were calibrated within the specified periodicity. In addition, the inspectors interviewed operations, maintenance, and engineering department personnel regarding the tests and test results. Also, the inspectors verified that minor issues identified during this inspection were entered into the licensee's corrective action program.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors completed one inspection sample by evaluating the following temporary plant modification on risk significant equipment:

- Temporary Sump Pumps and Connection to Essential Service Return Header

The inspectors reviewed this temporary plant modification to determine that the instructions were consistent with applicable design modification documents and that the modification did not adversely impact system operability or availability. The inspectors verified that the licensee controlled temporary modifications in accordance with Nuclear Station Procedure NSP CC-AA-112, "Temporary Configuration Changes," Revision 11.

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors verified that minor issues identified during this inspection were entered into the licensee's corrective action program.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Drill Evaluation (71114.07)

a. Inspection Scope

The inspectors observed licensee performance during one site emergency preparedness drill in the Technical Support Center. This drill was in conjunction with a Force-on-Force inspection documented in Inspection Report 05000454/2007201 and 05000455/2007201. The inspectors observed communications, event classification, and event notification activities by the simulated shift manager. The inspectors also observed portions of the post drill critique to determine whether their observations were also identified by the licensee's evaluators. The inspectors verified that minor issues identified during this inspection were entered into the licensee's corrective action program. The inspectors completed one inspection sample.

The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (IP 71121.01)

.1 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed jobs being performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) that present the greatest radiological risk to workers. The inspectors reviewed radiological job requirements outlined in the Radiation Work Permit (RWP), work procedure, and RWP job briefings. The inspectors observed job performance with respect to these requirements. The inspectors evaluated whether radiological conditions in the work area were adequately communicated to workers through briefings and postings.

The inspectors reviewed the adequacy of radiological controls, radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls during these job performance observations.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel for high radiation work areas with significant dose rate gradients (factor of 5 or more).

The documents reviewed during this inspection are listed in the Attachment to this report.

These reviews represented three samples.

b. Findings

No findings of significance were identified.

.2 High Risk Significant, High Dose Rate High Radiation Area (>25 rem in one hour @30 cm) and Very High Radiation Area Controls.

a. Inspection Scope

The inspectors discussed High Dose Rate - High Radiation Area (HDR-HRA) and Very High Radiation Area (VHRA) controls and procedures with the Radiation Protection

Manager (RPM). The discussion focused on changes to licensee procedures to assess that the changes did not substantially reduce the effectiveness and level of worker protection.

The documents reviewed during this inspection are listed in the Attachment to this report.

This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Radiation Worker Performance

a. Inspection Scope

The inspectors observed radiation worker performance with respect to stated radiation protection work requirements. The inspectors assessed whether workers were aware of the significant radiological conditions in their workplace, the RWP controls/limits in place, and that their performance considered the level of radiological hazards present.

The inspectors reviewed radiological problem reports since the last inspection in which the cause of the event was due to radiation worker errors. The inspectors assessed whether there was an observable pattern traceable to a similar cause. The inspectors reviewed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed any problems with the correction actions planned or taken with the RPM.

The documents reviewed during this inspection are listed in the Attachment to this report.

These reviews represented two samples.

b. Findings

No findings of significance were identified.

.4 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed radiation protection technician performance with respect to radiation protection work requirements. The inspectors assessed technician awareness of the radiological conditions in their workplace and the RWP controls/limits and whether their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed radiological problem reports since the last inspection in which the cause of the event was radiation protection technician error. The inspectors assessed if there was an observable pattern traceable to a similar cause. The inspectors reviewed if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed any problems with the correction actions planned or taken with the RPM.

The documents reviewed during this inspection are listed in the Attachment to this report.

These reviews represented two samples.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable Planning and Controls (ALARA) (IP 71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed site specific procedures associated with maintaining occupational exposures ALARA, including a review of processes used to estimate and track work activity specific exposures. This review represented one sample.

The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolutions

a. Inspection Scope

The inspectors reviewed the licensee’s self-assessments, audits, and Special Reports related to the ALARA program since the last inspection. The inspectors assessed whether the scope and frequency of the licensee’s audit program (for all applicable areas under the Occupational Cornerstone) met the requirements of 10 CFR 20.110(c).

The inspectors review placed emphasis on ensuring problems are identified, characterized, prioritized, entered into a corrective action, and resolved. For repetitive deficiencies or significant individual deficiencies in problem identification and resolution identified above, the inspectors evaluated if the licensee’s self-assessment activities were also identifying and addressing these deficiencies.

The documents reviewed during this inspection are listed in the Attachment to this report.

These reviews represented two samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstone: Initiating Events, Barrier Integrity, Emergency Preparedness

.1 Initiating Events and Barrier Integrity Performance Indicators

a. Inspection Scope

The inspectors sampled the licensee's submitted materials for performance indicators (PIs) and periods listed below. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following four PIs for Unit 1 and Unit 2, for a total of eight samples, were reviewed:

- Unit 1 Unplanned Scrams per 7000 Critical Hours (January 2005 to March 2007);
- Unit 2 Unplanned Scrams per 7000 Critical Hours (January 2005 to March 2007);
- Unit 1 Scrams with Loss of Normal Heat Removal (January 2005 to March 2007);
- Unit 2 Scrams with Loss of Normal Heat Removal (January 2005 to March 2007);
- Unit 1 Unplanned Transients per 7000 Critical Hours (January 2005 to March 2007);
- Unit 2 Unplanned Transients per 7000 Critical Hours (January 2005 to March 2007);
- Unit 1 Reactor Coolant System Specific Activity (January 2005 to March 2007); and
- Unit 2 Reactor Coolant System Specific Activity (January 2005 to March 2007)

The inspectors reviewed selected applicable condition reports and data from logs, licensee event reports, and work orders from January 2005 through March 2007 for each PI area specified above. The inspectors independently reperformed calculations where applicable. The inspectors compared that information with the performance indicator definitions in the guideline to ensure that the licensee reported the data accurately.

For the reactor coolant system specific activity PI, the inspectors reviewed the licensee's Chemistry Department records and selected isotopic analyses to verify that the greatest Dose Equivalent Iodine value obtained during those months corresponded with the value reported to the NRC. The inspectors also reviewed selected dose equivalent iodine calculations to verify that appropriate conversion factors were used in the assessment as required by TSs.

The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed screening of all items entered into the licensee's corrective action program. This was accomplished by reviewing the description of each new IR and attending selected daily management review committee meetings. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up Review

a. Inspection Scope

During this quarter, the inspectors performed a routine follow-up to a licensee IR regarding a minor discrepancy between the four Refueling Water Storage Tank (RWST) level indicators. This included a visual inspection walkdown of the equipment, discussions with the applicable licensee's engineering staff, and a review of associated doucmentation

The documents reviewed during this inspection are listed in the Attachment to this report.

This review represented one inspection sample.

b. Assessment and Observations

While Unit 2 was in a refueling outage, instrument and controls personnel were performing a routine surveillance on each of the four RWST level transmitters. Licensee personnel observed that following the surveillance, 2-LT-0930 did not return to its original as-found value. The difference was very small, nonetheless, the licensee began looking for the source of the difference. On April 21, 2007, the licensee performed an inspection (boroscope) of the sensing line to the transmitter and found some water and dirt-like particles on the horizontal section of tubing. Maintenance personnel cut the tubing and removed the water and particles. The material was later analyzed in the laboratory and found to be consistent with the Type 304 Stainless Steel material of the tubes.

The inspectors discussed the licensee's findings with engineering personnel and determined that a section of line to 2-LT-0930 had an improper slope and could trap material. A proper slope would have the line slope towards a drain so that if any moisture accumulated it would not be trapped and would not press up against the differential pressure transmitter. Licensee personnel also stated that previously (more than 20 years ago) the sensing lines to the four RWST level transmitters had been subject to water intrusion when the tank was at a very high level. A modification had corrected the design issue but some water had apparently been left in the line. During the surveillance activity the line had been disturbed enough that the water and debris had shifted causing blockage in the line to the upper portion of the RWST.

