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

July 27, 2010

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

SUBJECT: BYRON STATION, UNITS 1 AND 2, INTEGRATED INSPECTION REPORT 05000454/2010003; 05000455/2010003

Dear Mr. Pacilio:

On June 30, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed inspection report documents the inspection findings which were discussed on July 6, 2010, with Mr. Brad Adams and other members of your staff.

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

Based on the results of this inspection, one self-revealed and five NRC-identified findings of very low safety significance were identified. The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section VI.A.1 of the NRC 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, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Byron Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at Byron.

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

Sincerely,

/RA by Kenneth Riemer for/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor

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

Enclosure: Inspection Report No. 05000454/2010003 and 05000455/2010003
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2010003 and 05000455/2010003
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	April 01, 2010, through June 30, 2010
Inspectors:	B. Bartlett, Senior Resident Inspector J. Robbins, Resident Inspector R. Ng, Project Engineer T. Bilik, Reactor Inspector J. Bishop, Reactor Engineer D. Jones, Reactor Inspector B. Jose, Senior Reactor Engineer T. Go, Health Physicist V. Meghani, Reactor Inspector C. Thompson, Resident Inspector, Illinois Department of Emergency Management B. Metrow, Safety Engineer, Illinois Department of Emergency Management
Approved by:	R. Skokowski, Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000454/2010003, 05000454/2010003; 04/01/10 – 06/30/10; Byron Station, Units 1 & 2; Operability Evaluations, Outage Activities, Component Design Basis Inspection, Identification and Resolution of Problems, and Follow-Up of Events.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Five Green findings were identified by the inspectors. One additional Green finding was self-revealed. The findings were considered Non-Cited Violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events, Mitigating Systems

- Green A self-revealed finding of very low safety significance and associated Non-Cited Violation of Byron Operating License Condition 2.C(6) for Unit 1 and 2.E for Unit 2 for the licensees failure to identify the separation of the 0B Fire Pump discharge valve, 0FP018B, valve stem and valve disk. As a result, the mitigating functions associated with the 0B Diesel driven fire pump would not be assured. The licensee entered this issue into the Corrective Action Program (CAP) as Issue Report (IR) 1063395 and repaired the valve.

  The issue is more than minor because it affected the Mitigating Systems Cornerstone attribute of Protecting Against External Events and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Based on a Phase 3 significance evaluation, the finding is determined to be of very low safety significance. The primary cause for this finding was related to the cross-cutting area of Problem Identification and Resolution and its associated component for CAP (P.1(c)) because licensee personnel failed to identify the discharge valve's functionality was impacted by its degraded state. (Section 1R12.b)

- Green. The inspectors identified a finding of very low safety significance and associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, for the inadequate design evaluation of the shim packs for the Upper Steam Generator Lateral Supports. Specifically, the licensee's calculations failed to demonstrate that the stresses in the shims and the concrete met the acceptance criteria. The licensee entered the issue into the CAP as IR 1068066 to revise the design basis calculations.

  The finding is more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control and Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is of very low safety significance because it was a design qualification deficiency confirmed

not to result in the loss of operability or functionality. This finding is not assigned a cross-cutting aspect because it is not reflective of current licensee performance due to its age. (Section 1R15.b)

- Green. The inspectors identified a finding of very low safety significance and associated NCV of Byron Operating License Condition 2.C(6) for Unit 1 and 2.E for Unit 2 for the licensee failing to provide an adequate floor drain system as required by the Fire Protection Program. Specifically, the floor drain system in the Upper Cable Spreading Room (UCSR) was not adequate to prevent firefighting water from entering the Control Room through the floor openings and affecting equipments. The licensee entered this issue into the CAP as IR 1046794 and subsequently sealed the UCSR floor.

  The finding is greater than minor because it was associated with the protection against external factors attribute of the Initiating Events Cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding is of very low significance because safety equipment functions remained available to control room personnel. This finding was related to the cross-cutting area of Problem Identification and Resolution and its associated component for CAP (P.1(d)) because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. (Section 1R15.b)

- Green. The inspectors identified a finding of very low safety significance and associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the licensee's failure to perform an engineering evaluation required by procedure when loose debris items was brought into Unit 2 containment prior to Mode 5. The licensee entered this issue into the CAP as IR 1058304 and completed an evaluation to verify that the containment sump was not adversely affected.

  The finding is more than minor because, if left uncorrected, the issue could have become a more significant safety concern. Since this finding did not result in loss of safety function for the containment recirculation sump, this issue is screened as very low safety significance. This primary cause of this finding is related to the Work Control component of the Human Performance cross-cutting area because the licensee failed to coordinate work activities and the need for work groups to coordinate with each other. (H.3(b)) (Section 1R20.b)

- Green: A finding of very low safety significance and associated NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified by the inspectors for the licensee's failure to have an appropriate analysis for the second level undervoltage (degraded voltage) relay timer settings. Specifically, Byron's analysis, Engineering Change 377631, "Evaluation and Technical Basis for the AP System Second Level Undervoltage (Degraded Voltage) Time Delay Settings," dated February 3, 2010, failed to demonstrate the ability of the permanently connected safety-related loads to continue to operate for 5 minutes and 40 seconds without sustaining damage during a worst case, non-accident degraded voltage condition. The licensee entered this issue into their CAP as IR 1071667 and revised the affected procedures.

The performance deficiency was determined to be more than minor because the finding affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, there was reasonable doubt as to whether the permanently connected safety-related loads would remain operable during a worst case, non-accident degraded voltage condition for the duration of the time delay chosen. This finding is of very low safety significance (Green) because the design deficiency was confirmed not to result in loss of operability or functionality. The primary cause of this finding is related to the decision making aspect of the Human Performance cross-cutting area (H.1(b)) because the licensee did not use conservative assumptions based on NRC approved changes to the licensing basis in choosing the worst case degraded voltage condition in their February 2010 analysis. (Section 1R21.b)

- SL IV. A Severity Level IV, NCV of 10 CFR 50.72(b)(3)(iv)(A) was identified by the inspectors for the licensee's failure to recognize that a valid Unit 2 automatic Reactor Protection System (RPS) and Auxiliary Feedwater (AF) actuation while shut down were reportable conditions. Consequently, the licensee failed to make an 8 hour report as required by 10 CFR 50.72. This issue was documented in the licensee's CAP as IR 1060177 and the licensee subsequently reported the event.

  This finding was evaluated under Traditional Enforcement because it had the potential for impacting the NRC's ability to perform its regulatory function. However, this violation was of very low safety significance because immediate NRC follow-up action was not required. The NRC has characterized this violation as a Severity Level IV NCV in accordance with Section IV.A.3 and Supplement 1 of the NRC Enforcement Policy. The cause of this finding was directly related to the cross-cutting area of Problem Identification and Resolution (P.1(c)) because the licensee did not thoroughly evaluate and classify a condition adverse to quality for reportability. (Section 4OA3).

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power through most of the inspection period.

Unit 2 operated at or near full power through most of the inspection period. At the start of the inspection period, power was allowed to slowly reduce as the reactor was near the end of its fuel cycle. Just prior to the start of the refueling outage, power was approximately 89 percent. On April 13, 2010, power was reduced to 78.5 percent for main steam safety valve testing. After the testing activities were completed reactor power was returned to about 90 percent. The unit was shut down for its 15th refueling outage on April 18, 2010, and returned to service on May 8, 2010. Reactor power was slowly increased to 100 percent as part of the planned return to service. Unit 2 returned to full power on May 13, 2010.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems, including conditions that could lead to an extended drought.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Specific documents reviewed during this inspection are listed in the Attachment. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Auxiliary Building Ventilation System; and
- Unit Auxiliary, Station Auxiliary, and Main Power Transformers.

This inspection constituted one seasonal adverse weather sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

- Unit 2 Train A Diesel Generator (DG) while Unit 2 Train B DG was Inoperable

The inspectors selected the system based on its risk significance relative to the Reactor Safety Cornerstones at the time it was inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, Technical Specification (TS) requirements, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the system incapable of performing their intended functions. The inspectors also walked down accessible portions of the system to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted one partial system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On April 26, 2010, the inspectors performed a complete system alignment inspection of the Unit 2 Residual Heat Removal system during the refueling outage to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of outstanding work orders was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

These activities constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 11.1A-0; Train A Essential Service Water Pump Room;
- Fire Zone 11.1B-0; Train B Essential Service Water Pump Room;
- Fire Zone 9.2-2; 2A Diesel Generator Room;
- Fire Zone 9.1-2; 2B Diesel Generator Room;
- Fire Zone 10.1.2; 2B Diesel Fuel Oil Storage Tank Room; and
- Essential Service Water Extended Allowed Outage Time Areas During Unit 2 Refueling Outage.

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

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

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area(s) to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Auxiliary Building general areas, including; Elevations 401, 383, 364, and 346.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings of significance were identified.

.2 Underground Vaults

a. Inspection Scope

The inspectors selected underground bunkers/manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors determined that the cables were not submerged, that splices were intact, and that appropriate cable support structures were in place. In those areas without dewatering devices, the inspectors verified that the cables were qualified for submergence conditions. The inspectors also reviewed the licensee's corrective action documents with respect to past submerged cable issues identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of 10 of the 12 safety related manholes on site and one non-safety related manhole subject to flooding including the eight listed below:

- Manhole 0A2, Essential Service Water (SX) Tower North West Room;
- Manhole 0B1, SX Tower South East Room;
- Manhole 0B2, SX Tower South West Room;
- Manhole 0A1, SX Tower North East Room;
- Manhole 1H1, SX Field;
- Manhole 2H2, SX Field;

- Manhole 1G1, SX Field;
- Manhole 2G1, SX Field; and
- Non-Safety Related Manhole 1M1G, South of the Unit 1 Main Transformers.

This inspection constituted one underground vaults sample as defined in IP 71111.06-05.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08P)

From April 19, 2010, through May 6, 2010, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system, steam generator (SG) tubes, emergency feedwater systems, risk-significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, R08.3, IR08.4, and 1R08.5 below constituted one inservice inspection sample as defined in IP 71111.08-05.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed and reviewed records of the following non-destructive examinations mandated by the American Society of Mechanical Engineers (ASME) Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Ultrasonic Examination (UT) of feedwater pipe-to-valve weld 2FW03DA.16 C01(R-A, R1.11);
- UT of feedwater pipe weld 2FW03DA.16 C02 (R-A, R1.11); and
- Liquid Penetrant Examination (PT) of closure plate weld, 2SI03DA-2/W-08A.

The inspectors reviewed the following examinations completed during the previous outage with relevant/recordable conditions/indications accepted for continued service to determine if acceptance was in accordance with the ASME Code Section XI or an NRC approved alternative.

- UT of SG channel head to tubesheet circumferential weld 2RC-01-BA/SGC-01;
- UT of SG nozzle ring, lower barrel "A" circumferential weld 2RC-01-BB/SGC-03); and
- PT Indication Assessment of pressurizer seismic support lug RY/2RY/PSL-1, weld 2PZR-1.

The inspectors reviewed the following pressure boundary weld completed for risk-significant systems since the beginning of the last refueling outage to determine

if the licensee applied the pre-service non-destructive examinations and acceptance criteria required by the Construction Code and ASME Code, Section XI. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedures were qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

- 1F-39B Reactor Coolant Pump (RCP) Seal Injection Filter Inlet Valve and Piping, CV-00303B, Welds FW1-8, Code Class 2.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 2 reactor vessel head, in accordance with the alternative examination frequency approved in Relief Request I3R-16, the licensee performed a bare metal visual examination of all penetrations, and a volumetric and surface examination for penetration nozzle 68. Per Relief Request I3R-16, the licensee was approved to perform volumetric and/or surface examinations of all penetrations at a frequency of once every second refueling outage or 4 calendar years, whichever is less, except for penetration 68, which is to be volumetrically, surface, and visually examined each refueling outage.

The inspectors reviewed records of the bare metal visual examination conducted on the Unit 2 reactor vessel head at penetrations 6, 9, and 23 to determine if the activities were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed that:

- the required visual examination scope/coverage was achieved and limitations (if applicable) were recorded in accordance with the licensee procedures,
- the licensee criteria for visual examination quality and instructions for resolving interference and masking issues were adequate, and
- if indications of potential through-wall leakage were identified, the licensee entered the condition into the corrective action system and implemented appropriate corrective actions.

