May 4, 2005

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

SUBJECT: BYRON STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000454/2005003;
05000455/2005003

Dear Mr. Crane:

On March 31, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on April 04, 2005, with Mr. D. Kuczynski 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, one NRC-identified and five self-revealed findings of very low safety significance (Green) are documented in this report. All of these findings were determined to involve violations of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, one licensee identified violation is listed in Section 4OA7 of this report.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the Resident Inspector office at the Byron facility.

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Sincerely,

/RA/

David Passehl, Acting Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000454/2005003; 05000455/2005003
w/Attachment: Supplemental Information

cc w/encl:
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Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer
Senior Vice President - Nuclear Services
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2005003; 05000455/2005003
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	4450 N. German Church Road Byron, IL 61010
Dates:	January 1, through March 31, 2005
Inspectors:	R. Skokowski, Senior Resident Inspector P. Snyder, Resident Inspector R. Alexander, Radiation Specialist R. Daley, Senior Reactor Inspector J. Giessner, Reactor Inspector M. Holmberg, Reactor Inspector D. McNeil, Reactor Engineer R. Ng, Reactor Inspector R. Smith, Reactor Engineer T. Tongue, Reactor Engineer A. Walker, Senior Reactor Inspector M. Wilk, Reactor Inspector R. Winter, Reactor Engineer C. Thompson, Illinois Emergency Management Agency, Resident Inspector
Observers:	J. Robbins, Reactor Inspector
Approved by:	D. Passehl, Acting Chief Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000454/2005003; 05000455/2005003; on 01/01/2005-03/31/2005; Byron Station, Units 1 and 2; Post Maintenance Testing, Surveillance Testing, Access Control to Radiologically Significant Areas, Event Followup, Other Activities.

This report covers a 3-month period of baseline resident inspection and announced baseline inspection on inservice testing and radiation protection. In addition, inspections were conducted using Temporary Instructions 2515/150 and 2515/160. The inspections were conducted by Region III inspectors, and the resident inspectors. Six Green findings, which were violations of NRC requirements, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. 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. Inspector-Identified and Self-Revealed Findings

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and an associated Non-Cited Violation (NCV) of Technical Specification (TS) 5.4.1 regarding procedure quality was self-revealed. Specifically, an inadequate procedure used by operators during the post maintenance testing of three steam dump valves resulted in the unexpected opening of all the steam dump valves causing a small power increase. The primary cause of this finding was related to the cross-cutting area of Human Performance (organization) in that during the recent revision to the procedure, the reviewers did not complete a sufficient validation of the changes.

  The finding was more than minor because it affected the Barrier Integrity Cornerstone objective of providing reasonable assurance that the physical design barrier of fuel cladding protect the public from radionuclide releases caused by accidents or events, and was associated with the attribute of procedure quality. The finding was of very low safety significance because the fuel cladding barrier was not degraded. (Section 1R19)

- Green. A finding of very low safety significance and an associated NCV of TS 3.9.4c was identified by the NRC. Specifically, the inspectors determined that during the performance of local leak rate tests the licensee failed to maintain containment penetrations closed while core alterations were in progress as was required by the TS.

  The finding was more than minor because it affected the configuration control, specifically containment boundary preservation, attribute associated with the Reactor Safety Barrier Integrity Cornerstone objective to provide reasonable assurance that physical barriers, specifically containment, protect the public from radionuclide releases caused by accidents or events. This finding was of very low safety significance because (1) the issue did not increase the likelihood of a loss of primary coolant system inventory; (2) the issue did not degrade the licensee's ability to terminate a leak path or add RCS inventory when needed; and (3) the issue did not degrade the licensee's ability to recover decay heat removal once lost. Furthermore, the issue only impacted the containment function without affecting core damage frequency, and was associated with a shutdown condition during periods when the reactor vessel water level was greater than or equal to the level required for fuel moves. (Section 1R22)

- Green. A finding of very low safety significance and an associated NCV for operating in excess of the licensed thermal power limits was self-revealed. Specifically, it was determined that for periods between May 2000 and August 2003, the installed feedwater ultrasonic flow measurement instruments provided non-conservative data to the reactor power calculation which resulted in power operation greater than the licensed maximum thermal power output of 3586.6 megawatts thermal (100 percent power). Unit 1 operated with a maximum power level of 102.62 percent. Unit 2 operated with a maximum power level of 101.88 percent. This finding was related to the cross-cutting area of Problem Identification and Resolution (evaluation) because the licensee missed several opportunities to determine that an over power condition existed.

  The finding was more than minor because it affected the Barrier Integrity Cornerstone objective of providing reasonable assurance that the physical design barrier of fuel cladding protect the public from radionuclide releases caused by accidents or events, and was associated with the attribute of design control (core design analysis). The finding was of very low safety significance because the fuel cladding barrier was not degraded. (Section 4OA5.3)

Cornerstone: Emergency Preparedness

- Green. A finding of very low safety significance and an associated NCV of Title 10 of the Code of Federal Regulations Part 50.54q regarding the implementation of emergency plans was self-revealed. Specifically, operators failed to declare an Unusual Event upon determining that reactor coolant system dose equivalent I-131 activity exceeded 1.0 FCi/gm. Reactor coolant system dose equivalent I-131 greater than 1.0 FCi/gm was the limit specified in the licensee emergency plan for an Unusual Event. The primary cause of this finding was related to the cross-cutting area of Human Performance (organization) in that licensed operators failed to realize that an Emergency Action Level threshold had been exceeded and that an Unusual Event declaration was required.

  The finding was more than minor because it was associated with Reactor Safety / Emergency Preparedness Cornerstone Attribute of Response Organization performance and affected the cornerstone objective of providing reasonable assurance that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. The finding was of very low safety significance because, although it involved an actual event, the event was only an Unusual Event, and the finding only involved a failure to comply with the emergency plan and there were no indications of Planning Standard problems. (Section 4OA3)

Cornerstone: Occupational Radiation Safety (OS)

- Green. One self-revealed finding of very low safety significance and an associated NCV was identified when, on March 12, 2005, the licensee failed to conduct an adequate evaluation of the radiological conditions prior to removing the charcoal adsorber portion of High Efficiency Particulate Air units associated with work on the Unit 1 steam generators. Subsequently, Unit 1 Containment radiological conditions changed such that several air monitors went into high alarm on the iodine channel and 28 personnel were found to have unintended, low-level, internal contamination.

  The primary cause of this finding was related to the cross-cutting area of Human Performance (organization). The issue was more than minor because it was associated with the Human Performance attribute of the Occupational Radiation Safety Cornerstone and affected the cornerstone objective of ensuring adequate protection of worker health and safety from exposure to radioactive materials in that multiple workers received unintended dose from small intakes. In that the finding was not specifically related to As Low As Reasonably Achievable (ALARA) or planning issues, there were no radiological overexposures, nor the substantial potential for an overexposure, and the licensee's ability to assess worker dose was not compromised, the finding was determined to be of very low safety significance. The licensee's corrective actions for this issue included reinstalling the charcoal adsorbers and initiating additional containment atmosphere treatment, revising procedures to include specific criteria for charcoal absorber removal, and modifying the outage schedule such that charcoal absorber removal is logically tied to steam generator manway installation. One NCV for the failure to adequately evaluate radiological conditions in accordance with 10 CFR 20.1501 was also identified. (Section 2OS1.1)

- Green. One self-revealed finding of very low safety significance and an associated NCV was identified when, on March 9, 2005, a contract radiation worker, while supporting polar crane movement of equipment used for the upper internals split pin modification, entered a High Radiation Area (HRA) without receiving a high radiation area brief from the radiation protection staff as required by the Radiation Work Permit.

  The primary cause of this finding was related to the cross-cutting area of Human Performance (personnel). The issue was more than minor because it was associated with the Human Performance attribute of the Occupational Radiation Safety Cornerstone and affected the cornerstone objective of ensuring adequate protection of worker health and safety from exposure to radioactive materials in that two barriers (i.e., the HRA briefing and compliance with the HRA posting) in place to prevent unplanned, unintended worker dose failed. In that the finding was not specifically related to ALARA or planning issues, there were no radiological overexposures, nor the substantial potential for an overexposure, and the licensee's ability to assess worker dose was not compromised, the finding was determined to be of very low safety significance. The licensee's corrective actions for this issue included enhancing the physical and administrative RP controls over HRAs within containment. One Non-Cited Violation for the failure to obtain a HRA briefing prior to entry into the area in accordance with licensee procedures and Technical Specification 5.4.1 was also identified. (Section 2OS1.4)

B. Licensee Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power for the quarter except for January 8, 2005, when power was reduced by 14 percent for a turbine throttle valve and governor valve surveillance test, and February 23, 2005, when power was reduced by 6 percent for main steam line safety valve testing. Also, on February 26, 2005, power was reduced by three percent for the completion of auxiliary feedwater full flow testing. On February 27, 2005, Unit 1 was shut down for a refueling outage, on March 24, 2005 restart activities began with the unit reaching full power on March 28, 2005. Following the restart, the unit operated at or near full power throughout the remainder of the inspection period except on March 29, 2005 when power was reduced by five percent due to an unplanned isolation of the 14A feedwater heater after a failure of the emergency drain level controller.

Unit 2 operated at or near full power throughout the inspection period except on January 1, 2005, when power was reduced by about 11 percent for a turbine throttle valve and governor valve surveillance test.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

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

The inspectors verified the alignment of the following:

- Unit 1 train A emergency diesel generator while train B was unavailable due to planned maintenance;
- Unit 1 train B essential service water while train A was unavailable due to planned maintenance;

- Unit 2 train B essential service water while train A was unavailable due to planned maintenance; and
- fuel handling building ventilation and filtration system during refueling machine hoist failure.

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

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

During the inspection, the inspectors finished one complete system alignment inspection of the accessible portions of the Unit 1 charging system. This system was selected because it was considered both safety-related, and risk significant in the licensee's probabilistic risk assessment. The inspection consisted of the following activities:

- a review of plant procedures (including selected abnormal and emergency procedures), drawings, and the UFSAR to identify proper system alignment;
- a review of outstanding work requests on the system;
- a review of outstanding temporary modifications on the system;
- a review of the system health information; and
- a walkdown of the system to determine proper alignment, component accessibility, availability, and current condition.

The inspectors also reviewed selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection were listed in the Attachment at the end of this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Walkdowns

a. Inspection Scope

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

- OP-AA-201-006; Control of Temporary Heat Sources, Revision 0;
- OP-MW-201-007; Fire Protection System Impairment Control, Revision 3;
- OP-AA-201-009; Control of Transient Combustible Material, Revision 4; and
- Chemetron Vendor Manual; Fire Extinguishing Equipment.

The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The Byron Station Pre-Fire Plans applicable for each area inspected were used by the inspectors to determine approximate locations of firefighting equipment.

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

- Unit 1 train A emergency diesel generator room (Zone 9.2-1);
- Unit 1 division 11 ESF switchgear room (Zone 5.2-1);
- Unit 2 upper cable spreading room (Zone 3.3A-2);
- Unit 2 upper cable spreading room (Zone 3.3B-2);
- Unit 2 upper cable spreading room (Zone 3.3C-2);
- Unit 2 upper cable spreading room (Zone 3.3D-2);
- Unit 1 upper cable spreading room (Zone 3.3D-1);
- Unit 1 train B emergency diesel generator room (Zone 9.1-1); and
- Unit 1 containment.

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

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (Annual)

a. Inspection Scope

The inspectors completed one annual testing and performance review inspection sample by observing and evaluating the licensee's inspection of the following safety-related heat exchanger:

- Unit 1 train B auxiliary feedwater pump diesel jacket water heat exchanger inspection (1SX01K).

This heat exchanger was selected for review because essential service water was ranked high in the plant specific risk assessment and the heat exchangers were a support system directly connected to the safety-related auxiliary feedwater system.

In addition to observing the inspection, and reviewing the heat exchanger inspection results, the inspectors discussed the results and heat exchanger performance with the licensee's engineer responsible for the heat exchanger inspection program.

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

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (IP 71111.08)

.1 Piping Systems ISI

a. Inspection Scope

From March 2, 2005 through March 11, 2005, the inspectors conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries for Unit 1. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed the following two types of nondestructive examination activities:

- ultrasonic examination (UT) of the alpha loop reactor vessel outlet; nozzle-to-safe-end weld (RPVS-E-F1) to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements; and
- bare metal visual examination of the pressurizer to evaluate compliance with licensee commitments to NRC Bulletin 2004-01 penetrations (Section 4OA5.1).

The inspectors reviewed a Code VT-3 examination from the previous outage with relevant indications identified on support 1CV06009C to determine if the licensee's corrective actions and extent of condition reviews were in accordance with the ASME Code requirements.

The inspectors reviewed pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage, to determine if the welding acceptance and preservice examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed records of field welds associated with the replacement of the 1B seal injection filter inlet isolation valve (1CV01FB).

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

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

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

The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.2 Pressurized Water Reactor Vessel Head Penetration ISI

a. Inspection Scope

The inspectors did not perform an inspection under this procedure section (reduction in one inspection sample), because this area was inspected under Temporary Instruction (TI) 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles" (report Section 4OA5.2).

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

From February 15, 2005 through March 11, 2005, the inspectors reviewed the Unit 1 BACC inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary."

The inspectors observed the licensee during BACC visual examinations of the reactor coolant and other borated systems conducted on February 15, 2005 and February 28, 2005, to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In particular, the inspectors observed these examinations to determine if the licensee focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed engineering evaluations performed for boric acid found on reactor coolant system piping and components to verify that the minimum design code required section thickness had been maintained for the affected component(s). Specifically, the inspectors reviewed:

- Evaluation No. 2003-01 for Component 1RC8029D, "Leakage From the 1D Reactor Coolant Loop Bypass Vent Valve;" and
- Evaluation No. 2003-015 for Component 2FC8762A, "Body to Bonnet Leak."

The inspectors reviewed licensee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI. Specifically, the inspectors reviewed:

- Evaluation No. 2003-060 for Component 2AB03P, "Leakage found at Pump Seal;" and
- Evaluation No. 2003-065 for Component 2SI097, "Quick Disconnect Found Leaking."

The documents reviewed during this inspection are listed in the Attachment to this report. The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.4 Steam Generator (SG) Tube ISI

a. Inspection Scope

From March 7, 2005 through March 17, 2005, the inspectors performed an on-site review of SG tube examination activities conducted pursuant to TS and the ASME Code Section XI requirements.

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documents related to the SG ISI program to determine if:

- in-situ SG tube pressure testing screening criteria and the methodologies used to derive these criteria were consistent with the Electric Power Research Institute (EPRI) TR-107620, "Steam Generator In Situ Pressure Test Guidelines;"
- the in-situ SG tube pressure testing screening criteria were properly applied in terms of SG tube selection based upon evaluation of the list of tubes with measured/sized flaws;

- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee's previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to identify tube degradation based on site and industry operating experience by confirming that the ET scope completed was consistent with the licensee's procedures, plant TS requirements and EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6;"
- the SG tube ET examination scope included tube areas which represent ET challenges such as the tubesheet regions, expansion transitions and support plates;
- the licensee identified new tube degradation mechanisms;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements;
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below the detection threshold during the previous operating cycle;
- the licensee did an evaluation for unretrievable loose parts identified in the 1D SG;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6; and
- the licensee identified deviations from ET data acquisition or analysis procedures.

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

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

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

The NRC inspectors concluded that the reviews discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of the inspection procedure, but the sample was completed to the extent possible.

The specific activities which were not available for the NRC inspectors' review to complete the procedure sample and the basis for their unavailability is identified below.

- Procedure 71111.08, Steps 02.04.a.3 and 02.04.a.4 associated with review of in-situ pressure testing and tube performance criteria were not available for

review because none of the degraded SG tubes met the screening requirements for pressure testing.
- Procedure 71111.08, Step 02.04.d associated with review of licensee activities for new SG tube degradation mechanisms was not available for review because no new tube degradation mechanisms were identified.
- Procedure 71111.08, Step 02.04.h associated with review of corrective actions for primary-to-secondary leakage greater than three gallons per day was not available for review because primary-to-secondary leakage was below the minimum detectable threshold during the previous operating cycle.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On February 2, 2005, the inspectors completed one inspection sample by observing and evaluating an operating crew during an "out-of-the-box" requalification examination on the simulator using Scenario "Number 05-1-1," Revision 0. The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- ability to take timely actions;
- prioritization, interpretation and verification of alarms;
- procedure use;
- control board manipulations;
- supervisor's command and control;
- management oversight; and
- group dynamics.

