January 26, 2005

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

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000456/2004008;
05000457/2004008

Dear Mr. Crane:

On December 31, 2004, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Braidwood Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on January 4, 2004, with Mr. T. Joyce and other members of your staff.

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

Based on the results of this inspection, two self-revealed findings of very low safety significance were identified. One finding involved a violation of NRC requirements. However, because the violation was of very low safety significance and because the issue was entered into the licensee's corrective action program, the NRC is treating the finding as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy. The second finding was determined not to involve a violation of NRC requirements.

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, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Braidwood facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

David Passehl, Acting Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000456/2004008; 05000457/2004008
w/Attachment: Supplemental Information

cc w/encl:
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Plant Manager - Braidwood Station
Regulatory Assurance Manager - Braidwood Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
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REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2004008; 05000457/2004008
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	35100 S. Route 53 Suite 79 Braceville, IL 60407-9617
Dates:	October 1 through December 31, 2004
Inspectors:	S. Ray, Senior Resident Inspector N. Shah, Resident Inspector C. Acosta, Reactor Engineer T. Bilik, Reactor Engineer L. Haeg, Reactor Engineer J. House, Senior Radiation Specialist C. Roque-Cruz, Reactor Engineer T. Tongue, Project Engineer B. Metrow, Illinois Emergency Management Agency J. Roman, Illinois Emergency Management Agency
Observers:	P. Smith, Illinois Emergency Management Agency M. Wilk, Reactor Engineer
Approved by:	D. Passehl, Acting Chief Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000456/2004008, 05000457/2004008; 10/01/2004 - 12/31/2004; Braidwood Station, Units 1 & 2; Operator Performance During Non-Routine Evolutions and Events.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on radiation protection and inservice inspections. The inservice inspection; TI 2515/152, Revision 1; and TI 2515/160 inspections for the Braidwood Station were conducted by Region III inspectors and resident inspectors. Two Green findings were identified. One of the Green findings was associated with a Non-Cited Violation. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance was identified through a self-revealing event when, during the Unit 1 core reload, the licensee inadvertently bumped two fuel assemblies together. The primary cause of this event was related to the cross-cutting area of Human Performance; specifically, that the licensee staff failed to follow the applicable procedures controlling fuel movement.

  This finding was considered more than minor, because it challenged the integrity of the fuel cladding barrier. This finding was considered of very low safety significance as it only affected the fuel cladding barrier. Because of the failure to follow station procedures, the finding was considered a Non-Cited Violation of regulatory requirements. (Section 1R14.1)

Cornerstone: Initiating Events

- Green. A finding of very low safety significance was identified through a self-revealing event when the main control room received low level alarms for the Unit 1 electro-hydraulic fluid reservoir during the return-to-service of the 1C turbine-driven feedwater pump. The primary cause of this event was related to the cross-cutting area of Human Performance. Licensee maintenance staff had improperly installed a servo valve on the 1C pump resulting in the electro-hydraulic fluid leak during the subsequent pump start. The same staff had also improperly installed a cover plate over the servo valve, preventing station operators from identifying the leak during post-maintenance testing.

This finding was considered more than minor, because it increased the likelihood of a reactor transient. Specifically, the loss of electro-hydraulic fluid could have led to a turbine trip followed by a reactor trip, as both the 1B and C feedwater pumps and the main turbine share a common reservoir. This finding was of very low safety significance because of the short exposure time and the fact that the 1A motor driven feedwater pump was running and therefore available as a mitigating component. (Section 1R14.2)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 was shutdown, starting from about 95 percent power on October 4, 2004, for a refueling outage. Unit 1 was taken critical and the generator was placed on the grid on October 24, and the unit reached full power on October 28, 2004. Unit 1 operated at or near full power for the remainder of the inspection period except that power automatically ran back to about 78 percent on November 18, 2004, due to an inadvertent isolation of some of the feedwater heaters. The plant was restored to full power on November 19, 2004.

Unit 2 operated at or near full power for the entire inspection period, except for a unit trip occurring on December 22, 2004. The trip was caused when the feedwater regulating valve went closed in an effort to match an erroneous low steam flow signal caused by a failed isolation card. Unit 2 was restored to full power on December 25, 2004.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

Readiness for Seasonal Susceptibilities

a. Inspection Scope

The inspectors verified that the licensee had started its seasonal preparations for cold weather before the cold weather actually presented a challenge. The inspectors reviewed the licensee's completed freezing temperature annual surveillances conducted in accordance with the following procedures:

- 0BwOS XFT-A1, Unit 0 Freezing Temperature Equipment Protection Surveillance, Revision 12;
- 0BwOS XFT-A4, Unit 0 Freezing Temperature Equipment Protection Inside Surveillance, Revision 0;
- OP-AA-108-109, Seasonal Readiness, Revision 1; and
- OP-AA-108-111-1001, Severe Weather Guidelines, Revision 0.

The inspectors also performed walkdowns of the Units 1 and 2 refueling water and condensate storage tanks and associated heating systems and power supplies. Specifically, the inspectors observed whether these risk significant components were maintained consistent with the requirements of the Technical Specifications (TS), the Technical Requirements Manual, and the Updated Final Safety Analysis Report (UFSAR) with respect to cold weather protection. The inspectors reviewed the identification and resolution of conditions listed in the Attachment. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

Partial Walkdowns

a. Inspection Scope

The inspectors performed partial walkdowns of the accessible portions of risk-significant system trains during periods when the train was of increased importance due to redundant trains or other equipment being unavailable. The inspectors utilized the valve and electric breaker checklists listed to determine whether 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 whether there were no obvious deficiencies. The inspectors reviewed outstanding Work Orders (WOs) and Condition Reports (CRs) associated with the train to determine whether those documents identified issues affecting train function. The inspectors used the information in the appropriate sections of the TS and the UFSAR to determine the functional requirements of the system. The inspectors also reviewed the licensee’s identification of and the controls over the redundant risk-related equipment required to remain in service. In addition, the inspectors reviewed the adequacy of identification and resolution of the conditions listed in the Attachment.

The inspectors completed two samples of this requirement by walkdowns of the following trains:

- 1A auxiliary feedwater (AF) train in preparation for anticipated emergent work on the 1B AF train using the following checklists:

  - BwOP AF-E1, Electrical Lineup - Unit 1 Operating, Revision 9; and
  - BwOP AF-M1, Operating Mechanical Lineup Unit 1, Revision 10.

  The anticipated work on the 1B AF train was postponed. However, later in the week, the 1A AF train became protected equipment for the emergent work on the 1A diesel generator (DG), so the walkdown was still a risk-significant sample.

- 1B DG due to emergent unavailability of the 1A DG using the following checklists:

  - BwOP DG-E2, Electrical Lineup - Unit 1 1B DG, Revision 2E4;
  - BwOP DG-M2, Operating Mechanical Lineup Unit 1 1B DG, Revision 11; and
  - BwOP DO-M13, Operating Mechanical Lineup Unit 1 DG 1B Fuel Oil, Revision 3.

The equipment alignment walkdown of the 1B DG also included observations of a surveillance test required by TS using the following procedures:

- 1BwOSR 3.8.1.2-2, Unit 1 1B DG Operability Surveillance, Revision 10; and
- 1BwVSR 3.9.1.14-2, Unit 1 1B DG 24 Hour Endurance Run 18 Month, Revision 2.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Quarterly Inspection

a. Inspection Scope

The inspectors conducted fire protection walkdowns which 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 selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events with later additional insights or their potential to impact equipment which could initiate a plant transient. The inspectors used the Fire Protection Report, Revision 20, to determine: whether 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 inspectors completed eight samples of this inspection requirements during the following walkdowns:

- Unit 1 containment building inside the missile barrier (Fire Zone 1.1-1);
- Unit 1 containment building annulus area (Fire Zone 1.2-1);
- 2A centrifugal pump room (Fire Zone 11.3D-2);
- 1B DG room (Fire Zone 9.1-1);
- auxiliary building 401 foot elevation common area (Fire Zone 11.5-0);
- Unit 1 upper cable spreading rooms (Fire Zones 3.3 A-1, B-1, C-1, and D-1);
- Unit 2 upper cable spreading rooms (Fire Zones 3.3 A-2, B-2, C-2, and D-2); and
- diesel-driven fire pump room (Fire Zone 18.13-0).

The inspectors checked to see that minor issues identified during the inspection were entered into the licensee’s corrective action program by reviewing the documents listed in the Attachment.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

Internal Flood Protection Features

a. Inspection Scope

The inspectors performed an inspection of internal flooding vulnerabilities and protective measures for the 1B AF pump room. This room contained risk significant equipment and was potentially susceptible to flooding based on the licensee's risk analysis. The inspection consisted of a review of the internal flooding design features described in the UFSAR and in the licensee's internal auxiliary building flooding calculations. The inspectors performed a walkdown of the room to observe the condition of flood mitigating equipment credited in the licensee's calculation. The inspectors verified that the licensee was entering issues into its corrective actions program by reviewing the documents listed in the Attachment. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Annual Review

a. Inspection Scope

The inspectors completed two samples by reviewing the thermal performance test results for the Unit 0 component cooling heat exchanger and observing the inspection and cleaning of the Unit 1 main generator hydrogen seal oil cooler.

For the Unit 0 component cooling heat exchanger testing, conducted under WO 567863, "Thermal Performance Testing of Unit 1 Component Cooling Heat Exchanger," dated October 7, 2004, the inspectors observed that the testing methodology was consistent with applicable industry practice, that instrument uncertainties were properly accounted for, and that the test met the licensee's acceptance criteria.

For the Unit 1 main generator hydrogen seal oil cooler, the inspectors observed whether the inspection and cleaning were performed consistent with licensee procedures and with the guidance described in NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

Between October 1 and December 9, 2004, the inspectors conducted direct visual and record reviews of the implementation of the licensee's inservice inspection (ISI) program for monitoring degradation of the reactor coolant system (RCS) boundary, risk-significant piping system boundaries, and the containment boundary.

.1 Inspection Activities Other Than Steam Generator (SG) Tube Inspections, Pressurized Water Reactor (PWR) Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control (BACC)

The inspectors completed one sample by conducting a review of the following nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code or an NRC approved alternative:

- ultrasonic testing of two Unit 1 pressurizer nozzle to shell welds, weld 1PZR-01-N4B and 1PZR-01-N4C;
- liquid penetrant test of a Unit 1 integral welded attachment on the chemical and volume control system, weld 1CV-19-23.