The inspectors questioned the licensee regarding other possible locations in the RWST level sensing lines that could have similar vulnerabilities since all the instruments shared a common upper level tap. The licensee's position was that this was the only transmitter impacted because it was the only one that had a shift during the surveillance. The inspectors noted that the identified water and debris had remained unnoticed in the line to 2-LT-0930 for many years before it had adversely affected the transmitter. Therefore, if other sensing lines had an improper slope, trapped water could unexpectedly cause a negative affect on the accuracy of the RWST level transmitters. After some discussion, licensee personnel stated that they would examine the sensing lines to the other three level transmitters on Unit 2.

After inspecting the remaining Unit 2 sensing lines, the licensing initially determined that the sensing lines to the other three transmitters were properly sloped. The inspectors, who have previously inspected the Unit 2 and the Unit 1 RWST level sensing lines noted two locations on the Unit 2 sensing lines were improperly sloped. Subsequently, the licensee performed additional inspections and removed more water from the sensing lines to one other RWST level transmitter. The water in the line had not caused blockage of the transmitter. The licensee performed UT measurements of other portions of RWST sensing lines in Unit 1 and Unit 2 and did not identify any other adverse amounts of water. No violations of NRC requirements were identified.

.3 Semiannual Review to Identify Trends

a. Inspection Scope

The inspectors performed a review of the licensee's Corrective Action Program (CAP) and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment and corrective maintenance issues with additional insights from the daily inspector CAP item screening discussed in Section 4OA2.1. The review also included issues documented outside of the normal CAP including focus area self-assessments, corrective maintenance backlog reports, common cause analysis reports, component status reports, and maintenance rule assessments. The inspectors' review nominally considered the six-month period of January 2007 through June 2007, although examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in the licensee's mechanisms for identifying and correcting trends.

The review was accomplished by grouping IRs into broad categories during the daily screenings. These groups included, but were not limited to, items involving the same issue, same equipment/components, or the same program. This activity completed one sample.

b. Findings

No findings of significance were identified.

4OA3 Event Followup

(Open) Licensee Event Report (LER) 455/2007-001 "Reactor Pressure Vessel Head Control Rod Drive Mechanism [CRDM] Penetration Nozzle Weld Indication Due to an Initial Construction Weld Defect Allowing the Initiation of Primary Water Stress Corrosion Cracking"

On April 9, 2007, the licensee was performing volumetric examination of the Unit 2 CRDM penetration nozzle 68 when an UT indication was identified. This condition was reportable as a condition that resulted in a principal safety barrier being seriously degraded. Pending additional data from the licensee and subsequent NRC review, this LER will remain open. See additional discussion in Section 4OA5 below.

4OA5 Other Activities

.1 Pressurized Water Reactor Containment Sump Blockage (Temporary Instruction (TI) 2515/166)

a. Inspection Scope

The purpose of this TI was to support Nuclear Regulatory Commission review of licensee's activities in response to NRC Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors (PWRs)." This TI required NRC inspectors to verify actions implemented in response to NRC Generic Letter (GL) were complete and where applicable were programmatically controlled.

The inspectors performed a review in accordance with TI 2515/166 of the licensee's response to GL 2004-02 for Unit 1. The inspectors also reviewed changes to the licensee's facility and verified they were evaluated in accordance with 10 CFR Part 50.59. The licensee had received permission to deviate from the schedule in GL 2004-02 for Unit 1 regarding the downstream effects portion of their modifications.

Thus, the downstream effects modification was not implemented during the 2007 Unit 1 Refueling Outage.

The inspectors reviewed the licensee's modification packages, attended planning meetings, observed training activities in a recirculation sump mockup, and reviewed regulatory submittals as part of their preparation activities before the Unit 2 refueling outage. During the refueling outage the inspectors periodically observed work activities focusing on the critical attributes selected by the inspectors. For example, the inspectors compared trash racks, sump screens, and supports to installation drawings. In addition, the inspectors closely observed Foreign Material Exclusion program and practices to ensure foreign material was not left inside of the new sump screens.

The documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program.

b. Evaluation of Inspection Requirements

The TI requested the inspectors to include answers to the following questions in this inspection report.

(1) Did the licensee implement the plant modifications and procedure changes committed to in their GL 2004-02 responses?

The licensee did implement the plant modifications and procedure changes committed to in their GL 2004-02 responses. No additional inspections are required to verify that GL 2004-02 was implemented for Unit 2. All actions were completed prior to restart of Unit 2 following refueling outage B2R13, May 2007. The inspectors:

- verified that the Design Attributes Review document that is a part of the configuration Change Procedure was revised to incorporate a requirement for reviewing the impact of a proposed change of the documentation that forms the design basis for the response to GL 2004-02;

- observed the installation of the new recirculation sump screens and verified selected critical attributes were installed in accordance with plant drawings;

- assessed the procedures for the licensee's closeout of containment and independently performed a closeout inspection of containment as required by NRC inspection procedure 71111.20;

- verified that no loose debris was present near the screen doors between the area inside of the missile barrier and the area outside of the missile barrier;

- verified that an action tracking assignment to write a predefined activity had been added to the licensee's computerized tracking program to perform latent debris measurements on a frequency of every four refueling outages;

- verified that selected installed labels and tags were in compliance with the licensee's design basis during the containment closeout inspections; and

- verified that procedure changes made necessary by the installation of the new recirculation sump screens were implemented and required training was given to the plant operators.

(2) Has the licensee updated its licensing bases to reflect the corrective actions taken in response to GL 2004-02?

The inspectors reviewed the completed 10 CFR Part 50.59 assessments performed by the licensee and verified that the documents contained updates to the UFSAR to be submitted to the NRC at the next regular update.

The licensee had received permission to deviate from the schedule in GL 2004-02 for Unit 1 regarding the downstream effects portion of their modifications. All other modifications have been completed and the review of these modifications was documented in Integrated Inspection Report 05000454/2007003; 05000455/2007003.

.2 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles TI 2515/150, Revision 3)

a. From April 9, 2007, through April 20, 2007, the inspectors performed TI 2515/150. The objective of this TI is to support the review of the licensee's reactor pressure vessel (RPV) head and vessel head penetration (VHP) nozzle inspection activities that are implemented in accordance with the requirements of Order EA-03-009 (NRC Accession Number ML040220391), issued on February 20, 2004. This TI validates that a plant conforms to its inspection commitments and requirements, during its next and subsequent refueling outages, using procedures, equipment, and personnel that have been demonstrated to be effective in the detection and sizing of primary water stress corrosion cracking (PWSCC) in VHP nozzles and detection of RPV head wastage.

As an ancillary benefit, this TI promotes information gathering to help the NRC staff identity and shape possible future regulatory positions, generic communications, and rulemaking.

During the Unit 2 outage, the licensee performed remote BMV, UT, and EC examinations, and some PT examinations of the RPV and VHP nozzles. The inspectors performed a review in accordance with TI 2515/150 of the licensee's procedures, equipment, and personnel used for examinations of the Unit 2 RPV and VHP to confirm that the licensee met requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004). The results of the inspectors' review included documentation of observations in response to the questions identified in part "b" (Evaluation of Inspection Requirements). To evaluate the licensee's efforts in conducting examinations, the inspectors:

- Reviewed VHS recordings of remote BMV of the RPV head VHP nozzles;
- Observed personnel conducting PT examination of an RPV head VHP nozzle;

- Observed personnel conducting remote UT and EC examinations of RPV head VHP nozzles;
- Conducted interviews with the nondestructive examination personnel performing non-destructive examinations of the vessel head;
- Reviewed the head inspection procedures;
- Reviewed the certification records for the nondestructive examination personnel performing examinations of the vessel head;
- Reviewed the procedures used for the identification and resolution of boric acid leakage from the systems and components above the vessel head; and
- Reviewed the licensee's procedures and corrective actions to be implemented for boric acid leakage.

The inspectors conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with the requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004, or approved Order relaxation requests), using procedures, equipment, and personnel qualified for the detection of PWSCC on vessel VHP nozzles and detection of vessel head wastage.