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

- OP-AA-101-111, Roles and Responsibilities of On-Shift Personnel, Revision 1;
- OP-AA-103-102, Watchstanding Practices, Revision 3;
- OP-AA-103-103, Operation of Plant Equipment, Revision 0; and
- OP-AA-104-101, Communications, Revision 1.

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- Unit 1 train B emergency diesel generator jacket water leak and overpressurization, voltage regulator and speed sensor failures;
- Switchyard and transformer oil level and leaks, cooling fan failures, and relay and control switch failures; and
- Unit 1 train B auxiliary feedwater pump attached essential service water booster pump seal failure.

During this inspection, the inspectors evaluated the licensee's monitoring and trending of performance data for the past two years, verified that performance criteria were established commensurate with safety, and verified that equipment failures were appropriately evaluated in accordance with the maintenance rule. These aspects were evaluated using the maintenance rule scoping and report documents. The inspectors also verified the basis for classification as (a)(1) or (a)(2) and the criteria for change of classification. For the systems reviewed, the inspectors also evaluated selected work orders, condition reports and other documents to determine that failures were properly identified, classified, and corrected, and that unavailable time had been properly calculated.

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

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

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

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

- ER-AA-600, Risk Management, Revision 3;
- ER-AA-310, Implementation of the Maintenance Rule, Revision 3;
- OU-AA-103, Shutdown Safety Management Program, Revision 4;
- OU-AP-104, Shutdown Safety Management Program, Revision 7;
- WC-AA-101, On-Line Work Control Process, Revision 10;
- Byron Operating Department Policy 400-47, June 23, 2004, Revision 5; and
- Byron Nuclear Power Station Probabilistic Risk Assessment, Revision 5B.

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

- Unit 1 train B emergency diesel generator concurrent with the train B circulating water make-up pump;
- Unit 1 train A residual heat removal concurrent with 1D steam generator power operated relief valve, Unit 1 start-up feedwater pump, and train A containment spray sump isolation valve;
- Unit 1 and Unit 2 train A essential service water (SX) concurrent with Unit 1 train A safety injection, and Unit Common train A control room ventilation;
- Unit 1 and Unit 2 train A SX unavailable during the replacement of the pump suction valves;
- Unit 2 train B auxiliary feedwater pump emergent inoperability due to unexpected overspeed trip during testing;
- Unit 0 and Unit 1 station air compressors out of service concurrent with the cross connect of DC buses 212 and 112; and
- Unit 1 shutdown risk.

For the review of the Unit 1 and Unit 2 train A SX unavailable during the replacement of the pump suction valves, the inspectors utilized the following references:

- BAP 300-1, OP-AA-100 Conduct of Operations Manual, Byron Addendum, Revision 22;
- 2BOL 7.8, Byron SX Train A Outage Summary of Compensatory Measures, Revision 5;
- Commitment Change Tracking 01-060, one SX pump from each unit will not intentionally be taken out of service at the same time for maintenance, December 18, 2001;

- Exelon Letter RS-03-228, Request for Additional Information Regarding a License Amendment for a One-Time Extension of the Essential Service Water Train Completion Time, December 5, 2003;
- Safety Evaluation by the Office of NRR related to Amendment 24 to Facility Operating License NPF-37 and Amendment 24 to Facility Operating License NPF-66; and
- Safety Evaluation by the Office of NRR Related to Amendment 136 to Facility Operating License 37, Byron Station, Unit 1.

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

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-routine Plant Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors completed five inspection samples by observing and evaluating control room operators during the following non-routine evolution:

- Unit 1 operators' response to a failure of the process computer;
- Unit 1 and Unit 2 operators' response to a loss of circulating water makeup;
- Unit 1 shutdown for the outage;
- Unit 1 operators' response to unanticipated intermediate range readings during reactor startup; and
- Unit 1 startup from the refueling outage.

The inspectors evaluated crew performance in the areas of:

- prioritization, interpretation and verification of alarms;
- procedure use;
- control board manipulations;
- supervisor's command and control;
- management oversight; and
- group dynamics.

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

- OP-AA-101-111, Roles and Responsibilities of On-Shift Personnel, Revision 1;
- OP-AA-103-102, Watchstanding Practices, Revision 3;
- OP-AA-103-103, Operation of Plant Equipment, Revision 0; and
- OP-AA-104-101, Communications, Revision 1.

In addition, the inspectors utilized the following references during the completion of their review:

- BAR 1-4-A6, Computer Trouble, Revision 9;
- 0BOA SEC-11, Inadequate Circulating Water Makeup, Revision 0;
- 1BOL 3.h, Limiting Condition for Operation Action Requirement (LCOAR) Power Distribution Monitoring System, Revision 4;
- BOP CX-16, Interrogation of the Process Computer, Revision 3;
- BOP CW-9, Circulating Water Make-up Pump Start-up, Revision 24;
- 1BOSR NR-2, Axial Flux Difference Monitor Alarm Inoperable Surveillance, Revision 4;
- 1BOSR RD-3, Bank Demand vs DRPI 4 Hour Position Survey; and
- 1BOSR 2.4.1-1, Quadrant Power Tilt Ratio Weekly Surveillance.

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

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

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

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

- CR 289268, 2B SX Pump cubicle cooler fans not running;
- BB PRA 017.38, risk assessment of missed surveillance of Byron auxiliary building ventilation and control room ventilation filter surveillance testing, Revisions 1, 2, & 3;
- CR 296192, diesel generator check valve stuck open;
- CR 290617, No reactor trip breaker closed indication during 1BOSR 3.1.5-2;
- Operability Determination 05-001 SX 168 controlled by nonsafety-related thermostat; and
- licensee's justification for not correcting existing degraded and nonconforming conditions during Byron Station Unit 1 Refueling Outage Thirteen (B1R13).

The inspectors compared the operability and design criteria in the appropriate section of the TS including the TS Basis, the Technical Requirements Manual (TRM) and UFSAR to the licensee's evaluations to determine that the components or systems were operable. The inspectors determined whether compensatory measures, if needed, were taken, and determined whether the evaluations were consistent with the requirements of licensee's Procedure LS-AA-105, "Operability Determination Process," Revision 1. The inspectors also discussed the details of the evaluations with the shift managers and appropriate members of the licensee's engineering staff.

The inspectors utilized the following references during the completion of their review:

- NRC Inspection Manual Part 9900: Technical Guidance, Operable/Operability: Ensuring the Functional Capability of a System or Component;
- NRC Inspection Manual Part 9900: Technical Guidance, Resolution of Degraded and Nonconforming Conditions, October 8, 1997;
- NRC Generic Letter No 91-18: Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions, Revision 1;
- NUREG-0800, Standard Review Plan, 9.5.6 emergency diesel engine starting system;
- ER-AA-600-1045, Risk Assessments of Missed or Deficient Surveillances, Revision 0; and
- NF-AP-551, power distribution monitoring system operability and administration, Revision 5.

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

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

The inspectors completed two operator workaround samples. The first sample evaluated the following condition to determine if it reached the threshold for being considered operator workarounds or operator challenges:

- compensatory actions for the Unit 1 train C higher than normal reactor coolant pump seal 1 leakoff.

The inspectors compared this condition to the threshold provided in the licensee's Procedure OP-AA-102-103, "Operator Work-around Program," Revision 1.

The second sample was a semi-annual sample of the licensee's aggregate review of operator workarounds. The inspectors assessed the cumulative effects of operator workarounds and operator challenges to determine that they did not adversely impact the ability to operate the plant. In particular, the inspectors focused on the following attributes:

- the cumulative effects of operator workarounds and challenges on the reliability, availability and potential for missed operation of a system;
- the cumulative effects of operator workarounds and challenges that could affect multiple mitigating systems;

- the cumulative effects of operator workarounds and challenges on the ability of operators to respond in a correct and timely manner to plant transients and accidents; and
- assessed the classification of existing operator workarounds and challenges.

During these reviews, the inspectors interviewed operating and engineering department personnel and reviewed applicable documents.

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

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Byron Administrative Procedure (BAP) 1600-11, Work Request Post Maintenance Testing Guidance, Revision 12; and
- Nuclear Station Procedure MA-AA-716-012, Post Maintenance Testing, Revision 5.

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

- Unit 1 train B emergency diesel generator jacket water leak repair;
- Unit 1 train B emergency diesel generator voltage regulator replacement;
- Unit 1 train B emergency diesel generator speed sensor replacement;
- Unit 2 train B essential service water cubicle cooler fan controller repair;
- Unit 2 train B auxiliary feedwater pump repairs following unexpected overspeed trip during testing;
- Unit 1 steam dump valve testing following repairs;
- Unit 1 fuel handling machine hoist repair following failure;
- Unit 1 and Unit 2 train A essential service water pump suction valve replacements; and

- Unit 1 digital rod position indication urgent failure alarm after periodic maintenance circuit card replacement.

For the review of the Unit 1 steam dump valve testing following repairs, the inspectors utilized the following reference during their review:

- OP-AA-300-1540, Reactivity Management Administration, Revision 0.

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

b. Findings

Introduction: A Non-Cited Violation (NCV) of TS 5.4.1a, having very low safety significance (Green) was self-revealed. Specifically, operators used an inadequately changed procedure to perform a post maintenance test (PMT) of the instrument air system for the steam dump (SD) valves on Unit 1 while the plant was at full power. This resulted in an unexpected opening of several other SD valves and a power increase of 0.8 percent.

Description: On February 27, 2005, with Unit 1 at full power, the operators performed a PMT following leak repair of the instrument air (IA) system for three steam dump valves, 1MS004D, H, and M. The operators used procedure "1BOSR MS-Q1 Unit 1 Steam Dump Valve Operability Quarterly Surveillance," Revision 5. This procedure was revised approximately nine months earlier and this was the first time the procedure was to be used. The intent of the revised procedure was to allow for isolating instrument air to selected steam dump valves and therefore prevent their opening without having to shut the backup steam valves.

When the test was initiated, the operators noticed most or all of the SD valve position indications going from a full closed position to an intermediate position. In addition, steam flow increased indicating that the steam dump valves were at least partially open. Immediately upon identification of the unexpected SD valve position changes and higher steam flow, the operators took the proper actions to shut the SD valves. The transient lasted for less than one minute and the reactor power increased by 0.8 percent. The matter was reported to the supervisors and the test was secured. The licensee generated an issue report and investigated the event.

The licensee's initial review of the event identified several shortcomings associated with Revision 5 of 1BOSR MS-Q1. In particular, the revision was made to allow the Byron procedure to more closely match the procedure used at the Braidwood Station, and because of similarities between the stations, the revision was made without validation, and the procedure was unclear regarding the specific IA valves to use for isolating the SD valves. Also the isolation points selected left a volume of air trapped within the piping between the isolation points and the SD valve operator, and this entrapped air may have been sufficient to reposition the SD valves. Based on these shortcomings, the inspectors considered the procedure to be inadequate and it resulted in an unexpected operation of the SD valves and associated unplanned reactor power transient.

Analysis: The inspectors determined that the inadequate procedure used during the PMT of the SD valves 1MS004D, H, and M, which allowed other SD valves opened unexpectedly and resulted in an unplanned reactor power increase, was a performance deficiency. This performance deficiency warranted a significance evaluation in accordance with Inspection Manual Chapter (IMC) 0612 "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening" issued on January 14, 2004. The inspectors determined that the finding was more than minor because it affected the procedure quality attribute associated with the Reactor Safety Barrier Integrity Cornerstone objective to provide reasonable assurance that physical barriers, specifically fuel cladding, protect the public from radionuclide releases caused by accidents or events.

The inspectors determined that the inadequate procedure affected the cross-cutting area of Human Performance (organization) because during the recent revision to the procedure, the reviewers did not complete a sufficient validation of the changes.

The inspectors determined that the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process," because the finding was associated with the Barrier Integrity cornerstone and protection of the fuel cladding. The Phase 1 screening, under the "Reactor Coolant System (RCS) Barrier or Fuel Barrier" screened as Green for fuel barrier issues.

Enforcement: Technical Specification 5.4.1 states that written procedures shall be established, implemented and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. This includes operating procedures for the main steam and instrument air systems. Contrary to the above, on February 27, 2005, Procedure 1BOSR MS-Q1, "Unit 1 Steam Dump Valve Operability Quarterly Surveillance," Revision 5, used as a post maintenance test for the Instrument Air system repair work for steam dump valves 1MS004D, H and M; was inadequate in that it resulted in an unexpected opening of other steam dump valves and an associated reactor power transient. Because this violation was of very low safety significance and the issue was entered into the licensees corrective action program (CR 305949, Power Transient From Steam Dump IA Isolation Problem U1), it was treated as an NCV, consistent with Section V1.A of the NRC enforcement Policy. (NCV 05000455/2005003-01)

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during Refueling Outage B1R13 beginning February 27, 2005, and ending on March 25, 2005. These inspection activities represent the completion of one inspection sample.

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

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

The inspectors observed portions of the plant cooldown, including the transition to shutdown cooling, to verify that the licensee controlled the plant cooldown in accordance with the TS. In addition, the inspectors completed numerous visual inspections inside the Unit 1 containment. This included a tour of the Unit 1 containment at Mode 3 during the cooldown at the beginning of B1R13 so that the inspectors could assess the initial material condition of equipment inside containment immediately following the operating cycle. During the visual inspections the inspectors focus on the material condition of the equipment and particularly on any indication of boric acid.

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

- verification that core reload was completed in accordance with the core loading plan for Byron Unit 1 Cycle 14;
- evaluation of foreign material exclusion control practices during significant work activities;
- verification that correct system lineups were maintained for key mitigating systems;
- verification that RCS boundary leakage requirements were met prior to entry into mode 4 (cold shutdown) and subsequent operational mode changes;
- verification that containment integrity was established prior to entry into mode 4; and

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

The inspectors also observed portions of the plant heatup and reactor startup, to verify that the licensee controlled the plant heatup in accordance with the TS and approved procedures.

The inspectors utilized the following references during the completion of their review:

- BFP FH-14; Operation of Refueling Machine, Revision 17;
- CC-AA-201; Plant Barrier Control Program, Revision 6;
- ER-AP-331-1002; Boric Acid Corrosion Program Identification, Assessment, and Evaluation, Revision 2;
- HU-AA-104-101; Procedure Use and Adherence, Revision 0;
- OP-AA-108-108; Unit Restart Review, Revision 3;
- OP-MW-109-101; Clearance and Tagging, Revision 2;
- OP-MW-201-007; Fire Protection System Impairment Control, Revision 3;
- OU-BY-204; Fuel Handling Activities in the Spent Fuel Pool for Byron and Braidwood, Revision 1;
- OU-AA-103; Shutdown Safety Management Program, Revision 4;
- OU-BY-205; Fuel Handling Activities in Containment During Refuel Outages for Byron and Braidwood, Revision 1;
- SA-AA-129-2118; Management and Control of Temporary Power, Revision 2;
- Byron Station Refuel Cavity Foreign Material Exclusion Plan, B1R13 Refueling Outage, Revision 1; and
- B1R13 Failed Fuel Action Plan Summary.

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

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

The inspectors completed eight inspection samples by observing and evaluating the following surveillance tests:

- Unit 1 train B residual heat removal pump ASME surveillance;
- Unit 1 reactor coolant system leakrate surveillance;
- Unit 1 main steamline safety valve lift setpoint testing;
- Unit 1 train A auxiliary feedwater pump simulated undervoltage start surveillance test;
- Unit 1 train B manual safety injection initiation and manual phase A initiation surveillance test;
- Unit 1 train A solid state protection system containment ventilation actuation signal;
- Unit 1 train A component cooling water supply containment isolation valve local leak rate test (LLRT); and
- Unit 1 summation of primary containment local leakage tests.

Additionally the inspectors used the documents listed in the Attachment to this report to determine that the testing met the frequency requirements; that the tests were conducted in accordance with the procedures including establishing the proper plant conditions and prerequisites; that the test acceptance criteria were met; and that the results of the tests were properly reviewed and recorded. The inspectors verified that the individuals performing the tests were qualified to perform the test in accordance with the licensee's requirements, and that the test equipment used during the test were calibrated within the specified periodicity. In addition, the inspectors interviewed operations, maintenance and engineering department personnel regarding the tests and test results.

b. Findings

Introduction: The NRC identified an NCV of TS 3.9.4 finding of very low safety significance (Green). Specifically, the inspectors determined that during the performance of LLRTs the licensee failed to maintain containment penetrations closed while core alterations were in progress as was required by the TS.

