February 13, 2008

Mr. Charles G. Pardee
Chief Nuclear Officer and
Senior Vice President
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2007005 AND 05000455/2007005

Dear Mr. Pardee:

On December 31, 2007, 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 January 10, 2008, with Mr. D. Hoots and other members of your staff.

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

This report documents two NRC-identified findings of very low safety significance (Green). Both findings involved violations of NRC requirements however, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations, consistent with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of the Non-Cited Violations, 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 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/

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

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

Enclosure: Inspection Report No. 05000454/2007005 and 05000455/200705
w/Attachment: Supplemental Information

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

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Letter to C. Pardee from Richard A. Skokowski dated February 13, 2008

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report No:	05000454/2007005 and 05000455/2007005
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL 61010
Dates:	October 1, 2007, through December 31, 2007
Inspectors:	B. Bartlett, Senior Resident Inspector R. Ng, Resident Inspector T. Bilik, Reactor Engineer J. Cassidy, Reactor Engineer R. Jickling, Senior Emergency Preparedness Analyst R. Jones, Reactor Engineer D. Lords, Reactor Engineer C. Moore, Operations Engineer B. Palagi, Senior Operations Engineer C. Thompson, Illinois Dept. Of Emergency Management
Approved by:	R. Skokowski, Chief Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000454/2007005, 05000455/2007005; 10/01/2007 – 12/31/2007; Byron Station, Units 1 and 2; Maintenance Risk Assessments and Emergent Work Control, Operability Evaluation.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two Green findings were identified by the inspectors. The findings were considered Non-Cited Violations 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-Revealing Findings

Cornerstone: Mitigating Systems

- Green The inspectors identified a Non-Cited Violation (NCV) of 10 CFR 50.65(a)(4), for the licensee's failure to conduct an adequate risk assessment of the maintenance performed at the Unit 0 Train B essential service water basin. Specifically, the maintenance activities lowered the Unit 0 Train A Essential Service Water (SX) basin level and resulted in an unrecognized increase in the level of risk as determined by the licensee's shutdown safety management program. The primary cause of this finding was related to the cross-cutting area of human performance for failure to appropriately coordinate work activities between departments to assure plant and human performance. (H.3(b))

  The finding was determined to be more than minor because the unplanned red risk condition was entered and the risk assessment had incorrect assumptions that had the potential to change the outcome of the assessment. The inspectors assessed the finding using Inspection Manual Chapter (IMC) 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria," and determined the finding to be of very low safety significance (Green) because the safety function of the ultimate heat sink was not lost. (Section 1R13)

- Green The inspectors identified a Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion V, for the licensee's failure to appropriately classify a safety related part. Specifically, the replacement rocker cover gasket for the Unit 1 Train B (1B) diesel driven auxiliary feedwater pump was not classified as a safety related component, which led to the use of an inappropriate gasket for the diesel engine and rendered the pump unable to perform its fire protection safe shutdown function when an excessive leak developed prematurely. The licensee took the pump out of service and repaired the gasket leak within the 72 hours of the Technical Specification allowable outage time. Subsequently, the licensee re-classified the replacement cover gasket as a safety related component.

  The finding was determined to be more than minor since if left uncorrected, the finding could become a more significant safety concern that affects other cover

gaskets of the diesel driven auxiliary pump. The finding was evaluated under the SDP using Appendix F of the NRC IMC 0609, “Fire Protection Significance Determination Process” and screened as very low safety significance (Green) as the finding only affected the ability to reach and maintain cold shutdown conditions. (Section 1R15)

B. Licensee Identified Findings

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power throughout the inspection period with the following exception:

- On October 2, 2007, the unit reduced power to 95 percent to start a feedwater pump for maintenance. The unit returned to full power the same day.
- On October 5, 2007, the unit reduced power to 95 percent to start a feedwater pump for maintenance. The unit returned to full power the same day.
- On October 19, 2007, the unit shut down due to a leak in the essential service water system. The unit returned to full power on November 2, 2007.
- On November 10, 2007, the unit reduced power to 95 percent to swap a feedwater pump. The unit returned to full power the same day.
- On December 1, 2007, the unit reduced power to 95 percent to swap a feedwater pump. The unit returned to full power on December 2, 2007.

Unit 2 operated at or near full power throughout the inspection period with the following exception:

- On October 19, 2007, the unit shut down due to a leak in the essential service water system. The unit returned to full power on November 2, 2007.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. 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. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors also reviewed corrective action program items to verify that the licensee was

identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues:

- Plant Heating (System AS); and
- Heat Tracing (System HT).