In NRC Bulletin 2002-02, the effective degradation year (EDY) is used as a basis to establish appropriate inspection programs for VHP nozzles based on increasing susceptibility to nozzle cracking with increasing EDY. For Unit 2, the licensee calculated an EDY of 2.219 as of April 1, 2007, end-of-cycle (EOC) of B2R13 would categorize the Unit as low susceptibility. However, based the guidance given in the NRC Order, since flaws were found and repaired during the current outage (B2R13), Unit 2 is now categorized as a highly susceptible unit for PWSCC.

<u>Summary</u>: The licensee did not identify any leaking vessel head penetration nozzles. However, volumetric examinations by the licensee identified flaws in the J-groove weld and tube for penetration No. 68. This was the first volumetric examination of the RPV VHP nozzles. A previous remote bare metal VT examination had failed to identify any evidence of leakage in the VHP annulus area above the head. A supplementary PT examination of penetration No. 68 showed a 0.050" rounded indication in the J-groove weld as well as a 0.150" linear axial indication in the J-groove weld which also extended 0.040" downward past the J-groove weld into the tube. In response to these flaws, the licensee performed a weld overlay repair of this weld and submitted, as part of the relief request submittal for the repair of this weld, analysis which addressed/bounded crack growth for the weld overlay of an embedded flaw repair. In addressing the TI requirement to review repairs, the inspectors reviewed the certified materials test reports, weld procedure specifications and weld procedure qualification records related to the weld overlay process. The inspectors also conducted interviews with engineering personnel coordinating and overseeing the repair process.

b. <u>Evaluation of Inspection Requirements</u>

In accordance with requirements of TI 2515/150, Revision 3, the inspectors evaluated and answered the following questions:

For each of the examination methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel?

   Yes. The inspectors verified that the examinations were performed by qualified and certified examiners.

2. Performed in accordance with demonstrated procedures?

   Yes. UT/EC, PT, and BMV examinations were conducted during this outage. The inspectors verified that the volumetric exams were performed per EPRI demonstrated procedures. The inspectors viewed the PT examination performed and verified that the examination was performed in accordance with procedures. The inspectors also reviewed a video of the BMV examination and verified that it was conducted in accordance with procedures which required examination personnel with knowledge of identifying CRDM leakage.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The inspectors concluded from observing video of the remote BMV examination process and viewing the reactor vessel head (RVH) penetration remote visual inspection that the licensee had sufficient access to perform a remote visual examination of 100 percent of the bare metal of the reactor head as well as 360 degree coverage of each penetration. The inspection included both remote visual inspection and video taping accomplished via the use of a magnetic wheeled crawler mounted remote manipulator and manually articulated video probe cameras. No evidence of penetration leakage or boric acid accumulation was identified. The inspectors also concluded from observing portions of the remote volumetric inspection process that demonstrated procedures were being followed and that the methods used in the examination (as evidenced by identified flaws in, and repair of, the No. 68 penetration) were able to identify, disposition and resolve deficiencies. The inspectors also remotely observed the PT examination that the licensee performed which identified the rounded and linear indications on penetration No. 68 which led to the embedded flaw repair.

4. Capable of identifying the PWSCC and/or RPV head corrosion phenomena described in Order EA-03-009?

   Yes. The inspectors determined through observing a record of the BMV exam, and remotely observing the surface and volumetric inspection processes, that the licensee's efforts were capable of, and in fact did, detect and characterize PWCSS.

5. What was the condition of the reactor head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

   The reactor head is covered with mirror type insulation. However, this insulation did not obstruct the exam. Some of these insulation panels were removed to allow for access for the inspection equipment/probes. The inspectors determined that the licensee had complete viewable coverage with the aid of remote controlled high resolution cameras mounted on a magnetic wheeled crawler, and when the crawler movement was restricted, a manually articulated camera. The as-found pressure vessel head condition was clean. No evidence of loose boric acid particles was identified.

6. Could small boron deposits, as described in Bulletin 01-01, be identified and characterized?

   Yes. The inspectors determined through a review of the inspection video and the visual inspection procedure, that small boron deposits, as described in the Bulletin 01-01, could be identified and characterized. No such deposits were evident.

7. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

   Penetration No. 68 had a 0.05" rounded indication in the J-groove weld and a 0.150" axial linear indication in the J-groove weld which extended 0.040" into the penetration tube that were detected during the volumetric examination and further identified during PT non-destructive testing. The licensee elected to repair these indications with a weld overlay employing the embedded flaw repair methodology.

8. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

   Impediments to volumetric exams included 55 nozzles with thermal sleeves. These impediments were overcome by using multiple test probes. The licensee had sufficient access to perform a remote visual examination with 360 degree coverage of each penetration. The penetration subject to surface examination (No. 68) was also free of impediments.

9. What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations (e.g., thermal hydraulic modeling, instrument uncertainties), etc.?

   The basis for the temperatures used in the susceptibility ranking calculation is plant specific data used in a Westinghouse calculation to derive a reactor vessel upper bulk mean fluid temperature of the vessel head area.

10. During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix B of this TI? If not, was a more restrictive flaw evaluation guidance used?

    Yes. During the current refueling outage (Unit 2 Spring 2007) volumetric examinations of the VHPs identified an unacceptable axial indication, confirmed by dye penetrant examination, in VHP No. 68.

The licensee obtained verbal relief from ASME Code from the NRC for an alternative repair technique (embedded flaw methodology) and performed weld overlays of this weld. The licensee employed the embedded flaw process described in Westinghouse WCAP-15987, Revision 2-A, “Technical Basis for the Embedded Flaw Process for Repair of Reactor Vessel Head Penetrations.” The embedded flaw methodology had been previously approved generically by the NRC.

Supporting the embedded flaw methodology was the analysis provided in Westinghouse WCAP-16401-P, Revision 0, “Technical Basis for Repair Options for Reactor Vessel Head Penetration Nozzles and Attachment Welds: Byron and Braidwood Units 1 and 2.” This WCAP provided the technical basis for use of an embedded repair by evaluating the bounding load conditions, fatigue crack growth predictions, and fracture mechanics results.

11. Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the RPV head?

    Yes. The inspectors verified that procedures existed as part of the licensee’s BACC program to identify boric acid leaks from pressure retaining components above the RPV head. The procedures included inspection locations, implementation and inspection guidelines, screening and evaluation, and deposit sampling and analysis.

12. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPV head?

    No evidence of leakage was noted during inspection.

c. <u>Findings</u>

No findings of significance were identified.

4OA6 <u>Meetings</u>

.1 On July 10, 2007, the resident inspectors presented the inspection results to Mr. D. Hoots and his staff, who acknowledged the findings. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 <u>Interim Exit Meetings</u>

Interim exits were conducted for:

- Occupational Radiation Safety Program for Access Control to Radiologically Significant Areas and ALARA Planning and Controls programs with Ms. M. Snow on April 9, 2007.

- Baseline procedure 71111.08 and TI2515/150 with Mr. D. Hoots and other members of licensee management on April 20, 2007. The inspectors returned proprietary information reviewed during the inspection and the licensee confirmed that none of the potential report input discussed was considered proprietary.

- Closure of URI 05000454/2004005-04; 05000455/2004005-04 as an NCV with Mr. A. Giancatrino and other licensee personnel on May 3, 2007.

4OA7 Licensee-Identified Violations

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

Cornerstone: Mitigating Systems

- Part 50 of 10 CFR, Appendix B, Criterion XI, "Test Control," states, in part, that a test program shall be established to assure that all testing required to demonstrate that safety-related structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures. Contrary to this, on August 21, 2006, the licensee's test program failed to ensure testing of at least 14 safety-related component cooling water system valves, to demonstrate that the valves would perform satisfactorily in service. Specifically, the licensee identified through the review of operating experience that Byron Emergency Operating Procedures, for both units, 1BEP ES-1.3, "Transfer to Cold Leg Recirculation Unit 1," Revision 104, and 2BEP ES-1.3, "Transfer to Cold Leg Recirculation Unit 2," Revision 105, specified seven manual component cooling water (CCW) system valves in each procedure which had not been tested. Operators were required to manipulate these valves, to meet the safety analysis CCW water flow of 5000 gallons per minute (gpm) for the residual heat removal heat exchangers, after an accident. Therefore, these CCW valves required testing in accordance with the IST program; however, the licensee did not test the valves because the valves were not included in the program. The licensee's failure to test the valves was due to an inadvertent omission of these valves in the inservice test program. The licensee's corrective action for this issue included generating an IR and placing the valves on the plan-of-the-day meeting agenda to ensure testing of the valves. This issue was considered to be of very low safety significance because it was not a design or qualification deficiency confirmed not to result in loss of function per Generic Letter 91-18; did not represent a loss of system safety function; did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk-significant per 10 CFR 50.65 for greater than 24 hours; did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. This issue has been entered into the licensee's corrective action program as IR 611158.