The inspectors observed the volumetric (ultrasonic) examination and reviewed the documentation of the surface (liquid penetrant) examination conducted on the Unit 2 reactor vessel head at penetration 68 to determine if the activities were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed that:

- The required examination scope (volumetric and surface coverage) was achieved and limitations (if applicable) were recorded in accordance with the licensee procedures;
- The ultrasonic examination equipment and procedures used were demonstrated by blind demonstration testing;

- If indications or defects were identified, the licensee documented the conditions in examination reports and/or entered this condition into the corrective action system and implemented appropriate corrective actions; and
- If indications were accepted for continued service, the licensee evaluation and acceptance criteria were in accordance with the ASME Section XI Code, 10 CFR 50.55a(g)(6)(ii)(D) or an NRC approved alternative.

The licensee did not perform any welded repairs to vessel head penetrations since the beginning of the preceding outage for Unit 2. Therefore, no NRC review was completed for this inspection procedure attribute.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC)

a. Inspection Scope

On April 18, 2010, the inspectors observed the licensee staff performing visual examinations of the reactor coolant system within containment to determine if these visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of reactor coolant system components with boric acid deposits to determine if degraded components were documented in the corrective action system. The inspectors also evaluated corrective actions for any degraded reactor coolant system components to determine if they met the component Construction Code, ASME Section XI Code, and/or NRC approved alternative.

- BAE944766 09-077; Chemical Volume Control (AB HDR to U-1 Boric Acid Blender Isolation Valve), August 27, 2009; and
- BAE965397 09-125; U-1 Chemical Volume Control at Demineralizer 1CV02D Inlet Isolation Valve (EOP VLV), October 26, 2009.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- IR 964484; 1RC01PB Main Flange, Boron Accumulation; and
- IR 966831; 1RY024, Boric Acid Leakage at Packing and Bolted Connection.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

The inspectors performed an on-site review of the Unit 2 SG tube examination activities conducted pursuant to TS and the ASME Code, Section XI requirements. The NRC inspectors reviewed eddy current (ET) data, and documentation related to the SG ISI program to determine if:

- In-Situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute (EPRI) TR-107620, Steam Generator In-Situ Pressure Test Guidelines and that these criteria were properly applied to screen degraded SG tubes for in-Situ pressure testing;
- 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 meet the TS, and the EPRI 1003138, Pressurized Water Reactor Steam Generator Examination Guidelines;
- The SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- The licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- The licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- The licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- The licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle;
- The ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for Eddy Current Examination, of EPRI 1003138;
- The licensee performed secondary side SG inspections for location and removal of foreign materials;
- The licensee implemented repairs for SG tubes damaged by foreign material; and
- Inaccessible foreign objects were left within the secondary side of the SGs, and if so, that the licensee implemented evaluations which included the effects of foreign object migration and/or tube fretting damage.

The licensee did not perform in-situ pressure testing of SG tubes. Therefore, no NRC review was completed for this inspection attribute.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if;

- the licensee had established an appropriate threshold for identifying ISI related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

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

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On May 26, 2010, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program sample as defined in IP 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Unit 2 Pressurizer Safety Valve A Seat Leak-By;
- Chemical and Volume Control Pump Shaft Performance Monitoring; and
- Unit Common Train B Diesel Driven Fire Pump Discharge Isolation Valve Failure.

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

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

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This inspection constituted three quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

(1) 0B Fire Pump Discharge Valve Discovered Closed

Introduction: A self-revealed finding of very low safety significance and associated NCV of Byron Operating License (OL) Condition 2.C(6) for Unit 1 and 2.E for Unit 2 for the licensee's failure to identify that separation of the 0B Fire Pump discharge valve, 0FP018B, valve stem and valve disk created a lack of positive control such that the mitigating functions associated with the 0B Diesel Driven Fire Pump would not be assured.

Description: On April 14, 2010, during the performance of the Unit Zero Fire System Leakage Trace Surveillance, an anomaly was noted with the valve stem associated with the 0B Fire Pump discharge valve, 0FP018B. The valve stem was observed to spin freely during operation. Given that the stem was spinning free, the position of the disk could not be verified and therefore the water flow from the fire pump could not be assured. Issue Report 1056679, Valve Stem Spins Free When Valve Fully Open, was placed in the licensee's CAP. The valve was declared operable and returned to service. The basis for returning the valve to service was that the valve was operated open; therefore the fire pump could perform its intended function. The licensee did not identify that the disc was separated from the stem. A work order was generated in response to the equipment issue identified.

On April 26, 2010, as a result of anomalies noted during a routine surveillance on the 0B Fire Pump, IR 1061778 was initiated. Pressure anomalies were identified and attributed to sensing line plugging. The equipment was returned to service a second time and another work order was initiated to address line plugging.

On April 29, 2010, during the work window to clear the plugged sensing line, the licensee entered a Limiting Condition for Operation Action Statement upon discovering the discharge valve was closed.

Analysis: The inspectors determined that the failure to identify the separation of the 0B Fire Pump discharge valve disk and stem was a performance deficiency and was contrary to the Fire Protection Program requirement of promptly identifying and correcting items or occurrences that are adverse to quality or might adversely affect the safe operation of a nuclear generating station.

The issue was more than minor because it affected the Mitigating Systems Cornerstone attribute of Protecting Against External Events and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using Table 4a from IMC 0609.04, under the Mitigating Systems Cornerstone, the inspectors determined that the finding represented an actual loss of safety function of one or more non-Tech Spec trains of equipment designated as risk-significant per 50.65 for greater than 24 hours. The inspectors contacted a regional risk analysis specialist for support in determining the appropriate risk characterization.

Consequently, the finding was evaluated by a Senior Reactor Analyst (SRA). The SRA evaluated the finding using the Risk-Informed Inspection Notebook for Byron Station

(Revision 2.1a). Using Table 2 from the notebook, the Fire Pumps only potentially affected the Loss of Essential Service water (LESW) initiating event. Using the SDP Worksheet for the LESW initiating event (i.e., Table 3.12), the only sequence that included the Fire Pumps involved a sequence where the Fire Pumps were used to provide cooling to the centrifugal charging pumps by a local operator action to hook up fire hoses. This action allowed use of the charging pumps for reactor coolant pump seal cooling to prevent a potential reactor coolant pump seal LOCA. However, the sequence gave no credit for this operator action, and thus the results indicated no change in risk significance with the OB Fire Pump unavailable. As a further check on the risk significance of the finding, the SRA performed a Phase 3 evaluation of the issue using the Standardized Plant Analysis Risk (SPAR) model for Byron Station (Revision 3P, Change 3.51). Modeling the performance deficiency as a failure-to-run of the OB Fire Pump for 15 days resulted in a ΔCDF of 1.0E-7 per year. Based on the Phase 3 analysis, the inspectors determined that the finding was of very low safety significance (Green).

Enforcement: Byron OL Condition 2.C(6) for Unit 1 and 2.E for Unit 2 requires in part; that the licensee implement and maintain in effect all provisions of the approved fire protection program as described in the Fire Protection Report (FPR). Section 3.4, "Quality Assurance," of the FPR states, in part, that nonconforming equipment is identified as a result of tests and corrective actions are taken to rectify any deficiencies as provided by the Quality Assurance Program. The Quality Assurance Program is implemented in accordance with the Quality Assurance Topical Report, NO-AA-10, Rev.84. The requirements section of Chapter 16, "Corrective Action," of the Quality Assurance Topical Report states, in part, that the Company implements a CAP to promptly identify and correct items or occurrences that are adverse to quality or might adversely affect the safe operation of a nuclear generating station.

Contrary to the above, the licensee's failure to promptly identify the stem-disc separation of the 0B Fire Pump discharge valve on April 14, 2010, was a violation of the Byron Operating License (OL) Condition 2.C(6) for Unit 1 and 2.E for Unit 2. The primary cause for this finding was related to the cross-cutting area of Problem Identification and Resolution and its associated component for CAP (P.1(c)) The licensee failed to thoroughly evaluate the problem which resulted in the resolution failing to address causes and extent of conditions. Because this violation was of very low safety significance and because it was entered into the licensee's CAP as Issue Report (IR) 1063395, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC enforcement policy. (NCV 05000454/2010003-01; 05000455/2010003-01; 0B Fire Pump Discharge Valve Discovered Closed)

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- SX Extended Allowed Outage Time During Unit Refueling Outage;
- Replacement of SX Valve 0SX147 while 1SX010 is Unable to Close;
- Unit 2 Train A Replacement of SX Pump and Motor (Heavy Load Lift);
- Risk Profile for Week of June 29, 2010; and
- Unit 1 Train B Auxiliary Feedwater Pump Diesel Driver Lube Oil Dilution from Fuel Oil.

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

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

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Operation of Unit 2 Reactor Vessel with One Closure Stud Out of Service;
- Fire Damper Electro Thermal Links due to In-Service Time approaching Shelf-Life;
- Vent Stack Radiation Monitors 1/2PR30J due to Issues Identified by Licensee Personnel During Operating Experience Reviews;
- Unit 1 and Unit 2 SX Make-Up Pumps due to River Screen House Dampers Opening on Loss of Electrical Power;
- Unit 1 and Unit 2 Deep Wells due to Changes in Risk Mitigation Strategy Described in Plant Analysis Documents;
- Main Steam Power Operated Relief Valve Capacity Low;
- Fire Seals in UCSR Not Water Tight;
- Unit 2 SG Upper Lateral Support Bolt Failure;
- Unit 2 Pressurizer Safety Valve A Seat Leak-By; and
- Unit 2 Train B DG Jacket Water Heater Over Temperature While in Manual.

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

This operability inspection constituted ten samples as defined in IP 71111.15-05.

b. Findings

(1) Inadequate Evaluation of Shim Pack for the Steam Generator Upper Lateral Supports

Introduction: A Green finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the inadequate design evaluation of the shim packs for the SG Upper Lateral Supports. Specifically, the licensee's calculations failed to demonstrate that the stresses in the shims and the concrete met the acceptance criteria.

Description: On May 4, 2010, during Byron Station Unit Two Refueling Outage, licensee personnel performing a walkdown of the SG enclosures observed that two of the bolts holding the Steam Generator Upper Lateral Support (SGULS) of the "C" SG were broken. The SGULS provides lateral support to the SG during a seismic or pipe beak event while permitting horizontal and vertical movements from thermal expansion during normal operation. Each unit at Byron Station has four SGs. The SGULS on each SG consists of two steel support brackets with two sets of shims (shim pack) at each bracket. The shim packs minimize the gaps between the SG structural supports and the steel plates embedded in the concrete enclosure walls thus limiting impact loads during a seismic and/or pipe break event. Based on the Byron UFSAR, the SG supports are safety category 1.

As a corrective action for the damaged SGULS, the licensee issued Engineering Change (EC) 380019 to repair the broken bolts during the outage using new Alternate Detail G3 that was similar to the existing Alternate Detail G2 on drawing S-1100. The supporting calculations for this detail are documented in Book 10.2.1.6 on pages 423-429, dated March 21, 1986, through May 1, 1986. Due to the similarity between the new Detail G3 and the existing Detail G2, the licensee concluded that new calculations to check the adequacy of Detail G3 were not required.

While reviewing the new Alternate Detail G3, the inspectors noticed a difference in the SGULS shim pack size from the original shim pack size described in design detail G on drawing S-1114-2. Specifically, Alternate Detail G3 specified a shim pack that had one third the surface contact area of the shim pack described in design detail G of safety

related equipment design drawing S-1114-2. During a seismic and/or pipe break event, a shim pack with a smaller surface contact area would result in a greater stress on the shims as well as on the restraining concrete structure. The inspectors raised the concern of whether or not the reduction in the shim area was adequately addressed in existing design calculations. In response to the inspector's questions, the licensee performed a review of the existing shim design calculation. During the review, the licensee found that the existing calculation indicated the compressive stresses on the shim pack were greater than the material's yield strength, but lower than its ultimate strength. This meant that the shim pack would deform but not break when subjected to a seismic and/or pipe break load. The calculation also stated the shim pack would be acceptable for faulted load condition. However, the calculation did not state how much the shim pack would deform nor did it have any justification for why the deformation would be acceptable. Furthermore, the concrete bearing stress on the SG concrete enclosure from the alternate shim pack design had not been calculated.