Description: On March 2, 2005, during NRC review of a LLRT Procedure 1BOSR 6.1.1-12 Revision 5, "Primary Containment Type C Local Leak Rate tests and ISI Tests of Component Cooling System," it was determined that the procedure had no prohibitions in the precautions and limitations about performing the procedure during core alterations. Implementation of the procedure created a direct access path from the containment atmosphere to the outside atmosphere and was not in accordance with the TS requirement for refueling operations. Although refueling was not occurring at the time of the inspectors' question, the supervisor for the testing indicated there was no prohibition to testing during core alterations, in fact several LLRTs were scheduled to be completed during refueling activities during the outage. Since refueling was scheduled less than 48 hours, the inspectors brought the concern to the attention of a licensed operator coordinating outage activities for Operations.

Based on the inspectors' question, the licensee wrote a condition report to evaluate the issue with licensing and operations. Since there had been no barriers preventing testing and other maintenance activities associated with containment to auxiliary building penetrations during core alterations, the Operations Department Management placed a hold on the applicable activities that were scheduled to be completed concurrently with the upcoming refueling activities.

Review of past refueling outages revealed that LLRTs were completed on both units during core alteration, and that the containment penetrations were not controlled in accordance with the TS. For example, on September 27, 2003, during the core offload for the Unit 1 refueling outage, the as-found LLRT for penetration P-30 for 1WM190/191 was performed, and on March 28, 2004, during the core offload for the Unit 2 refueling outage, the as-found LLRT for penetration P-44 for 2RY8028/8046 was performed.

Analysis: The inspectors determined that the failure to properly control containment penetrations during core alterations was a performance deficiency warranting a significance evaluation. This determination was made in accordance with IMC 0612 "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening" issued on January 14, 2004. The inspectors determined that the finding was more than minor because it affected the configuration control, specifically the containment boundary preservation, attribute associated with the Reactor Safety Barrier Integrity Cornerstone objective to provide reasonable assurance that physical barriers, specifically containment, protect the public from radionuclide releases caused by accidents or events.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," dated April 21, 2003, because the finding was associated with the Barrier Integrity cornerstone and protection of the reactor containment integrity. UFSAR Chapter 15 accident analysis (Chapter 15.7.4) for a fuel handling assumes the containment is isolated before any activity is released to the environment. The inspectors utilized the event information in conjunction with Appendix G, "Shutdown Operations Significance Determination Process," of Manual Chapter 0609, Checklist 4, "Pressurized Water Reactor (PWR) Refueling Operation Reactor Coolant System (RCS) Level > 23' OR PWR Shutdown Operation with Time to Boil > 2 hours AND Inventory in the Pressurizer." This NRC identified issue was determined to be of very low safety significance (Green) by the significance determination process because (1) the issue did not increase the likelihood of a loss of primary coolant system inventory; (2) the issue did not degrade the licensee's ability to terminate a leak path or add RCS inventory when needed; and (3) the issue did not degrade the licensee's ability to recover decay heat removal once lost. In addition Manual Chapter 0609 Appendix H, Containment Integrity Significance Determination Process was also used to assess the significance of this issue. Since the issue only impacted the containment function without affecting core damage frequency, and since the issue was associated with a shutdown condition during periods when the reactor vessel water level was greater than or equal to the level required for fuel moves, the review of the Containment Integrity SDP also indicated that the issue was of very low safety significance.

Enforcement: Technical Specification 3.9.4.c, states, in part, that each containment penetration providing direct access from the containment atmosphere to the outside atmosphere shall be closed by either an isolation valve, blind flange, manual valve, or equivalent during core alterations or movement of irradiated fuel within the containment. With the above requirement not satisfied, the TS required that the licensee immediately suspend all operations involving core alterations or movement of irradiated fuel in the Containment Building. Contrary to the above, on September 27, 2003, during the core offload for the Unit 1 refueling outage, penetration P-30 for 1WM190/191 was not closed by either an isolation valve, blind flange, manual valve, or equivalent. Similarly, on March 28, 2004, during the core offload for the Unit 2 refueling outage, penetration P-44 for 2RY8028/8046 was not closed by either an isolation valve, blind flange, manual valve, or equivalent. Because this violation was of very low safety significance and the issue was captured in the licensee's corrective action program (CR 308381), this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000454/2005003-02; 05000455/2005003-02).

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors completed three inspection samples by evaluating the following temporary plant modifications on risk-significant equipment:

- Engineering Change 353117, Temporary Setpoint Change to the 1C RCP seal Number 1 leakoff flowrate high alarm;
- Temporary Change 6D-05-0057, Revision 1 to Procedure BFP-FH-101, Lower Stuck Fuel Assembly from Refueling Machine with Polar Crane; and
- Temporary Change 351262, temporary power to 0VC01JB during Bus 144 outage.

The inspectors reviewed these temporary plant modifications to determine that the instructions were consistent with applicable design modification documents and that the modifications did not adversely impact system operability or availability. The inspectors verified that the licensee controlled temporary modifications in accordance with Nuclear Station Procedure (NSP) CC-AA-112, "Temporary Configuration Changes," Revision 8.

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

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys for selected radiation areas, high radiation areas (HRA), and airborne radioactivity areas, as available, in the following four radiologically significant work areas within the plant. The inspectors also reviewed work packages which included associated licensee controls and surveys for these areas to determine if radiological controls (including postings and barricades) were acceptable:

- Unit 1 Containment;
- Unit 1 Containment Access Facility;
- Auxiliary Building (in particular, the Unit 1 Penetration Area); and
- Radwaste Building.

The inspectors reviewed the radiation work permits (RWP) and work packages used to control work in these four areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to assess their knowledge of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down and surveyed these four areas to verify that the prescribed RWPs, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers (if necessary) were properly located.

The inspectors reviewed RWPs for the Unit 1 Containment which was controlled as an airborne radioactivity area on March 12, 2005, to verify barrier integrity and engineering controls performance (e.g., high efficiency particulate air (HEPA) ventilation system operation) and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. Other work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection.

The inspectors assessed the adequacy of the licensee’s internal dose assessment process by reviewing a variety of personnel contamination events (and associated dose assessments) for the B1R13 refueling outage. No personnel contamination events resulted in dose assignments of greater than 50 millirem committed effective dose equivalent during the refueling outage. However, the inspectors evaluated the licensee’s internal dose assessment process by reviewing the assessment for the highest intake (5 millirem) associated with work on the upper internal split pin modification during a period when containment was posted as an Airborne Radioactivity Area.

These reviews represented five inspection samples.

b. Findings

Introduction: One self-revealed Green finding and an associated NCV were identified when, on March 12, 2005, the licensee failed to conduct an adequate evaluation of the radiological conditions prior to removing the charcoal adsorber portion of HEPA units associated with work on the Unit 1 steam generators. Subsequently, Unit 1 Containment radiological conditions changed such that several air monitors went into high alarm on the iodine channel and 28 personnel were found to have unintended, low-level, internal contamination.

Description: During the B1R13 refueling outage, the licensee implemented several additional radiological controls and dose mitigation strategies in response to operational data indicating that a small number of fuel pins were faulted in Unit 1 during the previous cycle. One of the actions taken by the licensee was to install HEPA filtration units with charcoal adsorbers to control radioiodine levels within the steam generator bowls. The licensee specifically implemented the mitigation strategy as a requirement in the ALARA plan for RWP 10004695, “B1R13 Eddy Current Inspections and Repairs.” The ALARA plan also required that the HEPA units with charcoal adsorbers be utilized until air samples validated that noble gas and radioiodines were no longer a significant radiological concern.

Late on March 11, 2005, the Outage Control Center (OCC) Radiation Protection Manager (RPM) and the Radiation Protection (RP) Supervisor overseeing steam generator activities had discussions regarding plans for radiologically controlling various upcoming evolutions in the Unit 1 containment. During that conversation the OCC RPM inquired of the steam generator RP supervisor as to possible equipment that could be demobilized from the containment, using the steam generator HEPA charcoal adsorbers as an example. However, the steam generator RP supervisor believed the OCC RPM had given him direction to specifically remove the charcoal adsorbers from the containment. No three-way communication apparently occurred during this conversation relative to the demobilization of the charcoal adsorbers.

At approximately 4:30 a.m. on March 12, 2005, the charcoal adsorbers were disconnected from the steam generator HEPA units at the direction of the steam generator RP supervisor. No evaluation of the radiological conditions inside the steam generators was conducted prior to the charcoal adsorbers being disconnected. Additionally, there was no written turnover provided to the “day shift” RP personnel relative to the charcoal units being disconnected, though there was apparently a verbal statement from the steam generator RP supervisor during the RP turnover meeting at 6:00 a.m.

Between 6:00 a.m. and 7:00 a.m., reports from the Unit 1 Containment Access Facility indicated that several workers were having difficulties exiting containment due to external and potentially internal contaminations. At approximately 6:45 a.m., two process radiation monitors in or near the Fuel Handling Building (FHB) went into High Alarm on their iodine channels. In response to the alarms and the contamination events, licensee RP staff and contractors began reinstalling the charcoal adsorbers on the steam generator HEPA units at approximately 7:30 a.m. and completed the reinstallation around 9:30 a.m. As of 10:35 a.m., air samples from various levels of the Unit 1 containment and the FHB reveal airborne radioactivity greater than 0.3 derived air concentration (DAC) (with a maximum of 1.55 DAC on the 377' elevation, Inside Missile Barrier), resulting in both containment and the Fuel Handling Building being posted as Airborne Radioactivity Areas. The Operations Department and RP staffs coordinated to further clean up the Containment and FHB atmospheres by starting the mini-purge and FHB charcoal booster fan systems. At approximately 6:00 p.m. on March 12, 2005, air sample results in containment and the FHB showed airborne radioactivity levels of less than 0.3 DAC, and the areas were subsequently downposted.

As a result of the airborne radioactivity, 28 radiation workers were determined to have low-level, unintended intakes (of primarily radioiodines) ranging from 2 to 5 millirem of committed effective dose equivalent.

In addition to reinstalling the charcoal adsorbers and initiating additional containment and FHB atmosphere treatment, licensee corrective actions for this event included revising the steam generator RP control procedure to include specific criteria for charcoal adsorber removal and modifying the outage schedule such that charcoal adsorber removal is logically tied to steam generator manway installation.

Analysis: The inspectors determined that the licensee failed to adequately evaluate the radiological conditions inside the steam generator bowls and the potential consequences prior to removing charcoal adsorbers associated with HEPA units specifically implemented to control airborne radioactivity within the steam generators. This performance deficiency is associated with the Human Performance attribute and affects the Occupational Radiation Safety cornerstone objective of ensuring adequate protection of worker health and safety from exposure to radioactive materials, in that multiple workers received unintended dose from small intakes. The inspectors determined that the failure to evaluate the radiological conditions also affected the cross-cutting area of Human Performance (organization), because, despite the licensee’s planned and documented B1R13 dose mitigation strategies, the RP supervisors did not adequately perform self- and peer-checking to ensure the ALARA plan requirements were met. Therefore, the issue was determined to be more than minor and represents a finding which was evaluated using the SDP for the Occupational Radiation Safety Cornerstone.

The inspectors determined utilizing Manual Chapter 0609, Appendix C, “Occupational Radiation Safety SDP,” that the finding was not specifically related to ALARA or planning issues, there were no radiological overexposures, nor the substantial potential for an overexposure, and the licensee’s ability to assess worker dose was not compromised. Consequently, the inspectors concluded that the SDP assessment for this finding was of very low safety significance (Green).

Enforcement: Title 10 of the Code of Federal Regulations Part 20.1501 requires, in part, that each licensee shall make surveys that are reasonable under the circumstances to evaluate the magnitude and extent of radiation levels, concentrations or quantities of radioactive material, and the potential radiological hazards, to ensure compliance with the occupational dose limits contained in 10 CFR Part 20, Subpart C. Contrary to the above, on March 12, 2005, it was self-revealed that the licensee failed to evaluate the radiological conditions prior to removing the charcoal adsorber portion of HEPA units associated with work on the Unit 1 steam generators. However, because the licensee documented this issue in its corrective action program (CR 311872), took corrective actions to preclude reoccurrence, and the violation is of very low safety significance, it is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000454/2005003-03; 05000455/2005003-03).

.2 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following two activities that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Steam Generator Eddy Current Testing and Tube Repairs [RWP No. 10004695]; and
- Upper Internals Split Pin Modification [RWP No. 10004749].

The inspectors reviewed radiological job requirements for these two activities, including RWP and work procedure requirements, and attended pre-job Radiation Protection (RP) briefings. Additionally, the inspectors reviewed RWP requirements and observed in-field radiological briefings conducted by RP Technicians for containment demobilization and clean-up activities conducted by multiple workgroups.

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. The inspectors also verified the adequacy of radiological controls (including required radiation, contamination, and airborne surveys); radiation protection job coverage (including audio/visual surveillance for remote job coverage); and contamination controls.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. In particular, the steam generator eddy current activities involved evolutions where the dose rate gradients were severe, which increased the necessity of providing multiple or repositioned dosimetry and/or enhanced job controls.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.3 High Risk Significant, High Dose Rate HRA and Very HRA Controls

a. Inspection Scope

The inspectors held discussions with the Radiation Protection Manager concerning high dose rate-high radiation area 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.

The inspectors discussed with RP supervisors the controls that were in place for special areas that had the potential to become very high radiation areas during certain plant operations to determine if these plant operations required communication beforehand with the RP group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

The inspectors conducted plant walkdowns to verify the posting and locking of reasonably accessible entrances to high dose rate HRAs and very high radiation areas (focusing on those areas within the Unit 1 containment during the B1R13 refueling outage).

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection 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 accounted for the level of radiological hazards present.

These reviews represented one inspection sample.

b. Findings

Introduction: One self-revealed Green finding and an associated NCV were identified when, on March 9, 2005, a contract radiation worker, while supporting polar crane movement of equipment used for the upper internals split pin modification, entered a

HRA without receiving a high radiation area brief from the RP staff as required by the RWP.

Description: Between March 5, and late on March 8, 2005, a contract radiation worker crew was supporting equipment movement from the containment hatch to the area surrounding the reactor head stand on the 426' elevation. During this time period, the equipment moves were conducted in the counter-clockwise direction around containment, which required the contract crew (i.e., a foreman, spotters, and a signalman) to coordinate with RP Technicians to allow the crew to pass through an RP notification barrier (i.e., a swing gate) to complete the equipment move.

On March 9, 2005, due to other activities being conducted in the counter-clockwise load path, the equipment load path was reversed to the clockwise direction. At approximately 3:00 p.m., the contract crew was briefed at the RP containment desk as to the radiological conditions in containment for the equipment moves, and the crew signed in on the RWPs applicable to their activities (RWP No. 10004749, “Upper Internals Split Pin Modification,” and RWP No. 10004748, “ISI Inspections”). Both RWPs require a briefing by RP Technicians specific for HRAs, and other higher risk areas, prior to workers entering such areas. During the brief at the RP containment desk, the RP Technician specifically indicated that he was not providing a HRA briefing for the crew.

Between 5:45 p.m. and 7:00 p.m. on March 9, the contract crew began supporting equipment moves from hatch in the clockwise direction. Similar to previous moves, the crew was required to coordinate with an RP Technician in the field for clearance to pass through an RP notification barrier. The RP Technician in the field authorized the crew to pass through the RP notification barrier (i.e., an accordion gate) and opened the barrier, but he specifically indicated that the briefing did not authorize entry into a HRA.

During the first equipment move, the lead spotter of the crew was supposed to be about 20 feet in front of the load, but due to walk path obstructions he was diverted, and he ended up behind the load (though neither the signalman nor the tail spotter were aware of the lead spotter’s diversion). When the signalman stopped the load while other contract workers were discussing the exact location for the equipment to be set down, the lead spotter caught up to the load. At that point the load was suspended over a 4-foot wide path between the cavity foreign material exclusion barrier and the reactor head. However, the lead spotter found that his path was blocked in that he could not go under the suspended load. As such, the lead spotter turned around, went behind the reactor head, and walked through a HRA barrier (i.e., a swing gate) initially believing this was the barricade he had clearance to cross. During licensee interviews after the event, the lead spotter indicated that he did see the HRA posting but did not recognize that he was not authorized to be in the area. Once inside the HRA, the worker realized his error and immediately exited the HRA. The actions of the lead spotter were observed by a member of a different radiation worker crew who reported the incident to a contract RP Technician. The RP Technician and an RP supervisor immediately contacted the lead spotter and his foreman, and ordered them to immediately leave containment.