- Technical Specification 5.4 required implementation of the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Regulatory Guide 1.33, Appendix A, Part 1, Subsection b, recommended procedures for specifying the authorities and responsibilities for safe operation. Procedure OP-AA-101-111, “Roles and Responsibilities of On-Shift Personnel,” Revision 1, Step 4.6.4, required that one reactor operator (RO) on each unit shall be designated the Unit RO and shall be at-the controls. Contrary to the above, on April 3, 2007, licensee Senior Reactor Operators (SROs) determined that the Unit 1 RO left the at-the controls area. This issue was considered to be of very low safety significance because the operator was about 5 feet outside the boundary and was still inside the control room and thus available to respond to alarms; the Unit 1 SRO and two other SROs were within the Unit 1 at-the controls area; the RO was outside of the licensee defined at-the controls area for approximately 30 seconds; and Unit 1 was in a stable condition. This issue was entered into the licensee’s corrective action system as IR 612694.

Cornerstone: Occupational Radiation Safety

- Technical Specification 5.4.1 requires that written procedures be established and implemented for activities provided in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Procedures specified in Regulatory Guide 1.33 include radiation protection procedures for personnel monitoring, which are provided by licensee radiation protection procedure RP-AA-210, “Dosimetry Issue, Usage, and Control” Revision 9. The procedure requires Radiation Protection to issue dosimeters (TLD) to persons that will be working in the Radiologically Controlled Area (RCA). Contrary to these requirements, on April 8 and April 9, 2007, an individual was granted access to the RCA and entered containment, without assigning the individual a TLD. The individual was wearing an electronic dosimeter during these entries. This incident is documented in the licensee’s corrective action program as IR 00614817. This issue represented a finding of very low safety significance because it did not involve ALARA planning or work controls, there was no overexposure or substantial potential for an overexposure to the worker, nor was the licensee’s ability to assess worker dose compromised.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
D. Hoots, Site Vice President
M. Snow, Plant Manager
F. Beutler, Engineering, Fire Protection
D. Bohnert, System Engineer
D. Combs, Security Manager
D. DeMore, Radiation Engineering Superintendent
L. Doyle, Programs Coordinator
C. Gayheart, Work Control Manager
A. Giancatarino, Engineering Director
C. Gregory, Radiation Protection Instrumentation Coordinator
W. Grundmann, Regulatory Assurance Manager
E. Hernandez, Maintenance
T. Hulbert, Regulatory Assurance
S. Kerr, Chemistry Manager
W. Kouba, Nuclear Oversight Manager
B. Ledger, Engineering
R. McBride, ISI Engineer
V. Naschansky, Supervisor, Design Engineering, Electrical
D. Palmer, Radiation Protection Manager,
B. Perchiazzi, Design Engineering Manager
M. Prospero, Operations Manager
D. Sargent, Mechanical Design Engineer
M. Schlagel, Engineering
M. Shah, Engineering
J. Smith, Acting Engineering Programs Manager
B. Spahr, Training Manager
S. Swanson, Maintenance Director
D. Thompson, Technical Support Superintendent
N. Vakili, GL 89-13 Program Owner, Program Engineer
W. Walter, Operations

Illinois Emergency Management Agency
J. Roman, IEMA, Springfield

Nuclear Regulatory Commission
S. West, Deputy Director, Division of Reactor Projects
R. Skokowski, Chief, Branch 3, Division of Reactor Projects
D. Passehl, Senior Risk Analyst, Division of Reactor Safety
P. LaFlamme, Reactor Engineer, Inspector in Training Branch 3
L. Kozak, Senior Risk Analyst, Division of Reactor Safety
K. Coyne, Technical Assistant, Office of Nuclear Regulatory Research

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000455/2007-001-00	LER	Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Due to an Initial Construction Weld Defect Allowing the Initiation of Primary Water Stress Corrosion Cracking (Section 40A3)

Opened and Closed

05000454/2007003-01 05000455/2007003-01	NCV	Failure to Fire Proof Structural Steel Beams to Achieve a 3-Hour Fire Rating (Section 1R05.1)
05000454/2007003-02 05000455/2007003-02	NCV	Alternative Shutdown Using the Remote Shutdown Panel (Section 1R05.2)
05000455/2007003-03	NCV	Failure to Perform an MT Examination in Accordance with ASME Section XI (Section 1R08.1)
05000454/2007003-04	NCV	Failure to Properly Reinstall a Flood Seal Hatch/High Energy Line Break Barrier (Section 1R15)
05000454/2007003-05 05000455/2007003-05	NCV	Design Basis Analysis for the Postulated Drop of a Reactor Vessel Head During Refueling was Not Up-to-Date (Section 1R20)

Closed

05000454/2004005-04 (DRS) 05000455/2004005-04 (DRS)	URI	Alternative Shutdown Using the Remote Shutdown Panel (Section 4OA5)
05000454/2007002-03	URI	NRC Review of Licensee’s Operability Assessment of an Improperly Reinstalled Flood Seal Hatch/High Energy Line Break Barrier (Section 1R15)

Discussed

None

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.

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

IR 627818; Compliance Problems with WC-AA-107; Revision 3; May 10, 2007
IR 631738; River Screen House Power Cross Tied-Summer Reliability Issue
IR 640850; Increased Frequency for Oil Sample Needed for 1E MPT; June 15, 2007
SER 2007-20; Unit 1 East Main Power Transformer Leaking “B” Phase Bushing; April 25, 2007
Plant Issue Resolution Documentation for SER #2007-20
2007 Summer Readiness letter from Jack Feimster to Marseyne Snow; February 7, 2007
Statement of Byron Station Summer Readiness, Letter from Site Vice-President Dave Hoots to Senior Vice President Midwest Operations Mike Pacilio; dated May 21, 2007
WC-AA-107; Seasonal Readiness; Revision 4

<u>Corrective Action Documents as a Result of NRC Inspection</u>

IR 628311; Bus Tie 11-12 Above Red Circle Oil Level in Sight Glass; May 11, 2007 (NRC Identified)

<u>1R04</u> <u>Equipment Alignment</u>

Drawing M-37; Diagram of Auxiliary Feedwater; Revision AW
Drawing M-42; Diagram of Essential Service Water; Sheet Number 6, Revision AW
BOP AF-E1B; Auxiliary Feedwater Train “B” Electrical Lineup; Revision 1
BOP AF-M1B; Auxiliary Feedwater Train”B” Valve Lineup; Revision 5
Drawing M-46, Sheet 1A; “Diagram of Containment Spray;” Revision AN
Drawing M-46, Sheet 1B; “Diagram of Containment Spray;” Revision AR
Drawing M-46, Sheet 1C; “Diagram of Containment Spray;” Revision AK
BOP CS-E1; Revision 4; “Containment Spray System - Electrical Lineup”
BOP CS-E1B; Revision 1; “Containment Spray System - Train “B”
BOP CS-M1; Revision 13; “Containment Spray System - Valve Lineup”
BOP CS-M1B; Revision 1; “Containment Spray System - Train “B” Valve Lineup”
BOP CS-T1; Revision 2; “CS Check Valve Location”
BOP CS-3; Revision 6; “Filling and Venting the Containment Spray System”

<u>Corrective Action Documents as a Result of NRC Inspection</u>

IR 640087; NRC Walkdown Items Identified; June 13, 2007 (NRC Identified)

<u>1R05</u> <u>Fire Protection</u>

Pre-Fire Plan; Fuel Handling Building Elevation 401' -0", Zone 12.1-0; January 31, 2007
Pre-Fire Plan; Fuel Handling Building Elevation 426' -0", Zone 12.1-0; January 31, 2007
Pre-Fire Plan; Auxiliary Building Elevation 383'-0", Zone 11.4-0 North; January 31, 2007
Pre-Fire Plan; Auxiliary Building Elevation 383'-0", Zone 11.4-0 South; January 31, 2007