Upon identification of the concern, the licensee performed a preliminary evaluation using a finite element analysis of the embedded plate and concrete under the plate and concluded that the bearing stresses in the concrete enclosure wall would be within the design basis limits. Additional evaluation by the licensee to determine the operability of the shim design indicated that the shim pack's permanent deformation could result in a gap of 3/16", exceeding the design limit of 1/16" indicated on drawing S-1114-2. However, the licensee determined that the larger gap was acceptable based on review and concurrence from the nuclear steam supply system vendor for the SG component supports. The licensee has obtained further information from the vendor indicating that the actual loads on the support could be much lower than those used in the current analysis, and no plastic deformation would be expected under the revised loads.

The licensee has captured the issue in IRs 1068066 and 1072054 with corrective actions to revise the design basis calculations.

Analysis: The inspectors determined that the failure to verify the adequacy of the changes to the original SGULS shim pack design was contrary to the design control measures per 10 CFR 50 Appendix B requirements and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attributes of Design Control and Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to verify the adequacy of the changes to the original SGULS shim pack design affected the licensee's ability to ensure the availability, reliability, and capability of the SGULS to prevent SG damage during a response to a seismic and/or pipe break event.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of findings," Table 3b and 4a for the Mitigation Systems Cornerstone. The finding affects the Mitigation Systems Cornerstone because SG damage could cause a short term core decay heat removal degraded condition.

The inspectors did not identify a cross-cutting aspect associated with this finding because the performance deficiency was not reflective of current licensee performance.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, in Calculation 10.2.1.6 performed during the period between March 21, 1986, and May 1, 1986, the licensee failed to verify the adequacy of the changes in the shim pack design for the steam generator upper lateral supports. Specifically, in their calculation, the licensee did not evaluate the concrete stresses and did not provide justification for acceptance of the alternate shim pack design even though the calculation indicated that the shim pack would undergo permanent deformation that could result in a support gap exceeding the limit indicated on design drawing S-1114-2. Because this violation was of very low safety significance and it was entered into the licensee's CAP as IRs 1068066 and 1072054, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000455/201003-02, Inadequate Evaluation of Shim Pack for the Upper Steam Generator Lateral Supports)

(2) Water Intrusion Leads to Loss of Annunciators

Introduction: The inspectors identified a finding of very low safety significance for failing to provide adequate waterproofing between floors as required by the Fire Protection Report. Specifically, fire seals located in the floor separating the UCSR and the Control Room were not sufficiently waterproofed. The licensee had an opportunity to identify this issue following a water intrusion event in June of 2009. The licensee was in the process of evaluating the need for and selection of additional sealants when a second event occurred in March of 2010.

Description: On June 18, 2009, IR 933005 was initiated in response to water dripping from the control room ceiling. Subsequently, System Engineering identified the source of the leak as being associated with a leaking fire protection valve, 0FP472. This valve is located in the space directly above the control room commonly referred to as the upper cable spreading room. A work request (WR) was generated to replace the leaking valve: WR 0307273. This work was completed on August 7, 2009

On June 23, 2009, following clean-up activities and an engineering walkdown of the affected areas, IR 934429 was initiated. The main focus of this document was on the technical assessments associated with the inadvertent wetting of the fire barriers located in the floor of the UCSR and in the ceiling of the control room. The licensee concluded that the fire seal could still perform its fire barrier function but the seal was determined not to be waterproof.

In addition, IR 934040 was initiated in response to water being found inside an electrical cabinet, 0PM02J, located in the control room. This panel is located across the room from the location of the previously identified water intrusion event. Electrical cabinet 0PM02J houses the controls for the ventilation systems associated with; control room, auxiliary building, fuel handling building and the emergency diesel generators. These controls are designated as safety related. Several actions were initiated in response to this discovery. Among the actions initiated in response to water being located in the electrical panel was an action to evaluate sealants that could be applied to the fire seals to address the leak path between the upper cable spreading room and the control room.

Although the actions were the result of a process that was initiated in June, the task of performing an evaluation was not assigned until September 9, 2009, and the sealant was not applied until May 2, 2010, after the second event described below.

On March 24, 2010, the control room received an unexpected alarm that identified an electrical grounding issue with electrical panel 1PA30J. Electrical panel 1PA30J is located in a room adjacent to the control room and also below the upper cable spreading room. The Auxiliary Electrical Equipment Rooms are considered part of the Control Room Envelope. These rooms contain a number of electrical control cabinets and some of these control cabinets contain safety related equipments. Individuals dispatched to investigate this issue reported water pouring down on electrical panel 1PA30J. Maintenance personnel identified that the source of the water was a leaking isolation valve associated with fire protection equipment in the UCSR. Maintenance personnel isolated the leak and covered the tops of the electrical cabinets with tarps to limit their exposure to water that was still draining from the UCSR floor. A portion of the control room annunciators associated with electrical panel 1PA30J was affected for a short time. Electrical Panel 1PA30J does not contain any safety related equipment. Following this event, the licensee installed water proofing material to all of the penetrations in the UCSR for each unit.

Section 3.5 of the FPR contains NRC guidance for building design as it relates to fire protection. The FPR also contains the license's response; i.e., the licensee plans to comply with the NRC guidance or the licensee plans to deviate from the NRC Guidance. Section 3.5.a.(14) of the FPR states, in part, that floor drain systems be designed, provided and sized to remove expected firefighting water flow without flooding safety-related equipment if such firefighting water could cause unacceptable damage to safety related equipment. This section makes specific reference to NFPA 92, "Waterproofing and Draining of Floors," which provides methods for waterproofing and draining of floors in combination to prevent water damage from firefighting water. The FPR indicates that the licensee complies with section 3.5.a.(14).

Analysis: The inspectors determined that water, which moves between floors and results in shorting or grounding of electrical equipment, in control cabinets was contrary to the FPR and was a performance deficiency. The inspector concluded that the finding was greater than minor in accordance with IMC 0612, Appendix B, "Issue Disposition Screening." Specifically, it was associated with the protection against external factors attribute of the Initiating Events Cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings." The inspectors answered yes to the second question located in Table 2 under the heading "Initiating Events Cornerstone," finding is a transient initiator contributor. The inspectors answered yes to question seven in Table 3b, the finding affects the safety of an operating reactor and affects the Initiating Events Cornerstone. The inspectors answered no to question one located in Table 4a under the "Initiating Events Cornerstone" column and under the heading "Transient Initiators," the finding contributes to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The basis for this conclusion was that

electrical shorts and grounding may unintentionally actuate or limit the ability to actuate equipment from the control room but local control would remain available. Safety equipment functions would remain available to control room personnel. Therefore, the finding was determined to be of very low safety significance (Green).

The inspectors determined that the primary cause for this finding was related to the cross-cutting area of Problem Identification and Resolution (P.1(d)) and its associated component for CAP because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity.

Enforcement: Byron OL Condition 2.C.(6) for Unit 1 and 2.E for Unit 2 requires, in part; that the license implement and maintain in effect all provisions of the approved fire protection program as described in the FPR. Section 3.5.a.(14) of the FPR states that floor drains be provided and sized to remove expected firefighting water flow without flooding safety-related equipment and if such fire-fighting water could cause unacceptable damage to safety-related equipment.

Contrary to the above, on June 23, 2009, the floor drain system in the upper cable spreading room allowed leaking fire water to enter the main control room into a safety related cabinets and on March 24, 2010, water intrusion into the electrical cabinet 1PM07J resulted in sporadic alarm in the main control room. Because this violation was of very low safety significance and because it was entered into the licensee's CAP as IR 1046794, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC enforcement policy. (NCV 05000454/2010003-03; 05000454/2010003-03; Water Intrusion Leads to Loss of Annunciators)

1R18 Plant Modifications (71111.18)

.1 Permanent Plant Modifications

a. Inspection Scope

The following engineering design package was reviewed and selected aspects were discussed with engineering personnel:

- 0SX147 Valve Replacement and Vent Valve Installation.

This document and related documentation were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

This inspection constituted one permanent plant modification samples as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- Post Outage, Unit 2 Train B DG Sequencer Test;
- Post Outage, Unit 2 Train B DG Safe Shutdown and Single Load Reject Test;
- Unit 2 Train B Auxiliary Feedwater (AFW) Pump following Upstream Suction Isolation Valve Closure Control Scheme Change;
- Unit 1 Train A SX Valve 1SX001A following Scheduled Maintenance;
- Unit 2 Train B DG following Fuse Replacement; and
- Unit 2 Train B AFW Pump following Repairs associated with Level Control of Jacket Water.

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

This inspection constituted six post-maintenance testing sample as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 2 refueling outage (RFO), conducted April 18, 2010, to May 8, 2010, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment to this report.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out of service.
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.
- Controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor vessel inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of containment as required by TS.
- Refueling activities, including fuel handling.
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to RFO activities.

This inspection constituted one RFO sample as defined in IP 71111.20-05.

b. Findings

(1) Loose Debris Inside of Containment

Introduction: The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for the licensee’s failure to follow Procedure BAP 1450-1, “Access to Containment.”

Description: On April 18, 2010, the licensee was in the process of shutting down Unit 2 in order to enter a refueling outage. The inspectors performed a routine assessment of containment immediately following the licensee's entry into Mode 3, Hot Standby. While in containment the inspectors identified loose debris that had been brought in by the various work groups. The inspectors identified items that required either accompaniment by a person at all times so that it could be removed in the event of a Loss of Coolant Accident (LOCA) or the use of an engineering evaluation in order to leave it unaccompanied and unsecured, as required by Procedure BAP 1450-1, "Access to Containment." Step 3.2.1 of this procedure stated in part that, "Tools and Equipment taken into containment in Modes 1, 2, 3, or 4 will be removed when personnel exit containment. Engineering evaluation and approval is required to leave materials, tools, and equipment unattended in containment." Most of the items were of a minor nature. Examples included lengths of rope, Low Dose Waiting Area signs, boxes with radios for the polar crane, electrical cords, linemans bucket, plastic bags, and tools. The items would be acceptable in Mode 5 and lower; but in Mode 4 and higher, there still exists a possibility of a LOCA and the recirculation sump is required by TS to remain operable.

At the time when the inspectors performed their walkdown, the licensee was in Mode 3 and was about 8 hours away from Mode 5. The items that had been brought into containment were subsequently evaluated by the licensee as being acceptable and not a significant challenge to blocking the containment recirculation sump screens following a postulated accident

Analysis: The inspectors determined that the failure to control loose debris items inside containment prior to Mode 5 or to perform an engineering evaluation as required by procedure was a performance deficiency warranting a significance determination. Using IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 20, 2007; the inspectors concluded that the finding was greater than minor because, if left uncorrected, the issue could have become a more significant safety concern. The inspectors evaluated the finding using IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Finding," dated January 10, 2008, for the Mitigating Systems Cornerstone. Since this finding was not a design or qualification deficiency, did not result in loss of system or train safety function and was not safety significant due to external events, it was screened as very low safety significance (Green).