The inspectors performed a review of the following examination with a recordable indication that has been accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code or an NRC approved alternative:

- ultrasonic testing of a Unit 1 pressurizer main steam elbow to safe-end weld, weld 1MS-07-01.01 (indication found to be acceptable per ASME Code, Section XI, Table IWB-3514-1).

The inspectors reviewed the following pressure boundary welds which were completed to verify that the welding process and welding examinations were performed in accordance with ASME Code requirements or an NRC approved alternative:

- welds 10-2 and 11-2, ISI class 1 weld of 1AF017B, a Unit 1 AF valve replacement.

.2 PWR Vessel Upper Head Penetration Inspection Activities

Braidwood Station Unit 1 reactor pressure vessel (RPV) has a low susceptibility to primary water stress corrosion cracking as defined by Section IV, Paragraph B of NRC Order EA-03-009. A 100 percent bare metal visual exam was performed during the last refueling outage (A1R10). A 100 percent Bare metal visual examination is therefore not due again until A1R13 or five years, whichever occurs first. A volumetric exam is to be performed during A1R12 refueling outage (Spring 2006). As such, the only inspection requirement this outage was a Mode 3 visual inspection/walkdown (a Generic Letter 88-05 surveillance) to identify potential boric acid leaks from pressure-retaining components above the RPV. The licensee's examination identified small, dried residue/deposits on five components above the insulation, but no leakage running down to the head. The deposits are believed by the licensee to have been evidence of prior leakage already identified during the previous outage but not fully cleaned/removed last outage. Five smears were taken from the areas of interest and analyzed. Results indicated that the material did not come from a reactor coolant leak. On October 14, 2004, Region III, NRR, and licensee staff conducted a conference call to discuss the licensee's conclusion. This was not considered a fully completed sample.

.3 BACC Inspection Activities

Following shutdown, the inspectors reviewed one sample of BACC walkdown visual examination activities through direct observation. The inspectors verified that the visual inspections emphasized locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed two boric acid leak corrective actions to confirm that they were consistent with the requirements of the ASME code and 10 CFR Part 50, Appendix B, Criterion XVI. The inspectors also reviewed the engineering evaluation performed for the same corrective action document. The evaluation was verified, as applicable, to ensure that ASME Code wall thickness requirements were maintained.

.4 SG Tube Inspection Activities

The licensee replaced the Braidwood Unit 1 SGs during the fall 1998 outage with Babcock and Wilcox SG's containing 6633 I-690TT tubes.

The inspectors were unable to review the results of in-situ pressure testing for the SG tubes, because the licensee did not identify any tubes that required pressure testing.

Prior to the current outage, 25 tubes (0.094 percent) had been plugged (SG A = 10, B = 12, C = 3, D = 0). This inspection resulted in an additional five tubes being plugged (SG A = 0, B = 2, C = 2, D = 1). The estimated size and number of tube flaws detected during the current outage versus the previous outage operational assessment predictions were bounded by the assessment prediction projections.

The inspectors confirmed that the licensee's inspection scope as contained in ED-BRW-04-0014, "Braidwood Unit 1 Steam Generator Inspection Degradation Assessment and Condition Monitoring Input Checklist for A1R11," was consistent with the plant TS and the Electric Power Research Institute Guidelines, Revision 6.

The licensee's SG long-range strategic plan originally showed A1R11 as requiring no SG inspections, (i.e., skip). However, foreign object wear of 48 percent through wall being identified in the 1A SG during A1R10 caused the inspection results to be classified as Category C-2 per TS 5.5.9.c. This required the inspection of at least one SG during A1R11 per TS 5.5.9-1. Therefore, inspection of the 1B SG was planned to be performed during A1R11.

The 1B SG inspection scope was to consist of 100 percent full-length bobbin coils in the 1B SG, 25 percent plus point inspection of hot leg dents and dings >5.0 volts, and 100 percent visual inspection of installed plugs. While conducting 100 percent full length eddy current inspection of the 1B SG, as described in ED-BRW-04-0014, indications that had the characteristics of foreign object wear degradation were identified in two tubes at the 6th lattice grid elevation. No foreign objects were detected by eddy current testing and the locations were inaccessible for visual inspection. The indications were located in the high flow region of the tube bundle. Two regions of high flow were determined by analysis and inspection results to be most susceptible to foreign object wear. This caused the A1R11 scope to be expanded to include approximately 22 percent of the tubes in the 1A, 1C, and 1D SGs in accordance with the Electric Power Research Institute Guidelines recommendations. It was during this expanded examination of the other three SGs, that additional volumetric indications and the subsequent plugging referred to above were performed (even though all tubes met SG integrity requirements). On October 19, 2004, a conference call was conducted between the licensee, Region III, and NRR Staff to discuss licensee inspection results and expansion.

The licensee's inspection performed in accordance with procedures and using qualified equipment and test probes assured that potential degradation areas were adequately examined. The licensee identified no new degradation mechanisms during the outage. The only tube repairs planned and performed for A1R11 were tube plugging and stabilizing. These processes are not required to be specifically listed in the TS.

The TS plugging limit was 40 percent through wall degradation. During the outage, the licensee discovered no tubes that exceeded this limit; however, five tubes were conservatively plugged as previously stated. The inspectors reviewed the TS repair criteria, and based upon the results of the SG tube inspection, confirmed that repair and depth sizing criteria were being adhered to.

The licensee did not have SG leakage greater than three gallons per day. The inspectors confirmed that the eddy current test probes and equipment were qualified for the expected types of tube degradation and assessed the site specific qualification of one or more techniques (e.g., equipment, data quality/noise issues, degradation mode).

The inspectors also verified that the licensee identified ISI/SG problems at an appropriate threshold and entered them in the corrective action program; determined that the licensee's procedures directed the licensee to perform a root cause evaluation and take corrective actions when appropriate; verified the appropriateness of the corrective actions for a selected sample of problems associated with ISI and SG inspection documented by the licensee; and determined that the licensee assessed the applicability of operating experience to their ISI group. This was not considered a fully completed sample.

.5 Identification and Resolution of Problems

The inspectors reviewed a sample of ISI related problems documented in the licensee's corrective action program to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

In addition, the inspectors verified that the licensee correctly assessed operating experience for applicability to the ISI group.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

Quarterly Review of Testing/Training Activity

a. Inspection Scope

The inspectors completed one sample by observing operating crew performance during evaluated simulator out-of-the-box scenario, "Braidwood Station Licensed Operator Requalification Simulator Scenario Guide 0461, Reactor Core Transients/OOB with Qualified Nuclear Engineer Evaluation," Revision 1.

The inspectors evaluated crew performance in the following areas:

- clarity and formality of communications;
- ability to take timely actions in the safe direction;
- prioritization, interpretation, and verification of alarms;
- procedure use;
- control board manipulations;
- oversight and direction from supervisors; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in the following Exelon Nuclear Procedures:

- OP-AA-101-111, Roles and Responsibilities of On-Shift Personnel, Revision 1;
- OP-AA-103-102, Watchstanding Practices, Revision 2;
- OP-AA-103-103, Operation of Plant Equipment, Revision 0;
- OP-AA-104-101, Communications, Revision 1; and
- OP-AA-300, Reactivity Management, Revision 0.

The inspectors checked to see whether the crew completed the critical tasks listed in the 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 weaknesses had been entered into the licensee's corrective action program by reviewing the documents listed in the Attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

Routine Inspection

a. Inspection Scope

The inspectors reviewed the licensee's overall maintenance effectiveness for risk-significant event initiating, mitigating, and barrier integrity systems. This evaluation consisted of the following specific activities:

- observing the conduct of planned and emergent maintenance activities where possible;
- reviewing selected CRs, open WOs, and control room log entries in order to identify system deficiencies;
- reviewing licensee system monitoring and trend reports;
- attending various meetings throughout the inspection period where the status of maintenance rule activities was discussed;
- a partial walkdown of the selected system; and
- interviews with the appropriate system engineer.

The inspectors also reviewed whether the licensee properly implemented Maintenance Rule, 10 CFR 50.65, for the system. Specifically, the inspectors determined whether:

- the system was scoped in accordance with 10 CFR 50.65;
- performance problems constituted maintenance rule functional failures;
- the system had been assigned the proper safety significance classification;
- the system was properly classified as (a)(1) or (a)(2); and
- the goals and corrective actions for the system were appropriate.

The above aspects were evaluated using the maintenance rule program and other documents listed in the Attachment. The inspectors also checked to see that the licensee was appropriately tracking reliability and/or unavailability for the systems.

The inspectors completed one sample in this inspection requirement by reviewing the following system:

- Units 1 and 2 cooling lake and ultimate heat sink.

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 activities were chosen based on their potential impact on increasing the probability of an initiating event or impacting the operation of safety-significant equipment. The inspections were conducted to determine whether evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place where appropriate.

The licensee’s daily configuration risk assessments records, observations of operator turnover and plan-of-the-day meetings, and observations of work in progress, were used by the inspectors to determine whether the equipment configurations were properly listed, that protected equipment were identified and were being controlled where appropriate, that work was being conducted properly, and that significant aspects of plant risk were being communicated to the necessary personnel.

In addition, the inspectors reviewed selected issues listed in the Attachment, that the licensee encountered during the activities, to determine whether problems were being entered into the corrective action program with the appropriate characterization and significance.

The inspectors completed seven samples by reviewing the following activities:

- Unit 1 shutdown Orange risk condition due to unavailability of service water controlled by 1BwOA PRI-8 “Essential Service Water Malfunction Unit 1 Attachment E (Page 1 of 4) A1R11 SX Valve Replacement Contingency Actions,” Revision 101a;
- emergent maintenance on the 1B AF pump;
- contingency plans for the installation of a freeze seal to support maintenance on valve 1SI8819D, while the reactor water level was at the flange, in accordance with CC-AA-112, “Temporary Configuration Changes,” Revision 8;
- troubleshooting of electrical ground on DC bus 112, in accordance with BwOP DC-23-112, “125V DC Bus 112/114 Ground Detection,” Revision 0;
- installation of a temporary modification on unit auxiliary transformer 141-2, in accordance with WO 352045 00, “Change ‘2 of 2' Sudden Pressure Relay Logic to ‘1 of 1' Logic Due to DC Ground Associated with Sudden Pressure Relay ‘63-1' (UAT 141-1),” dated November 1, 2004;
- a first time evolution where oil was added to the lower bearing of the running 1B heater drain pump while the 1A heater drain pump was out-of-service for planned maintenance, in accordance with BwOP HD-300, “Sampling the Heater Drain Pump Motor Lubricating Oil Reservoirs,” Revision 1; and
- emergent unavailability of the 1A DG due to a failure during a 24-hour endurance run controlled by Memorandum, “Protected Equipment - 1A DG Emergent,” dated December 1, 2004.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors completed six samples by observing the following events:

- fire brigade response to an October 8, 2004, fire in the service building;
- inadvertent bumping of fuel bundles during loading of the Unit 1 reactor core in accordance with:
  - Westinghouse F-5, "Instructions, Precautions, and Limitations for Handling New and Partially Spent Fuel Assemblies," Revision 17;
  - OU-AP-200, "Administrative Controls During Fuel Handling Activities for Byron and Braidwood," Revision 0; and
  - OU-AP-205, "Fuel Handling Activities in Containment During Refuel Outages for Byron and Braidwood," Revision 0c;
- main control room alarms caused by electro-hydraulic fluid leak following the return-to-service of the 1C main feedwater pump;
- operator response to an automatic turbine runback due to isolation of feedwater heaters on Unit 1 as recorded in Braidwood's Archival Operations Narrative Logs, November 18 - November 19, 2004;
- operator response to an unplanned isolation of the extraction steam to the Unit 1 "C" low pressure heaters on December 13, 2004; and
- reactor startup on Unit 2 on December 23, 2004.