Pre-Fire Plan; Auxiliary Building Elevation 383'-0", Zone 11.4-0 West; January 31, 2007
Pre-Fire Plan; Auxiliary Building Elevation 451'-0", Zones 5.4-1 and 5.6-1 North; January 31, 2007
Plant Barrier Impairment Permit #07-187; May 2, 2007
IR 647511; UFSAR Not Clear with Respect to Piping Cracks in the MSIV RO; July 5, 2007

1R05T Triennial Fire Protection

IR 231049; Return to PHC with Proposed Scope of Testing for Remote Shutdown Panel Control Switches, See November 8, 2004, PHC Notes; dated December 13, 2004
IR 238339; NRC Issue with FP Alternate Shutdown Licensing Basis; dated July 23, 2004
IR 528750; Work Order to Test VC System Remote Switches; dated September 8, 2006
IR 524664; Testing of Remote Shutdown Panel Switches; dated August 28, 2006
IR 524916; Work Order Needed to Create Instruction to Test RSP Switch [1VPXXXXXXX]; dated August 29, 2006
IR 524920; Work Order Needed to Create Instruction to Test RSP Switch [2VPXXXXXXX]; dated August 29, 2006
IR 532177; Remote Shutdown Panel Testing During B1R14; dated September 17, 2006
IR 552847; Test 1PL04J RSP Equipment from the RSP; dated November 3, 2006
IR 552848; Test 1PL05J RSP Equipment from the RSP; dated November 3, 2006
IR 552849; Test 1PL06J RSP Equipment from the RSP; dated November 3, 2006
IR 552850; Test 2PL04J RSP Equipment from the RSP; dated November 3, 2006
IR 552852; Test 2PL05J RSP Equipment from the RSP; dated November 3, 2006
IR 552854; Test 2PL06J RSP Equipment from the RSP; dated November 3, 2006
IR 552855; Test 1PL05JA Equipment from 1PL05JA; dated November 3, 2006
IR 599367; SXCT Operability Concerns Require PED and RA Assistance; dated March 5, 2007
IR 621113; R3 - Annunciator Will Not Clear; dated April 24, 2007
IR 621381; Failed Remote Shutdown Panel Indication for 2C MSIV; dated April 25, 2007
IR 623324; 2BOSR PL-R2-CV.2 Procedure Error; dated April 30, 2007
0B0A PRI-5; Control Room Inaccessibility; Revision 101
1B0A PRI-5; Control Room Inaccessibility Unit 1; Revision 106
2B0A PRI-5; Control Room Inaccessibility Unit 2; Revision 109
2BOSR PL-R1; Remote Shutdown Panel Control Power Check; Revision 4
2BOSR PL-R2-CV.2; Remote Shutdown Panel Control Switch Functional Check (CV Valves); Revision 0
2BOSR PL-R2-MS.1; Remote Shutdown Panel Control Switch Functional Check (MSIVs); Revision 0
NUREG-0876, Supplement No. 3; Safety Evaluation Report Related to the Operation of Byron Station, Units 1 and 2; dated November 1983
NUREG-0876, Supplement No. 5; Safety Evaluation Report Related to the Operation of Byron Station, Units 1 and 2; dated October 1984
Regulatory Guide 1.68.2; Initial Startup Test Program to Demonstrate Remote Shutdown Capability For Water-Cooled Nuclear Power Plants; Revision 1
Startup Test 2.63.35 (PWR 87251); Shutdown from Outside the Control Room; dated March 26, 1985
Drawing A810; Structural Steel Fireproofing Details; Revision Z
Drawing A818; Auxiliary Building Cable Spreading Room Elevation 463'-5" and Auxiliary Building Ground Floor Plan Elevation 401'-0" Structural Steel Fireproofing; Revision V

Drawing A820; Auxiliary Building Main Floor Plan Elevation 451'-0" Structural Steel Fireproofing Plan; Revision L
Letter from T. Tramm (Com Ed) to H. Denton (NRC); Byron Generating Station Unit 1 and 2 Fire Protection Report; August 20, 1984
Byron Safety Evaluation Report Supplement No. 5; October 1984
Fire Protection Report; Section 2.3.18.7; Control Room HVAC Equipment Room, Train A (Fire Zone 18.4-1); December 1990
Pre-Fire Plan; Auxiliary Building Upper Cable Spreading Room; Elevation 463'-4.5" (Zone 3.3A-1); November 18, 1999
Pre-Fire Plan; Auxiliary Building Upper Cable Spreading Room; Elevation 463'-4.5" (Zone 3.3A-2); January 31, 2007

Corrective Action Documents as a Result of NRC Inspection
IR 231542; Consider Testing of RSP Switches; dated June 25, 2004 (NRC Identified)
IR 617838; Chair Chained to FP Piping; April 16, 2007 (NRC Identified)
IR 625349; UFSAR Revision Required to Clarify the Use of RSPs; dated May 4, 2007 (NRC Identified)
IR 630782; NRC Steel Beam Fireproofing Questions; May 17, 2007 (NRC Identified)
IR 631310; Housekeeping Issues; May 18, 2007 (NRC Identified)
IR 639518; Non-Standard Trash Receptacles in the Plant; June 12, 2007 (NRC Identified)

1R06 Flood Protection Measures
0BMSR DD-1; Water-Tight Barrier Inspection (CM-6.1.1); Revision 4
Drawing S-1062; Sections and Details Containment Building; Revision W
IR 606111; NRC Concern, 1DSFS008 AF Tunnel Flood Seal Opening Not Sealed; March 19, 2007

1R08 Inservice Inspection (ISI) Activities

NDE Procedures
EXE-ISI-70; Magnetic Particle Examination; Revision 3
EXE-PDI-UT-2; Ultrasonic Examination of Austenitic Piping Welds in Accordance with PDI-UT-2; Revision 5
PDI Piping and Bolting Program; Krautkramer Model USN-58Lsw and USN-60sw; October 6, 2005
TQ-AA-122; Qualification and Certification of Nondestructive (NDE) Personnel; Revision 3
ER-AA-335-016; VT-3 Visual Examination of Component Supports; Attachments and Interior of Reactor Vessels; Revision 4
ER-AA-330-004; Visual Examination of Snubbers; Revision 4
WDP-9.2; Qualification and Certification of Personnel in Nondestructive Examination; Revision 9

Head Exam
WDI-UT-013; IntraSpect UT Analysis Guidelines; Revision 12
WDI-UT-010; IntraSpect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave; Revision 13

ER-AP-335-1012; Bare Metal Visual Examination of PWR Vessel Penetrations and Nozzle Safe-Ends; Revision 3
ER-AP-331; Boric Acid Corrosion Control (BACC) Program; Revision 3
ER-AP-331-1003; RCS Leakage Monitoring and Action Plan; Revision 2
ER-AP-331-1004; Boric Acid Corrosion Control (BACC) Training and Qualification; Revision 2

<u>NDE Exam Documents</u>
Byron Unit 2 B2R13 Degradation Assessment & Condition Monitoring Checklist; Revision 0
CBE-R13-BP01-68-01 (Ultrasonic Report Sheet); Penetration No. 68; dated April 9, 2007
WDI-TJ-1008; Evaluation of the Effect of Increasing RVHI RF Data Cable Length to 75 Feet; dated October 31, 2005
WDI-PJF-1303502-TR-003; Investigation on the Variation in Reference Sensitivity Between Nominal 3/32-Inch (0.094) Diameter Side-Drilled Holes with Diameter Increases Up to 0.0025-Inch; Revision 0
WO 708759; Outage Visual Examinations of TRM Snubbers; dated August 24, 2005