The licensee’s followup investigation of the lead spotter’s actions identified that the worker’s electronic dosimetry did not alarm, and that the highest dose rate measured was 7.9 millirem per hour and his total accumulated dose for the event was 3 millirem.

The dosimetry alarm setpoints were 80 millirem accumulated dose and 100 millirem per hour dose rate, in accordance with RWP No. 10004749. The licensee's investigation determined that the apparent cause of the event was the individual's misunderstanding of which barriers he was allowed clearance, which may have been exacerbated by the quality of pre-job briefs and the adequacy of radiation worker knowledge.

In addition to administratively locking the foreman and the lead spotter out of the radiologically controlled area and initiating a prompt investigation of the event, licensee corrective actions for this issue included: adding or reinforcing more robust HRA barriers inside containment; requiring that a RP Technician open and maintain positive control over all HRAs in containment when workers are in the areas; and initiating a root cause evaluation to further review the event's primary and contributing causes and to recommend additional corrective actions.

Analysis: The inspectors determined that the contract radiation worker failed to receive the HRA briefing (either at the RP containment desk or in the field) as required by the RWP, and the individual failed to recognize that he was not authorized to be in the HRA when he saw the HRA posting and entered the area. The performance deficiency is associated with the Human Performance attribute and affects the Occupational Radiation Safety cornerstone objective of ensuring adequate protection of worker health and safety from exposure to radioactive materials in that two barriers (i.e., the HRA briefing and compliance with the HRA posting) in place to prevent unplanned, unintended worker dose failed. The inspectors determined that the radiation worker's error also affected the cross-cutting area of Human Performance (personnel) because, despite the worker's training, the worker failed to recognize that he was not briefed nor authorized to enter the HRA. Therefore, the issue was determined to be more than minor and represents a finding which was evaluated using the SDP for the Occupational Radiation Safety Cornerstone.

The inspectors determined utilizing Manual Chapter 0609, Appendix C, "Occupational Radiation Safety SDP," that the finding was not specifically related to ALARA or planning issues, there were no radiological overexposures, nor the substantial potential for an overexposure, and the licensee's ability to assess worker dose was not compromised. Consequently, the inspectors concluded that the SDP assessment for this finding was of very low safety significance (Green).

Enforcement: Byron Technical Specification 5.4.1 requires, in part, that the licensee establish, implement, and maintain written procedures for activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Regulatory Guide 1.33, Appendix A, Section 7.e.1, recommends that radiation protection procedures be written and implemented governing access control to radiation areas including the use of a radiation work permit system. Licensee procedure RP-AA-403, "Administration of the Radiation Work Permit Program," (Revision 1), Step 4.5.3, requires that radiation workers comply with all the requirements of the RWP as well as verbal instructions given by RP personnel. Radiation Work Permit No. 10004749, "B1R13: Upper Internal Split Pin Mod," lines 109 - 110, requires a radiation protection briefing prior to worker entry into a HRA (and other higher risk areas). Contrary to these requirements, on March 9, 2005, it was self-revealed that a contract radiation worker entered a posted HRA without receiving a HRA briefing from RP personnel. However, because the licensee documented this issue in its corrective action program (IR 310707), took corrective actions to preclude reoccurrence, and the violation is of very low safety significance, it is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000454/2005003-04; 05000455/2005003-04).

.5 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their oversight of radiological activities was consistent with their training and qualifications with respect to the radiological hazards and work activities.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

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

.1 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities for the B1R13 refueling outage ranked by estimated exposure that were in progress, and reviewed the following three work activities of highest exposure significance or radiological challenge:

- Steam Generator Eddy Current Testing and Tube Repairs [RWP No. 10004695];
- Reactor Head Disassembly and Reassembly [RWP No. 10004707]; and
- Upper Internals Split Pin Modification [RWP No. 10004749].

For these three activities, the inspectors reviewed the ALARA evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA.

b. Findings

No findings of significance were identified.

.2 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed 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. This review included a determination if adjustments to estimated exposures (intended dose) were based on sound radiation protection and ALARA principles, rather than adjustments to account for failures to adequately control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process. In particular, the inspectors reviewed and discussed with the RP staff the Work-In-Progress reviews conducted for the steam generator project RWPs (post-forced oxidation cleanup).

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

.1 Inspection Planning and Verification of Calibration/Operability of Instrumentation

a. Inspection Scope

The inspectors reviewed the plant UFSAR to identify applicable radiation monitors associated with transient high and very high radiation areas including those used in remote emergency assessment. The inspectors identified the types of portable radiation detection instrumentation used for job coverage of high radiation area work, other temporary area radiation monitors currently used in the plant, continuous air monitors associated with jobs with the potential for workers to receive 50 millirem committed effective dose equivalent, whole body counters, and the types of radiation detection instruments utilized for personnel/equipment release from the radiologically controlled area.

The inspectors reviewed the applicable licensee procedures and calibration documentation to verify the calibration, operability, and alarm setpoints (if applicable) of the following 17 instruments:

- Unit 1 and Unit 2 Containment High Range Monitors (1RE-AR021 and 2RE-AR020);
- Spent Fuel Pool Fuel Handling Incident Area Monitor (0RE-AR056);
- Unit 2 Containment Fuel Handling Incident Area Monitor (2RE-AR012);
- Auxiliary Building 451' El. Area Monitoring Loop (0RE-AR062J);
- Canberra FastScan Whole Body Counting System;
- NE Technologies Personnel Whole Body Frisking Monitors (IPM-7/8/9);
- Eberline Whole Body Portal Monitors (PM-7);
- NE Technologies Small Article Monitors (SAM-9/11);
- Neutron Survey Instrument (ASP-2e/NRD Rem-Ball);
- Ion Chamber Survey Meter (RO-20);

- Electronic Dosimetry (Thermo Electron EPD Mark 2 and EPD-N2);
- MGP Telepole Meter;
- Eberline ASP2/AC3-7 Alpha Frisker;
- MGP AMP-100 Meter (used for underwater surveys); and
- Low Volume Air Sampler (H809VI).

The inspectors determined what actions were taken when, during calibration or source checks, an instrument was found significantly out of calibration (by greater than 50 percent), determined possible consequences of instrument use since last successful calibration or source check, and determined if the out of calibration result was entered into the corrective action program. The inspectors also reviewed the licensee's 10 CFR Part 61 source term reviews to determine if the licensee was cognizant of the station source term composition, instrument capabilities to detect the source term, and that calibration/check sources used were representative of the station's source term.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments and audits, as available, that involved personnel contamination monitor alarms due to personnel internal exposures to verify that identified problems were entered into the corrective action program for resolution. Though there were no licensee identified events since the last inspection in this area involving internal exposures greater than 50 millirem committed effective dose equivalent, the inspectors reviewed and discussed licensee procedures with Radiation Protection staff to determine if the licensee would be capable of appropriately identifying and analyzing low-level radiological personnel intakes utilizing calibrated and appropriately sensitive equipment.

The inspectors reviewed corrective action program reports related to exposure significant radiological incidents that involved radiation monitoring instrument deficiencies since the last inspection in this area. 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.

The inspectors reviewed licensee self-assessment activities to determine if those activities were identifying and addressing repetitive deficiencies or significant individual deficiencies in problem identification and resolution.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.3 Radiation Protection Technician Instrument Use

a. Inspection Scope

The inspectors reviewed the calibration expiration and source response check currency for radiation detection instruments staged for use, and observed radiation protection technicians for appropriate instrument selection and self-verification of instrument operability prior to use.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Self-Contained Breathing Apparatus (SCBA) Maintenance and User Training

a. Inspection Scope

The inspectors reviewed the status and surveillance records of SCBAs staged and ready for use in the plant and evaluated the licensee's capability for refilling and transporting SCBA air bottles to and from the control room, operations support center (OSC), and bottle filling station during emergency conditions. The inspectors determined if control room operators and other emergency response personnel were trained and qualified in the use of SCBAs (including personal bottle change-out). Specifically, the inspectors reviewed current SCBA/respiratory protection qualification matrices for the Operations, Maintenance, Chemistry and Radiation Protection Departments, to verify that sufficient numbers of individuals required to respond to the control room and the OSC during emergency conditions were qualified to use SCBAs and/or other respiratory protection devices per the requirements of the licensee's Emergency Plan, Part II, Section O (Revision 16).

As the licensee does not itself conduct maintenance of vital components of SCBA units, the inspectors reviewed licensee and vendor maintenance/surveillance procedures, including those for the low-pressure alarm and pressure-demand air regulator, and the SCBA manufacturer's recommended practices to determine if there were inconsistencies between them. The inspectors also reviewed the vital component maintenance records (for activities conducted by a SCBA manufacturer-trained vendor) over the past several years for four SCBA units currently staged and designated as "ready for service:" Rack 170, Rack 126, Training Rack 203, and Rack 155. The inspectors also ensured that the required, periodic air cylinder hydrostatic testing was documented and up to date, and that the Department of Transportation-required retest air cylinder markings were in place for those four, and additional, staged units.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

Cornerstones: Mitigating Systems, Barrier Integrity, Public Radiation Safety

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 that they were being entered into the licensee's corrective action system 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 system as a result of inspectors' observations are generally denoted in the list of documents reviewed at the back of the report.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

a. Inspection Scope

The inspectors completed one inspection sample by reviewing the February 28, 2005, failure of the licensed operators to declare an Unusual Event upon determining that reactor coolant system dose equivalent Iodine 131 (DEI-131) activity exceeded 1.0 FCi/gm as specified in the licensee's Standardized Radiological Emergency Plan (Procedure EP-AA-110, Revision 16). The inspectors reviewed the applicable logs, associated licensee procedures and discussed the event with operators, and members of the licensee's staff and management.

b. Findings

Introduction: An NCV of 10 CFR 50.54(q) having very low safety significance (Green) was self-revealed when the operators failed to declare an Unusual Event upon determining that DEI-131 exceeded 1.0 FCi/gm. DEI-131 greater than 1.0 FCi/gm was the threshold specified in the licensee's emergency plan for declaring an Unusual Event.

Description: On February 27, 2005, operators were shutting down the Unit 1 reactor in preparation for a refueling outage. In accordance with licensee procedures, power was reduced below twenty percent and then at 11:05 p.m., Unit 1 was manually tripped. Technical Specification 3.4.16 required the licensee to verify reactor coolant activity following any fifteen percent or greater power change in one hour. A reactor coolant sample was taken by a chemistry technician on February 28, 2005 at 1:06 a.m. The average temperature of the reactor coolant system at this time was 514° F.

At approximately 2:06 a.m. the chemistry technicians concluded that DE I-131 was 1.069 FCi/gm. The licensee evaluated this condition against TS 3.4.16, and concluded that the Unit was not in the Mode of applicability for the TS; i.e., the Unit was in Mode 3 with average temperature of the average reactor coolant system below 500° F. However, the licensee did not evaluate this condition against the Emergency Action Level (EAL) requirements. Another sample was taken at 9:30 a.m. as part of routine water chemistry monitoring program. This second sample showed that I-131 levels had fallen below 1.0FCi/gm.

During the afternoon of February 28, 2005, the licensee determined that the EAL threshold had been exceeded and the licensee failed to declare an Unusual Event as specified by EAL MU7 for DEI-131 specific activity greater than 1.0 FCi/gm. This EAL requirement is for all modes of operation regardless of RCS temperature. Upon discovery, the licensee notified the NRC of this discrepancy in a timely manner. The licensee also initiated an internal investigation of the missed EAL requirements.

Analysis: The inspectors determined the failure to implement required Emergency Action Level procedures associated with reactor coolant activity was a performance deficiency warranting a significance evaluation. This determination was made in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on January 14, 2004. The inspectors also determined that the issue was greater than minor. This was based on the failure to recognize the Unusual Event on February 28, 2005; therefore, the finding was associated with Reactor Safety / Emergency Preparedness Cornerstone attribute of Response Organization performance and affected the cornerstone objective of providing reasonable assurance that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency.

The inspectors also determined that the finding had a cross-cutting aspect of human performance (organization), in that licensed operators failed to realize that an Emergency Action Level threshold had been exceeded and that an Unusual Event declaration was required.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” dated April 21, 2003. Specifically, the inspectors evaluated this finding using IMC 0609, Appendix B, “Emergency Preparedness Significance Determination Process,” dated March 3, 2003. Since the finding was associated with failure to meet or implement a regulatory requirement and an actual event, the inspectors used Worksheets 1 and 2. In regards to Sheet 1, ‘Failure to Comply’ worksheet, the inspectors answered “no” to the Planning Standards decision box indicating that the issue was of very low safety significance (Green). In regards to Sheet 2, ‘Actual Event Implementation Problem’ worksheet, the inspectors answered “yes” to the ‘Notice of Unusual Event’ decision block indicating that the issue was of very low safety significance (Green). In accordance with paragraph ‘b’ of the SDP guidance section and the most significant results are used to determine the significance of the issue. Since both results were Green, the inspectors concluded that the finding was of very low safety significance (Green) and was assigned to the Emergency Preparedness Cornerstone of Unit 1.

Enforcement: Title 10 CFR 50.54(q) states that a licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in 10 CFR 50.47(b) and the requirements in Appendix E of this part.

Title 10 CFR 50.47(b)(4) states that a standard emergency classification and action level scheme, the bases of which include facility system and effluent parameters, is in use by the nuclear facility licensee, and State and local response plans call for reliance on information provided by facility licensees for determinations of minimum initial offsite response measures.

The licensee’s action level scheme was defined in the Exelon Nuclear Standardized Radiological Emergency Plan; EP-AA-1000, Revision 16. The licensee’s Emergency Action Level MU7 specifically identifies the condition of DEI-131 in excess of 1.0 FCi/gm requiring declaration as an Unusual Event.

Contrary to the above, on February 28, 2005 the licensee failed to declare an Unusual Event for EAL MU7, DEI-131 in excess of 1.0 FCi/gm. Because this violation was of very low safety significance and the issue was entered into the licensees corrective action program (CR 0306538), it was treated as an NCV, consistent with Section V1.A of the NRC Enforcement Policy. (NCV 05000454/2005003-05)

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R19 of this report had as a primary cause a human performance deficiency (organization). Specifically, during the recent revision to the procedure, the reviewers did not complete a sufficient validation of the changes.

.2 A finding described in Section 2OS1.1 of this report had as a primary cause a human performance deficiency (organization). Both the Outage Control Center RP Manager and the steam generator RP supervisor failed to ensure that the radiological conditions within Unit 1 steam generators supported the removal of the charcoal adsorber portions of the HEPA units.

.3 A finding described in Section 2OS1.4 of this report, had as primary causes, human performance deficiencies (personnel). The individual was confused as to which barriers he was allowed clearance for, and he failed to recognize that he was not authorized to be in the HRA. In addition, the quality of the pre-job ALARA briefings given by radiation protection personnel was poor.

.4 A finding described in Section 4OA3 of this report had as a primary cause a human performance deficiency (organization). Specifically, licensed operators failed to realize that an Emergency Action Level threshold had been exceeded and that an Unusual Event declaration was required.

.5 A finding described in Section 4OA5.3 of this report affected the crossing cutting area of problem identification and resolution (evaluation). Specifically, following the initial indications of a possible over power condition, the licensee missed several opportunities to conclude that the over power condition existed.

4OA5 Other Activities

.1 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (PWRs) (TI 2515/160)

a. Inspection Scope

On May 28, 2004, the NRC issued Bulletin 2004-01, “Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWR.” The purpose of this Bulletin was to:

(1) Advise PWR licensees that current methods of inspecting Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections may need to be supplemented with additional measures to detect and adequately characterize flaws due to primary water stress-corrosion cracking (PWSCC);

(2) Request PWR addressees to provide the NRC with the information related to the materials from which the pressurizer penetrations and steam space piping connections at their facilities were fabricated; and

(3) Request PWR licensees to provide the NRC with the information related to the inspections that have been and those that will be performed to ensure that degradation of Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections will be identified, adequately characterized, and repair.