For each event, as applicable, the inspectors observed the control room response, interviewed plant operators and reviewed plant records including control room logs, operator turnovers, and CRs. The inspectors checked to see whether the control room response was consistent with station procedures and determined whether identified discrepancies were captured in the corrective action program. Corrective action documents reviewed as part of this inspection are listed in the Attachment.

b. Findings

.1 Inadvertent Fuel Bumping During Unit 1 Core Reload

Introduction: A finding of very low safety significance (Green) was identified through a self-revealing event when, during the Unit 1 core reload, the licensee inadvertently bumped two fuel assemblies. The bumping was caused by a failure to follow licensee procedures during fuel movement. The finding was considered a Non-Cited Violation (NCV) of regulatory requirements. This finding resulted in potential degraded performance of the fuel integrity barrier.

Description: On October 14, 2004, during Unit 1 core reloading, the fuel assembly being loaded into core location F-8, became stuck as it was being loaded onto the lower core plate. A subsequent, attempt to remove the stuck assembly was unsuccessful. The Senior Reactor Operator, after consulting with other licensee staff involved with the core load, decided to laterally move the stuck assembly into "open water" (i.e., laterally move the assembly while maintaining two inches of space between adjacent assemblies). During the move, the stuck assembly began to tilt with the top of the fuel assembly moving away from the relative position of the assembly bottom nozzle. When the top of the assembly was two full locations away from the original position (above core location F-6), the bottom broke free, swung and impacted the face of a new fuel assembly stored in core location F-5. All fuel moving activities were then suspended and the licensee started a prompt investigation.

The licensee investigation determined that the primary cause of the event was a failure of the Senior Reactor Operator and the other licensee staff to verify that the lateral fuel move was allowed by procedures and to involve licensee management prior to the move. The licensee determined that the move was not permitted by station procedures and that two other licensee managers assigned to oversee refueling were not informed prior to the move. The licensee identified that two adjacent assemblies, in core locations G-8 and G-9, were improperly placed onto the lower core support plate and were free standing. This interfered with the insertion of the assembly into core location F-8, resulting in that assembly getting stuck. Contributing to the event, was the fact that the Senior Reactor Operator was newly licensed and that this was his first supervision of a core reload.

The licensee subsequently identified that the fuel assembly in core location G8 had suffered damage. This assembly was a once burned assembly. This assembly was returned to the spent fuel pool, reconstituted and subsequently reloaded into the core. There were no fission product releases detected or other adverse radiological consequences from this event.

Analysis: The inspectors determined that the failure to follow station procedures for performing fuel moves was a performance deficiency warranting a significance evaluation in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued June 20, 2003. This finding was considered more than minor, because it challenged the integrity of the fuel cladding barrier. The inspectors determined that this event also affected the cross-cutting area of Human Performance, because of the actions of the Senior Reactor Operator and the refueling crew in failing to assure that the fuel in core locations G-8 and G-9 were properly seated and in deciding to move a stuck fuel assembly, outside of station procedures, resulting in damage to another fuel assembly.

The inspectors performed a significance determination of this issue, using IMC 0609, "Significance Determination Process," dated March 21, 2003, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," dated September 10, 2004.

For the Phase 1 screening, the inspectors determined that the event only affected the fuel barrier under the RCS Barrier/Fuel Barrier Cornerstones column. Therefore, this finding is considered of very low safety significance (Green). This finding was assigned to the Barrier Integrity Cornerstone for Unit 1.

Enforcement: Technical Specification 5.4 requires, in part, that written procedures be implemented covering those activities in Regulatory Guide 1.33, Revision 2, Appendix A. Appendix A of Regulatory Guide 1.33, Revision 2, required that procedures be developed to cover refueling and core alterations. Licensee procedure OU-AP-205, "Fuel Handling Activities in Containment During Refuel Outages for Byron and Braidwood," Revision 0, contained guidelines for close contact fuel movement. The licensee determined that the lateral fuel movement performed on October 14, 2004, was not permitted by this procedure. As stated, the licensee halted all fuel movement, initiated an investigation and entered the issue into the corrective action program as CR 263845. Because this violation was of very low safety significance and was entered into the licensee's corrective action program, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000456/2004008-01).

.2 Near Trip of Unit 1 Due to Electro-Hydraulic Fluid Leak

Introduction: A finding of very low safety significance (Green) was identified through a self-revealing event when the main control room received low level alarms for the Unit 1 electro-hydraulic (EH) fluid reservoir during the return to service of the 1C turbine driven feedwater pump. The EH fluid leakage was caused, in part, by the improper installation of a servo valve associated with the feedwater pump low pressure governor valve. The finding was not considered a violation of regulatory requirements. This finding increased the probability of a reactor transient.

Description: On November 5, 2004, the Unit 1 control room received a low level alarm, and shortly thereafter, a low-2 alarm for the EH reservoir for the 1C feedwater pump. An operator was immediately dispatched to isolate the EH fluid to the pump. A subsequent, licensee investigation identified that a servo valve had been improperly installed on the 1C pump, causing the EH fluid to leak. Additionally, an enclosure cover had been installed over the servo valve preventing the leak from being identified by plant operators during post maintenance testing. This event could have resulted in a turbine trip followed by a reactor trip, as both the 1B and C feedwater pumps and the main turbine share a common EH fluid reservoir. The inspectors observed a substantial accumulation of EH fluid (estimated to be about 100 gallons by the licensee) around the 1C pump shortly after the event.

Analysis: The inspectors determined that the improper installation of the servo valve and the enclosure cover were performance deficiencies warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. This finding was considered more than minor, because it increased the likelihood of an initiating event (i.e., reactor trip due to a main turbine trip). The inspectors determined that this event also affected the cross-cutting area of Human Performance, due to the improper maintenance on the pump.

The inspectors performed a significance determination of this issue, using IMC 0609, "Significance Determination Process," dated March 21, 2003, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," dated September 10, 2004.

For the Phase 1 screening, the inspectors answered "No" to all of the questions listed under the Initiating Events column. This was due to the short exposure time and the fact that the 1A motor driven feedwater pump was running and therefore available as a mitigating component. Therefore, this finding (FIN 05000456/2004008-02) is considered of very low safety significance. This finding was assigned to the Initiating Event Cornerstone for Unit 1.

Enforcement: The inspectors concluded that no violation of regulatory requirements had occurred as the 1C main feedwater pump is a non-safety related component. The licensee entered this event into its corrective action system as CR 270727, “EH Leak on 1C Main Feedwater Pump,” on November 5, 2004.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated plant conditions and selected CRs 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 compared the operability and design criteria in the appropriate section of the UFSAR to the licensee’s evaluations presented in the CRs and documents listed to determine whether the components or systems were operable. The inspectors also conducted interviews with the appropriate licensee system engineers and conducted plant walkdowns, as necessary, to obtain further information regarding operability questions.

The inspectors completed two samples by reviewing the following operability evaluations and conditions:

- CR 265800, “Potentially Unqualified Relay Base Installed in the 1B Auxiliary Feedwater Pump,” October 21, 2004, evaluated per BRW-04-0083-E, “Review of the Tentec Seismic Qualification Test Report to A Replacement Potter Brumfield Relay Socket for use on the Auxiliary Feedwater Pump Diesel Engine,” Revision 0, October 21, 2004; and
- Braidwood Technical Evaluation Engineered Calculation 351809, October 12, 2004, “Use of Alternative Source Term Calculation in Support of Operability Determination for Control Room Tracer Gas Testing at the Byron and Braidwood Generating Stations.”

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Review of Selected Operator Workarounds

a. Inspection Scope

The licensee had no formally identified operator workarounds during this inspection period. Therefore, the inspectors conducted reviews of plant conditions and documents to determine whether there were any issues that should have been evaluated and tracked as an operator workaround. The inspectors attempted to find conditions that could increase the potential for personnel errors or that would require compensatory actions to operate equipment during transients or events.

The inspectors completed two samples by conducting the following reviews:

- a walkdown of mitigating equipment in the plant and the equipment's controls in the main control room; and
- a review of condition reports written in the previous six months.

b. Findings

No findings of significance were identified.

.2 Semi-annual Review of Cumulative Effect of Operator Workarounds

a. Inspection Scope

The inspectors completed a semi-annual review of the cumulative effect of operator workarounds. Since there were no active workarounds at the time of the inspection, the inspectors expanded the scope to review other issues that might affect operations. This review included current temporary configuration changes, disabled alarms, operator challenges, deficiencies requiring compensatory actions or monitoring, operability determinations, and other main control room distractions. The inspectors also attended Plant Health Committee meetings where the status of corrective actions on operator issues were discussed. The inspectors checked to see that the licensee had plans and schedules to correct the conditions in a reasonable time and that the conditions did not affect operability of risk-significant equipment or the ability of operators to respond to a transient or event. Documents reviewed during this inspection are listed in the Attachment. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during the Unit 1 refueling outage conducted between October 4 and October 24, 2004. This inspection constituted one sample of the inspection requirement.

Inspection activities included a review of the outage schedule, safe shutdown plan and administrative procedures governing the outage, periodic observations of equipment alignment risk control, maintenance activities, and control room activities. Specifically, the inspectors determined whether the licensee effectively managed elements of shutdown risk pertaining to reactivity control, decay heat removal, inventory control, electrical power control, containment integrity, and vital support systems.