<u>Corrective Action Documents</u>
IR 526801; Minor Boric Acid Leak at Pipe Cap; dated September 2, 2006
IR 526840; Boric Acid Lead at Packing; dated September 2, 2006
IR 539226; Depth Measurements Need Clarification; dated October 3, 2006
IR 562740; Variation in WesDyne Cal Block Side Drilled Hole; dated November 28, 2007
IR 577764; B1R14 Ultrasonic Transducer Certification Cannot be Located; dated January 11, 2007
IR 596176; 1CV380A Minor Packing Leak (Boric Acid); dated February 23, 2007
IR 601704; Pre-Freeze UT Thickness Results < 87.5 percent Nominal 1SXB1AB-3"
IR 612383; NRC Identified Leaking Containment Valve; dated April 3, 2007
IR 614558; NRC Question on 2RC01BA ISI Exam; dated April 7, 2007
IR 614547; 2A SG Steam Drum Component Erosion - B2R13; dated April 8, 2007
IR 614983; UT Indication Discovered During CRDM Exam on Penetration 68; dated April 9, 2007
IR 614601; 2A SG Steam Drum Inspection Identified Foreign Object; dated April 8, 2007
IR 616077; SG Eddy Current Closeout Ids Additional Insp Required; April 12, 2007
IR 616619; B2R13 SG Foreign OBJ Wear Identified in Upper Tube Bundle; April 12, 2007
IR 616703; Foreign Objects Found in SGs 2B and 2C Secondary Side; dated April 13, 2007
IR 617341; 2C Steam Generator Drum Component Erosion - B2R13; dated April 15, 2007
IR 617259; Foreign Objects Found in 2A SG Secondary Side - B2R13; dated April 14, 2007
IR 617501; 2D Steam Generator Secondary Side Foreign Objects - B2R13; dated April 15, 2007
IR 617264; Minor Accumulation of Substance in Area of Penetration 68 (2RC01R); dated April 14, 2007

Welding Documents

Welding Procedures and Qualification Records
WPS 843/52 MC-GTAW; Revision 6
WPS 43 MC-GTAW; Revision 5
WPS 43 MN-GTAW/SMAW; Revision 7
PQR 603; dated September 19, 1997
PQR 677; dated April 9, 2001
PQR 694A; dated November 13, 2001
PQR 430; dated July 24, 1995
PQR 307; dated June 29, 1992
PQR 467; dated September 12, 1994
PQR 644; dated April 29, 1999
Special Metals - CMTR No. 00073117, Heat No. NX4023, Inconel Filler Metal 52; dated October 19, 2004
Welding Products Company - CMTR No. 00075407, Heat No. NX4034JK, Inconel Filler Metal 52; dated February 22, 2005
ESAB Welding and Cutting Products - CMTR No. N583783, Heat No. 316010, Arcaloy ER 316L; dated December 13, 2001
WO851489-01; MM R2 - Seal Weld Kerotest Check Valve Cap; September 29, 2005
WO850824-01; MM Seal Weld Kerotest Check Valve Cap; October 4, 2005

1R11 Licensed Operator Qualification Program (Quarterly)
Training - LORT Cycle 07-03 Week 4 OBE Failures; June 19, 2007

1R12 Maintenance Effectiveness
ER-AA-310-1004; Maintenance Rule - Performance Monitoring; Revision 5
IR 231049; Return to PHC with Proposed Scope of Testing for Remote Shutdown Panel Control Switches, See November 8, 2004, PHC Notes; dated December 13, 2004
IR 238339; NRC Issue with FP Alternate Shutdown Licensing Basis; dated July 23, 2004
IR 528750; Work Order to Test VC System Remote Switches; dated September 8, 2006
IR 524664; Testing of Remote Shutdown Panel Switches; dated August 28, 2006
IR 524916; Work Order Needed to Create Instruction to Test RSP Switch [1VPXXXXXXX]; dated August 29, 2006
IR 524920; Work Order Needed to Create Instruction to Test RSP Switch [2VPXXXXXXX]; dated August 29, 2006
IR 532177; Remote Shutdown Panel Testing During B1R14; dated September 17, 2006
IR 552847; Test 1PL04J RSP Equipment from the RSP; dated November 3, 2006
IR 552848; Test 1PL05J RSP Equipment from the RSP; dated November 3, 2006
IR 552849; Test 1PL06J RSP Equipment from the RSP; dated November 3, 2006
IR 552850; Test 2PL04J RSP Equipment from the RSP; dated November 3, 2006
IR 552852; Test 2PL05J RSP Equipment from the RSP; dated November 3, 2006
IR 552854; Test 2PL06J RSP Equipment from the RSP; dated November 3, 2006
IR 552855; Test 1PL05JA Equipment from 1PL05JA; dated November 3, 2006
IR 599367; SXCT Operability Concerns Require PED and RA Assistance; dated March 5, 2007
IR 611595; Unit 2 Startup Feedwater Pump Trip During Unit Shutdown; dated April 1, 2007
IR 621113; R3 - Annunciator Will Not Clear; dated April 24, 2007

IR 621381; Failed Remote Shutdown Panel Indication for 2C MSIV; dated April 25, 2007
IR 623324; 2BOSR PL-R2-CV.2 Procedure Error; dated April 30, 2007
0B0A PRI-5; Control Room Inaccessibility; Revision 101
1B0A PRI-5; Control Room Inaccessibility Unit 1; Revision 106
2B0A PRI-5; Control Room Inaccessibility Unit 2; Revision 109
2BOSR PL-R1; Remote Shutdown Panel Control Power Check; Revision 4
2BOSR PL-R2-CV.2; Remote Shutdown Panel Control Switch Functional Check (CV Valves); Revision 0
2BOSR PL-R2-MS.1; Remote Shutdown Panel Control Switch Functional Check (MSIVs); Revision 0
NUREG-0876, Supplement No. 3; Safety Evaluation Report Related to the Operation of Byron Station, Units 1 and 2; dated November 1983
NUREG-0876, Supplement No. 5; Safety Evaluation Report Related to the Operation of Byron Station, Units 1 and 2; dated October 1984
Regulatory Guide 1.68.2; Initial Startup Test Program to Demonstrate Remote Shutdown Capability For Water-Cooled Nuclear Power Plants; Revision 1
Startup Test 2.63.35 (PWR 87251); Shutdown from Outside the Control Room; dated March 26, 1985
EACE 611595-07; Apparent Cause Report (Equipment) Unit 2 Startup Feedwater Pump Trip During Unit Shutdown

1R13 Maintenance Risk Assessments and Emergent Work Control
Byron Station Plan of the Day; Week of April 30, 2007; Revision 2
Protected Equipment Log; May 4, 2007
Protected Equipment Log; May 18, 2007;Revision 13
Unit 1 Risk Configurations; Week of April 16, 2007; Revision 4
Unit 1 Risk Configurations; Week of April 30, 2007; Revision 2
Shutdown Safety Approval; Outage B2R13; April 29, 2007
OU-BY-104 (Interim #07-0-016; Shutdown Safety Management Program Byron/Braidwood Annex; Revision 9

1R15 Operability Evaluations
WO 1017364 01; 2CC9518 Failed LLRT; April 12, 2007
WO 1017364 06; 2CC9518 Failed LLRT; April 17, 2007
Work Request 980110557 01; Primary Containment Type C LLRT of 2CC685, 2CC9438, 2CC9518; October 26, 1999
LLRT for P-24 - 2CC9518, 2CC9438, and 2CC685; April 10, 2001
WO 99276948 01; LLRT For P-24 - 2CC9518; September 14, 2002
WO 504148 01; LLRT for P-24 - 2CC9518; March 19, 2004
WO 695410 15; Perform Leak Seal Injection on North Wall of Unit 1 AFW Tunnel
WO 695410 22; ST MM Install Flood Seal Cover - Access to AF Tunnel
IR 614091; R2 - RTD Bent Over Used as Foot Peg; April 4, 2007
IR 618939; Seismic Mounting Support for Wide Range RTDS; April 18, 2007
IR 620080; AF Tunnel FSO Structural Calculation Error; April 18, 2007
IR 634495; Excessive Air Venting Unit 2 ECCS System; May 29, 2007
IR 636916; Unventable Gas Void Discovered in 2SI06BB-24"; June 4, 2007
IR 647511; UFSAR Not Clear with Respect to Piping Cracks in the MSIV RO; July 5, 2007