This finding is related to the Work Control component of the Human Performance cross-cutting area for the licensee's failure to coordinate work activities and the need for work groups to coordinate with each other (H.3(b)). The personnel who took the material into containment assumed it was acceptable as they had documented the material in a surveillance data sheet. No work group or individual questioned the potential impact upon the recirculation sump screens or coordinated with other work groups to ensure the containment sump screens would not be overloaded during a postulated LOCA. A subsequent engineering evaluation determined the sump screens were not overloaded although all but about 25 square feet of margin was used up.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by procedures and accomplished in accordance to these procedure. Byron Administrative Procedure BAP 1450-1, Revision 37, "Access to Containment," was written in

accordance with Appendix B. Step 3.2.1 stated in part that, "Tools and Equipment taken into containment in Modes 1, 2, 3, or 4 will be removed when personnel exit containment. Engineering evaluation and approval is required to leave materials, tools, and equipment unattended in containment." Contrary to the above, on April 18, 2010, the inspectors identified that licensee personnel took material inside of containment in Mode 3 that was required to be controlled with the knowledge that the material would remain present through lower modes and an engineering evaluation had not been performed and the material was left unattended. Because this violation was of very low safety significance and was captured in the licensee's CAP (IR 1058304), it is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000455/2010003-04, Loose Debris Inside of Unit 2 Containment at the Start of the Refueling Outage)

1R21 Component Design Bases Inspection (71111.21)

.1 Component Design Bases Inspection

a. Inspection Scope

During the 2009 Component Design Bases Inspection (CDBI) at Byron Nuclear Station, inspectors opened an unresolved item (URI 05000454/2009007-04; 05000455/2009007-04) related to licensee's failure to have an analysis for the second level undervoltage (degraded voltage) relay timer settings. In response to the inspectors' concerns, the licensee issued IR 892610, "2009 CDBI issue; degraded voltage 5-minute timer." In the IR, the licensee indicated that they would develop a technical basis for the 5 minutes and 40 seconds delay and completed EC 377631 on February 3, 2010. The inspectors reviewed the EC and determined that the licensee's current analysis did not address the worst case, non-accident degraded voltage condition. During this inspection period, the inspectors reviewed related documents and discussed the licensing and design basis with NRR staff to verify and confirm Byron's licensing and design basis requirements. This review did not represent an inspection sample. Specific documents reviewed are listed in the Attachment of this report.

b. Findings

(1) Insufficient Design Bases for Second-Level (Degraded) Voltage Timer Settings.

Introduction: The inspectors identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to have an appropriate analysis for the second level undervoltage (degraded voltage) relay timer settings. Specifically, Byron's analysis of EC 377631, "Evaluation and Technical Basis for the AP System Second Level Undervoltage (Degraded Voltage) Time Delay Settings," dated February 3, 2010, failed to demonstrate the ability of the permanently connected safety-related loads to continue to operate for 5 minutes and 40 seconds without sustaining damage during a worst case, non-accident degraded voltage condition.

Description: The inspectors determined that Byron's recent analysis for the second level undervoltage (degraded voltage) relay timer settings did not account for the potential worst case, non-accident degraded voltage condition and, therefore, did not demonstrate the operability of permanently connected safety-related loads under those conditions.

In the original safety evaluation report, Section 8.2.4 of NUREG-0876, dated February 1982 for Byron Station, it is clearly stated that: "…the voltage and time setpoints will be determined from analysis of voltage requirements of the safety-related loads and actual field measurements of bus voltages under various motor starting conditions…if the degraded voltage is not corrected within 5 minutes, the bus will automatically disconnect from the offsite power source and connect to its onsite diesel generator." The inspectors reviewed EC 377631 and determined that the licensee's current analysis did not address the worst case, non-accident degraded voltage condition. Specifically, the licensee's current analysis only evaluated the operability of permanently connected safety-related loads to a maximum degraded voltage of 75 percent of nominal. The licensee chose 75 percent of nominal voltage as the lower limit of degraded voltage based on an operator manual action, not formally approved by NRC, to trip the offsite source, if the voltage were to degrade below 75 percent of nominal. Without the operator action, the voltage could drop to just above first level undervoltage setpoint of approximately 66 percent of nominal during the 5 minutes and 40 seconds time delay period and the licensee did not address operability of permanently connected safety-related loads at those voltage levels. The licensee also failed to determine whether non safety-related loads such as circulating water pumps would not trip at the lowest possible degraded voltage causing a plant trip, at which, the safe shutdown loads such as motor driven auxiliary feedwater pump would be able to start and perform its safety function.

Discussions with the licensee regarding this issue indicated that the licensee had received formal NRC approval in TS Amendments 103 and 108 for Dresden Nuclear Power Station (a different Exelon nuclear unit), for the use of operator manual action to trip the offsite power if the voltage dropped below 75 percent of nominal. The licensee then informed the NRC by letter dated April 21, 1989, that they planned to implement a similar scheme at their other nuclear plants including Byron Station. Although, the licensee implemented the use of operator manual action to trip the offsite power if the voltage dropped below 75 percent of nominal at Byron Station, the licensee did not follow through formally and obtain prior NRC acceptance and approval as part of licensing basis as was done at Dresden Nuclear Power Station. The inspectors confirmed this with NRC's Office of Nuclear Reactor Regulation. Therefore, the inspectors concluded that the licensee was required to demonstrate operability of permanently connected safety-related loads at the worst case degraded voltage, which is the first level (loss of voltage) undervoltage of approximately 66 percent of nominal, as specified in the Byron TS. The inspectors were not concerned with current operability of permanently connected safety-related loads as the licensee revised the alarm response procedures associated with safety-related 4 kV busses to open the Station Auxiliary Transformer (SAT) breaker upon receiving and confirming an actual degraded bus condition of 92.5 percent as an interim corrective action.

Analysis: The inspectors determined that the failure to perform adequate analysis to demonstrate that permanently connected safety-related loads will not be damaged for the duration of the time delay for a worst case, non-accident degraded voltage condition and to ensure that safe shutdown loads would be able to start and perform their safety function in response to a potential plant trip caused by such a degraded voltage condition, was contrary to 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency.

The performance deficiency was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, there was reasonable doubt as to whether the permanently connected safety-related loads would remain operable during a worst case, non-accident degraded voltage condition for the duration of the time delay chosen.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, Attachment 04, and Table 4a for the Mitigating Systems Cornerstone. The inspectors conservatively assumed a loss of system safety function and answered "Yes" to question number 2 in Column 2. With the assistance of SRAs, the inspectors performed a Phase 2 evaluation of the SDP using "Table 3.2, SDP Worksheet for Byron Station, Units 1 and 2 – Transients with Loss of PCS (TPCS)" and determined the finding was of very low safety significance (Green).

The inspectors identified a cross-cutting aspect associated with this finding in the area of human performance, decision making because the licensee did not use conservative assumptions in choosing the worst case degraded voltage condition in their February 2010, analysis (H.1(b)). Specifically, in their February 2010 analysis, the licensee chose 75 percent of nominal voltage as their lower limit of degraded voltage based on a not formally approved manual action as opposed to the worst possible degraded voltage of approximately 66 percent of nominal (first level undervoltage setpoint). Also, although the inspectors questioned the validity of 75 percent of nominal voltage for their degraded voltage limit during the 2009 CDBI and documented in the CDBI inspection report, the licensee failed to verify and validate this assumption.

Enforcement: 10 CFR 50, Appendix B, Criterion III, "Design Control" requires, in part, that design control measures provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of suitable testing program.

Contrary to the above, as of May 25, 2010, the licensee's design control measures failed to verify the adequacy of the degraded voltage relay setpoint and time delay design. Specifically, the licensee failed to analyze that, the permanently connected safety-related loads would have adequate voltage to continue to run without sustaining damage during a worst case, non-accident degraded voltage condition. Because this violation was of very low safety-significance and because the issue was entered into the licensee's CAP as IR 1071667, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000454/2010003-05; 05000455/2010003-05; Failure to Appropriately Analyze the Degraded Voltage Timer Settings).

Based on the above discussion, Unresolved Item (URI) 05000454/2009007-04; 05000455/2009007-04, Insufficient Design Bases for Second-Level (Degraded) Voltage Timer Settings, is considered closed.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- Unit 1 Train B DG Monthly Surveillance;
- Unit 2 Train A DG Monthly Surveillance;
- B2R15 Pre-Outage Trevi-Testing of 2MS014C;
- Unit 2 Train A DG Sequencer Test 8.1.11-1;
- Unit 2 Train A DG Load Rejection Test 8.1.9-1;
- Unit 2 Reactor Coolant System (RCS) Leak Detection; and
- Unit 2 Train A Residual Heat Removal Pump Comprehensive IST for 2RH01PA.

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;

- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted five routine surveillance testing samples, one in-service testing sample, and one reactor coolant system leak detection inspection sample(s), as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Evaluation Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee simulator practice on June 8, 2010, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the control room (simulator) and technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

This inspection constitutes a partial sample as defined in IP 71124.01-5.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed all licensee performance indicators (PIs) for the Occupational Exposure Cornerstone for follow-up. The inspectors reviewed the results of radiation protection program audits (e.g., licensee's quality assurance audits or other independent audits). The inspectors reviewed any reports of operational occurrences related to occupational radiation safety since the last inspection. The inspectors reviewed the results of the audit and operational report reviews to gain insights into overall licensee performance.

b. Findings

No findings of significance were identified.

.2 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors evaluated if there have been changes to plant operations since the last inspection that may result in a significant new radiological hazard for onsite workers or members of the public. The inspectors assessed whether the licensee assessed the potential impact of these changes and has implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed the last two radiological surveys from several selected plant areas. The inspectors determined whether the thoroughness and frequency of the surveys was appropriate for the given radiological hazard.

The inspectors conducted walk-downs of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements to verify conditions.

The inspectors selected the following radiologically risk-significant work activities that involved exposure to radiation.

- SG Activities, Platform Work, Manway and Diaphram, ET, and all Tube Repairs;
- Outage Scaffolds Work;
- Reactor Head Dissemble and Reassembly – All activities; and
- Shielding Activities.

For these work activities, the inspectors assessed whether the pre-work surveys performed were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the radiological survey program to determine if hazards were properly identified, including the following:

- identification of hot particles;
- the presence of alpha emitters;
- the potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials (this evaluation

may include licensee planned entry into non-routinely entered areas subject to previous contamination from failed fuel);

- the hazards associated with work activities that could suddenly and severely increase radiological conditions; and
- severe radiation field dose gradients that can result in non-uniform exposures of the body.

The inspectors observed work in potential airborne areas and evaluated whether the air samples were representative of the breathing air zone. The inspectors evaluated whether continuous air monitors were located in areas with low background to minimize false alarms and were representative of actual work areas. The inspectors assessed whether the licensee had a program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

b. Findings

No findings of significance were identified.

.3 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors selected three to five containers holding nonexempt licensed radioactive materials that may cause unplanned or inadvertent exposure of workers, and assessed whether the containers were labeled and controlled in accordance with 10 CFR 20.1904, "Labeling Containers," or met the requirements of 10 CFR 20.1905(g).

The inspectors reviewed the following radiation work permits (RWPs) used to access high radiation areas (HRAs) and evaluated the specified work control instructions or control barriers.

- RWP 10010584; Shielding Activities; Reactor Head Shielding, Steam Generator Packages, Reactor Coolant Pumps Shadow Shield, and CRDM LHRA Vestibule Shielding;
- RWP 10010563; Reactor Head Disassembly and Reassembly Work Activities; Removed and Replaced CRDM and Related Cables, Removal and Installation;
- RWP 10010582; Install and Remove Outage Scaffolds for All Tasks; and
- RWP 10010592 – 10010596; Steam Generators Eddy Current Testing and All Tube Repairs; Equipment Staging Including Decon Tent Activities; Platform Tear Down and Decon Activities, Manway – Diaphragm Removal and Re-Installation.

For these RWPs, the inspectors assessed whether allowable stay times or permissible dose (including from the intake of radioactive material) for radiologically significant work under each RWP were clearly identified. The inspectors evaluated whether electronic dosimeter (ED) alarm set-points were in conformance with survey indications and plant policy.

The inspectors reviewed selected occurrences where a worker's ED noticeably malfunctioned or alarmed. The inspectors evaluated whether workers responded

appropriately to the off-normal condition. The inspectors assessed whether the issue was included in the CAP and dose evaluations were conducted as appropriate.

For those work activities selected in 2OS1.3.a, the inspectors assessed whether the licensee had established a means to inform workers of charges that could significantly impact their occupational dose.

b. Findings

No findings of significance were identified.

.4 Contaminations and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitors potentially contaminated material leaving the radiological control areas and inspected the methods used for control, survey, and release from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use and evaluated whether the work was performed in accordance with plant procedures. The inspectors also reviewed whether the procedures were sufficient to control the spread of contamination and prevent unintended release of radioactive materials from the site. The inspectors assessed whether the radiation monitoring instrumentation had appropriate sensitivity for the type(s) of radiation present.

The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicates the presence of licensed radioactive material.

The inspector reviewed the licensee's procedures and records in order to assess that radiation protection detection instrumentation usage was based on appropriate counting parameters (i.e., counting times and background radiation levels). In addition, the inspector assessed whether Byron Station established a de facto "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator levels or locating the instrument in a high-radiation background area.

b. Findings

No findings of significance were identified.