The inspectors performed the following activities on a daily basis during the outage:

- attended control room operator and outage management turnover meetings to determine whether shutdown risk and plant status were well understood and communicated;

- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of RCS instrumentation and compared channels and trains against each other;
- performed walkdowns of the auxiliary and containment buildings to observe ongoing work activities; and
- reviewed selected issues that the licensee entered into its corrective action program to determine whether the problems were being entered with the appropriate characterization and significance, and that operability issues were resolved before startup.

During the routine walkdowns, the inspectors selectively checked to see that equipment configuration was appropriately maintained and that redundant equipment was available when maintenance was occurring on plant systems.

Additionally, the inspectors performed the following specific activities:

- reviewed the detailed outage schedule and risk control plans;
- observed the control room staff during portions of the plant shutdown and cooldown;
- participated in the initial containment Mode 3 walkdowns for evidence of reactor coolant leakage;
- observed portions of fuel offloading and onloading;
- observed portions of ISIs of the upper reactor head area, the lower reactor head, the pressurizer penetration welds, and the SGs (documented in other sections of this report);
- observed several outage surveillance tests and post maintenance tests (documented in other sections of this report);
- observed control room response during periods of reduced reactor coolant inventory; and
- reviewed the results of startup core physics testing.

The inspectors checked to see that minor issues identified during the inspection were entered into the licensee's corrective action program. Documents reviewed during these inspection activities are listed in the Attachment.

b. Findings

No findings of significance were identified.

1RST Post-Maintenance and Surveillance Testing - Pilot (71111.ST)

a. Inspection Scope

The inspectors reviewed post-maintenance and surveillance testing activities associated with important mitigating systems, barrier integrity, and support systems to ensure that the testing adequately demonstrated system operability and functional capability. For post-maintenance testing, the inspectors used the appropriate sections of the TS and UFSAR, as well as the WOs for the work performed, to evaluate the scope of the maintenance and to determine whether the post-maintenance testing was performed adequately, demonstrated that the maintenance was successful, and that operability was restored. For surveillance testing, the inspectors determined whether the testing met the TS, the UFSAR, and licensee procedural requirements, and demonstrated that the equipment was capable of performing its intended safety functions. The inspectors determined whether the testing met the frequency requirements; that the tests were conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; that the test acceptance criteria was met; and that the results of the tests were properly reviewed and recorded. The activities were selected based on their importance in demonstrating mitigating systems capability and barrier integrity. The inspectors checked to see that minor issues identified during the inspection were entered into the licensee's corrective action program by reviewing the documents in the Attachment.

Note that this inspection is a pilot for a proposed consolidated procedure combining the previous Post-Maintenance Testing (71111.19) and Surveillance Testing (71111.22) procedures.

Five samples were completed by observing post-maintenance testing after the following activities:

- testing of the Unit 1 engineered safety features actuation logic following relay replacement in accordance with 1BwOSR 3.3.2.8-602A, "Unit 1 Engineered Safety Features Actuation System Instrumentation Slave Relay Surveillance (Train A - K602 and K647)," Revision 2;
- 1B DG sequence testing following governor and sequence timer work in accordance with 1BwVSR 3.8.1.19-2, "1B Diesel Generator Emergency Core Cooling System Sequencer Surveillance," Revision 7;
- planned and emergent maintenance on the 1B AF pump in accordance with 1BwVSR 5.5.8.AF.2, "Unit 1 Diesel Driven Auxiliary Feedwater Pump ASME Quarterly Surveillance," Revision 8, and 1BwOSR 3.7.5.4-2, "Unit 1 Diesel Driven Auxiliary Feedwater Pump Surveillance," Revision 7;
- emergent maintenance on the 1A DG field excitation circuit in accordance with 1BwVSR 3.8.1.14-1, "Unit 1 1A Diesel Generator 24 Hour Endurance Run 18 Month," Revision 2; and
- emergent maintenance on the 1A DG due to failure to come up to speed and voltage within ten seconds in accordance with the same procedure as the above sample.

Five samples were completed by observing and evaluating the following surveillance tests:

- 2A DG slave start test in accordance with 2BwOSR 3.3.2.8-611A, "Unit Two Engineered Safety Features Actuation System Instrumentation Slave Relay Surveillance (Train A Automatic Safety Injection - K611)," Revision 2;
- Unit 1 AF full flow testing in accordance with:
    - A1R11 1B AF Pump Testing Sequence;
    - 1BwVS 800-14, "Unit 1 Full Flow Test and Equipment Response Time of Auxiliary Feedwater Pumps," Revision 6;

    - BwOP AF-7, “Auxiliary Feedwater Pump B (Diesel) Startup on Recirc,” Revision 25; and
    - 1BwOS TRM 2.7.a.1, “Unit 1 Auxiliary Feedwater Diesel Prime Mover Performance Surveillance,” Revision 0;
- 1A DG sequencer testing in accordance with 1BwVSR 3.8.1.19-1, “1A Diesel Generator Emergency Core Cooling System Sequencer Surveillance,” Revision 6;
- tracer gas testing of the 0A and 0B trains of control room ventilation in accordance with Special Test Procedure 01-012, “Control Room Envelope Tracer Gas Test,” Revision 0; and
- review of Unit 1 RCS leakage test results in accordance with 1BwOSR 3.4.13.1, “Unit One Reactor Coolant System Water Inventory Balance Surveillance,” Revision 7, and Braidwood’s Archival Operations Narrative Logs - Unit 1, Search Criteria “3.4.13.1,” January 1, 2004 through November 30, 2004.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the installation of a freeze seal to support planned maintenance on the 1SI8819D valve conducted in accordance with Contingency Plan, “Outage Safety Assessment Performance of 1SI8819B & D Replacements (Safety Injection Cold Leg Injection Upstream Check Valve) During A1R11.” The inspection consisted of observing the seal installation and removal, reviewing the applicable station procedures and reviewing licensee contingency plans in the event of seal failure. The inspectors also checked to see whether minor issues identified during the inspection were entered into the licensee’s corrective action program. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors discussed performance indicators (PIs) with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any PIs for the occupational exposure cornerstone to review. There were none.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified three radiologically significant work areas within radiation areas, high radiation areas (HRA), and areas for potential airborne radioactivity in the plant. Work packages for these areas and other work sites having significant radiological risk were reviewed to determine if radiological controls including surveys, postings and barricades were acceptable.

These work areas were walked down and surveyed to verify that the prescribed radiation work permit (RWP), procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located. These areas included, but were not limited to, steam generators, the vessel head, and the seal table. This review represented one sample.

The inspectors reviewed the RWPs and work packages used to access these and other high radiation work areas, and evaluated the work control instructions and control barriers that had been specified. Technical specification HRA and locked high radiation area requirements were used as standards for the necessary barriers. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Pre-job work briefings for work crews and radiation protection (RP) personnel were attended to verify that workers were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review represented one sample.

The inspectors reviewed RWPs for work in airborne radioactivity areas to determine if there was a potential for individual worker internal exposures of >50 millirem committed effective dose equivalent. Barrier integrity and engineering controls performance, such as high efficiency particulate filtration ventilation system operation, were evaluated. Work areas having a history of, or the potential for, airborne transuranic isotopes were evaluated to verify that the licensee had considered the potential for these isotopes, and had provided appropriate worker protection. This review represented one sample.

The licensee’s internal dose assessment process for internal exposures > 50 millirem committed effective dose equivalent was assessed for adequacy. This review represented one sample.

The inspectors examined the licensee’s physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within the spent fuel or other storage pools. This included discussions with cognizant licensee representatives. This review represented one sample

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution For Access Control To Radiological Areas

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, Licensee Event Reports, and Special Reports related to the access control program to verify that identified problems were entered into the corrective action program for resolution. This review represented one sample.

Corrective action reports related to access controls and HRA radiological incidents (non-PIs identified by the licensee in high radiation areas <1Rem/hr) were reviewed. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies identified in the problem identification and resolution process, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies. This review represented one sample.

The inspectors discussed PIs with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any PIs for the occupational exposure cornerstone to review. There were none. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors selected three jobs being performed in radiation areas, potential airborne radioactivity areas, and HRAs for observation of work activities that presented the greatest radiological risk to workers. This involved work that was estimated to result in higher collective doses, and included preparation and inspection of steam generators, and other work areas where radiological gradients were present.

The inspectors reviewed radiological job requirements including RWP requirements and work procedure requirements, and attended as low as is reasonably achievable (ALARA) job briefings. Job performance was observed with respect to these requirements to verify that radiological conditions in the work areas were adequately communicated to workers through pre-job briefings and postings. This review represented one sample.

The inspectors also verified the adequacy of radiological controls including required radiation, contamination, and airborne surveys for system breaches; RP job coverage which included audio and visual surveillance for remote job coverage, and contamination controls. This review represented one sample.

Radiological controls for work in HRAs having significant dose rate gradients were reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel, and to verify that licensee controls were adequate. Radiological conditions in these work areas, which included the steam generators, along with the vessel head and bottom of the vessel, increased the necessity of providing multiple dosimeters or enhanced job controls. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate, High Radiation Area, and Very High Radiation Area Controls

a. Inspection Scope

The inspectors reviewed the licensee's PIs for high risk, high dose rate and HRAs, and for all very high radiation areas to verify that workers were adequately protected from radiological overexposure. Discussions were held with radiation protection management concerning high dose rate/HRA and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to verify that any procedure modifications did not substantially reduce the effectiveness and level of worker protection. This review represented one sample.

The inspectors evaluated the controls that were in place for special areas that had the potential to become very high radiation areas during certain plant operations including spent resin transfer operations and control of highly radioactive items stored in the spent fuel pool. Discussions were held with RP supervisors to determine how the required communications between the RP group and other involved groups would occur beforehand in order to allow corresponding timely actions to properly post and control the radiation hazards. This review represented one sample.

During plant walkdowns, the posting and locking of entrances to high dose rate HRAs, and very high radiation areas were reviewed for adequacy. This review represented one sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated RP work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This review represented one sample.

Radiological problem reports, which found that the cause of an event resulted from radiation worker errors, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions were discussed with radiation protection management. This review represented one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed and evaluated RP technician performance with respect to RP work requirements. This was done to evaluate whether RP technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities. This review represented one sample.

Radiological problem reports, which found that the cause of an event was RP technician error, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This review represented one sample.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends along with ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average collective exposure in order to help establish resource allocation and to provide a perspective of significance for any resulting inspection finding assessment. This review represented one sample.