The objective of TI 2515/160, “Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors,” was to support the NRC review of licensees’ activities for inspecting pressurizer penetrations and steam space piping connections made from Alloy 82/182/600 materials, and to determine whether the inspections of these components are implemented in accordance with the licensee responses to Bulletin 2004-01. In response to Bulletin 2004-01, the licensee committed to perform a bare metal visual inspection of 100 percent of the five susceptible Inconel pressurizer penetrations in the upper pressurizer head using a VT-2 qualified examiner. On March 3, 2005, the inspectors observed the licensee performing this inspection and performed a review, in accordance with a TI 2515/160, of the licensee's controls and personnel used for pressurizer penetration nozzles and steam space piping connections examinations to confirm that the licensee met commitments associated with

Bulletin 2004-01. The results of the inspectors' review included documenting observations and conclusions in response to the questions identified in TI 2515/160.

b. Observations

Summary: Based upon a bare metal visual examination of the pressurizer, the licensee did not identify any indications of boric acid leaks from pressure retaining components in the pressurizer system.

Evaluation of Inspection Requirements

In accordance with the requirements of TI 2515/160, inspectors evaluated and answered the following questions:

1. For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee conducted a direct visual examination of the bare metal surface of the upper pressurizer head heater penetration nozzles with a knowledgeable staff member certified to Level III as a VT-2 examiner in accordance with procedure TQ-AA-122, "Qualification and Certification of Nondestructive (NDE) Personnel." This qualification and certification procedure referenced the industry standards SNT-TC-1A, "Personnel Qualification and Certification in Nondestructive Testing," and ANSI/ANST CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. For each of the examination methods used during the outage, was the examination performed in accordance with demonstrated procedures?

   No. The inspectors observed the licensee inspector performing the bare metal inspection of the pressurizer nozzles in accordance with work order 00745801 which did not reference an inspection procedure. The work order specified performing a VT-2 examination of the five pressurizer nozzles as described in the licensee's response to Bulletin 2004-01. The licensee's examiner used a flashlight for illumination during this inspection and photographed each penetration nozzle. However, the licensee did not demonstrate adequate visual resolution commensurate with an ASME Code VT-2 type inspection. Specifically, the licensee did not demonstrate the capability of resolving lower case alpha numeric characters at 6 feet nor was the illumination measured to determine if the 15 foot-candle minimum lighting requirement was met.

The lack of Code visual acuity checks for the visual examinations discussed above did not constitute a violation of NRC requirements, because these inspections were not required by the ASME Code. Additionally, the licensee had not committed to perform Code qualified VT-2 visual examinations in response to NRC Bulletin 2004-01.

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

   Yes. The inspectors concluded that the licensee's direct visual examinations were capable of detecting leakage from cracking in pressurizer penetrations if it had existed. This conclusion was based upon the inspectors direct observations of pressurizer penetration locations which were free of debris or deposits that could mask evidence of leakage in the areas examined.

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' basis is discussed in the answer to question 3 above.

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)?

   The upper pressurizer head Inconel penetrations included three safety relief valve penetration nozzles, a power operated relief valve nozzle and a spray line penetration nozzle. The inspectors observed that the canned metal reflective insulation had been removed from the pressurizer at these penetration locations to allow a bare metal visual examination. The inspectors performed a direct visual inspection for these pressurizer penetrations. Based on this examination, the area examined was clean and free of debris or deposits or other obstructions which could mask evidence of leakage.

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

   The licensee conducted a direct bare metal visual examination of these pressurizer penetrations.

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

   The licensee performed a bare metal inspection of the five steam space piping connections/nozzles which included 360 degrees around the circumference of each penetration nozzle.

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

   Yes. The inspectors determined through direct observation of the licensee's efforts that the licensee staff were capable of detecting pressurizer nozzle leakage, if any had existed. However, due to the lack of an inspection procedure, identification or characterization of deposits was left entirely up to the judgment and training of the licensee's inspector. The licensee relied on the corrective action system process to make decisions on how to characterize deposits. Because the licensee did not identify any deposits indicative of leakage in the areas examined, the inspectors could not assess the licensee's plans to characterize leakage on pressurizer components.

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

   The licensee did not identify any material deficiencies 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)?

    The licensee did not identify any impediments to an effective examination. All of the insulation had been removed around the nozzles to allow a direct visual examination of the bare metal for 360 degrees around the circumference of each penetration nozzle.

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?

    Not applicable. The licensee did not perform augmented volumetric or surface examinations.

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

    Not applicable. The licensee did not identify any indications of boric acid leaks from pressure retaining components in the pressurizer system.

c. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

a. Inspection Scope

On February 11, 2003, the NRC issued Order EA-03-009 (ADAMS Accession Number ML030410402). This order required examination of the reactor pressure vessel head and associated vessel head penetration (VHP) nozzles to detect PWSCC of VHP nozzles and corrosion of the vessel head. The purpose of TI 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," was to implement an NRC review of the licensee's head and VHP nozzle inspection activities required by NRC Order EA-03-009.

The inspectors performed a review in accordance with TI 2515/150 of the licensee's procedures, equipment, and personnel used for examinations of the reactor vessel closure head (RVCH) and VHP nozzles to confirm that the licensee met requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004). The results of the inspectors' review included documentation of observations in response to the questions identified in TI 2515/150.

From March 7, 2005 through March 17, 2005, the inspectors performed a review of the licensee's RVCH inspection activities completed in response to NRC Order EA-03-009. This review included:

- observation of the licensee personnel conducting automated UT of 2 VHP nozzle locations from the on-site data acquisition trailer;
- interviews with nondestructive examination personnel performing nondestructive examinations of the RVCH and VHP nozzles from an on-site trailer;
- certification records of nondestructive examination personnel performing examinations of the RVCH and VHP nozzles;
- UT and ET examination procedures used for examinations of the RVCH and VHP nozzles;
- procedures used for identification and resolution of boric acid leakage from systems and components above the vessel head;
- the licensee's procedures and corrective actions implemented for boric acid leakage; and
- UT and ET examination records for the RVCH and VHP nozzles.

The inspectors conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with requirements of NRC Order EA-03-009, using procedures, equipment, and personnel qualified for the detection of PWSCC in vessel VHP nozzles and detection of vessel head wastage.

From March 14, 2005 through March 17, 2005, the inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation to:

- verify that appropriate plant-specific information was used as input;
- confirm the basis for the head temperature used by licensee; and
- determine if previous VHP cracks had been identified, and if so, documented in the susceptibility ranking calculation.

The documents reviewed by the inspectors in conducting this inspection are listed in the attachment to this report.

b. Observations

Summary: As of the end of operating cycle 13, the Byron Unit 1 vessel head was at 2.2 effective degradation years (EDY), which is in the low susceptibility ranking category as described in NRC Order EA-03-009. To meet the inspection requirements of Order EA-03-009, the licensee completed automated UT and ET examinations for each of the 78 VHP nozzles and head vent line penetration nozzles. The licensee identified six vessel head penetrations with minor limitations in the volumetric examination scope required by Order EA-03-009. The licensee intended to request relaxation from the Order to accept these limitations after plant restart. Additionally, six vessel head penetrations were identified with scratches on the inside diameter of the nozzles which required further evaluation to determine if they would serve to facilitate the onset of PWSCC.

Overall, the inspectors concluded that the licensee had completed an examination of the reactor vessel head which was consistent with the requirements of NRCs Order EA 03-009. The inspectors documented conclusions in response to 11 specific questions related to the quality of personnel, procedures, and equipment used to perform the vessel head examination. For some of the questions in this temporary instruction, the inspectors could not independently confirm the ability of some of the nondestructive examination techniques to detect PWSCC. This condition reflected a lack of industry or vendor "qualified" techniques and did not represent a deviation from NRC Order EA-03-009, which did not specify qualification or demonstration standards for the nondestructive examination techniques used. Additionally, the inability to identify PWSCC within the J-groove weld is consistent with the requirements of Order EA-03-009, which does not require examination of the J-groove welds when UT of the nozzle base material has been completed.

Evaluation of Inspection Requirements

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

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

1. Performed by qualified and knowledgeable personnel?

Yes. The licensee's vendor personnel that performed the automated UT and ET examinations were certified to level I, II, or III in UT examination in accordance with vendor Procedures WDP-9.2, "Qualification and Certification of Personnel in Nondestructive Examination," GBRA 009 227 F, "Written Practice Nondestructive Testing Education, Training, and Examination of Nondestructive Testing Personnel," SSI-A-005, "Qualification and Certification of Nondestructive Examination

Personnel," and ANATEC-08, "Certification of Nondestructive Examination Personnel."

2. Performed in accordance with demonstrated procedures?

   Yes. The licensee's vendor performed automated UT and ET of VHP nozzles in accordance with Procedure WDI-UT-010, "Intraspect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave," Revision 10. The vendor performed these examinations from the inside nozzle surface using probes which contained UT and ET equipment configurations which were consistent with those used during vendor mockup testing. The licensee's vendor had demonstrated an earlier version of this procedure on mockup VHP nozzles which contained cracks or simulated cracks as documented in EPRI MRP-89, "Materials Reliability Program Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations." The inspectors compared revision 10 of Procedure WDI-UT-010 to Revision 3, which had been demonstrated as documented in EPRI MRP-89, to ensure that any equipment configuration changes did not affect flaw detection capability.

3. Able to identify, disposition, and resolve deficiencies and capable of identifying the PWSCC and/or head corrosion phenomena described in Order EA-03-009?

   <u>Automated UT/ET of VHP Nozzles Equipped with a Thermal Sleeve</u>

   Yes. The licensee's vendor examined the 55 sleeved control rod drive VHP nozzle base metal using a "Trinity Blade Probe" from the inside surface of the nozzles. The Trinity Blade Probe contained a time-of-flight-diffraction UT transducer, a zero degree UT transducer, and an ET coil designed to optimize detection of both circumferential and axial oriented flaws. The UT portion of this probe was also configured to detect leakage paths in the shrink fit region between the VHP nozzle tube and the reactor vessel head material. The licensee's vendor had detected PWSCC in VHP nozzles at Beaver Valley Unit 1 as documented in PVP2004-2555, "Advanced Nondestructive Examination Technologies for Alloy 600 Components," dated July 25 - 29, using this examination technique. Therefore, the inspectors concluded that this examination would have been effective for detection of PWSCC in the Byron Unit 1 VHPs.

   <u>Automated UT/ET of VHP Nozzles without a Thermal Sleeve</u>

   Yes. The licensee's vendor examined the 23 unsleeved control rod drive VHP nozzle base metal using a rotating probe from the inside surface. This probe contained time-of-flight-distraction UT transducer pairs, zero degree UT transducers, and ET coils designed to optimize detection of both circumferential and axial oriented flaws. The UT portion of this probe was also configured to detect leakage paths in the shrink fit region between the VHP nozzle tube and the reactor vessel head material. The licensee's vendor had detected PWSCC in VHP nozzles at Beaver Valley Unit 1 as documented in PVP 2004-2555, "Advanced Nondestructive Examination Technologies for Alloy 600 Components," dated July 25 - 29, using this examination technique. Therefore, the inspectors concluded that this examination would have been effective for detection of PWSCC in the Byron Unit 1 VHPs.

Vent Line Penetration ET

Unknown. The licensee's vendor used probes containing an array of ET coils to examine the inside of the head vent line and vent line VHP nozzle J-groove weld. However, the ET technique used had not been demonstrated for detection on PWSCC type flaws. Therefore, the inspectors could not independently confirm that this examination would have been effective at detection of PWSCC.

VHP Nozzle J-Groove Welds

No. The licensee's vendor examinations of the VHP nozzle base material were not designed to detect PWSCC contained entirely within the VHP nozzle J-groove welds. Therefore, the inspectors concluded that these examinations would not be effective at identification of PWSCC flaws located in this region.

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

Not applicable. The licensee was not required by the NRC Order EA-03-009 to conduct visual examinations of the Byron Unit 1 vessel head during this refueling outage and therefore did not perform one. Additionally, during the boric acid walkdown at the beginning of the refueling outage, the licensee did not identify any indication of boric acid leakage from sources above the vessel head. Because no potential for boric acid deposits on the head were identified, the inspectors did not observe the physical condition of the vessel head.

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

Not applicable. The licensee performed a volumetric examination of the reactor from under the vessel head during the refueling outage and did not perform a bare metal visual examination as discussed above.

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

None.

e. 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)?

The licensee identified physical limitations (due to RVCH and VHP nozzle design configurations) to completing the extent of the examination coverage required by NRC Order EA-03-009. Specifically, the licensee could not meet the NRC Order EA-03-009, Requirement IV.C.(5)(I) to perform ultrasonic testing to at least 1 inch below the lowest point at the toe of the J-groove weld for six VHP nozzles. The extent of coverage achieved below the toe of the J-groove weld for: VHP nozzle No. 62 was 0.84 inch; VHP nozzle No. 66 was 0.96 inch; VHP nozzle No. 68 was 0.64 inch; VHP nozzle No. 69 was 0.68 inch; VHP nozzle No. 74 was 0.72 inch; and VHP nozzle No. 75 was 0.56 inch. For VHP nozzle No. 68, the extent of UT coverage was 0.50 inch below the weld, and the licensee supplemented this coverage using the "Grooveman" ET probe from the outside diameter of the tube to achieve a total coverage of 0.64 inch below the J-groove weld.

Because these nonvisual examinations were completed earlier than required under the NRC Order EA-03-009, the licensee did not need to rely on the inspection results to remain in compliance with the Order prior to restart. To remain in compliance with the NRC Order, the licensee intended to request relaxation from the NRC Order EA-03-009 requirements for the six VHP nozzles with limitations after restart and before the next refueling outage.

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

NRC Order EA-03-009 required licensees to calculate the susceptibility category of the reactor head to PWSCC-related degradation. The susceptibility category in EDY established the basis for the head inspections scope. The licensee documented the EDY for the Byron Unit 1 reactor head in EC-354172, "B1R13 End of Cycle 13 Effective Degradation Years In Accordance with NRC Order EA-03-009," Revision 0. In this calculation, the licensee used the formula required by NRC Order EA-03-009 and determined the EDY for the vessel head. At the end of operating cycle 13, the Byron Unit 1 reactor vessel head was at 2.2 EDY, which placed it in the low susceptibility category.

NRC Order EA-03-009, required the licensee to have used best estimate values for the vessel head temperature in the EDY calculation used to determine the susceptibility category. The licensee determined that the current operating head temperature was 558 degrees Fahrenheit in EC-354172. In this calculation, the licensee had used a vessel head temperature derived from a vendor table with references which could not be located. Therefore, the inspectors could not confirm that the licensee had used appropriate plant specific information for operating head temperatures in calculating the head EDY. At the conclusion of the inspection, the licensee intended to pursue additional information to justify the temperatures used in this calculation. Because of the large amount of margin available to the next susceptibility category (8 EDY), the inspectors concluded that if there was an error in the best estimated head temperature, it would not likely impact the current susceptibility ranking of the Byron Unit 1 vessel head. Additionally, the licensee had completed a non-visual head examination which would have been the required inspection if the vessel head had been in a higher susceptibility bin. The inspectors considered this issue an unresolved item (URI-05000454/2005003-06) pending review of additional information to confirm that the operating head temperatures used in this calculation were best estimate values applicable to the Byron Unit 1 head in accordance with Section IV.A of NRC Order EA-03-009. The licensee captured this issue in AR No. 00313216.

Because the licensee had not provided the inspectors with information to confirm that appropriate best estimate vessel head temperatures were used in the Byron Unit 1 reactor head EDY calculation, TI-2515/150 could not be completed.

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

Unknown. The licensee did not identify any indications for which they had applied a flaw evaluation. However, the inspectors identified indications which may require additional licensee evaluations.

On March 15, 2005, the inspectors reviewed the licensee's summary report which documented the results of the UT and ET examinations. The licensee had completed review and acceptance of their vendors' UT and ET data results, which confirmed the absence of PWSCC in the VHP nozzles. However, based upon review of the UT and ET data records for VHP nozzles Nos. 1 through 39, the inspectors identified three nozzles with indications that required additional evaluation.

For VHP nozzles Nos. 13 and 35, the licensee's vendor identified subsurface (nonservice induced) volumetric indications in the parent tube material and the inspectors questioned if these indications would meet the original material specifications. At the conclusion of this inspection, the licensee was pursuing original material records to confirm the acceptability of these indications.