.5 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels) during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, RWPs, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage (including audio and visual surveillance

for remote job coverage), and contamination controls. The inspectors evaluated the licensee's use of EDs in high noise areas as HRA monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee was properly employed an NRC-approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high-radiation work areas with significant dose rate gradients.

The inspectors reviewed the following RWPs for work within airborne radioactivity areas with the potential for individual worker internal exposures.

- RWP 10010563; Reactor Head Disassembly and Reassembly Work Activities; Removed and Replaced CRDM and Related Cables, Removal and Installation;
- RWP 10010582; Install and Remove Outage Scaffolds for All Tasks; and
- RWP 10010592 – 10010596; Steam Generators Eddy Current Testing and All Tube Repairs; Equipment Staging Including Decon Tent Activities; Platform Tear Down and Decon Activities, Manway – Diaphragm Removal and Re-Installation.

For these RWPs, the inspectors evaluated airborne radioactive controls and monitoring, including potentials for significant airborne levels (e.g., grinding, grit blasting, cutting, system breaches, entry into tanks, cubicles, and reactor cavities). The inspectors assessed barrier (e.g., tent or glove box) integrity and temporary high-efficiency particulate air (HEPA) ventilation system operation for selected airborne radioactive material areas

The inspectors inspected the posting and physical controls for selected HRAs and very high radiation areas (VHRAs), to verify conformance with the Occupational PI.

b. Findings

No findings of significance were identified

.6 Risk-Significant High Radiation Area and Very High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors discussed with the Radiation Protection Manager (RPM) the controls and procedures for high-risk HRAs and VHRAs. The inspectors assessed whether any changes to licensee procedures substantially reduce the effectiveness and level of worker protection.

The inspectors reviewed special areas that have the potential to become VHRAs during certain plant operations (e.g., pressurized-water reactor PWR thimble withdrawal into the reactor cavity sump). The inspectors discussed these areas with first-line health physics (HP) supervisors (or equivalent positions having backshift HP oversight authority) to assess whether the communication beforehand with the HP group would allow for corresponding timely actions to properly post, control, and monitor the radiation hazards

including re-access authorization. The inspectors evaluated licensee controls for VHRAs, and areas with the potential to become a VHRA, and assessed whether an individual was able to gain unauthorized access to the VHRA.

b. Findings

No findings of significance were identified.

.7 Radiation Worker Performance (02.07)

a. Inspection Scope

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

The inspectors reviewed a maximum of 10 radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed with the RPM any problems with the corrective actions planned or taken.

b. Findings

No findings of significance were identified.

.8 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors observed the performance of radiation protection technicians with respect to all radiation protection work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace and the RWP controls/limits and whether their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed a maximum of 10 radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

b. Findings

No findings of significance were identified.

.9 Problem Identification and Resolution (02.09)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring and exposure control were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring and exposure controls. The inspectors assessed the licensee's process for applying operating experience to their plant.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Transients per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients per 7000 Critical Hours PI for Unit 1 and Unit 2 for the period from the third quarter 2009 through the first quarter 2010. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports and NRC Integrated Inspection Reports for the period of July 1, 2009, through March 31, 2010, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned transients per 7000 critical hours sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

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

a. Inspection Scope

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

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

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the

results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6 month period of December 1, 2009, through May 31, 2010, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings of significance were identified.

.4 Selected Issue Follow-Up Inspection: Charcoal Filter Test Failures

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting the failure of charcoal filter samples associated with the fuel handling building and auxiliary building ventilation systems, IR 1013278 and IR 1051767 respectively. The purpose of the charcoal filters is to reduce (capture) airborne radioactive material post accident. The licensee performed an Apparent Cause Evaluation that identified the issues apparent cause as an age management issue. The corrective actions proposed in the report are to reassess the testing frequency and replacement criteria associated with the charcoal filters.

The inspectors reviewed the licensee's corrective actions for the issues identified to verify whether: (1) the problems were accurately identified; (2) the causes were adequately ascertained; (3) extent of condition and generic implications were appropriately addressed; (4) previous occurrences were considered; and (5) corrective actions proposed/implemented were appropriately focused to address the problems and were commensurate with the safety significance of the issues. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 Failure to Report an Automatic RPS and AF Actuation While Shut down Per 10 CFR 50.72

Introduction: A Severity Level IV, NCV of 10 CFR 50.72(b)(3)(iv)(A), was identified by the inspectors for the licensee's failure to recognize that the valid Unit 2 automatic RPS and AF actuation while shut down was a reportable condition. Consequently, the licensee failed to make an 8-hour report as required by 10 CFR 50.72.

Description: On April 19, 2010, Byron Unit 2 was in a planned refueling outage and the unit entered Mode 4 at 3:08 a.m. At the time of the event, all the control rods had been inserted into the core and the two auxiliary feedwater pumps were secured. Shutdown cooling was handled by the residual heat removal system.

As part of a planned maintenance during the refueling outage, the licensee conducted feedwater isolation testing which would isolate feedwater to the SGs. During performance of the test, SG levels decreased and inadvertently were allowed to reach the Lo-Lo level setpoint on the 2D SG. This generated a reactor trip and AF system start signals at 5:03 a.m. However, all control rods were already fully inserted and both AF pumps were secured prior to the feedwater isolation testing. The SG blowdown was automatically isolated to preserve SG inventory. Level in the SG was promptly restored above the Lo-Lo level setpoint. Therefore, there was no adverse impact to the shutdown unit as a result of the transient.

This condition was not recognized by the licensee as a reportable event pursuant to both 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) until questioned by the inspectors. The licensee initially screened this event as not reportable because both RPS and AF were not in their modes of applicability per their TS. Therefore, the two systems did not have a safety function at that mode. The actuation signals were invalid because they were not initiated to perform safety functions of the systems. The licensee agreed that the Lo-Lo SG level was not a planned activity. The inspectors questioned the licensee's logic as the actuation was valid since it was in response to an actual plant conditions and was not a pre-planned activity. Based upon further review, the licensee determined the condition was reportable and reported the event pursuant to 10 CFR 50.72(b)(3)(iv)(A) at 2:17 p.m. on April 22, 2010. An LER No. 05000455/2010-001, Revision 0, was submitted pursuant to 10 CFR 50.73(a)(2)(iv)(A) on June 18, 2010. This LER will be reviewed in a subsequent inspection report.

Analysis: The licensee's failure to recognize that the Unit 2 automatic RPS and AF actuation on April 19, 2010, met the requirements for an 8 hour report pursuant to 10 CFR 50.72, was a performance deficiency. This issue was considered as traditional enforcement because it had the potential for impacting the NRC's ability to perform its regulatory function. The issue was more than minor because it is similar to a Severity Level IV example provided in Supplement I of the Enforcement Policy. The finding was of very low safety significance because there was no adverse impact to Unit 2. The cause of this finding was directly related to the cross-cutting area of Problem Identification and Resolution (P.1(c)) because the licensee did not adequately evaluate and properly classifying reportable conditions adverse to quality.

Enforcement: 10 CFR 50.72 requires that the licensee make a report for any valid actuation of the systems described therein within eight hours of the occurrence of the event. Contrary to the above, on April 19, 2010, the licensee failed to recognize that the aforementioned event met the reporting requirements of 10 CFR 50.72(b)(3)(iv)(A) and did not report the event until April 22, 2010. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as IR 1060177, this issue is being treated as a Severity Level IV NCV in accordance with Section IV.A.3 of the NRC Enforcement Policy.
(NCV 05000455/2010003-06, Failure to Report an Automatic RPS and Auxiliary Feedwater Actuation While Shut Down)

.2 (Closed) Licensee Event Report 05000454/2009-001-00 and Revision 01: Drain Procedure for ECCS Suction Line Creates an Unanalyzed Condition Due to Inadequate Configuration Requirements

This LER reported a licensee identified condition in which Byron Station has periodically operated in an unanalyzed condition during which the containment sump recirculation valve was energized concurrent with auxiliary building vent and drain valves in the sump suction line being open. Following a postulated LOCA, the containment sump recirculation valve would automatically open. Coupled with the open valves in the auxiliary building, this would result in a containment bypass event as the contaminated sump water flowed into the auxiliary building.

Description: On October 27, 2009, the licensee was performing a pre-planned evolution designed to reduce the dose in selected Residual Heat Removal (RHR) piping. The Unit 1 Train B RHR pump was removed from service and the pump suction was intentionally drained. As no work was being performed on the containment sump recirculation valve (1SI8811B), the power was not removed from valve 1SI8811B. This left the valve in a condition where it could open automatically.

If a large break LOCA had occurred while valve 1SI8811B had power available then some amount of containment sump water would have flowed into the auxiliary building when the valve auto-opened as a part of the swapover to cold leg recirculation. This unintended flow path would have bypassed containment and could have resulted in auxiliary building flooding, increased offsite dose, and a partial loss of inventory for the Emergency Core Cooling System (ECCS).

During the placement of the clearance order to open one drain and two vent valves as part of the draining evolution two non-licensed equipment operators questioned shift management regarding the adequacy of the clearance order. After the operators' questions had been resolved, a reactor operator questioned whether the evolution might represent an unanalyzed condition. Shift management subsequently determined that the evolution was acceptable but an IR was written documenting the question. Further review by other members of the licensee staff during the corrective action process determined that in fact, this was an unanalyzed condition. By the time the determination was completed, the work evolution was completed and the RHR piping had been refilled.

Analysis: The inspectors determined that the failure to have adequate procedures to ensure a flow path from containment into the auxiliary building did not exist if a recirculation sump valve automatically opened was a performance deficiency. This condition made the plant vulnerable to a containment bypass event. This finding is more

than minor because the 1SI8811B valve being left in a closed but energized state was associated with the configuration control attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective to protect the public from radioactive releases caused by accidents or events.

Region III SRAs evaluated the risk significance of this issue, including impact to the Mitigating System Cornerstone. The SRAs determined that the Mitigating System Cornerstone was not impacted since there was no net change in core damage frequency risk. The open paths outside containment were from three 0.75-inch valves which calculation showed did not result in sufficient loss of inventory to cause a loss of the recirculation function. Further, the maintenance configuration for the system drains the suction of the associated RH train rendering it unavailable. This unavailability of the RH train is already captured as part of the average test and maintenance configuration incorporated into the base risk model. Lastly, dose considerations were evaluated and there were no adverse impacts to operators or plant equipment.

The SRAs evaluated risk impact to the containment barrier. Using IMC 0609, "Significance Determination Process," Attachment .04, "Initial Screening and Characterization of Findings," the inspectors determined that the finding represented an actual open pathway in the physical integrity of reactor containment. The SRA continued the risk evaluation using IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." The SRAs determined this finding to be a Type B finding, which is a finding related to a degraded condition that has potentially important implications for containment without affecting the likelihood of core damage.

Appendix H Table 4.1, "Containment-Related SSCs Considered for LERF Implications," was used to conduct an initial screening of the finding. The table includes containment isolation valves in lines "connecting RCS to environment or open systems outside containment." The LERF significance states "Small lines (<1-2 inch dia) and lines connecting to closed systems would not generally contribute to LERF." The SRAs calculated the equivalent diameter of the three 0.75-inch valves and determined that it was less than 2 inches. In addition, Table 6.2 addresses findings involving leakage rates (e.g., containment leakage). The table shows that leakage from containment to the environment that is greater than 100 percent containment volume/day is risk significant. The SRAs calculated the leakage to be less than 100 percent containment volume/day. Therefore, the SRAs concluded that the risk of this finding was very low (Green).

Enforcement: The enforcement aspects of this finding are discussed in Section 4OA7 of this report. Licensee Event Reports 05000454/2009-001-00 and Revision 01: Drain Procedure for ECCS Suction Line Creates an Unanalyzed Condition Due to Inadequate Configuration Requirements are closed.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000454/2009007-04; 05000455/2009007-04: Insufficient Design Bases for Second-Level (Degraded) Voltage Timer Settings that could affect the operability of permanently connected safety-related loads during a worst case, non-accident degraded voltage condition.