The inspectors reviewed the outage work scheduled during the inspection period along with associated work activity exposure estimates including the five work activities which were likely to result in the highest personnel collective exposures. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and selected the three work activities of highest exposure significance. This review represented one sample.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, along with engineering and work controls, that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the assumptions and bases for the current annual collective exposure estimate. Procedures were reviewed in order to evaluate the licensee's methodology for estimating work activity-specific exposures and the intended dose outcome. Dose rate and man-hour estimates were evaluated for reasonable accuracy. This review represented one sample.

The licensee's process for adjusting exposure estimates or re-planning work, when unexpected changes in scope, emergent work or higher than anticipated radiation levels were encountered, was evaluated. This included determining that adjustments to estimated exposure (intended dose) were based on sound radiation protection and ALARA principles and not adjusted to account for failures to control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process. This review represented one sample.

The licensee's exposure tracking system was evaluated to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution was sufficient to support control of collective exposures. RWPs were reviewed to determine if they covered too many work activities to allow work activity specific exposure trends to be detected and controlled. During the conduct of exposure significant work, the inspectors evaluated if licensee management was aware of the exposure status of the work and would intervene if exposure trends increased beyond exposure estimates. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Controls

a. Inspection Scope

The inspectors selected work activities in radiation areas, potential airborne radioactivity areas, and HRAs for observation emphasizing work activities that presented the greatest radiological risk to workers. Jobs that were expected to result in significant collective doses were observed and included steam generator and vessel head inspection activities and work in areas that involved potentially changing or deteriorating radiological conditions. The licensee's use of ALARA controls for these work activities was evaluated using the following:

- The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding. This review represented one sample.

- Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays. This review represented one sample.

- The inspectors attended work briefings and observed ongoing work activities to determine if workers received appropriate on-the-job supervision to ensure the ALARA requirements were met. This included verification that the first-line job supervisor ensured that the work activity was conducted in a dose efficient manner by minimizing work crew size, ensuring that workers were properly trained, and that proper tools and equipment were available when the job started. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RP technician performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and HRAs that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved. This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

Cornerstones: Mitigating Systems and Barrier Integrity

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors determined whether the licensee had correctly reported performance indicator data, in accordance with the criteria in Nuclear Energy Institute 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 2. The data reported by the licensee was compared to a sampling of control room logs, CRs, and other sources of data generated since the last verification. The inspectors completed four samples by examining the following performance indicators:

Unit 1

- unplanned power changes per 7000 critical hours; and
- safety system unavailability - PWR high pressure safety injection system.

Unit 2

- unplanned power changes per 7000 critical hours; and
- safety system unavailability - PWR high pressure safety injection system.

b. Findings

No findings of significance were identified.

Cornerstones: Occupational and Public Radiation Safety

.2 Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's PI submittals for the 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 PIs were reviewed:

- Occupational Exposure Control Effectiveness: Units 1 and 2

  The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety, to determine if indicator related data was adequately assessed and reported during the previous four quarters. The inspectors compared the licensee's PI data with the condition report database, reviewed radiological restricted area exit electronic dosimetry transaction records, and conducted walkdowns of accessible locked high radiation area entrances to verify the adequacy of controls in place for these areas. Data collection and analysis methods for PIs were discussed with licensee representatives to verify that there were no unaccounted for occurrences in the Occupational Radiation Safety PI as defined in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline." This review represented one sample.

- Radiological Environmental Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences: Units 1 and 2

  The inspectors reviewed data associated with the RETS/ODCM PI to determine if the indicator was accurately assessed and reported. This review included the licensee's condition report database for the previous four quarters, to identify any potential occurrences such as unmonitored, uncontrolled or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also selectively reviewed gaseous and liquid effluent release data and the results of associated offsite dose calculations and quarterly PI verification records generated over the previous four quarters. Data collection and analyses methods for PIs were discussed with licensee representatives to determine if the process was implemented consistent with industry guidance in Revision 2 of Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline.” This review represented one sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to determine whether they were being entered into the licensee’s corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee’s corrective action program as a result of the inspectors’ observations are generally denoted in the Attachment. These activities were part of normal inspection activities and were not considered separate samples.

b. Findings

No finding of significance were identified.

.2 Semiannual Review for Trends

a. Inspection Scope

The inspectors reviewed all CRs generated during the time period between May 31 and November 1, 2004, in an attempt to identify potential trends involving adverse human or equipment performance. This inspection was part of the requirements of Inspection Procedure 71152 for monitoring plant status but was not considered an inspection procedure sample. Documents reviewed which indicated previously unrecognized trends are listed in the Attachment. The inspectors verified that minor issues identified during this inspection were entered into the licensee’s corrective action program.

The screening was accomplished by grouping CRs into broad categories during daily screening. These groups included, but were not limited to, items involving the same issue, same equipment/components, or the same program. For the period of review, the inspectors also obtained lists of all completed or ongoing licensee common cause investigations, all CRs where the title indicated a trend or potential trend, all systems currently in the maintenance rule (a)(1) status, and the licensee’s most recent System

Health Indicator Program report. These documents were considered licensee-identified trends. The following items were eliminated from the scope of this inspection:

- CRs dealing with company policies, administrative issues, and other minor issues;
- CRs associated with established licensee trending programs/processes, such as the rework program, that were previously reviewed during the semi-annual trend evaluation discussed in Inspection Report 2004-04;
- single CRs with no repeat occurrences or common issues;
- CRs that discussed NRC-identified trends from previous inspection activities;
- CRs that discussed strictly programmatic problems, as the inspection specifically focused on human and equipment performance issues;
- CRs involving Security, Radiation Protection, ISI and Emergency Preparedness issues, that were reviewed by regional specialists during ongoing inspection activities;
- CRs that were duplicates of other CRs involving the same event or failure;
- CRs generated as a result of a special licensee initiative to specifically look for issues in a certain area; and
- CRs associated with a trend previously identified by the licensee.

The review of equipment issues was limited to the reactor coolant, residual heat removal, essential and non-essential service water, feedwater, component cooling, pressurizer, safety injection, AF, circulating water, fire protection, emergency DG and DC battery systems. These systems were selected based on their risk significance per the licensee's probabilistic risk assessment model. The remaining groups were screened for potential common cause issues and were considered potential trends. These potential trends were then provided to the licensee for discussion and additional followup.

b. Finding and Observations

The inspectors determined that licensee employees were writing CRs with a low threshold, that employees at all levels of the organization were writing CRs, and that CRs were written for all issues of significance. The largest group of CRs concerned industrial safety issues, however, the inspectors also noted a large number of CRs for employee identified equipment issues. Collectively, this provided one indication of a safety conscious work environment.

The majority of the trends were identified by the licensee. Each trend was documented in a CR and evaluated to determine if a common cause evaluation was necessary. The licensee-identified trends were identified by a combination of the work groups involved with the issues, department or station corrective action program coordinators, department managers, and the nuclear oversight group, indicating that multiple groups were looking for trends.

The inspectors identified the following potential trends that had not been previously evaluated by the licensee:

- recurring issues with blocked or inoperable fire protection equipment;

- several instances of elevated temperatures on switchyard breakers;
- several instances of low dielectric on switchyard breakers;
- numerous problems with direct current ground detectors;
- numerous examples of errors with the licensee's probabilistic risk assessment model; and
- numerous examples of oil leaks on the emergency DGs.

The inspectors also found several examples of potential trends identified in CRs, but which apparently were not evaluated by the licensee. The licensee captured the above issues in CR 282949, issued on December 15, 2004.

4OA3 Event Followup (71153)

The inspectors completed two inspection samples in this area.

.1 Licensee Event Report (LER) Review

a. (Closed) LER 05000257/2004-001-00: Unit 2 Pressurizer Backup Heater Groups A and D Identified to be Inoperable Greater Than Required TS Allowed Outage Time.

On September 25, 2004, the Unit 2A and 2D pressurizer backup heater groups failed to energize when their control switches were placed in the "ON" manual position. The last time both heater groups were verified operable, was during post maintenance testing conducted on March 3 and 4, 2004, respectively. The period of inoperability exceeded the 72 hours of Allowed Outage Time permitted by TS 3.4.9.

The root cause was determined to be a lack of torque specifications for the heater armature mounting screws, resulting in improper torquing of the screws. The loose screws caused mechanical binding of the armature, preventing proper operation of the heaters. As a corrective action, the licensee planned to develop a new maintenance procedure specifying the proper torque values. This issue was captured in the licensee's corrective action program as CR 256955, issued the day of the event.

The inspectors concluded that this issue was less than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. Specifically, the pressurizer backup heaters were non-safety related and were not specifically credited in the accident analyses as discussed in the licensee's UFSAR. However, because the TS Allowed Outage Time was exceeded, this event was considered a violation of minor significance that is not subject to enforcement action in accordance with Section VI of the NRC's Enforcement Policy. This LER is considered closed.

.2 Unit 2 Reactor Trip

On December 22, 2004, Unit 2 tripped from 100% power due to a low-low steam generator water level on the 2C steam generator. The low level was caused by an erroneous low steam flow signal from a failed isolation card associated with the steam generator water level control logic. Specifically, the erroneous signal generated a steam flow/feed flow mismatch error that caused the steam generator water level control system to close the feedwater regulating valve. During this event, the operators unsuccessfully attempted to restore steam generator water level by taking manual control of the feedwater regulating valve. The reactor trip was uncomplicated and all systems responded as designed; Unit 2 was returned to full power on December 25, 2004.

This isolation card was used in all feed and steam flow channels on both Units 1 and 2 at Braidwood and Byron. The cards were original components (i.e., installed circa 1975-1979) and were considered "run-to-failure." Preventative maintenance activities consisted of a quarterly Analog Channel Operation Test and an 18 month calibration. For the card involved in the above trip, the most recent test was a successful Analog Channel Operation Test performed on November 22, 2004. The licensee concluded that scheduled replacement of these cards was unnecessary, based primarily on prior good response to steam generator level transients by licensed operators. Therefore, the cards were only replaced if a problem was identified during routine surveillance testing.

The licensee was planning a root cause evaluation for this event. This evaluation will include a determination of the susceptibility of future card failures and whether the preventative maintenance program for these cards needs to be revised. This event and the associated corrective actions was captured in the licensee's corrective action program as CR 285216.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R14.1 of this report had, as its primary cause, a human performance deficiency in that the failure to follow station procedures during Unit 1 core reloading, resulted in the inadvertent bumping of fuel assemblies.