EC 359057; Evaluation of Non-Condensable Gas Accumulation in Unit 2 RH System; January 24, 2006
EC 365542; Seismic Qualification of Wide Range RTD Assemblies for RCS Hot and Cold Legs; April 23, 2007
EC 366163; Unventable Gas Voids in Containment Recirc Sump Piping; June 7, 2007
EC Evaluation 366201; Evaluation of Non-Condensable Gas Accumulation in the Unit 2 RH System; Revision 0
Analysis No.: BYR07-051; RCS Wide Range Hot Leg RTD Seismic Qualification; Revision 0

Corrective Action Documents as a Result of NRC Inspection
IR 606111; NRC Concern, 1DSFSO08 AF Tunnel Flood Seal Opening Not Sealed; March 19, 2007 (NRC Identified)

1R19 Post Maintenance Testing
IR 618013; Incorrect Range Setting on 2B DG DRU; April 17, 2007
IR 640961; 0SX03CE Passed PMT But Degraded Due to Unexpected High Vibrations; June 15, 2007
IR 644162; 1A CS Pump Work Improvements; June 25, 2007
IR 644572; Possible Minimum Wall Pipe Thickness Issue; June 26, 2007
WO 675697 01; Pressurizer HTR ACB 2445BC Relay Routine CAL; May 7, 2007
WO 675697 02; OA Pressurizer ACB 2445BC Trip Checks; May 8, 2007
WO 1000702 01; Upper & Lower Motor Bearing Oil Change; May 8, 2007
WO 1000702 02; OP PMT: Verify Proper RH Pump Motor Oil Level; May 8, 2007
WO 827559 02; POS PMT - Verify Proper Flow
WO 856488 03; OPS PMT-LLRT; EM Perform Diagnostic Test
WO 856488 06; PIT 2BOSR 0.5-2.CS.3-3 For 2CS007A; April 23, 2007
WO 855564 02; As left LLRT For P-1 - 2CS0007A and 2CS008A; April 23, 2007
WO 895893 13; OPS PMT - Stroke Valve Verify Flow and Leakage
WO 995138 01; 2BOSR 6.3.5-22.1, STT for 2CS007A (WK F); April 23, 2007
Diagram of Containment Spray M-129; Sheet Number 1A; Revision AK
1BOSR 0.5-2.CS.1-1; Revision 9; "Stroke Time Test of 1CS001A, 009A and 019A." \
1BOSR 0.5-2.CS.3-3; Revision 3; "Position Indication Test for 1CS007A, 001A, -009A, 019A, 010A

1R20 Refueling & Outage Activities
IR 612322; B2R13 Compromises RC Overpressure Protection; April 3, 2007
IR 613004; Acceptability of UFSAR Noncompliance; April 4, 2007
IR 623891; Heavy Load Movement Licensing Basis Ambiguous; April 27, 2007
IR 624320; R2 Replace Missing Bolt in Polar Crane; May 1, 2007
IR 624521; WO Needed to Perform Cleaning of Polar Crane During B2R14; May 1, 2007
2BGP 100-2; Plant Startup; Revision 33
2BGP 100-6; Refueling Outage; Revision 41
2BGP 100-6TI; Refueling Outage Flow Chart; Revision 22
BMP 3118-7; Reactor Vessel Closure Head Installation; Revision 26
Plant Issue Resolution Documentation; Unit 2 Polar Crane (2HC01G); April 28, 2007
OU-AA-103; Shutdown Safety Management Program; Revision 7
OU-AP-104/OU-BY-104 (Interim #07-0-016); Revision 9 Expires July 1, 2007

IR 622875; Unit 2 Polar Crane Making Rumbling Noise While Bridging; April 28, 2007
IR 623821; Unit 2 Polar Crane Wheel Bearings - 3 More; May 1, 2007
Standing Order; Byron Unit 2 Cycle 14 RCS Boron Requirements for Modes 3-5; Log Number 07-025
NF-AP-440; Attachment 3; Fuel Conditioning Instruction Clarifications and Changes
E-Mail from Andre Mitchell to Tracey Hulbert; ECCS Sump Inspection Results; April 30, 2007
Cable Tabulation - Main File (S101-1) for 2CV181
Electrical Installation cable Information 6E-0-3000B; Revision AC
NF-BY-312; Core Reload Testing Sequence and Verification; Revision 1
NF-BY-510; Low Power Physics Test Program; Revision 3
2BGP 100-2T1; Plant Startup Flowchart; Revision 14
2BGP 100-2A1; Reactor Startup; Revision 21
BOP PC-1T1; Unit ½ Containment Closure Verification Checklist; Revision 5
B2R13 OCC Turnover; April 2, 2007 to May 2, 2007
B2R13 OCC Closed Issues
Selected B2R13 Shutdown Risk Update from April 2, 2007 to May 2, 2007
B2R13 Outage News; April 2, 2007 to May 2, 2007
OU-AA-103; Shutdown Safety Management Program; Revision 6
OU-BY-104; Shutdown Safety Management Program Byron/Braidwood Annex; Revision 9
Standard N-EM-0019; Non-Metallic Tie Wraps; Revision 6
Westinghouse LTR-MRCDA-07-74; Comparison of Head Drop Parameters and Nozzle Stresses for Byron Unit 2 and South Texas; April 28, 2007
NRC Letter; Evaluation of Postulated Reactor Vessel Head Assembly Drop (RESAR-41); November 30, 1976
NS-CE-1101; RESAR 41 Drop Analysis; June 11, 1976

Corrective Action Documents as a Result of NRC Inspection
IR 611661; B2R13 LL Loose Material in Unit 2 Containment; April 2, 2007 (NRC Identified)
IR 622832; NRC Questions on RX Head Drop Analysis; April 27, 2007 (NRC Identified)
IR 623891; Heavy Load Movement Licensing Basis Ambiguous; May 1, 2007 (NRC Identified)
IR 624105; NRC B2R13 Containment Cleanliness Walkdown; May 1, 2007 (NRC Identified)
IR 628108; 2TI-RC024B Reading Below Expected Temperature; May 11, 2007 (NRC Identified)

1R22 Surveillance Testing
IR 618354; M&TE OOT - Safety Injection System Hot Leg Flow Balance Surveillance; April 17, 2007
IR 624542; Unit 2 Rod Drop Trending Results; May 2, 2007
IR 640815; Contact Volts Low For 2B RX Trip and Bypass Breaker; June 15, 2007
BVP 500-34; Set Up and Checkout of CRDM and Automated Rod Drop Timing Equipment; Revision 2
2BOSR 3.1.5-2; Unit 2 Train B Solid State Protection System Bi-Monthly Surveillance (Staggered); Revision 31

2BOSR 3.2.3-1; Unit 2 Undervoltage Simulated Start of 2A Auxiliary Feedwater Pump; Revision 2
2BVSR5.c.3-1; Unit 2 Safety Injection System Cold Leg Flow Balance; Revision 1
WO 819482 01; Clean & Inspect Battery Charger 1B (Inoperable for On-line Risk); May 30, 2007
WO 854564 01; 2A Diesel Generator Sequencer Test; April 12, 2007
WO 854564 03; Pre-Cal Recorder For 2BOSR 8.1.11-1 2A DG Sequence Test; April 12, 2007
WO 857173 01; Automated Rod Drop Timing Test; May 2, 2007
MA-BY-723-053-BY06; 1B AF Diesel Battery Charger 1AF01EB Battery Charger Test; May 30, 2007
Schematic Diagram ESF Sequencing and Actuation Cabinet Train A 2PA13J, 6E-2-4030EF01; Revision N

Corrective Action Documents as a Result of NRC Inspection
IR 639811; Procedure Enhancement for 1AF01EB-1 MA-BY-723-053-BY06; June 12, 2007 (NRC Identified)

1R23 Temporary Plant Modifications
IR 614651; B2R13: 2WF06PA (SX Room Sump Pump) Degraded Performance; April 9, 2007
IR 614654; B2R13: 2WF06PB (SX Room Sump Pump) Degraded Performance; April 9, 2007
IR 617118; Contractor Pipefitter Working Without Fall Protection; April 14, 2007
WO 97098856 37; Install Dewatering Pump/Hose Per TCCP EC 365398; April 10, 2007
WO 97098856 38; FNM Remove Dewatering Pump Following Valve Work per EC 365398; April 11, 2007
EC 365398; Installation of Temporary Sump Pumps and Connection to SX 42" Return Header to Facilitate 2SX033 Valve Placement; Revision 0
Technical Specification; Submersible Pump B2102, 60Hz
Issue 515247; Flooding and SX Inventory Risk Assessments; April 8, 2007