For VHP nozzle No. 32, the licensee's vendor had identified a shallow axially oriented surface scratch at the J-groove weld elevation on the inside surface of the tube. The inspectors were concerned that this condition could increase the susceptibility of this nozzle to PWSCC (e.g., reduce the initiation time for the onset of PWSCC). At the Palisades Nuclear Power Plant, the licensee had identified scoring/scratches at the inside diameter surface of penetration nozzles and concluded that these scratches could facilitate PWSCC (reference NRC IR 05000255/2004012). The inspectors also noted that rough grinding at the inside diameter of control rod drive housings had been found to contribute to PWSCC in type 347 stainless steel at the Palisades Nuclear Power Plant (reference NRC IR 05000255/2001015) and scratches/grooves in Inconel 600 SG tubes for once through type SGs have been found to promote stress corrosion cracking and intergranular corrosion (reference Davis-Besse Surveillance Test Procedure DB-PF-05058 “Steam Generator Eddy Current Data Analysis Guidelines”).

Based upon the inspectors’ concern, the licensee reviewed the UT and ET data records for the remaining nozzle locations and identified five additional VHP nozzles with shallow surface scratches at the inside surface. At the conclusion of the inspection, the licensee was evaluating this information and had entered the condition of the affected nozzles into the corrective action system (AR 00313173). The inspectors noted that the Palisades licensee had performed a fracture mechanics type evaluation to demonstrate VHP nozzle structural and leakage integrity with PWSCC initiation and growth occurring preferentially at the scratch locations. However, the inspectors noted differences between the Palisades VHP nozzle surface conditions and the Byron 1 VHP nozzle surface conditions which could affect the licensee’s evaluation of this issue. Specifically, the Palisades surface scoring was circumferentially oriented and generally located below the J-groove weld and the Byron 1 axially oriented scratches traversed the J-groove weld elevation. Additionally, the Byron 1 VHP nozzles were not due to be reinspected again (with UT and ET) for seven years, vice one operating cycle for the Palisades plant. This issue was not an immediate operability concern because the growth of structurally limiting PWSCC would require a substantive period of plant operation. Therefore, the inspectors judged that the licensee had sufficient time to perform appropriate evaluations and followup inspections as required to ensure the integrity of these nozzles.

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

Yes. Procedure ER-AP-331-1001, “Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation and Inspection Guidelines,” contained general walkdown inspection requirements. This procedure required BACC inspections after plant shutdown during each scheduled refueling outage by VT-2 examiners. To meet the requirements of NRC Order EA-03-009, the licensee performed Work Order No. 00731921-02 to perform a visual inspection of the area above the mirror insulation on the RPV head. The licensee did not identify any boric acid leaks from pressure-retaining components above the vessel head during this inspection.

I. Did the licensee perform appropriate follow-on examinations for boric acid leaks from pressure retaining components above the vessel head?

Not applicable. The licensee did not identify any boric acid leaks from pressure retaining components above the vessel head.

c. <u>Findings</u>

No findings of significance were identified.

.3 (Closed) Unresolved Item (URI) 50-454/455/03-02-02: Evaluation for Unit 1 Potentially Exceeding Licensed Thermal Power Limits

Introduction: An NCV of the Byron Operating License, having very low safety significance (Green), was self-revealed when it was determined that between May 2000 and August 2003, the installed feedwater ultrasonic flow measurement instruments

(UFMs) provided non-conservative data to the reactor power calculation which resulted in power operations greater than 100 percent.

Description: The feedwater UFMs were installed on each of the feedwater loops at Braidwood in April 1999 and at Byron in May 1999 to recover lost power due to feedwater venturi fouling. UFMs are not subject to feedwater fouling. Since feedwater mass flow rate is a significant parameter used in determining reactor thermal power, the installation of improved feedwater flow instruments would allow the licensee to more accurately determine reactor power as well as maintain the unit at a constant power level throughout the operating cycle.

The pre-implementation test data obtained by the Byron licensee indicated that if the UFMs were used for determining feedwater flow rates, then the Byron units, particularly Byron Unit 1, would produce more electricity than the similar Braidwood units. The licensee could not explain why this was the case. It was also recognized that if the UFMs were implemented at Byron, then several secondary plant parameters would indicate a non-conservative bias compared to Braidwood. Because of this the licensee did not implement the UFMs at Byron pending further evaluation. However, in June 1999, the UFMs were implemented at Braidwood.

Further evaluation by the licensee provided no explanation as to why the implementation the UFMs on Byron Unit 1 would result in electrical production that was higher than previously measured and higher than the output from the similar Braidwood unit. Nonetheless, based on the assumption that the UFMs were accurate and all other instrument behavior was within estimated uncertainty bounds, although unexplainably non-conservative, the licensee implemented the UFM at Byron Unit 1 and Unit 2 in May 2000.

Following implementation, the estimated Byron/Braidwood differences were immediately observed. Later, Byron Unit 1 was not able to fully implement a five percent power uprate approved by the NRC in May 2001. This issue was submitted to the licensee's corrective action program as CR 91771, "Unexplained Differences Between Byron and Braidwood." The CR noted that many plant parameters, other than those provided by the UFMs, were indicating that Byron Unit 1 was possibly operating at a power higher than its licensed thermal power limit. Although differences between the Byron and Braidwood Units continued to be acknowledged, the Byron licensee was not able to identify the cause for the differences between Byron and Braidwood, and continued to use the UFMs.

The Byron licensee completed its apparent cause evaluation for CR 91771 in October 2002. The NRC reviewed this apparent cause evaluation in early 2003. The licensee's evaluation included reviews of:

- plant design and calculations, including changes associated with power uprate;
- UFM installation, calibration and performance;
- fuel burn-up rate; and
- primary and secondary plant parameters and calorimetrics.

Part of the licensee's evaluation included an independent assessment completed by Exelon engineers from their Mid-Atlantic Regional Operating Group. This evaluation concluded that the licensee was operating Byron Unit 1 within its licensed thermal power limit. Furthermore, Exelon engineers concluded that the difference in electrical production between Byron and Braidwood was most likely linked to the UFMs. However, their review failed to identify an apparent cause. The Byron licensee created corrective actions to review Byron plant performance following each of the next operating cycles.

Based on the inspectors' uncertainty regarding the operation of Byron Unit 1 in relation to its licensed thermal power limit, and the technical complexity of this issue, the inspectors generated a task interface agreement (TIA) with the Office of Nuclear Reactor Regulation (NRR) for additional review and assessment. This resulted in correspondence between NRR and the licensee, and a meeting between the two organizations on January 24, 2003, to discuss the Byron Unit 1 thermal power issues. Because NRR's review and assessment of this issue was ongoing at the conclusion of the NRC resident inspectors' first quarter CY 2003 inspection period, the issue was considered unresolved pending the completion of NRR's review. Since the initial identification of the issue in the subject NRC Inspection Report, updates were provided in NRC Inspection Reports 05000454/2003-006, 007, 2004-02 and 04.

Based on the conflicting data between the secondary plant parameters and the UFM feedwater flow rates, the licensee installed an additional UFM instrument on the common feedwater header to measure flow. In May 2003, the licensee compared the overall feedwater flow rate measured by the UFM on the common feedwater header to the sum of flow rates from the normally used UFM feedwater instruments installed on the four individual feedwater loops. The results of this comparison were acceptable, however, a concern with electronic signal noise on the individual feedwater loop UFM instruments was noted.

As a result, the licensee reperformed the feedwater flow comparison test in August 2003; this time, the test results indicated that the sum of the individual feedwater loops was non-conservative when compared to the flow rate measured by the UFM instrument installed on the common feedwater header. The licensee removed the UFM instruments and adjusted thermal power using the originally installed venturi feedwater instruments. The resulting power level was lower than with the UFMs in service. The licensee concluded that the electronic noise on the individual loop UFM instruments caused the erroneous readings and they issued a Licensee Event Report (LER) 2003-003-00 describing the concern and associated overpower operations.

In February 2004, the licensee conducted further feedwater flow testing, this time utilizing a radioactive tracer chemical to determine feedwater flow rate. The flow rate obtained during this test closely matched the flow rates provided by the feedwater venturi instruments, and indicated that the flow rates provided by the UFM instruments showed a non-conservative bias. This new information, including the associated maximum power levels experienced by the Byron plants during the period the UFMs were used to determine reactor power, was described in LER 2003-003-01.

Based on February 2004 test results, NRR concluded on June 30, 2004, in their response to the TIA (TIA 2003-02), that both Byron Unit 1 and Unit 2 reactors (as well as those at Braidwood) had operated for periods of time above their respective licensed thermal power limits. Specifically, an overpower condition had existed for Byron, Unit 1, since initial implementation of the UFMs in May 2000, with a maximum power level of 102.62 percent. Comparable conditions existed at Byron, Unit 2, and Braidwood, Units 1 and 2, with maximum calculated power levels of 101.88 percent, 101.07 percent, and 101.21 percent, respectively. The Braidwood Station UFM issues were resolved and documented in NRC Inspection Report 05000456/2004003 and 05000457/2004003.

Analysis: The inspectors determined that operating above the licensed power limits was a performance deficiency warranting a significance evaluation in accordance with IMC 0612 "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening" issued on January 14, 2004. The inspectors determined that the finding was more than minor because it impacted the Barrier Integrity Cornerstone attribute of Reactor Safety and affected the design control attribute of core design analysis. The finding was associated with actions that challenged fuel cladding thermal limits. By operating the reactor at a power level greater than 100 percent thermal power. The licensee failed to provide reasonable assurance that the cladding barrier would protect the public from radionuclide releases caused by accidents or events.

The inspectors determined that operating in excess of the licensed power limit affected the cross-cutting area of problem identification and resolution (evaluation). Following the initial indications of the possibility of an over power condition, the licensee missed several opportunities to conclude that the over power condition existed.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process." The finding was associated with the Barrier Integrity cornerstone and protection of the fuel cladding barrier. Therefore, Phase 1 screening under "RCS Barrier or Fuel Barrier" screened as Green for fuel barrier issues. Furthermore, the significance of the maximum power level achieved was evaluated during the TIA process and supports the conclusion of very low safety significance.

Enforcement: The licensed maximum thermal power output for a reactor is defined in each licensee's operating license. As stated in the Byron Station's Unit No. 1 and Unit No. 2 Operating Licenses: "The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent power) in accordance with the conditions specified herein."

Contrary to the above, the licensee operated Byron Unit 1 and Unit 2 in excess of 3586.6 megawatts thermal during various periods between May 2000 and August 2003. Because this violation was of very low safety significance (Green) and the issue was entered into the licensees corrective action program (CR 173510), it was treated as an NCV, consistent with Section V1.A of the NRC enforcement Policy.
URI 50-454/455/03-02-02 is closed. (NCV 05000454/2005003-07; 05000455/2005003-07)

.4 (Closed) URI 05000454/2004007-02: Potential Past Inoperabilty of the 1A Auxiliary Feedwater Pump (AFW) due to Failure to Establish Preventive Maintenance for, or Monitor the Performance of, the 1A AFW Oil Cooler Outlet Valve

Introduction: A licensee identified NCV of 10 CFR 50.65 (a)(1)/(a)(2) was noted following the June 28, 2004 surveillance test failure of the 1A AFW pump. This issue was considered to be of very low safety significance. Following the surveillance test failure the licensee was able to demonstrate that, for the conditions experienced by the 1A AFW pump between June 28, 2004, and the last successfully completed surveillance test on March 15, 2004, the 1A AFW pump was capable of performing its intended safety function.

Description: On June 28, 2004, during the performance of a routine quarterly surveillance on the 1A AFW pump, lube oil temperatures exceeded the licensee's acceptance criteria limit, and operators secured the pump. After troubleshooting, the licensee determined that the cooling water outlet isolation valve (1SX101A) to the lube oil cooler was stuck in the closed position and did not automatically open during the pump start as designed. This valve was normally closed and opens when the AFW pump receives a start signal. The function of the oil cooler was to provide a means of removing heat from the lubricating oil, which circulates to lubricate the pump bearings, to ensure that oil temperature remains below design limits. Proper operation of the motor driven AFW pump requires that the oil cooler outlet solenoid valve opens and remains in the open position while the AFW pump was running.

The licensee restored flow to the oil cooler by de-energizing and mechanically agitating the solenoid operated cooling water valve (1SX101A). The licensee then reran the pump to determine that the valve was open and that bearing oil temperatures were within the expected range. Subsequent oil analysis confirmed that no damage was done to the pump bearings during the short time period when the lubricating oil temperatures were elevated. Additionally, as corrective actions, the licensee completed a temporary modification to fail the valve in the open position to ensure adequate cooling water flow.

During the inspectors' initial review of this issue, as documented in NRC Inspection Report 05000454/2004007, the issue was considered unresolved pending the licensee's completion and NRC review of the past operability assessment. The licensee's root cause of the failure of 1SX101A to open during the surveillance test on June 28, 2004, determined that the causes for the problem included:

- misapplication of a tight clearance pilot operated globe valve in a raw water system;
- not implementing a preventive maintenance corrective action which had been

implemented at the Braidwood Station;
- identifying critical preventive maintenance in 1998 but not assigning a preventive maintenance activity; and
- not assigning the appropriate priority to a proposed modification to remove the valve.

Furthermore, prior to the surveillance test failure, the licensee had not been monitoring the performance of the 1A AFW pump cooling water outlet isolation valve to the lube oil cooler against established goals, in a manner sufficient to provide reasonable assurance that it was capable of fulfilling its intended function. Nor did the licensee demonstrate that the performance of the 1A AFW pump cooling water outlet isolation valve to the lube oil cooler was being effectively controlled through the performance of appropriate preventive maintenance.

Upon completion of the licensee's past operability assessment, the licensee concluded that the pump would have been capable of performing the intended safety function for the period between the test failure on June 28, 2004 and the last successfully complete surveillance test completed on March 15, 2004. The inspectors, along with technical expertise from the Office of Nuclear Reactor Regulation, reviewed the licensee's assessment, and acknowledged that for the conditions experienced by the 1A AFW pump between the June 28, 2004 and the last successfully complete surveillance test completed on March 15, 2004, the pump was capable of performing the intended safety function. The inspectors noted that, although not needed for determining past operability, the assessment only reviewed the actual conditions experienced by the pump during the period in question, and did not address all design basis conditions.

Analysis: The inspectors determined that the failure to adequately perform preventive maintenance on the AFW pump cooling water outlet isolation valve to the lube oil cooler 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 on January 14, 2004. The inspectors determined that the finding was more than minor because it was associated with the mitigating system cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure of 1SX101A to open during a 1A AFW pump start affected the reliability and capability of the pump to respond to initiating events.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," dated April 21, 2003, because the finding was associated with the operability, availability and reliability of a train of a mitigating system. For the Phase 1 screening, the inspectors answered "no" to the questions in the Mitigating System column, because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the TS allowed outage time, and no risk due to external events. Therefore, the finding was of very low safety significance (Green).

Enforcement: Since this finding was revealed through the licensee's process of surveillance testing, the violation is considered licensee identified and therefore the

enforcement aspect was described in Section 4OA7 of this report.
URI 05000454/2004007-02 Is closed.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. S. Kuczynski and other members of licensee management at the conclusion of the inspection on April 4, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. The Exelon Outage Schedule and information associated with the UFMs were identified as proprietary information that was used for inspection activities. The propriety information was not included in this report and the material was properly destroyed.

.2 Interim Exit Meetings

An interim exit meeting was conducted for:

- Occupational Radiation Safety, radiological instrumentation and protective equipment program inspection with Mr. D. Hoots on February 18, 2005.

- Occupational Radiation Safety, ALARA and access control programs inspection with Mr. D. Hoots on March 18, 2005.

- Temporary Instruction 2515/150, Temporary Instruction 2515/160, and Procedure 7111108 with Mr. S. Kuczynski and other members of licensee management at the conclusion of the inspection on March 17, 2005. The inspectors returned proprietary information reviewed during the inspection and the licensee confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee Identified Violations

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

Cornerstone: Mitigating Systems

10 CFR 50.65, “Requirement for Monitoring the Effectiveness of Maintenance,” Section (a)(1), states that licensee’s shall monitor the performance of a structure system or component (SSC), against licensee-established goals, in a manner sufficient to provide reasonable assurance that the SSC is capable of fulfilling its intended functions. Section (a)(2), states that monitoring as specified in paragraph (a)(1) is not required where it has been demonstrated that the performance or condition of a SSC is being effectively controlled through the performance of appropriate preventive maintenance such that the SSC remains capable of performing its intended function.