.2 A finding described in Section 1R14.2 of this report had, as its primary cause, a human performance deficiency, in that the improper installation of a servo valve on the 1C feedwater pump resulted in a significant loss of electro-hydraulic fluid, significantly increasing the potential for a Unit 1 reactor trip.

4OA5 Other Activities

.1 Reactor Pressure Vessel Lower Head Penetration Nozzles (Temporary Instruction (TI) 2515/152, Revision 1)

a. Inspection Scope

Between October 1 and October 13, 2004, and again between November 30 and December 6, 2004, the inspectors performed both direct visual and record reviews associated with TI 2515/152. The objective of TI 2515/152, "Reactor Pressure Vessel Head and Vessel Head Penetration [VHP] Nozzles (NRC Bulletin 2003-02)," Revision 1, is to support the review of licensees' RPV lower head inspection activities that are implemented in response to Bulletin 2003-02 (ADAMS Accession Number ML032320153), which was issued on August 21, 2003. This TI validates that a plant is meeting its inspection commitments using procedures, equipment, and personnel that have been demonstrated to be effective in detecting signs of leakage from the RPV lower head penetration nozzles and the detection of RPV lower head degradation.

As an ancillary benefit, this TI promotes information gathering regarding the condition of the RPV lower head to help the NRC staff identify and shape possible future regulatory positions, generic communications, and rulemaking.

Based on the actions committed to by Exelon Generation Company, LLC in response to NRC Bulletin 2003-02, the licensee performed a bare metal visual examination of the Unit 1 RPV lower head and penetrations during this refueling outage. Insulation panel RA-1 was removed from the RPV lower head to allow access to the head and all 58 instrument penetrations. The examination was performed remotely using a high resolution camera mounted on a remotely operated vehicle or "crawler." Lighting was provided by two fixed sources at the access point to the bottom head and one source mounted on the camera. Images acquired were processed directly to electronic media, including both video and audio. The examination was recorded by visual testing (VT)-2 examiners using approved procedures. Inspectors directly observed approximately 40 percent of the licensee's examination of the RPV bottom head and VHP areas and reviewed 100 percent of the video tape.

<u>Summary</u>: The licensee did not identify any leaking RPV lower head penetration nozzles. However, during the inspection, minor accumulations of debris were noted at penetrations 38, 43, 44, 45 and 52 with the largest deposit located at penetration 44. A total of 11 samples were taken from these accumulations, 10 of them smear samples that did not contain any significant material on the smear. The activity in the smears ranged from 10^{-4} to 10^{-5} microcuries per smear. None of the smears taken indicated a typical footprint for an RCS leak. One physical sample was taken from penetration 44, which after visual analysis by the use of an electron beam microscope, was determined to be aluminum-silicate insulation. This issue was discussed and resolved in a conference call with the licensee, Region III, and NRR staff.

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

In accordance with requirements of TI 2515/152, Revision 1, 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 licensee's procedure required personnel who conducted the examination to be certified VT-2 Level II or III. The inspectors verified that the examination was performed by qualified and certified Level III VT-2 examiners. The examiners had been involved with several prior examinations of RPV top and bottom heads, and penetration surfaces at this and another station. The personnel received specific additional instruction pertaining to RPV head examination which included a review of previous inspection results, inspection techniques, and effects of surface condition on detection and evaluating indications of VHP leakage. In addition, photographs of the actual conditions from the South Texas Project bottom head were available to these examiners. The procedure included specific actions to be take should boric acid deposits be identified on the RPV head or the surrounding areas.

2. Performed in accordance with demonstrated procedures?

Yes. The inspectors verified that the remote visual examination was conducted in accordance with procedure ER-AP-335-1012, Revision 1, "Visual Examination of PWR Reactor Vessel Head Penetrations," and that the procedure was used along with guidance in ER-AA-335-015, "VT-2 Visual Examination," Revision 3.

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

Yes. The inspectors concluded from remote observation and a review of the video tapes of the inspection that the licensee was able to identify, disposition and resolve deficiencies. The high resolution camera and mobility of the crawler permitted 360 degree coverage of each penetration and a direct visual exam of the five penetrations with indications was also conducted. The inspectors concluded that the licensee's ability to detect and identify small, suspect boric acid deposits in the bottom head penetration area of the RPV was effective. The inspectors confirmed the licensee's process was methodical with full coverage of each penetration. Contingency actions taken following discovery of suspected areas of concern were well planned and communicated to the inspectors in a timely manner.

4. Capable of identifying pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion?

Yes. The inspectors determined through review of the electronic records (video tape) and direct visual inspection that the licensee personnel (certified Level III VT-2 examiners) were capable of detecting and characterizing VHP nozzle leakage and/or RPV head corrosion. Access to, and visibility of, the lower RPV head and the annulus region of all 58 penetrations appeared to be clear and unobstructed.

5. Could small boric acid deposits representing RCS leakage, as described in the Bulletin 2003-02, be identified and characterized, if present, by the visual examination method used?

Yes. The inspectors determined through observation of the video tapes that the personnel (certified Level III VT-2 examiners) were capable of detecting and characterizing VHP nozzle leakage and/or RPV head corrosion. Access to, and visibility of, the lower RPV head and the annulus region of all 58 penetrations appeared to be clear and unobstructed.

6. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

The inspection was performed using a high resolution camera mounted on a crawler. Images acquired were processed directly to electronic media (video tape).

7. How complete was the coverage (e.g., 360 degrees around the circumference of all the nozzles)?

There was 360 degree coverage around all 58 penetrations.

8. What was the physical condition of the RPV lower head (e.g., debris, insulation, dirt, deposits from any source, physical layout, viewing obstructions)? Did it appear that there are any boric acid deposits at the interface between the vessel and the penetrations?

The RPV lower head showed signs of light rust over much of the surface with some heavier rust streaking/staining from what the licensee identified as previous seal leakage/rundown. Some light rusting existed around the annulus region of the penetrations. It appeared from the video that the rust did not bridge the annulus region nor would it prevent the ability to detect boric acid leakage or deposits in the annulus region. There did not appear to be any indication of recent rundown or leakage from the vessel above. There was also some light staining/splattering on some of the penetrations but no indication of any thickness or buildup of the material and it did not appear to be emanating from any of the penetrations. The licensee indicated that this too was from the previous seal leakage.

No. It did not appear that there were any boric acid deposits at the interface between the vessel and the penetrations (e.g., the annulus region).

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

There were no material deficiencies identified that required repair.

10. What, if any, impediments to effective examination, for each of the applied non-destructive examination methods, were identified (e.g., insulation, instrumentation, nozzle distortion)?

There were no impediments to effective examination (see response to reporting requirement “8” above).

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

There were no indications of boric acid leaks from pressure-retaining components above the RPV lower head. The accumulations noted in the summary were proven to be non-relevant thorough chemistry analysis. The rust streaking noted previously did not appear to be recent.

12. Did the licensee take any chemical samples of the deposits? What type of chemical analysis was performed (e.g., Fourier Transform Infrared, what constituents were looked for (e.g., boron, lithium, specific isotopes), and what

were the licensee's criteria for determining any boric acid deposits were not from RCS leakage (e.g., Li-7, ratio of specific isotopes, etc.)?

The licensee took 11 samples of minor accumulations of debris at 5 penetrations, 10 of which were smears. Gamma Spectroscopy was performed to characterize all samples. All radionuclides identified were activation products that could be formed from the reactor vessel material. Although fission products were present in the coolant due to a fuel leak during the previous operating cycle, none were found in the smears. According to the licensee, none of the smears taken indicated a typical footprint for an RCS lead. The radioisotopes that were present on the smears were Cobalt-60, Tungsten-187, Chromium-51, and Zinc-65. Short-lived radionuclides (Sodium-24, Cesium-134, and Cobalt-58) that are present in reactor coolant were not found on any of the smears taken.

13. Is the licensee planning to do any cleaning of the head?

The licensee was not planning to perform any cleaning of the head.

14. What are the licensee's conclusions regarding the origin of any deposits present and what is the licensee's rationale for the conclusions?

See response to reporting requirement "12".

c. Findings

No findings of significance were identified.

.2 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. PWRs TI 2515/160)

a. Inspection Scope

Between October 1 and October 13, 2004, and between November 30 and December 6, 2004, the inspectors performed a record review coupled with direct observation associated with TI 2515/160. The objective of this TI is to support the review of licensees' activities for inspecting pressurizer penetrations and steam space piping connections made from Alloy 82/182/600 material and to determine whether the inspections of these components are implemented in accordance with pertinent licensee responses to NRC Bulletin 2004-01 (ADAMS Accession Number ML0480034), which was issued on May 28, 2004. This TI validates that the licensee for a plant addressed by NRC Bulletin 2004-01 is meeting its inspection commitments using procedures, equipment, and personnel that have been demonstrated to be effective in detecting leakage from Alloy 82/182/600 pressurizer penetrations and steam space piping connections.

As an ancillary benefit, this TI promotes information gathering regarding the condition of Alloy 82/182/600 pressurizer penetrations or nozzles, pressurizer steam space piping connections, and pressurizer heads and shells to help the NRC staff identify and shape possible future regulatory positions, generic communications, and rulemaking.

Summary: The licensee did not identify any leaking Alloy 82/182/600 pressurizer penetrations or steam space piping connections.

b. Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/160, 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? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

Yes. The inspectors verified that the examination was performed by qualified and certified Level II VT-2 examiners.

2. Performed in accordance with demonstrated procedures?

Yes. Through a record review the inspectors verified that the visual examination was performed in accordance with procedure ER-AA-335-015, Revision 3.

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

Yes. The certified Level II VT-2 examiners performed the examination in accordance with procedures and in addition had completed supplemental BACC training to aid in identifying boric acid leakage. The visual examination procedure included acceptance criteria/recordable conditions, and evaluation and corrective measures. The supplemental boric acid control training and the overall and boric acid control program enabled the licensee to disposition and resolve deficiencies.

4. Capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01?

Yes. The inspectors determined through still photographs and interviews with the inspectors that the personnel (certified Level II VT inspectors) were capable of detecting and characterizing leakage in nozzle or stream space piping components.

5. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

From direct observation and a review of still photographs the inspectors determined that the physical condition of the penetration nozzles and steam space piping components was free of debris, dirt, and boron. The insulation had been completely removed and with the physical layout permitted complete access to all penetrations (360 degrees around all penetrations).

6. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

The inspection was conducted by direct visual examination.

7. How complete was the coverage (e.g., 360 degrees around the circumference of all the nozzles)?

All of the insulation had been removed around the five steam space piping connections/nozzles so that coverage was 360 degrees around the circumference of all of the penetrations.