This issue is described in Section 1R21 above and is resolved to an NCV of 10 CFR Part 50, Appendix B, Criterion III, Design Control.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 8, 2010, the inspectors presented the inspection results to Mr. B. Adams and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspectors presented the results of the inspection and review of licensee corrective actions pertaining to URI 05000454/2009007-04; 05000455/2009007-04 to Site Work Management Director, Mr. B. Youman, and other members of the licensee's staff via telephone on May 25, 2010. Licensee personnel acknowledged the inspection results presented.

- The results of the inservice inspection were presented to Mr. D. Enright, Site Vice President on May 6, 2010.

- The results of Radiological Hazard Assessment and Exposure Controls inspection were presented to the Site Vice President, Mr. D. Enright, on April 30, 2010.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI.A.1 of the NRC Enforcement Policy for being dispositioned as an NCV.

Cornerstone: Barrier Integrity

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality be accomplished in accordance with prescribed

instructions, procedures, or drawings. Contrary to the above, Byron Operating Procedure (BOP) RH-4, “Draining the RH System,” Revision 15, did not adequately control vent and drain valves during the online draining of the RH system resulted in an unanalyzed condition for the unit. The finding is of very low safety significance as document in Section 4OA3 of this report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

B. Adams, Plant Manager
B. Youman, Work Management Director
S. Greenlee, Engineering Director
D. Gudger, Regulatory Assurance Manager
D. Thompson, Radiation Protection Manager
E. Bogue, Training Manager
B. Askren, Security Director
C. Gayheart, Operations Director
S. Kerr, Chemistry Manager

Nuclear Regulatory Commission

R. Skokowski, Chief, Division of Reactor Projects, Branch 3

Illinois Emergency Management Agency
R. Zuffa, Section Chief

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000454/2010003-01; 05000455/2010003-01	NCV	0B Fire Pump Discharge Valve Discovered Closed (Section 1R12)
05000455/2010003-02	NCV	Inadequate Evaluation of Shim Pack for the Upper Steam Generator Lateral Supports (Section 1R15)
05000454/2010003-03; 05000455/2010003-03	NCV	Water Intrusion Leads to Loss of Annunciators (Section 1R15)
05000455/2010003-04	NCV	Loose Debris Inside of Unit 2 Containment at the Start of the Refueling Outage (Section 1R20)
05000454/2010003-05; 05000455/2010003-05	NCV	Failure to Appropriately Analyze the Degraded Voltage Timer Settings (Section 1R21)
05000455/2010003-06	NCV	Failure to Report an Automatic RPS and Auxiliary Feedwater Actuation While Shut Down (Section 4OA3)
05000454/2009-001-01	LER	Drain Procedure for ECCS Suction Line Creates an Unanalyzed Condition Due to Inadequate Configuration Requirements (Section 4OA3)
05000455/2010-001-00	LER	Automatic RPS and Auxiliary Feedwater Actuation While Shut Down (Section 4OA3)

Closed

05000454/2010003-01; 05000455/2010003-01	NCV	0B Fire Pump Discharge Valve Discovered Closed (Section 1R12)
05000455/2010003-02	NCV	Inadequate Evaluation of Shim Pack for the Upper Steam Generator Lateral Supports (Section 1R15)
05000454/2010003-03; 05000455/2010003-03	NCV	Water Intrusion Leads to Loss of Annunciators (Section 1R15)
05000455/2010003-04	NCV	Loose Debris Inside of Unit 2 Containment at the Start of the Refueling Outage (Section 1R20)
05000454/2010003-05; 05000455/2010003-05	NCV	Failure to Appropriately Analyze the Degraded Voltage Timer Settings (Section 1R21)
05000455/2010003-06	NCV	Failure to Report an Automatic RPS and Auxiliary Feedwater Actuation While Shut Down (Section 4OA3)
05000454/2009-001-01	LER	Drain Procedure for ECCS Suction Line Creates an Unanalyzed Condition Due to Inadequate Configuration Requirements (Section 4OA3)
05000454/2009007-04; 05000455/2009007-04	URI	Insufficient Design Bases for Second-Level (Degraded) Voltage Timer Settings (Section 1R21)

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.

Section 1R01: Adverse Weather Protection (Quarterly)

- List of Issues Identified in Plant IQ as pertaining to Summer Readiness, June 2010
- WC-AA-107; Seasonal Readiness, Revision 7
- Workdown Plan for 2010 Summer Readiness, June 15, 2010
- System Health Reports for Auxiliary Building HVAC, Second Quarter 2010
- System Health Reports for Main Power, Second Quarter 2010
- IR 1077530; 2010 LTAM Strategy for Transformers, June 6, 2010
- IR 1085276; Preliminary UAT/SAT ABB Transformer Assessment Recommendation, June 28, 2010

Section 1R04: Equipment Alignment (Quarterly)

- BOP DG-E2; Unit 2 Diesel Generator Electrical Lineup, Revision 4
- BOP DG-E2A; Unit 2 Diesel Generator Train “A” Electrical Lineup, Revision 2
- BOP DG-M2A; Train “A” DG System Valve Lineup, Revision 7
- BOP DG-1; DG Alignment to Standby Condition, Revision 13
- BOP RH-13; RH System SI Check Valve Flush, Revision 1

Section 1R05: Fire Protection (Quarterly)

- Byron Station Pre-Fire Plans, Zone 10.1-2; Auxiliary Building – 383’ Elevation – 2B Diesel Fuel Oil Storage Tank Room, Revision 5
- Byron Station Pre-Fire Plans Zone, 11.1A-0 and 11.1B-0; Auxiliary Building – 330’ Elevation – Essential Service Water Pump Room, Revision 4
- Byron Station Pre-Fire Plans, Zone 9.2-2; Auxiliary Building – 401’ Elevation – 2A DG and Day Tank Room. Revision 5
- Byron Station Pre-Fire Plans, Zone 9.1-2; Auxiliary Building – 401’ Elevation – 2B Diesel Generator and Day Tank Room, Revision 5
- EC-EVAL 339805; Fire Door Acceptance Criteria
- 0BOL 10.f; LCOAR Fire Hose Stations TRM LCO #3.10.f, Revision 6
- 0BOL 10.c; LCOAR Water Systems TRM LCO #3.10c, Revision 5
- Drawing M-96 Sheet 1; Diagram of Control Room HVAC System, Revision AC
- Drawing M-96 Sheet 3; Diagram of Control Room HVAC System, Revision U

Corrective Action Documents As a Result of NRC Inspection

- IR 1060757; NRC Identified Issues with Transient Combustible, April 23, 2010
- IR 1077596; NRC Questions Regarding Potential Halon/CO_2 Migration into Main Control Room

Section 1R06: Flood Protection Measures

- IR 1077327; Non-Safety-Related Manhole 2ME(2E) Inspection, May 19, 2010
- IR 1077328; Manhole 1MN(1N) Inspection, May 26, 2010
- IR 1077329; Manhole 1ML(1L) Inspection, May 24, 2010
- IR 1077331; Manhole 2M2J(2J2) Inspection, May 19, 2010
- IR 1077332; Manhole 1M1J(1J2) Inspection, May 19, 2010
- IR 1073696; As Found Conditions of Manhole 1MM, May 27, 2010
- IR 0920054; Auxiliary Building Leak Detection Sump Not Alarming, May 15, 2010
- IR 0924378; Auxiliary Building Floor Drain Plugged – House Keeping Concern, May 27, 2010
- IR 0947678; Resource Issues for WF A(1) Action Plan, July 30, 2009
- IR 0960677; Multiple Floor Drains Backed Up, September 2, 2009
- IR 1013449; Auxiliary Building Floor Drain Plugged, January 7, 2010
- IR 1064229; 1WF06PA 1A SX Floor Drain Sump Failed PMT, May 1, 2010

Section 1R08: Inservice Inspection Activities (71111.08P)

- EXE-PDI-UT-1; Ultrasonic Examination of Ferritic Pipe Welds, Revision 5
- EXE-ISI-210; Manual Ultrasonic Examination of Vessel Welds Greater than 2", Revision 3
- EXE-UT-350; Procedure for Acquiring Material Thickness and Weld Contours, Revision 2
- ER-AP-331; Boric Acid Corrosion Control (BACC) Program; Revision 5
- ER-AP-331-1002; Boric Acid Corrosion Control Program Identification; Screening, and Evaluation, Revision 5
- ER-AP-335-001; Bare Metal Visual Examination for Alloy 600/82/182 Materials, Revision 1
- ER-AP-420-002; Byron/Braidwood Unit 2: Steam Generator Eddy Current Activities, Revision 9
- ER-AP-420; Steam Generator Management Program Activities, Revision 9
- ER-AP-420-007; Byron/Braidwood Unit 2: Steam Generator Secondary Side Visual Surveillance Activities, Revision 6
- ER-MW-335-1003; Steam Generator Eddy Current Data Analysis Guidelines for Braidwood and Byron Stations Unit 2, Revision 5
- ER-MW-335-1009; Site Specific Performance Demonstration Program, Revision 5
- ER-AP-335-039; Multifrequency Eddy Current Data Acquisition of Steam Generator Tubing, Revision 7
- ER-AP-335-040; Evaluation of Eddy Current Data for Steam Generator Tubing, Revision 5
- EXE-ISI-11; Liquid Penetrant Examination, Revision 2
- EXE-ISI-8; Visual VT-1 and VT-3 Examination at Exelon, Revision 1
- WDI-STD-1040; Procedure for Ultrasonic Examination of Reactor Vessel Head Penetrations, Revision 5
- WDI-STD-1041; Reactor Vessel Head Penetration Ultrasonic Examination Analysis, Revision 3
- Letter, TAC Nos. MD3855 and MD3856; Byron Station, Unit Nos. 1 and 2 – Evaluation of Proposed Risk-Informed Request for an Inservice Inspection Program for the
- Third 10-Year Inservice Inspection Interval, September 25, 2007
- N-566-2; Corrective Action for Leakage Identified at Bolted Connections Section XI, Division 1, March 28, 2001
- Code Interpretation V-04-04; Section V, Article 6, Para. T-676.3 (2001 Edition, 2003 Addenda), December 17, 2003
- IR 1134482; 1RY024 (Boric Acid Leakage at Bolted Connection), September 18, 2009
- IR 1060265; NRC Identified Inconsistency in Two BACC Evaluations, April 22, 2010

- IR 1060446; NRC Questioned NDE Illumination Verification for NDE, April 23, 2010
- IR 1060421; the NRC Questioned Maximum Temperature Limits, April 23, 2010
- IR 1051175; 2FIS-RC0438A, 5 Way Equalization Valve B/B is Leaking, April 1, 2010
- IR 1057786; Recordable Indications Discovered During ISI Examination, April 16, 2010
- IR 0964040; Additional Dose Needed to Complete ISI Examination, September 11, 2009
- IR 0964961; Unable to Perform ISI Inspections as Scheduled, September 15, 2009
- IR 0971753; B1R16 LL Porosity on the Inner Ring Seating Area of RX Head, September 28, 2009
- IR 0978175; Third Quarter 2009 ISI Program Equipment Cornerstone Red, October 12, 2009
- IR 0993228; Need Limited Liner Plate Inspection behind U2 Containment MB, November 13, 2009
- IR 1001318; Late RRR Paperwork Submittal, December 4, 2009
- IR 1043999; NOS ID Self-Assessment for NRC Readiness not Complete, March 17, 2010

Section 1R12: Maintenance Effectiveness (Quarterly)

- IR 0717641; CV Pump Shaft Performance Monitoring Revisited, January 3, 2008
- IN 94-76; Recent Failures of Charging / Safety Injection Pump Shafts, October 26, 1994
- IR 1001318; Late RRR Paperwork Submittal, December 4, 2009
- IR 1056779; Valve Stem Spins Freely when Valve Full Open, April 14, 2010
- IR 1061778; Possible Pressure Sensing Line Plugged, April 26, 2010
- IR 1063395; Unplanned LCOAR Entry – 0FP03PB, April 29, 2010
- IR 1063780; 0B Fire Pump Available During SX AOT?, April 15, 2010
- IR 1066333; Lack of Rigor in SX AOT Fire Protection Commitments, May 6, 2010

IR Written As a Result of NRC Inspection

- IR 1063268; Inadequate Closure of Assignment 717641-02 and -03, April 29, 2010

Section 1R13: Maintenance Risk Assessments and Emergent Work Control (Quarterly)