Contrary to this, prior to June 28, 2004, the licensee failed to monitor the performance of the 1A AFW pump cooling water outlet isolation valve to the lube oil cooler against established goals, in a manner sufficient to provide reasonable assurance that it was capable of fulfilling its intended functions. Nor did the licensee demonstrate that the performance of the 1A AFW pump cooling water outlet isolation valve to the lube oil cooler was being effectively controlled through the performance of appropriate preventive maintenance because no preventive maintenance was being done on this component. This was evidenced during the June 28, 2004, surveillance test, when the 1A AFW pump cooling water outlet isolation valve failed to open due to a known potential susceptibility to silting. Subsequent evaluation by the licensee determined that, for the conditions experienced by the 1A AFW between the June 28, 2004 and the last successfully complete surveillance test completed on March 15, 2004, the pump was capable of performing the intended safety function. Therefore, this violation is of very low safety significance. This issue was entered into the licensee's corrective action program as Condition Report 232158.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Kuczynski, Site Vice President
D. Hoots, Plant Manager
B. Adams, Engineering Director
S. Briggs, Shift Operations Supervisor
D. Combs, Site Security Manager
D. Drawbaugh, Emergency Preparedness Manager
T. Fluck, NRC Coordinator
D. Goldsmith, Radiation Protection Director
W. Grundmann, Regulatory Assurance Manager
K. Hansing, Nuclear Oversight Manager
D. Hoots, Plant Manager
S. Kerr, Chemistry Manager
W. Kouba, Nuclear Oversight Manager
D. Palmer, Radiation Protection Manager
M. Snow, Work Management Director
S. Stimac, Operations Manager
D. Thompson, Radiation Protection Technical Lead
B. Youman, Maintenance Manager

Nuclear Regulatory Commission

D. Chyu, Reactor Engineer, RIII
R. Clark, Senior Reviewer, Reactor Operations Branch, NRR
G. Dick, Project Manager, NRR
J. Isom, Operations Engineer, Inspection Program Branch, NRR
R. Jickling, Emergency Preparedness Analyst, RIII
T. Koshy, Senior Reviewer, Division Engineering, NRR
D. Passehl, Acting Chief, Projects Branch 3, Division of Reactor Projects, RIII
J. Pulsipher, Senior Reviewer, Probabilistic Safety Assessment Branch, NRR
A. Stone, Chief, Systems Engineering, RIII
S. Unikewicz, Mechanical Engineer, Division Engineering, NRR

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000454/2005003-01	NCV	Inadequately Changed Procedure Results in Unexpected Seam Dump Valves Opening During a Test (1R19)

05000454/2005003-02	NCV	Failure to Control Containment Penetrations in accordance with Technical Specification 3.9.4c during Core Alterations (Section 1R22)
05000454/2005003-03 05000455/2005003-03	NCV	Failure to Evaluate Radiological Conditions Prior to a Significant Equipment Configuration Change (Section 2OS1.1)
05000454/2005003-04 05000455/2005003-04	NCV	Failure to Obtain a Radiation Protection Briefing Prior to an Entry Into a High Radiation Area (Section 2OS1.4)
05000454/2005003-05	NCV	Failure to Declare an Unusual Event for EAL MU7, Dose Equivalent Specific Activity for Iodine RCS dose equivalent I-131 in Excess of 1.0 FCi/gm (Section 4OA3)
05000454/2005003-07 05000455/2005003-07	NCV	Exceeding 100% Licensed Power Following the Implementation of the Ultrasonic Feedwater Flow Measuring Instruments (Section 4OA5.3)

<u>Opened</u>

05000454/2005003-06	URI	Unverified Vessel Head Temperatures Used in EDY Calculation (Section 4OA5.2)

<u>Closed</u>

50-454/455/03-02-02	URI	Evaluation for Unit 1 Potentially Exceeding Licensed Thermal Power Limits (Section 4OA5.3)
05000454/2004007-02	URI	Potential Past Inoperabilty of the 1A Auxiliary Feedwater Pump due to Failure to Establish Preventive Maintenance for, or Monitor the Performance of the 1A AFW Oil Cooler Outlet Valve (Section 4OA5.4)

<u>Discussed</u>

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.

1R04 Equipment Alignment

WO 663709; Inspect Gear Speed Increaser Bearings For Wear, March 21, 2005
WO 719871; Replace 1A Chemical & Volume Control System (CV) Pump Seals With New Design, March 19, 2005
CR 315745; CV Check Valve Identified With External Leakage, March 23, 2005
BOP CV-E1; Unit 1 CV Electrical Lineup, Revision 7
BOP CV-M1; Unit 1 CV Valve Lineup, Revision 28
BOP WX-103-7; Transferring the Spent Resin from the Spent Fuel Pit Demineralizer (1/2FC01D) to the Spent Resin Storage Tank (0WX05T) or to the Portable Radwaste System, Revision 8
OP-MW-109-101; Clearance and Tagging, Revision 3
CR 274453; Loss of Level in the SFP Due to Inadequate Valve Line-up, November 17, 2004
Clearance Order 32397; Unit 1 Spent Fuel Pit Demin Filter, Completed November 17, 2004
Issue 317039; Dried Boric Acid on 1CV8548C Isolation Valve, March 25, 2005 (NRC Identified)
Plant Drawing —64, Chemical and Volume Control and Born Thermal Regeneration System

1R05 Fire Protection

CR 292655; Byron Station Review of OE 19826, February 17, 2005
CR 297682; NRC Question About Fire Damper S-Hook Orientation, February 4, 2005 (NRC Identified)
Issue 307786; NRC Walkdown Items in Upper Cable Spreading Room (UCSR) - Unit 2, February 23, 2005
EC-Evaluation 350613; Evaluation of Fire Damper S-Hook Orientation Impact, Rev. 0
Byron Station Pre-Fire Plans; Revision 4
Material Safety Data Sheet (MSDS) for Dry Chemical Fire Extinguishers, Ansul Inc.

1R07 Heat Sink Performance

WO 588793; 1SX01K - HX Inspection Per Generic Letter 89-13, March 16, 2005

1R08 Inservice Inspection Activities

Corrective Action Program Documents With Engineering Evaluations

Evaluation No. 2003-01 for Component 1RC8029D; Leakage From the 1D RC Loop Bypass Vent Valve, November 11, 2003
Evaluation No. 2003015 for Component 2FC8762A; Body to Bonnet Leak, August 1, 2004
Evaluation No. 2003-060 for Component 2AB03P; Leakage found at Pump Seal, August 6, 2004
Evaluation No. 2003-065 for Component 2SI097; Quick Disconnect Found Leaking, August 29, 2004

Corrective Action Program Documents

CR 200725; UT Examination Volume Coverage in U1R08 for R-ISI, February 10, 2004
CR 211301; Foreign Objects Found in 2B SG Preheater Region, March 27, 2004
CR 211395; Foreign Objects Found in Secondary Side of 2C Steam Generator, March 28, 2004
CR 211672; Foreign Objects Found in Secondary Side of 2A Steam Generator, March 28, 2004
CR 212270; 2A SG Waterbox Foreign Objects, April 1, 2004
CR 239701; Relief Request Not Submitted in ISI 90 Day Report, July 28, 2004
CR 249589; Required Code Relief Requests for B1R13, September 2, 2004
CR 307703; ISI Inspection for 1RC24AB-4 Has Boric Acid from 1SI8822C, March 3, 2005
CR 307710; B1R13 LL Verification of ISI Inspection Points, March 3, 2005
ISSUE-309031; NOS Rejected Weld at Final Visual Inspection, March 6, 2005

Documents Related to Code Pressure Boundary Welding

WO 5999592; 1B Seal Injection Filter 1CV01FB Inlet Isolation Valve, September 30, 2003
ASME Weld Data Record; 1CV8384B/1CV13AB-2, September 30, 2003
WPS 8-8-GTSM; Revision 0
WPS 8-8-B; Revision 4
ASME Fillet Socket Weld Record; FW-1 and FW-2, September 29, 2003
Surface Exam Data; FW-1, FW-4, September 30, 2003
Surface Exam Data; FW-2, FW-3, September 30, 2003
VT-2 Visual Examination Record; 1CV83848, October 13, 2003
PQR; A-004; February 8, 2000
PQR; A-003; February 8, 2000
PQR; 1-51A; December 28, 1983
PQR; 4-51A; September 12, 1986
PQR; 002-41-093; December 23, 1996
PQR; —1022-77; November 3, 1983
PQR; W-84-48; June 1, 1984
PQR; —394-81; November 21, 1983

PQR; —3967-80; February 2, 1984
PQR; 002-41-058; August 17, 1994

Documents Associated with ASME Code Nondestructive Testing

Ultrasonic Examination Report; RPVS-E-F1 DM Outlet Nozzle 220 degrees, March 10, 2005

Documents Associated with Disposition of Relevant Indications

VT-3 Examination Record for Component Supports/Attachments; 1CV06009C, September 28, 2003
VT-3 Examination Record for Component Supports/Attachments; 1CV06009C, September 29, 2003
VT-3 Examination Record for Component Supports/Attachments; 1CV06009C, October 3, 2003
Drawing M-1CV06009C; Revision D
Condition Report 178080; Support 1CV06009C Cold Support Setting Incorrect, October 1, 2003

Other Documents

Commonwealth Edison letter dated September 2, 1988; Response to Generic Letter 88-05 (TAC No. 68904, 68905, 68906, and 68907), September 2, 1988
Byron Letter 2004-0125; Byron Unit 1 Inspection Degradation Assessment and Condition Monitoring Checklist for B1R13, December 1, 2004
EA-AP-420-0051; Conduct of Steam Generator Management Program Activities, Revision 5
Sonic Systems International Inc., ASME XI Appendix VIII Hands-On-Practice (8 Hours) Documentation; Wade Holasek, January 11, 2005
Wesdyne International Appendix VIII Hands-On Training/Practice Record; Darrell Moreau, January 13, 2005
Westinghouse Electric Document; ETSS CAE-0001-0305; 0.56-inch Diameter Bobbin Probe, March 2, 2005
Westinghouse Electric Document; ETSS CAE-0002-0305; 0.54-inch Diameter Bobbin Probe, March 2, 2005
Westinghouse Electric Document; ETSS CAE-0004-0305; +Point 0.560-inch MRPC, March 2, 2005
Westinghouse Electric Document; MRS-TRC-1610; Use of Appendix H Qualified Techniques at Byron B1R13 Outage, February 4, 2005
Westinghouse Electric Document; MRS-TRC-1273; Comparison of 0.560" Diameter Probes on Fan Bare Indications, May 30, 2002
Westinghouse Electric Document; LTR-SGDA-01-61; Technical Justification for Use of Lower Fill Factor Bobbin Probes, March 8, 2000
Byron Letter; Tube Plugging and Stabilizing List for Steam Generator 1B B1R13, March 13, 2005
Byron Letter; Tube Plugging and Stabilizing List for Steam Generator 1A B1R13, March 13, 2005

Byron Letter; Tube Plugging and Stabilizing List for Steam Generator 1D B1R13, March 13, 2005
EC 354327; Evaluation of Foreign Material Not Retrieved from the 1D Steam Generator During B1R13, Revision 0
ER-AP-331-1001; Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation and Inspection Guidelines, Revision 1
ER-AP-331-1002; Boric Acid Corrosion Control Program Identification, Assessment, and Evaluation, Revision 1

1R12 Maintenance Effectiveness

CR 199754; Negative Sequence Relay for U2 Generator failed Accept Test, February 5, 2004
CR 215553; 2E MPT Fans Running Backwards, April 18, 2004
CR 235249; Loss of Fan Cooling to 1E Main Power Transformer, July 11, 2004
CR 242823; 1B AF Pump SX Booster Pump Seal Excessive Leakage, August 09, 2004
CR 252632; Follow-up Review of 1E MPT Cooling Response, September 14, 2004
CR 264444; Active Oil leak on Bus 5 Side Bushing “B” phase, October 17, 2004
CR 271026; 2E MPT Fan not Working, November 6, 2004
CR 271182; 142-2 SAT Outage Bus 158 Cub 7 Local Control Switch Fails, November 8, 2004
CR 281710; UAT 241-2 Possible Relay Buzz, December 12, 2004
CR 282148; Replace UAT 241-2 27-1 and 27-2 Loss of Power Alarm Relays, December 13, 2004
CR 283125; MCB Alarm on U2 MPT Low Oil Pump Flow Alarms, December 16, 2004
CR 283826; Generator Voltage Regulator Logic Power Failure Alarm, December 17, 2004
CR 284063; Voltage Regulator Unexpected Alarm, December 18, 2004
CR 285504; Fan Belt is Churping, December 24, 2004
CR 285537; Fan GRP 4 Indicating Light not Lit, December 25, 2004
CR 287057; 1B Bus Duct Fan Belts Loose, January 3, 2005
CR 287315; 2B Bus Duct Cooling Fan Mounting has Broken Weld, January 3, 2005
CR 287651; 1A Bus Duct Fan Motor Mount has Two Cracks on Separate Welds, January 4, 2005
CR 289324; NRC Identified Issues in 1B SX Pump Room, January 10, 2005
CR 289832; Cooling Fan Not Operating, January 12, 2005
CR 289039; BTB 5-6 Bus 5 ‘C’ Phase Current Transformer Oil Level Low, January 9, 2005
CR 289040; BTB 3-4 ‘A’ Phase Current Transformer Oil Level Low, January 9, 2005
CR 293390; Oil Leak, January 23, 2005
CR 293741; Repair Oil Leaks on UAT 241-2, January 24, 2005
CR 293750; OCB 5-6 Low Bushing Oil Leak, January 23, 2005
CR 295835; Issues Involved With 1B Diesel Generator (DG) Work Window 1/31/05 First Shift
CR 296145; 1B DG Jacket Water (JW) Seal/ Wearing Ring Issues, January 31, 2005
CR 297103; 1B DG JW Leak From Vitaulic Coupling, February 2, 2005
CR 297621; 1B DG 1R Cylinder Linner Expansion Bellows Leak, February 3, 2005
CR 297726; JW System Leak Testing Post Maintenance, February 3, 2005

CR 297828; JW Flexmaster (Vitaulic Coupling) Leak, February 2, 2005
CR 297978; Air Compressor Pressure is at 225 PSIG and Compressor Did Not Auto Start, February 4, 2005
CR 297987; 1B DG Pre-Lube Oil Pump Excessive Vibration When DG was Shutdown (SD), February 4, 2005
CR 298075; 1B DG Fuses Not Checked Under Trouble Shooting, February 4, 2005
CR 298198; Low Flow alarm on 2E MPT when Fan Bank Starts, February 6, 2005
CR 298201; 1B DG Voltage Regulator Cover Tight on Ring Tongue Lugs, February 6, 2005
CR 298205; Control Power Fuse Block Has A Chip Piece, February 6, 2005
CR 298288; Invalid "Main & Connection (Conn) Rod Generator Outboard BRG High Temperature, February 6, 2005
CR 298304; 1B DG Speed Probe 1SE-DG249B Bent By Diamond Plate Cover, February 6, 2005
CR 298348; Urgent 1B DG Lesson Learned Incorporate in Mechanical Maintenance Department (MMD) Work Order (WO), February 6, 2005
CR 298403; Work Performed Without Adequate Shift Authorization, February 7, 2005
CR 298560; Unexpected Annunciators on 1B DG, February 7, 2005
CR 298649; Protective Cover For 1B DG Contacts Speed Pickups, February, 7, 2005
CR 298657; 1B DG Cover Plate Guide Pins Prevents Proper Sealing Contact, February 7, 2005
CR 298705; 1B DG Loose Bracket and Fuel Leak, February 7, 2005
CR 298742; 1B DG Voltage Regulator Cover Not Replaced, February 8, 2005
CR 298771; IST Data on Starting Air System Not Met During DG Surveillance, February 8, 2005
CR 299260; Lessons Learned From 1B DG Work Window, February 6, 2005
CR 307691; B-Phase 25kV bushing Oil Leak, March 2, 2005
CR 308761; "B" Phase Transformer is Leaking Black material, March 5, 2005
CR 310685; Relay Out of Tolerance, March 1, 2005
CR 313656; Relay Shattering 27-2 Shattering in Control Cabinet, March 16, 2005
CR 315383; 1W MPT Transformer Oil Leaks, March 21, 2005
ACE 235249; 480 VAC feeds for forced oil and Forced Air Cooling System for 1 east Main Power Transformer (1MP01E or 1E MPT) tripped off causing the Transformer operating temperature to Increase, October 5, 2004
EACE 255260; - Abnormal Noise Noticed in BTB 4-5 During Testing, November 23, 2004
SY System; Quarterly Ship System Report, Dec-2004
SY System; Maintenance Rule - Performance, February 2000
Exelon PowerLabs Memo; Evaluation of a Mechanical Seal From the 1SX04P SX Booster Pump at Byron Station, October 01, 2004
Maintenance Rule Evaluation History; AF1 - Provide Emergency Water Supply to Steam Generators, January 7, 2005 and February 16, 2005
Maintenance Rule Performance Monitoring (Availability Graph); AF1 Unit 1 train B, January 01, 2003 to March 09, 2005