8. Could small boron deposits, as described in the Bulletin 2004-01, be identified and characterized?

The inspectors determined through direct observation and a review of still photographs that the personnel (certified Level II VT examiners) were capable of detecting and characterizing pressurizer nozzle leakage.

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

No material deficiencies were identified that required repair.

10. 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)?

There were no impediments to effective examination. All of the insulation had been removed around the nozzles so that coverage was 360 degrees around the circumference of all of the nozzles.

11. If volumetric or surface examination techniques were used for the augmented inspection examinations, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of the examinations?

No volumetric or surface examination techniques were used for augmented inspection examinations.

12. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components in the pressurizer system?

There were no indications of boric acid leaks from pressure-retaining components in the pressurizer system.

c. Findings

No findings of significance were identified.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. T. Joyce and other members of licensee management at the conclusion of the inspection on January 4, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- The access control to radiologically significant areas program, the ALARA planning and controls program, and performance indicator verifications for occupational exposure control effectiveness, and RETS/ODCM radiological effluents, with Mr. T. Joyce on October 14, 2004.
- ISI (Inspection procedure 71111.08), TI 2515/152, and TI 2515/160, with Mr. M. Smith on December 28, 2004.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Joyce, Site Vice President
K. Polson, Plant Manager
D. Ambler, Regulatory Assurance Manager
S. Butler, Licensing Engineer
B. Casey, ISI Coordinator
G. Dudek, Operations Director
R. Gilbert, Nuclear Oversight Manager
T. Johnson, Reactor Vessel Project Manager
J. Kuczynski, Chemistry Manager
J. Moser, Radiation Protection Manager
M. Sears, Steam Generator Program Owner
M. Smith, Engineering Director
E. Wrigley, Maintenance Director

Nuclear Regulatory Commission

D. Passehl, Acting Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000456/2004008-01	NCV	Failure to follow licensee procedures during Unit 1 core reload. (Section 1R14.1)
05000456/2004008-02	FIN	Increased probability of a reactor trip due to poor maintenance that caused an electro-hydraulic leak on the 1C turbine driven feedwater pump. (Section 1R14.2)

Closed

05000257/2004-001-00	LER	Unit 2 Pressurizer Backup Heater Groups A and D Identified to be Inoperable Greater Than Required Technical Specification Allowed Outage Time. (Section 4OA3)

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.

1R01 Adverse Weather Protection

CR 259352; Deficiencies in Station Heaters Found During 0BwOS SFT-A2B; October 2, 2004
CR 259494; Multiple Turbine Building Louvers Degraded per 0BwOS XFT-A1; October 2, 2004

1R04 Equipment Alignment

CR 203115; Bulletin 85-01 Commitment to Check AF Temperature Shiftly; February 20, 2004
CR 240974; Improper Basis for Operability on Issue 219399; August 2, 2004
CR 257716; Summary of the Byron/Braidwood Review of the AF Commonality Review; September 28, 2004
CR 261061; High Thrust Bearing Temperature on 1A AF Pump; October 7, 2004

1R05 Fire Protection

CR 124313; Air Dryer Modification Solenoids are Uninstallable Per Current Design; September 24, 2002
CR 269625; NRC Concern - Missing Insulation in 2A CV Pump Room Wall; November 2, 2004 [NRC-Identified]
CR 269631; NRC Identified Fire Door Unlocked; November 2, 2004 [NRC-Identified]
CR 274034; Cable Routing Question for 1A DG Air Dryer Skid #1; November 16, 2004 [NRC-Identified]

1R06 Flood Protection Measures

CR 262649; SX Returned to Service Too Soon - Flooded 1B Auxiliary Feedwater [AF] Pump Room; October 11, 2004
CR 263551; Procedure MA-BR-726-619 Does Not Specify Plant Flood Level; October 14, 2004
WO 412845 01; 1LSA-WF024 AF Pump 1B Leak Detect Sump Level Switch; June 23, 2004

1R08 Inservice Inspection Activities

CR 153405; Issue with 4 ISI Weld Exams Performed During A2R09; April 10, 2003
CR 165973; Magnetic Particle Testing and Radiography Non-Destructive Exam Requirements of Reactor Containment Fan Cooler Heads; July 2, 2003

CR 167486; Missed ISI Weld Exams in A1R10 (on the pressurizer); March 30, 2004
CR 239701; Repair/Replacements Not Submitted in ISI 90 Day Report; July 28, 2004
CR 260015; A1R11 Lesson Learned - Delays in Mode 3 ALARA Brief; October 4, 2004
CR 260564; A1R11 Lesson Learned - Mode 3 Walkdowns; October 6, 2004
CR 260950; A1R11 Lesson Learned - Delay in Entering Missile Barrier (Locked Door); October 6, 2004
CR 266402; External Leakage (1RC014 Sol. Va. Assemblies); October 23, 2004
CR 601844; CRDM Boric Acid Streaking; October 4, 2004
CY-AP-130-3100; Deposit Sampling and Analysis; Revision 0
DE-BRW-04-0014; Braidwood Unit-1 Steam Generator [SG] Inspection Degradation Assessment and Condition Monitoring Input Checklist for A1R11; July 1, 2004
ED-BRW-04-0014; Braidwood Unit-1 SG Inspection Degradation Assessment and Condition Monitoring Input Checklist for A1R11; July 1, 2004
ER-AA-330-001; Section XI Pressure Testing; Revision 4
ER-AA-335-015; VT-2 Visual Examination; Revision 3
ER-AP-331-1002; Boric Acid Corrosion Control Program Identification, Assessment, and Evaluation; Revision 1
ER-AP-331-1004; Boric Acid Corrosion Control (BACC) Training and Qualification; Revision 0
ER-AP-335-1012; Visual Examination of PWR Reactor VHPs; Revision 1
ER-AP-420-0051; Conduct of SG Management Program Activities; Revision 5
EXE-ISI-11; Liquid Penetrant Examination; Revision 1; August 30, 2002
EXE-ISI-210; Manual Ultrasonic Examination of Vessel Welds; Revision 0; August 30, 2002
EXE-UT-350; Procedure for Acquiring Material Thickness and Weld Contours; Revision 1; March 11, 2002
LS-AA-126-1005; Check-In Self-Assessment Report Template; Revision 1
MRS-TRC-1533; Use of Appendix H Qualified Techniques at Braidwood A1R11 Outage; Revision 1; September 7, 2004
PQR No. A-001; Clinton Power Station Procedure Qualification Record; April 19, 2004
PQR No. A-002; Clinton Power Station Procedure Qualification Record; April 19, 2004
PQR No. 1-50C; Clinton Power Station Procedure Qualification Record; April 19, 2004
WO 00439736-01; Cut-Out/Replace Valve 1AFO17B- Reinstall Existing Operator; July 16, 2004
WO 00439736-01; ASME Weld Data Record, Document No. 2A, Equipment No. 1AF017B, Weld No. 10-2; October 10, 2004
WO 00439736-01; ASME Weld Data Record, Document No. 2B, Equipment No. 1AF017B, Weld No. 11-2; October 10, 2004
WO 593993; Examination of Borated Bolted Connections in the Unit 1 Containment; October 7, 2004
WPS 1-1-GTSM-PWHT; ASME Procedure Qualification Record; Revision 1

1R11 Licensed Operator Requalification Program

CR 269004; Non-Licensed Individual Affecting Simulator Evaluation; November 1, 2004

1R12 Maintenance Effectiveness

CR 206414; Need to Increase CW Blowdown Flow to Improve Lake Chemistry; March 5, 2004
CR 240240; Lake Cooling System Placed in (A)(1); July 28, 2004
CR 240240 #02; Develop (a)(1) Corrective Actions and Goals for the Lake Cooling System to Address Cause(s) Contributing to the Maintenance Rule (a)(1) Classification; September 28, 2004
CR 255053; Action Level 1 Entry for Lake HEDP Residual; September 19, 2004
CR 262542; Outboard Pump Bearing Oil in the Bubbler Has Turned Dark; October 11, 2004
CR 263955; TS SR 3.6.6.3 Inconsistent with Bases Discussion; October 15, 2004
CR 269633; NRC Identified Door to 2B AF Pump Room Not Operating Properly; November 2, 2004 [NRC Identified]
CR 269616; 1A DV Pump Oil Leak; November 2, 2004 [NRC Identified]
Expert Panel Meeting; DC Power Storage and Distribution; July 31, 2003
Expert Panel Meeting Notes; Lake Cooling System; May 24, July 12, July 28, September 13, September 27, 2004
High Safety Significant Status of In-Scope Functions; DC Power System
Maintenance Rule - Expert Panel Scoping Determination; DC Power System
Maintenance Rule - Performance Criteria; DC Power System
Maintenance Rule - Evaluation History; DC Power System; January 1, 2003 through July 30, 2004

1R13 Maintenance Risk Assessments and Emergent Work Control

CR 261478; Initial Freeze Seal for 1SI8819D Unsuccessful; October 7, 2004
CR 261732; Nuclear Oversight [NOS] Identified Concern About Contingency Plans in Place; October 8, 2004
CR 266791; +88 Volts DC Ground on DC Bus 112; October 25, 2004
CR 269822; Byron IR 268459, Drawing Errors - Applicable to Braidwood; November 3, 2004
CR 269903; Inspect UAT 241-1 63X Relay Base for Elongated Screws; November 3, 2004
CR 270477; UAT 141-2 Sudden Pressure Relay Wire Landed on Wrong Side of Terminal Block; November 4, 2004
CR 271827; Nuclear Oversight Identified High Level Awareness Briefing Weaknesses; November 9, 2004
CR 271836; Nuclear Oversight Identified Work Package Deficiencies; November 8, 2004
CR 273888; Develop Method to Add Oil to Operating Heater Drain Pump; November 16, 2004
WO 753324 01; Fill 1B HD Pump Motor Lower Bearing with Oil; November 9, 2004

1R14 Operator Performance During Non-Routine Evolutions and Events

CR 263845; Unit 1 Reactor Fuel Assembly Contacted Another Assembly During Move; October 14, 2004
CR 264216; Unit 1 Fuel Assembly G9 in Unit 1 Reactor Not Fully Inserted; October 16, 2004