- EC #0376956; Install Temporary Plug Upstream of SX138A to Support the Drain of the SX Pump Suction for 1/2SX001A Valve Replacement, March 05, 2010
- BY-CRM-013; Configuration Risk Management Assessment – 1SX010 Unable to Close, Revision 1
- IR 941613; Issue Resolution Documentation Form; 1SX001A Binds in the Closed Direction, July 21, 2009
- Unit ½ Standing Order; Configuration Risk Management Assessment; ½ SX001A/B Unable to Close, Log Number 09-056
- BY-LIFT-006; Risk Assessment – Heavy Load Lifts – 2A SX Pump and Motor Replacement, Revision 0
- Affected Focus Area Components; Drawing A-219; Auxiliary Building Upper Basement Floor Plan 364' Area 2
- Affected Focus Area Components; Drawing A-222; Auxiliary Building Upper Basement Floor Plan 364' Area 5
- Affected Focus Area Components; Drawing A-229; Auxiliary Building Upper Basement Floor Plan 383' Area 2
- Affected Focus Area Components; Drawing A-230; Auxiliary Building Upper Basement Floor Plan 383' Area 3

- Affected Focus Area Components; Drawing A-253; Auxiliary Building Mezzanine Floor Plan 426; Area 2
- Unit 0/1/2 Standing Order 10-017; SX AOT Dedicated Operator Information, April 19, 2010
- Adverse Condition Monitoring and Contingency Plan; SX and CV Monitoring During 1/2SX001A AOT, April 21, 2010
- Byron Transient Combustible and Hot Work Control During SX Outage

IR Written As a Result of NRC Inspection

- IR 1060757; NRC Identified Issues with Transient Combustible, April 23, 2010

Section 1R15: Operability Evaluations (Quarterly)

- EC 379850; Operation of Reactor Vessel with One Out-Of-Service Closure Stud, April 30, 2010
- 2RPV-1-IS, Inspection Identification Drawing for Inservice Inspection for Reactor Pressure Vessel No. 2RC01R, Sheet # 3
- 113E977; 4 Loop 173.000 I.D Reactor Vessel, Sheet #1 and 2
- CC-AA-102; Design Attribute Review, EC #379850
- IR 1074711; NER NC-10-027 Results Somewhat Inconclusive, May 28, 2010
- Trend Data for Process Radiation Monitoring Instruments 1PR30J, 2PR30J, 1PR28J, and 2PR28J, August 1998 to May 2010
- MA-BY-EM-1-FP002-001; Fire Protection Zones 3.2A-1, 1Z1 Suppression Zones 1S43 Detection Zones 1D49 (Zone 3.2-1), 50, Revision 0
- Evaluation 013095; Procurement and Commercial Grade Dedication Requirements for Electro-Thermo Links, January 22, 2002
- IR 1084641; Evaluation of Lube Oil Dilution Rate for the 1B AFW pump
- Adverse Condition Monitoring and Contingency Plan (ACMP), Pressurizer Safety Valve 2RY8010A Leakage, June 17, 2010, Revision 0
- ACMP, Pressurizer Safety Valve 2RY8010A Leakage, June 17, 2010, Revision 1
- Quick Human Performance Investigation Report 2A DG Jacket Water Heater Over Temperature
- IR 1087155; Changes for All of the VA Main Supply and Exhaust Fans
- Letter To: M.J. Wallace, From: D.L. Samblin; Regarding Water Leaking into Braidwood Control Room From Upper Cable Spreading Room, June 26, 1987
- OP-AA-102-104; Upper Cable Spreading Room Fire Seal Compensatory Measures, Log 10-011
- OP-AA-102-104; Upper Cable Spreading Room Fire Seal Compensatory Measures, Log 10-012
- Drawing Number 12; Penetration Seal and Fire Protective System, Rev. 0
- IR 0933005; Water Dripping from MCR Ceiling, June 18, 2009
- IR 0934429; Following Leak-By of 0FP472, June 23, 2009
- IR 0934040; Water In Panel 0PM02J, June 23, 2009
- IR 1046792; Received Unexpected Alarm (1-4-7D) AN SYS Ground, March 24, 2010
- IR 1046794; 1BOA ELEC-7 Entry due to Water Intrusion in AEER, March 24, 2010
- IR 1053626; Erroneous Closure of Surveillance, April 07, 2010
- IR 1047146; Generate Work Order to Apply Sealant in UCSR Fire Zone 3.3A-1, March 24, 2010
- IR 1047370; Potential Flooding Effects on Protection and Control Cabinet
- IR 1047984; Potential Enhancements to UCSR Floor Fire Seals – Byron EOC, March 25, 2010

- IR 1050740; UCSR Fire Barrier to AEER NRC Feedback, March 31, 2010
- IR 1050754; Functionality Evaluation Needed for Fire Seals, March 31, 2010
- IR 1050961; Fire Seals Lessons Learned, March 31, 2010
- Drawing 20E-0-3600A; Instructions for Use of Electrical Floor and Wall Seal Tabulation, Revision G
- Drawing 6E-0-3600A; Electrical Floor and Wall Seal Tabulation Notes, Revision B
- 0BOSR Z.7.A.2-1; Unit Common Deepwell Pump Operability Monthly Surveillance, Revision 8
- 0A Deepwell Pump Flow Trend Data 1999 through 2010
- 0B Deepwell Pump Flow Trend Data 1999 through 2010
- Report GD-8; Design, Construction, and Testing of Byron Station Deep Well, November 24, 1980
- 2BOA ELEC-4; Loss of Off-Site Power, Unit 2, Revision 108

Corrective Action Documents As a Result of NRC Inspection

- IR 1091115; NRC Identified Discrepancy in Fire Protection Report

Section 1R18; Plant Modifications

- WO 880843; 0SX147 – Rebuild SMB-00/H3BC Gear Drive and Replace Valve
- WO 880843-32; OPS PMT 0SX007, April 07, 2010
- WO 880843-35; OPS PMT 0SX146, April 17, 2010
- EC 356163; Butterfly Valve 0SX147 Replacement and Vent Valve Installation, Revision 1

Section 1R19: Post Maintenance Testing (Quarterly)

- WO 1179087 01; 2BOSR 8.1.9-2, 2B DG Safe S/D Sequence and Single Load Reject, April 26, 2010
- WO 1179088 01; 2BOSR 8.1.11-2, 2B DG Sequence Test, April 26, 2010
- WO 1178175-01; Perform MOV Operator Inspection 2AF017B, April 22, 2010
- WO 1178175-02; Perform MOV Diagnostic Testing 2AF017B, April 23, 2010
- WO 1178175-03; 2AF017B STT, April 24, 2010
- WO 1178175-06; Reinstall Pipe Support, April 23, 2010
- WO 1191465-01; Revise Control Logic of 2AF017B, April 22, 2010
- WO 1191465-05; Operability Testing for 2AF017B, April 24, 2010
- WO 1191465-06' Perform Wiring Verification of 2AF017B, April 23, 2010
- EC 364837; Modify the MOV Closure Control Scheme of 2AF006A, 2AF017A and 2AF017B, Revision 1
- BOP SX-1; ½ Essential Service Water Pump Startup, Revision 19
- BOP SX-19; Installation of Jumpers for Bypassing the Interlocks of the SX016 and SX027 Valves with the SX Pumps, Revision 3
- Schematic Diagram Essential Service Water Pump 2B 2SX01PB,
- Sheet Number 6E-2-4030SX02, January 15, 2009
- IR 1064579; B2R15 LL Critical Path Delay for DG Testing, May 03, 2010
- IR 1064675; 2B SX Pump Failed to Start, May 03, 2010
- IR 1064923; 2B DG Trip During Cooldown Cycle, May 03, 2010
- EC 0380310; Evaluation of Common Mode Failure for C-Phase PT Primary Fuse Failure on 2B Emergency Diesel Generator, Rev. 1
- CC-AA-206; Fuse Control, Rev. 6
- 2BOSR 8.1.2-2; Unit Two 2B Diesel Generator Operability Surveillance, June 3, 2010

- WO 1264027; Perform Diagnostic Testing of 1SX001A, May 4, 2010
- WO 1323158; 2B Auxiliary Feedwater Pump Surveillance, May 5, 2010
- IR 1065019; B2R15 LL – Late Start 2B Auxiliary Feedwater Pump due to Low Oil Levels, May 3, 2010
- IR 1065038; Significant Lube Oil Leak during Post Maintenance Testing of 2B Auxiliary Feedwater Pump, May 4, 2010
- IR 1065043; Failed Post Maintenance Test of 2B Auxiliary Feedwater Pump Jacket Water Solenoid, May 4, 2010
- IR 1064998; Jacket Water Leaking 1 Drop every 3 Seconds – New Stud / Bolt 2B Auxiliary Feedwater Pump, May 3, 2010

Corrective Action Documents As a Result of NRC Inspection

- IR 1058304; NRC Identified Transient Material Inside Containment, April 19, 2010

Section 1R20: Refueling and Other Outage Activities (Quarterly)

- 2BGP 100-1; Plant heatup, Revision 47
- 2BGP 100-1T1; Plant Heatup Flowchart, Revision 22
- 2BGP 100-1T2; Mode 5 to 4 Checklist, Revision 22
- 2BGP 100-1T3; Mode 4 to 3 Checklist, Revision 19
- 2BGP 100-2A1; Reactor Startup, Revision 23
- 2BGP 100-2T1; Plant Startup Flowchart, Revision 14
- 2BGP 100-2T2; Mode 3 to 2 Checklist, Revision 21
- 2BGP 100-6T1; Refueling Outage Flowchart, Revision 22
- 2BGP 100-6T4; Core Alteration/Fuel Movement Checklist, Revision 15
- 2BGP 100-5; Plant Shutdown and Cooldown, revision 50
- IR 1066438; Rope on Davit Crane on the Polar Crane Cannot be Removed, May 06, 2010
- IR 1066488; 2D SI Accumulator Level Lowering, May 06, 2010
- IR 1066620; 2A RH Pump Time Response Calculated Incorrectly, May 07, 2010
- IR 1066773; 2BOSR Z.5.B.1-1 Conflicting Instructions, May 07, 2010
- Standing Order; Log Number 10-021, Material Controls in Containment, May 04, 2010
- EC 379798 00; Evaluation of Foreign Material in Unit 2 Containment Building B2R15, Material Staged in Modes 3 and 4, May 14, 2010
- BAP 1450-T2, Containment Entry Checklist, Revision 35
- 2BOSR Z.5.b.1-1, Unit Two Containment Loose Debris Inspection, Revision 10
- BAP 1450-1, Access to Containment, Revision 38
- BAP 1450-1, Access to Containment, Revision 39
- IR 1058248, Unit 2 Containment Hatch Outer Door Broken
- IR 1058271, Technical Specification 3.6.2 Containment Air Locks
- OU-AA-103, Shutdown Safety Management Program, Revision 9
- OU-AP-104, Shutdown Safety Management Program Byron/Braidwood Annex

Corrective Action Documents As a Result of NRC Inspection

- IR 1066237; Active Leak During B2R15 Mode 3 W/D, May 06, 2010
- IR 1066323; B2R15 Containment Closeout Walkdown, May 06, 2010
- IR 1063449; Dry Boric Acid Leak on 2SI8808D Packing Area, April 29, 2010
- IR 1063457; Dry Boric Acid Leak on 2SI-8810B, April 29, 2010
- IR 1063461; Dry Boric Acid Leak on 2SI8889C, April 29, 2010

- IR 1063977; Valve Leaks Not Identified by the Workforce, April 30, 2010
- IR 1063464; Dry Boric Acid Leak on 2SI8890B, April 29, 2010
- IR 1063467; Dry Boric Acid on 2PT-0150 5-Way Valve, April 29, 2010
- IR 1063470; Dry Boric Acid on 2PT-0151, April 29, 2010
- IR 1063472; Dry Boric Acid Leak on 2FI-0650, April 29, 2010
- IR 1063473; Dry Boric Acid Leak on 2FIS-0649, April 29, 2010
- IR 1064364; White Deposit on CC Flange to RCP "2C," May 02, 2010
- IR 1066390; Potential Inappropriate Rope Material Inside Containment, May 06, 2010
- IR 1062112; Issue with Chain Fall and Sling Over Cat 1 RH Piping, April 27, 2010
- IR 1063806; Plant Walkdown Items, April 30, 2010
- IR 1063977; Valve Leaks Not Identified by the Workforce, April 30, 2010
- IR 1058304, NRC Identifies Transient Material Inside of Containment
- IR 1059543, NRC Inspector Questions Prudency of Containment Air Lock Decision