1R13 Maintenance Risk Assessments and Emergent Work Control

Unit 1 & 2 Risk Configurations; Week of 01/31/05, Revision 1
Protected Equipment Placard/Barrier Locations for 1B DG Work Window
WO Task 747169 07; Mechanical Maintenance (MM) (Contingency) Replace Handwheel Shear Pin
WO Task 747169 10; MM Install Valve Block, Remove Actuator
WO Task 747169 11; MM Remove Valve Block, Reinstall Actuator, Adjust Stops
CR 285844; 1AF004A Did Not Auto Open During Fail Open Stroke test, December 27, 2004
CR 285844; 1AF004A Did Not Auto Open During Fail Open Stroke Test, December 27, 2004
CR 285849; Solenoid Valve On 1AF004A Vibrates After Troubleshooting, December 27, 2004
CR 287615; On-line Risk Questions For 1AF004A Functions, January 04, 2004 (NRC Identified)
CR 308429; NRC Questions Steam Generator (SG) Heat Sink Credit in Shutdown Risk Program, March 04, 2005, (NRC Identified)
CR 309192; Unit 1 and 2BOL 7.8 Protected Equipment List Question, (NRC Identified)
CR 309197; Some Protected Equipment Signs Are Yellow, Not Red, March 06, 2005 (NRC Identified)
CR 309249; NRC Concerns with Combustible Materials in Comb Free Zones, March 06, 2005 (NRC Identified)
Hourly Fire/Flood Watch Inspection Log, March 04, 2005
Continuous Fire Watch Inspection Log, March 05, 2005
2BOL 7.8; LCOAR Table Essential Service Water (SX) System, Revision 5
Calculation No. RC-95-WWK-01; Calculation That Determines Pressure That Precludes Gas Formation in SG Tubes, Revision 0

1R14 Personnel Performance Related to Non-routine Plant Evolutions and Events

CR 297126; Computer Trouble Alarm on Both Unit 1 and Unit 2 Annunciator, February 2, 2005
CR 297129; Plant Process Computer Failed Unit 1 (Unplanned LCO Entry), February 2, 2005
CR 316898; Both Intermediate Range NI’s Readings Incorrect on U1, March 24, 2005
BOP CW-12; Circulating Water Blowdown System Startup, Operation and Shutdown, Revision 20

1R15 Operability Evaluations

RM Documentation No. BB PRA-017.38; Risk Significance of Missed Surveillances at Byron Auxiliary Building HVAC (VA) & Control Room HVAC System (VC) Filter Surveillance Testing (CR 290634), Revision 0
EC 353305 000; Evaluate Potential Effects of Degraded Auxiliary Building Ventilation and Control Room Ventilation Due to Missed Surveillances, January 14, 2005

MA-BY-721-001; Three Phase Thermal Overload Relay Testing For Motor Operated Valves and Various Other Plant Equipment For 2B SX Cubicle Cooler Completed January 10, 2005
MA-BY-723-330; Electrical Testing of AC Motors Using Baker Instrument Advanced Winding Analyzer For 2B SX Cubicle Cooler Fans Completed January 10, 2005, Revision 0
WO 623377 01; Reactor Trip Breaker (RTB) Replacement, January 14, 2005
WO 623377 02; Post Maintenance Testing (PMT), January 14, 2005
WO 623377 03; PMT Reactor Trip Breaker, January 14, 2005
WO 770958; Troubleshoot 2B SX Pump Cubicle Cooler Fans Not Running, January 10, 2005
WO 99241962; 2VA01SB; Heat Exchanger (HX) Inspection Per Generic Letter 89-13, November 6, 2002
Schematic Diagram Reactor Trip Switchgear ESF-DIV. 12 6E-1-4030RD07, January 17, 2005
CR 090911; 1SX168 Failed During Scheduled Calibration, January 15, 2002
CR 289324; NRC Identified Issues in 1B SX Pump Room, January 10, 2005 (NRC Identified)
CR 290617; No Reactor Trip Breaker B (RTB) Closed Indication During 1BOSR 3.1.5-2, January 13, 2005
CR 296192; Diesel Generator (DG) Check Valve Found Stuck Open, January 31, 2005
CR 297139; 1DG5204B Check Valve Evaluation, February 02, 2005
CR 297140; NRC Question Regarding 4 Start Capability, February 03, 2005 (NRC Identified)
CR 300149, SX168 Controlled by Nonsafety Related Thermostat
CR 301242; NRC SR. Resident Challenge of Operability Basis For 1B DG, February 14, 2005
Calculation No. NED-H-MSD-039; Essential Service Water Pump Room Cubicle Cooler Requirements, March 30, 1995
NSP OP-AA-108-108, Attachment 1, Item #8; Open Operability Evaluation Status, March 16, 2005
Operability Evaluation # 04-002; 1A DG Inlet Manifold Air Leak, December 2, 2004
Operability Evaluation # 04-004; 2A DOST (2DO01TA) Wall Thickness Not Per Design, December 2, 2004
Operability Evaluation # 04-006; Boric Acid Transfer Pumps Seismic Calculation Incorrect, October 8, 2004
Operability Evaluation # 04-007; Essential Service Water (SX) and Well Water (WW) Lines - Inadequate Soil Cover, February 16, 2005
Operability Evaluation # 04-007; LCOAR Ultimate Heat Sink (UHS) Technical Specification LCO # 3.7.9, Affected Procedure Number & Revision 0BOL 7.9/005
Operability Evaluation # 05-001; SX 168 Controlled By Non-Safety Related Thermostat, February 16, 2005

1R16 Operator Workarounds

OP-AA-102-103; Operator Workaround Program, Revision 1, March 25, 2005
Fourth Quarter 2004 Operator Workaround Aggregate Impact Assessment, March 23, 2005

Byron Station - Plan of the Day (POD), March 25, 2005
0BOA ENV-1; Unit 0 Adverse Weather Conditions, Revision 101, March 25, 2005
1BOA ENV-1; Unit 1 Adverse Weather Conditions, Revision 100, March 25, 2005
CR 205934; Has Operations Been Let Down By the Team?, March 03, 2004
CR 213933; Latching Turbine Modification Incorrect, April 08, 2004
CR 222341; Unit 1 Main Steam Isolation Valve (MSIV) Performance, May 19, 2004
CR 222803; Unexpected Annunciator, May 21, 2004
CR 223232; False Alarms Being Generated By 2FR-RF008, May 22, 2004
CR 238667; Auxilary Building Supply Fan 0B Trip DP High/Low Annunciator, July 24, 2004
CR 261051; Long Term Problem Causes Unexpected Alarm and Work Around, October 07, 2004
CR 273464; Proceduralized Operator Work Around, November 15, 2004
CR 282738; Resin transfers Requires Shutdown (SD) Secured, December 15, 2004

1R19 Post Maintenance Testing

MA-BY-721-001; Three Phase Thermal Overload Relay Testing For Motor Operated Valves and Various Other Plant Equipment For 2B SX Cubicle Cooler Completed January 12, 2005, Revision 6
1BOSR 8.1.2-2; 1B DG Operability Surveillance, Revision 15
1BVSR 1.7.1-1; Unit One Digital Rod Position Indication (DRPI) Operability Checkout; Revision 8
2BVSRz.7.a.1; Unit 2 Auxiliary Feedwater Diesel Prime Mover Inspection, Revision 9
WO 424718 01; 1B DG Sequencer Test, September 28, 2003
WO 424720 01; 1B DG Safety Injection (SI) Signal Override Test, September 27, 2003
WO 424721 01; 1B DG Engineered Safety Feature (ESF) Actuation and Non-Emergency Trip and Generator Trip Surveillance, September 4, 2003
WO 424721 02; 1B DG ESF Actuation and Non-Emergency Trip and Generator Trip Surveillance, September 5, 2003
WO 424722 01; 1B DG Load Rejection and Overspeed Trip Surveillance, September 27, 2003
WO 424722 02; 1B DG Load Rejection and Overspeed Trip Surveillance, September 29, 2003
WO 476519 01; 1B DG 24 Hour Endurance Run and Hot Restart Surveillance, May 6, 2004
WO 556471; Replace Generator Exciter Fuses
WO 556471 03; Post Maintenance Test (PMT) Engine Startup (S/U) - 1B DG Reaches Rated Volts Within 10 Seconds
WO 602334 01; 1A DG Engine Analysis, January 20, 2005
WO 606894 01; 1B DG Engine Analysis, January 9, 2005
WO 619496; Replace All Normally Energized Agastate Relays Nuclear Work Request
WO 619496 03; PMT 1BOSR DG-3 & Engine Speed/Volts in Less 10 Seconds
WO 621497 01; 1B DG Safe SD Sequence and Single Load Reject, October 6, 2003
WO 621497 02; 1B DG Safe SD Sequence and Single Load Reject, October 6, 2003
WO 625873; Digital Rod Position OP Check, March 23, 2005
WO 637708 02; PMT - Perform 1BOSR DG-3
WO 637709; Clean and Inspect Motor Operated Potentiometer

WO 637709 02; PMT - Test Mode Engine Run and Verify Volt Adjust Response
WO 637788' DG 24 Month Relay Inspection
WO 638198; Exercise/Readjust Voltage Regulator R3 Potentiometer (POT)
WO 638198 02; OPS PMT Engine Run (Function Raise and Lower Voltage
WO 640337 01; 1B DG Operability - 24 Month - Inspect & Engine Analysis, February 8, 2005
WO 658178; JW Leak From Cylinder 10L
WO 658178 02; PMT - Verify No JW Leak at 10L Cylinder at Full Load
WO 695339 01; 1B DG Operability Monthly Surveillance, June 3, 2004
WO 695405; 1B DG JW Circulation Pump (PP) Mechanical Seal Leaks
WO 695405 04; Operations (OPS) PMT Run JW Pump
WO 705018 01; 1B DG Operability Monthly Surveillance, July 7, 2004
WO 716315 01; 1B DG Operability Monthly Surveillance, August 5, 2004
WO 719594; Inspect Fuse Block as Part of Extent of Condition From IR 23
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1R20 Refueling and Outage Activities

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CR 307612; NRC Identified Two Concerns in the Auxiliary Building, March 02, 2005
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CR 309207; Differential Pressure (DP) Gauge Pegged High, March 06, 2005
CR 309238; Compressor Mounting Bolts Loose, March 06, 2005 (NRC Identified)
CR 316062; B1R13 LL 1B RCP Motor Lead Box Suspended and Unattended,

March 15, 2005 (NRC Identified)
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1BCSR 5.4.4-1; Unit 1 RWST Boron Concentration Weekly Surveillance, Revision 6
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1BGP 100-2; Plant Startup, Revision 34
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1BGP 100-2T2; Mode 3 to 2 Checklist, Revision 12
1BGP 100-1T3; Mode 4 to 3 Checklist, Revision 14
1BGP 100-6T2; Mode 6 to 5 Checklist, Revision 10
1BGP 100-1T11; Mode Change Hourly Review for Change Mode, Revision 2
BOP DC-7; 125 V DC Engineered Safety Feature (ESF) Bus Crosstie/Restoration, Revision 13
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1BOSR 3.2.9-1; Unit 1 Train A Manual Safety Injection Initiation and Manual Phase A Initiation Surveillance, Revision 14
1BOSR 3.2.9-2; Unit 1 Train B Manual Safety Injection Initiation and Manual Phase A Initiation Surveillance, Revision 16
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WO 508881-03; Environs Monitoring (EM) Reactor Fuel Handling (FH) Functional Test of Crane After Repairs, March 08, 2005
WO 768271; Install TCCP Per EC 353117 For 1C RCP Seal #1 High Flow, January 05, 2005
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CR 254137; Tie Wrap Found on Cut Out Switch For HVAC Door, September 17, 2004
CR 244531; Apparent Cause Evaluation - Temporary Sump Pump Installed at Circ Water Pump House (CWPH) Sump, September 22, 2004
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Work-In-Progress Reports for RWP No. 10004749; dated through March 15, 2005
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4OA3 Event Follow-up

EP-AA-1000; Standardized Radiological Emergency Plan, Revision 16
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4OA5 Other Activities

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TQ-AA-122; Qualification and Certification of Nondestructive(NDE) Personnel, Revision 1
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Calculation 2004-08300; 1A Auxiliary Feedwater Pump Lube Oil Temperature Response with Loss of Cooling Water
Evaluation MPR-2743; Byron Auxiliary Feedwater Pump Evaluation of Operation Without Lube Oil Cooling, Revision 1
CR 232158; High Bearing Oil Temperatures During ASME Run, June 28, 2004
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1BVSR 5.5.8.AF.1-1; Unit 1 ASME Surveillance Requirements for the Motor Driven AF Pump, Revision 8
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10 CFR 50.59 Safety Evaluation Form 6G-00-0079; Ultrasonic Flow Measurement, Revision 1

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BYRON 2004-0061; Byron Station Unit 2 60-Day Response to First Revised NRC Order EA-03-009, Issuance of First Revised NRC Order (EA-03-009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water reactors, June 2, 2004
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EC-DCR 000354172; Determine EDY for Unit 1 in Accordance with NRC Order EA-03-009, March 1, 2005
Condition Report 309802; B1R13 CRDM Nozzle Volumetric Nozzle Volume Not Met March 12, 2005
Condition Report 309371; B1R13 - CRDM Head Inspection System Lost Signal, March 8, 2005
WDI-UT-010; Intraspect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave, Revision 10
WO 00731921-02; VT-2, Visual Examination Record, Attachment 1, Mode 3 Shutdown, Reactor Cavity Head Package, March 8, 2005
WDI-STD-114; RVHI Vent Tube Eddy Current Plus-Point Coil Bobbin Coil, Revision 3

LIST OF ACRONYMS USED

ADAMS	Agency wide Documents Access and Management System
AFW	Auxiliary Feedwater System
ALARA	As Low As Reasonably Achievable
AR	Action Request
ASME	American Society of Mechanical Engineers
B1R13	Byron Station Unit 1's 13th Refueling Outage
BACC	Boric Acid Corrosion Control
BAP	Byron Administrative Procedure
CAP	Corrective Actions Program
CFR	Code of Federal Regulations
CR	Condition Report
DAC	Derived Air Concentration
DEI	Dose Equivalent Iodine
DRP	Division of Reactor Projects; Region RIII
EAL	Emergency Action Level
EDY	Effective Degradation Years
EPRI	Electric Power Research Institute
ET	Eddy Current
FHB	Fuel Handling Building
gpm	Gallons Per Minute
HEPA	High Efficiency Particulate Air [Filtration]
HRA	High Radiation Area
IA	Instrument Air
IMC	Inspection Manual Chapter
IR	Inspection Report
ISI	Inservice Inspection
LER	Licensee Event Report
LLRT	Local Leak Rate Test
NCV	Non-Cited Violation
NRC	United States Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSP	Nuclear Station Procedure
OCC	Outage Control Center
OSC	Operations Support Center
PARS	Public Availability Records
PMT	Post Maintenance Testing
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RP	Radiation Protection
RPM	Radiation Protection Manager
RVCH	Reactor Vessel Closure Head
RWP	Radiation Work Permit
SCBA	Self Contained Breathing Apparatus
SD	Steam Dump
SDP	Significance Determination Process

SG	Steam Generator
SSC	Structure System or Component
SX	Essential Service Water
TI	Temporary Instruction
TIA	Task Interface Agreement
TRM	Technical Requirements Manual
TS	Technical Specification
UFM	Ultrasonic Flow Measurement Instruments
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VHP	Vessel Head Penetration
VHRA	Very High Radiation Area
WO	Work Order