CR 270727; EH Leak on 1C Main Feedwater Pump During RTS of 1MS5009B; November 5, 2004
CR 274718; Main Turbine Governor Valve Indication; November 18, 2004
CR 274721; High-2 Isolation of 15-17 Heaters Causing Over Power Delta Temperature Runback; November 18, 2004
CR 274741; Rod Insertion Greater Than Lo-2 Insertion Limit During Transient; November 18, 2004
CR 274746; Average Temperature - Reference Temperature Deviation Greater Than 4 Degrees During Transient; November 18, 2004
CR 281958; 1C HD Flash Tank HI-2 Causes Loss of Feedwater Heaters; December 13, 2004
CR 282274; NOS Identified Improper Feedwater Heater Controller Manipulations; December 14, 2004
CR 282798; Organization Issues Related to 1C Flash Tank Event; December 13, 2004
IR 263845; Fuel Assembly at Core Location F8 Contacted Assembly in Core Location F5 While Attempting to Remove Assembly; October 14, 2004
OU-AP-200; Administrative Controls During Fuel Handling Activities for Byron and Braidwood; Revision 0
OU-AP-205; Fuel Handling Activities in Containment During Refuel Outages for Byron and Braidwood; Revision 0
Westinghouse Field Specification F-5; Instructions, Precautions, and Limitations for Handling New and Partially Spent Fuel Assemblies; Revision 17
Westinghouse NF-CB-04-166; Fuel Handling Incident During Cycle 12 Refueling Outage FAR Nos. CC-04-3/PPE-04-852 and CC-04-4/PPE-04-854; October 15, 2004
WO 574587 01; 1EH5049B Replace Servo Valve and Rebuild Old Valve; November 4, 2004

1R16 Operator Workarounds

Plan of the Day; Operator Work Around Status Update; November 1, 2004
Plan of the Day; Deficiencies Requiring Compensatory Action or Monitoring; November 1, 2004
Plan of the Day; Temporary Configuration Changes; November 4, 2004
Plan of the Day; Braidwood Operations Main Control Room Distractions; November 8, 2004
Plan of the Day; Operability Determinations; November 11, 2004
Plan of the Day; Disabled Alarms; November 22, 2004
Plant Health Committee Agenda; November 15, 2004
Plant Health Committee Agenda; November 29, 2004

1R20 Refueling and Other Outage Activities

BwOP FC-1; Fuel Pool Cooling system Start-Up; Revision 17
BwOP RH-6; Placing the Residual Heat Removal System in Shutdown Cooling; Revision 32
CR 161080; Spent Fuel Rack G Cell Degradation Increased; October 4, 2004
CR 246712; Byron Versus Braidwood Outage Procedure comparison; August 24, 2004
CR 258221; Outage Shutdown Safety Presentation Rejected at PORC; September 28,2004

CR 260007; NOS Identified MCR Alarms Not Documented in OPS Narrative Log; October 4, 2004
CR 260012; NOS Identified Examples of Inadequate MCR Standards; October 4, 2004
CR 260072; A1R11 LL On Rampdown Plan; October 4, 2004
CR 260090; Seal DP Indication Suspect; October 5, 2004
CR 260091; Suspect Pressure Indication; October 5, 2004
CR 261141; Unplanned Unit 2 Online Risk Level Change Due to A1R11; October 6, 2004
CR 262278; Repeat Leakage (Twice) Repack Valve 1SI003C in A1R11; October 10, 2004
CR 263330; NOS Identified: Events Associated with Protected Equipment -Trend; October 13, 2004
CR 263601; NRC Inspector Identified Protected Equipment Sign Issues; October 12, 2004 [NRC Identified]
CR 264177; Dropped Steel Rod in SFP During Reconstitution; October 15, 2004
CR 264443; A1R11 - Reactor O-Rings Wetted During Reactor Head Installation; October 12, 2004
CR 264470; NOS Identified SAT 142-2 was not Posted as Protected Equipment; October 17, 2004
CR 265910; Inadvertent TRM LCOAR 3.4.C Entry Due to Excessive Pressurizer D/D; October 21, 2004
CR 267308; A1R11 LL RCP Seal DP Transmitter Failed Delaying Critical Path; October 5, 2004
CR 267315; A1R11 1B RCP Elevated Vibrations on Startup; October 23, 2004
WO 574854 01; Low Power Physics Test Program With Dynamic Rod Worth Measurement; October 20, 2004
Reactivity Maneuver (ReMa) Form; Braidwood Unit 1 Cycle 11 Burnup: EOL; Unit 1 RCS Cooldown for Refueling Shutdown; Revision 0

1RST Post-Maintenance and Surveillance Testing - Pilot

CR 259227; NLO Identifies Welding Activity Deficiencies in 2A DG Room; October 1, 2004 [NRC-Identified]
CR 259816; AF Full Flow Test - Strip Chart Recorder Problem; October 4, 2004
CR 259880; A1R11 LL Poor Coordination Results in Delay for AF Test; October 4, 2004
CR 259885; Confined Space Rescue Team Not Ready for Unit 1 AF Non-Rad; October 4, 2004
CR 261895; 200 Degree Differential Exhaust Temperature on 1A DG Run for 1BwVSR; October 8, 2004
CR 262569; A1R11-1B DG Starting System Malfunction; October 11, 2004
CR 262649; SX Returned to Service Too Soon - Flooded 1B AF Pump Room; October 11, 2004
CR 263787; Containment Spray Breaker Did Not Close at Proper Time for Emergency Core Cooling System Sequence; October 14, 2004
CR 265099; 1B AF Diesel Did Not Crank During Prime Mover Surveillance; October 19, 2004
CR 265236; Right Angle Gear Oil Leak and Other Issues with 1B AF Diesel; October 20, 2004
CR 278745; 1A DG Slow Start (Greater than 10 Seconds); December 3, 2004

EC 351809; Use of Alternative Source Term (AST) Calculation in Support of Operability Determination for Control Room Tracer Gas Testing at the Byron and Braidwood Generating Stations; October 12, 2004
HU-AA-1211; HLA/IPA Briefing Worksheet Page 2 of 5; Revision 1
SPP-04-012; Control Room Envelope Tracer Gas Test; Revision 0
SPP-04-012; Control Room Envelope Tracer Gas Test Overview; November 4-7, 2004

1R23 Temporary Plant Modifications

CR 270780; NRC Concerns Regarding Scaffold at 2B SI Pump Cubicle Cooler; November 2, 2004 [NRC Identified]

2OS1 Access Control to Radiologically Significant Areas
2OS2 ALARA Planning And Controls

RWP 10003892 And ALARA Plan; Boric Acid Sample From Reactor Head; Revision 0

RWP 10003911 And ALARA Plan; S/G Manway and Diaphragm Removal; Revision 0

RWP 10003913 And ALARA Plan; S/G Eddy Current Testing And All Tube Repairs; Revision 0

RWP 10003881 And ALARA Plan; Seal Table/Rack/Drive Box Disconnection, Maintenance And Cleaning; Revision 0

RWP 10003896 And ALARA Plan; ISI Incore Sump Work, Under Reactor Vessel Inspection; Revision 0

Braidwood 2003/2004 RCA Entries Greater Than 100 millirem; dated October 10, 2004

Unit 1 RCS Fuel Leak Indications

NF-AA-390; Spent Fuel Pool Material Control; Revision 0

RP-AA-222; Methods For Estimating Internal Exposure From In-Vivo And In-Vitro Bioassay Data; Revision 1

CY-AP-120-3000; PWR Shutdown Chemistry For Recirculating Steam Generators; Revision 3

RP-AA-460; Controls For High And Very High Radiation Areas; Revision 6

RP-AA-401; Operational ALARA Planning And Controls; Revision 4

RP-AA-220; Intake Investigation Form; Revision 2

ATI 261470; Quick Human Performance Investigation; dated October 14, 2004

NOSA-BRW-03-06; NOS Radiation Protection Audit Report; dated May 23, 2003

Health Physics/Radiation Protection Audit; dated August 11, 2003

AR 00263033; Protective Clothing Coveralls For Contaminated Areas; dated October 5, 2004

AR 00263204; ALARA Briefs Not Performed For > 0.3 DAC Hour Containment Entries; dated October 13, 2004

AR 00201363; Worker Entered RCA Without ED/RWP; dated February 12, 2004

AR 00262103; NOD ID'D Enhancement To Establish And Report Deltas For Dose; dated October 10, 2004

AR 00253080; Lessons Learned: U1 DAC Increase Event; dated September 14, 2004

AR 00253054; Increased Dose Rates On The U-1 CV System; dated September 15, 2004

AR 00253049; Cobalt Reduction Procedure Not Being Followed; dated June 24, 2004

AR 00251923; Deficiencies Identified During Source Term Reduction FASH; dated September 10, 2004

AR 00247304; RP-BR-340 Procedure Enhancement To Address RP Postings; dated August 25, 2004

LS-AA-2140; Monthly PI Data Elements For Occupational Exposure Control Effectiveness, May 2003 Through June 2004; Revision 3

LS-AA-2150; Monthly PI Data Elements For RETS/ODCM Radiological Effluent Occurrences, April 2003 Through June 2004; Revision 3

4OA2 Identification and Resolution of Problems

Braidwood Quarterly SHIP Report; 2nd Quarter 2004
CR 228869; MR A# Assessment Identifies System IT Review Needed; June 15, 2004
CR 249320; Replacement of Guide Vane Cable Assembly on 0WO02CB; September 1, 2004
CR 252284; 2004B/B Rod Drive System Review; September 13, 2004
CR 252429; Contractor Work Practices are Inconsistent with Exelon's; September 12, 2004
CR262376; Indicator OO.02 Main control Room Distractions in Variance; September 30, 2004
CR 269580; Masoneilan 7" Piston Actuator Diaphragm Cracked; November 2, 2004
Exelon Nuclear Issue 282949; NRC Question on Potential Trends at the Station; December 14, 2004

4OA3 Event Followup

CR 085263; Bus 10 CCVT Distorted Waveforms; December 23, 2004
2BwGP 100-A-13; Reactor Trip Root Cause Determination; Revision 6
IR 285216; Unit 2 Trip on LO-2 SG Level; December 22, 2004

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
AF	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Control Coordinator
BwOP	Braidwood Operating Procedure
BwOSR	Braidwood Operating Surveillance Requirement Procedure
BwVSR	Braidwood Engineering Surveillance Requirement Procedure
CFR	Code of Federal Regulations
CR	Condition Report
DG	Diesel Generator
EH	Electro-Hydraulic
HRA	High Radiation Area
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
LER	Licensee Event Report
NCV	Non-Cited Violation
NOS	Nuclear Oversight
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PARS	Publicly Available Records
PI	Performance Indicator
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
RP	Radiation Protection
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
VHP	Vessel Head Penetration
VT	Visual Testing
WO	Work Order