Section 1R21: Component Design Bases Inspection (CDBI) (71111.21)

- EC 377631; Evaluation and Technical Basis for the AP System Second level Undervoltage Time Delay Setting, February 03, 2010
- EC 378224; Degraded Voltage Relay Time Delay Comparison with Current Standards, February 24, 2010
- IR 892610; 2009 CDBI Issue "Degraded Voltage 5-Minute Timer, March 13, 2009
- ComEd letter to NRC; Dresden Station Units 2 and 3 4kV Undervoltage Setpoint Meeting Action Items, April 21, 1989
- NUREG-0876; Safety Evaluation Report Related to the Operation of Byron Station Units 1 and 2, February 19, 1982
- NRC Letter to ComEd; Technical Specification Amendments Related to 4 kV Undervoltage Setting (TAC Nos. 67562 and 67563), November 21, 1989

Section 1R22: Surveillance Testing (Quarterly)

- IR 1055522; Low SX Flow to 2A DG During Monthly Run, April 12, 2010
- IR 1009751; 2A DG Flow Element Inspection Removed From Window, December 22, 2009
- 2BOSR 8.1.2-1; Unit 2 2A Diesel Generator Operability Surveillance, April 13, 2010
- WO 01180125; 2A Diesel Generator Safe Shutdown Sequence and Single Load Reject, April 27, 2010
- WO 01180124; 2A Diesel Generator Sequencer Test, April 26, 2010
- 2BVSR 7.1.1-1; Main Steam Valves Operability Test, April 14, 2010
- BMP 3114-15; Main Steam Safety valve Verification of Lift Point Using Furmanite's Trevitest Equipment, Revision 25
- EC 380260; Operability Evaluation 10-002, Train 1B ESF Relay K611 Degraded, Rev. 0
- 1BOSR 8.1.2-2; Unit 1B Diesel Generator Operability Surveillance, Rev. 26
- OP-AA-102-104; Adverse Condition Monitoring Plan for any 1B Diesel Generator ESF Relay Start, Log Number 10-026
- Operability Evaluation 10-002; Train 1B ESF Relay K611 Degraded
- 2BOSR 4.13.1-1; Unit Two Reactor Coolant System Water Inventory Balance Surveillance Computer Calculation, Revision 22, June 30, 2010
- WO 0749927; Unit 2 RCDT Temperature Indication Failed Low, February 11, 2005
- WO 0783325; Reactor Coolant Drain Tank Temp Loop 2RE-1058 Calibration, November 1, 2006
- WO 1034883; Calibrate Transmitter, September 25, 2008

- WO 1172952; Calibrate Transmitter, March 24, 2010
- WO 1180585; 2RH01PA Comprehensive IST Requirements for Residual Heat Removal Pump, April 27, 2010

Section 2RS1: Radiological Hazard Assessment and Exposure Controls

- IR 1062055; Remote Monitoring Technician Received False Dose Rate Alarm, April 27, 2010
- IR 1059758; High Radiation Vacuum Issue, April 21, 2010
- IR 1051026; Survey of Laundered Scrubs Not Being Performed, May 01, 2010
- IR 1059549; B2R15- Forced Oxidation Controls, April 21, 2010
- IR 1060361; No Support to Trouble Shoot Radiation Issues when Problem Encountered, April 22, 2010
- IR 1058624; Workers in the Containment at Unit 2 Not Using Low Dose Waiting Area, April 19, 2010
- IR 1060903; Successful Line Flush Results in Dose Reduction, April 23, 2010
- IR 1060735; Temp Power Tracking to Exceed Dose Goal, April 23, 2010
- IR 1056095; Level One PCE on Shaw Iron Work, April 13, 2010
- IR 1059862; Documentation of Radiation Condition during Unit 2 Reactor Head Lift, April 21, 2010
- IR 1059044; RP Management Notified Laborers to Exit 383' Block Wall Area Prior to the Resin Transfer, April 20, 2010
- NOP-OP-4701-01; Radiological Survey Forms, Revision 0
- IR 1058742; Poor Communication from Radiation Protection at OCC, April 19, 2010
- IR 1054723; Additional Dose Required for Scaffold Built, April 09, 2010
- RWP 10010591; Steam Generator Radiation Protection Activities and Support, Revision 0
- RWP 10010592; Steam Generator Staging that Including Decontamination Tent activities and All RCA, Revision 0
- RWP 10010593; Steam Generator Platform and Bullpen Set-up/Tear Down and Decontamination Activities; Revision No. 0
- RWP 10010594; Steam Generator Manway and Diaphragm – Removal and Re-Installation and Bolt Cleaning; Revision No. 0 l
- RWP 10010595; Steam Generator Platform-Nozzle Cover – Removal and Re-installation; Revision No. 0
- RWP 10010618; A/D Platform Steam Generator Nozzle Cover- Removal and Re-installation; Revision No. 0
- RWP 10010582; Outage Scaffolds; Revision No. 1
- RP-AA-460; Control for High and Locked High Radiation Areas; Revision No. 19
- RWP 10010563; Reactor Head Disassemble/Re-Assemble all Activities; Revision No. 0
- RP-AA-441; Methods for Estimating Airborne Radioactivity Based Upon Contamination Levels and Work Activities; TEDE ALARA; Revision No. 4
- RWP 10010584; Shielding Activities; Revision No. 0

Section 40A1: Performance Indicator Verification

- Unit 1 Power History Curves, June 2009 through June 2010
- Unit 2 Power History Curves, June 2009 through June 2010
- Unit 1 Chart of 10 Minute Calorimetric Power, June 2009 through June 2010
- Unit 2 Chart of 10 Minute Calorimetric Power, June 2009 through June 2010
- Review of Operator Logs for Selected Dates, June 2009 through June 2010

Section 40A2: Problem Identification and Resolution

- NUCON Radioiodine Adsorbents, Bulletin 11B31, Rev. April 2006
- IR 1013278; 0VA09FA – FHB Charcoal Sample Failure, January 5, 2010
- IR 1051767; Charcoal Sample Failure – 0B Non-Accessible Plenum, April 2, 2010
- IR 1052054; Identified Discrepancies in Shelf Life on VA Filters, April 3, 2010
- IR 1069567; Braidwood vs Byron VA Fans Operations, May 14, 2010
- Radioiodine Test Report; Batch 299, Lot 55, April 4, 2010
- 0BVS 7.7.C-2; Unit 0, 0B Non-Accessible Exhaust Filter Plenum Carbon Sample Analysis, Revision 2
- 0BVSR 7.12.2-11; Unit 0, 0B Non-Accessible Exhaust Filter Plenum Carbon Sample Analysis, Revision 1
- 0BVSR 7.12.2-11; Unit 0, 0B Non-Accessible Exhaust Filter Plenum Carbon Sample Analysis, Revision 3
- Apparent Cause Evaluation; Charcoal Sample Failed Lab Analysis for 0B VA Non-Accessible Plenum, May 14, 2010

Section 40A3: Event Follow-up (Quarterly)

- EC 342009; Generic Evaluation of ECCS Leakage External to Containment, Revision 0
- EC 377806; Consequence of Containment Bypass Via Small Bore Piping, April 10, 2010
- EC 378072; Dose Assessment for Postulated Post LOCA Leakage from Open Vent and Drain Valves for Byron and Braidwood Stations. This EC is Applicable to Both Byron and Braidwood, March 17, 2010
- BB-SDP-001; Risk Assessment – IRs 985151 & 986813 RH Draining Configuration Control
- BOP RH-3; Filling and Venting of RH System, Revision 33
- BOP RH-3; Fill and Vent of the Residual Heat Removal System, Revision 34
- BOP RH-4; Draining the RH System, Revisions 14 & 15
  50.59 Review Coversheet Form for BOP RH-4, Draining the RH System
- BW100037; Isolation Time for SI8811A/B to Support EC #377806, March 23, 2010
- LTR Byron 2010-0004; Isolation Time for SI8811A/B to EC#377806, January 05, 2010
- IR 108554; Adequacy of Configuration Controls Measures in RH Drain Procedure, December 22, 2009
- IR 189881; OE.02.BYR/BRW.04 in Conjunction with Braidwood, Develop and Implement Flushing Options to Reduce Dose in ECCS Piping (e.g. 1/2SI8811A/B), June 01, 2004
- IR 308552; Need Justification for 1B RH PP Unavailability 04/04/05, March 04, 2005
- IR 774340; ESTs – The New Clearance Order Program, May 07, 2008
- IR 985151; Draining RH System, October 28, 2009
- IR 986659; Draining RH Suction without a Clearance Order-Again, October 28, 2009
- Relief Request RV-5 for Braidwood and Byron Stations; Alternative Testing of Containment Sump Suction Valves for the Second 10-Year Inservice Testing (IST) Interval, February 28, 2003
- Plant Issue Resolution Documentation: Should the 1SI8811A/B Stroke tests and Preventative Maintenance be Moved to the Online RH Suction Dose Reduction Drain down Work Windows?, May 26, 2006
- Standing Order Log Number 09-045; PRA Times for Operator Response, October 05, 2009
- BY-MD83-001; MD 8.3 Risk Assessment – IR 985151, RH Draining Evolution Configuration Control, Revision 0
- Issue 1001337; 1SI8811B Time Evaluation in Simulator, December 03, 2009
- LER 2009-001-00; Beaver Valley Power Station, Surveillance Test Inadvertently Violates Technical specification 3.6.1 for Containment Operability, May 22, 2009

- Root Cause Investigation Report; 1B Residual heat Removal Suction Vents and Drains Open with 1SI11B Available, December 14, 2009
- RS-02-156; Relief Request for Alternative Testing of Containment Sump Suction Valves 1/2SI8811A/B, October 18, 2002
- RS-03-004; Response to Request for Additional Information Supporting a Relief Request for Alternative Testing of Containment Sump Suction Valves 1/2SI8811A/B, January 23,2003
- Drawing 6E-2-4008A; Key Diagram 480V Auxiliary Building ESF MCC 231X1, Part 1, Revision M
- Drawing 6E-1-4008A; Key Diagram 480V Auxiliary Building ESF MCC 131X1, Part 1, Revision AB
- M-61 Diagram of Safety Injection, Revisions AI, AM, V, AV, AR, and AW
- M-62 Diagram of Residual Heat Removal, Revision BC
- 2BOSR 3.2.9-3; Unit Two Feedwater Isolation Valve Stroke on Simulated SI Signal, Revision 9
- IR 1058287; Lo-2 Steam Generator Level Reached During FW Isolation Test, April 19, 2010

Corrective Action Documents As a Result of NRC Inspection

- IR 1013563; Concern with BEP ES 1.3, January 07, 2010
- IR 1060177; Reportability Decision Revised After NRC Feedback, April 22, 2010

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CDBI	Component Design Bases Inspection
CFR	Code of Federal Regulations
DG	Diesel Generator
EC	Engineering Change
ECCS	Emergency Core Cooling System
ED	Electronic Dosimeter
EPRI	Electric Power Research Institute
ET	Eddy Current Testing
FPR	Fire Protection Report
HP	Health Physics
HRA	High Radiation Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report/Issue Report
ISI	Inservice Inspection
LER	Licensee Event Report
LESW	Loss of Service Water
LOCA	Loss of Coolant Accident
NCV	Non-Cited Violation
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PARS	Publicly Available Records
PI	Performance Indicator
PT	Liquid Penetrant Test
RFO	Refueling Outage
RHR	Residual Heat Removal
RPM	Radiation Protection Manager
RPS	Reactor Protection System
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generation
SGULS	Steam Generation Upper Lateral Support
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
SX	Essential Service Water
TS	Technical Specification
UCSR	Upper Cable Spreading Room
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VHRA	Very High Radiation Area
WR	Work Request

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Sincerely,

/RA by Kenneth Riemer for/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor

Docket Nos. 50-454; 50-455
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SUBJECT: BYRON STATION, UNITS 1 AND 2, INTEGRATED INSPECTION REPORT 05000454/2010003; 05000455/2010003

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