Corrective Action Documents as a Result of NRC Inspection
IR 618448; NRC Questions Rigging Activities for Sx Piping Replacement; April 17, 2007

1EP1 Drill Evaluation
Deliberately Blank

2OS1 Access Control to Radiologically Significant Areas/2OS2 ALARA Planning and Controls
Check-In Self-Assessment; B2R13 Outage ALARA Planning and Controls; ATI# 5585663-04; dated February 21, 2007
IR 00614843; B2R13 PZR WOL Project; dated April 9, 2007
ALARA Plan and associated ALARA Reviews; RWP 1007544; B2R13 Pressurizer Weld Overlay Welding, Grinding, Equipment Setup and Maintenance
ALARA Plan and associated ALARA Reviews; RWP 1007531; B2R13 Lower Core Barrel Moves
ALARA Plan and associated ALARA Reviews; RWP 1007522; B2R13 Manway/Diaphragm Removal/Installation and Bolt Clean
IR 614817; Individual Entered RCA without TLD; dated April 9, 2007

IR 614655; Worker Entered Aux Building Under Wrong RWP; dated April 8, 2007
IR 581157; Rad Worker Adherence 12 Month Rate Over Goal; dated January 19, 2007
IR 540053; B1R14LL / Shielding ALARA Post Job Review; dated October 4, 2006
IR 551176; U-1 RH System Drained Without Notification of On-Shift R.P; dated October 30, 2006
IR 459483; NOS ID: Improper Posting for Changing Radiological Conditions; dated February 27, 2006
IR 459830; NOS ID: RW Survey Did Not Show Current Posted Conditions; dated February 27, 2006
IR 615460; Issue for Radiation Monitoring Setpoints; dated April 10, 2007
RP-AA-460; Controls for High and Very High Radiation Areas; Revision 11
RP-AA-460-1001; Additional High Radiation Exposure Control; Revision 1
RP-AA-401; Operational ALARA Planning and Controls; Revision 7
RP-AA-400; ALARA Program; Revision 4
RP-AA-210; Dosimetry Issue, Usage, and Control; Revision 9

4OA1 Performance Indicator Verification

Byron Unit 1 PI: IE01; Unplanned Scrams per 7,000 Critical Hours
Byron Unit 1 PI: IE02; Scrams with Loss of Normal Heat Removal
Byron Unit 1 PI: IE03; Unplanned Power Changes per 7,000 Critical Hours
Byron Unit 2 PI: IE01; Unplanned Scrams per 7,000 Critical Hours
Byron Unit 2 PI: IE02; Scrams with Loss of Normal Heat Removal
Byron Unit 2 PI: IE03; Unplanned Power changes per 7,000 Critical Hours
Byron Unit 1 PI; BI01; Reactor Coolant System Activity
Byron Unit 2 PI; BI01; Reactor Coolant System Activity
Monthly Data elements for NRC/WANO Unit/Reactor shutdown Occurrences; January 2006 to March 2007;
LS-AA-2030; Monthly Data Elements for NRC Unplanned Power Changes per 7000 Critical Hours; January 2006 to April 2007;
LS-AA-2090; Monthly Data Elements for NRC Reactor Coolant System Specific Activity; January 2006 to April 2007

4OA2 Identification and Resolution of Problems

IR 563506; CDBI - Design Vulnerability with 1/2SI8969F Check Valve; November 29, 2006
IR 613708; R1-2CC9518 or 2CC9438 Failed LLRT; April 5, 2007
IR 614565; As-Found Inspection Failure of Check Valve 2CC9518; April 8, 2007
IR 620029; P-24 CC LLRT Failure; April 21, 2007
IR 620089; Water/Dirt Found in Vent Line of 2LT-0930 Transmitter; April 21, 2007
IR 622041; R1 Indication of Water in RWST Sensing Line; April 26, 2007
IR 623923; Gasket for SU FW Pump; April 30, 2007
IR 624214; Unit 2 S/U Feedwater Pump Tripped on Low Oil Pressure; May 1, 2007
IR 629361; MRC Directed Review of Steam Leaks Following B2R13; May 14, 2007
IR 633841; Unit 2 S/U FW PP Maintenance Rule Unavailability Not Communicated; May 25, 2007
M-139 Diagram of Component Cooling; Sheet 1; Revision AR
BYR-49573; Material Identification of Debris Found in a Vent Sensing Line From the RWST, Byron Unit 2; May 8, 2007

4OA5 Other Activities

IR 614168; R1 - Incorrect Layout of Weld Ring; April 6, 2007
IR 614174; Trash Rack Supplied by Vendor with Insufficient Welds; April 3, 2007
IR 617023; R1 - Incomplete Bolting on ECCS Trash Rake - Rework; April 13, 2007
IR 617603; Downstream Effects Testing Uncertainty; April 16, 2007
IR 617878; NOS ID Poor Placekeeping in ECCS Flow Balance Test; April 16, 2007
IR 617927; ECCS Sump Bolt Issue Extent of Condition; April 16, 2007
Quick Human Performance Investigation Report; Incomplete Bolting on ECCS Trash Rake; April 13, 2007
EC Number 359211; ECCS Sump Screed Modification; Revision 2
EC Number 365511 000; OP Evaluation 07-003, Incomplete Bolting on Unit 1 ECCS Sump Trash Rack; April 19, 2007
2BVSR 5.2.8-1 A ECCS Sump Inspection;Visual Inspection of the Containment Recirculation Sumps; April 30, 2007
Qualification Test Report #42481; Panduit Tefzel Products; July 15, 1997
S-1065B Plan; Sections & Details Containment Building Recirculating Sump Screens; Revision A
S-1070B Containment Building Recirculating Sump Sections & Details, Sheet 1; Revision A
S-1131 Containment Building Sections and Details; Revision H

Corrective Action Documents as a Result of NRC Inspection

IR 623298; R1 B2R13 ECCS Sump Inspection Findings (Including NRC Issues); April 30, 2007 (NRC Identified)

4OA7 Licensee-Identified Violations

IR 612694; Reactor Operator Momentarily Not in the “At the Controls Area”; April 3, 2007
LER 455-2007-001-00; “Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Due to an Initial Construction Weld Defect Allowing the Initiation of Primary Water Stress Corrosion Cracking”

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater System
ALARA	As Low As Reasonably Dose Achievable
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
BMV	Bare Metal Visual
CAP	Corrective Action Program
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
DRS	Division of Reactor Safety
EDY	Effective Degradation Year
EOC	End-of-Cycle
EPRI	Electric Power Research Institute
ET	Eddy Current
FHP	Fire Hazards Panel
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GL	Generic Letter
gpm	Gallons Per Minute
HDR-HRA	High Dose Rate - High Radiation Area
HELB	High Energy Line Break
HVAC	Heating, Ventilation, and Air Conditioning
IMC	Inspection Manual Chapter
IR	Issue Report
ISI	Inservice Inspection
LER	Licensee Event Report
MCR	Main Control Room
MOV	Motor Operated Valve
MT	Magnetic Particle Examination
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NRC	United States Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSO	Nuclear Station Operator
OOS	Out of Service
PARS	Publicly Available Records
PI	Performance Indicator
PT	Dye Penetrant Examination
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCA	Radiologically Controlled Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RI-ISI	Risk-Informed Inservice Inspection Program

RO	Reactor Operator
RPM	Radiation Protection Manager
RPV	Reactor Pressure Vessel
RSP	Remote Shutdown Panel
RVH	Reactor Vessel Head
RWP	Radiological Work Permit
RWST	Refueling Water Storage Tank
SDP	Significance Determination Process
SG	Steam Generator
SRO	Senior Reactor Operator
SSA	Safe Shutdown Analysis
SSC	Structure, System or Component
SX	Essential Service Water
TI	Temporary Instruction
TLD	Thermo-Luminescent Dosimeter
TRM	Technical Requirement Manual
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VHP	Vessel Head Penetration
VHRA	Very High Radiation Area
VHS	Video Home System
VT	Visual Examination
WO	Work Order