This inspection constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings of significance were identified.

.2 Readiness For Impending Adverse Weather Condition – Severe Thunderstorm

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for October 25, 2007, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. The inspectors walked down the Ultimate Heat Sink (UHS), the Essential Service Water mechanical draft cooling towers, in addition to the licensee's emergency AC power systems, because their safety related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds for loose debris, which could become missiles during a tornado, and ascertained operator staffing and if they could access controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment.

This inspection constituted one readiness for impending adverse weather condition sample as defined in Inspection Procedure 71111.01.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Unit 2 Train B Chemical and Volume Control System While Unit 2 Train A Charging Pump was Out of Service;
- Unit 1 Train A Residual Heat Removal (RHR) System while the Unit 1 Train B RHR System was Out of Service; and
- Unit 0 Train B Essential Service Water (SX) Makeup System While Unit 0 Train A SX Makeup Pump was Out of Service.

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were 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, Administrative TS, 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 systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems 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 corrective action program with the appropriate significance characterization. Documents reviewed are listed in the attachment.

These activities constituted three partial system walkdown samples as defined by Inspection Procedure 71111.04.

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 that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Main Control Room (Zone 2.1-0);
- Unit 2 Division 21 Miscellaneous Electrical Equipment and Battery Room (Zone 5.6-2);
- Unit 1 Division 12 ESF Switchgear Room (Zone 5.1-1);
- Unit 1 Auxiliary Building Elevation 364' General Area (Zone 11.3-0);
- Unit 1 Train B Auxiliary Feedwater Pump Room and Day Tank Room (Zone 11.4A-1);
- Unit 2 Turbine Building 426' General Area (Zone 8.5-2); and
- Auxiliary Building General Area (Zone 11.6-0).

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 had 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 corrective action program.

These activities constituted seven quarterly fire protection inspection samples as defined by Inspection Procedure 71111.05.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of heat exchangers to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing criteria. The following heat exchangers were assessed:

- Unit 2 Train A Charging Pump Room Cubicle Cooler; and
- Unit 2 Train B Diesel Generator Jacket Water Cooler.

This inspection constituted two samples as defined in Inspection Procedure 71111.07.

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 October 13, 2007 the inspectors observed a crew of licensed operators responding to a Steam Generator Tube Rupture and miscellaneous malfunctions 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.

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

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the operating and simulator tests (required to be given annually per 10 CFR 55.59(a)(2)) administered by the licensee from October 29 through December 7, 2007. The overall results were compared with the significance determination process in accordance with NRC Manual Chapter 0609,

Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP).”

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:

- SX Return Header Crosstie Isolation Valves Replacement;
- Unit 1 Train B Main Feedwater Pump Failures; and
- SX Pipe Leak.

The inspectors reviewed the risk significant systems that were degraded 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 corrective action program with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

This inspection constituted three quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12.

b. Findings

No findings of significance were identified.

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:

- Heavy Load Movement Affecting the Essential Service Water System during Unit 1 Train B Solid State Protection System Bimonthly Surveillance;
- Emergent Unit 0 Train A Essential Service Water Basin Level Drop;
- Unit 1 Train B RHR System while Unit 1 Train B Containment Spray System was Out of Service;
- Emergent Work Due to Unit 1 Train B Auxiliary Feedwater Pump Oil Leak; and
- Emergent Unit 0 Train A SX Makeup Pump Seal Failure.

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.

These activities constituted five samples as defined by Inspection Procedure 71111.13.

b. Findings

(1) Unit 0 Train A Essential Service Water Basin Level Drop

Introduction: The NRC identified a Non-Cited Violation of 10 CFR 50.65(a)(4), having very low safety significance, associated with the licensee’s failure to conduct an adequate risk assessment of the maintenance performed at the Unit 0 Train B essential service water basin. The maintenance activities lowered the Unit 0 Train A essential service water basin level and resulted in an unrecognized increase in the level of risk as determined by the licensee’s shutdown safety management program.

Description: On October 19, 2007, both Byron units shut down because a leak developed in one of the eight essential service water basin riser pipes. As part of the repair activities, the Unit 0 Train B essential service water basin was isolated and the Unit 0 Train A basin was in service as the ultimate heat sink for both units during that time. The two basins were interconnected at 64 percent level. Per Procedure OU-AP-104, “Shutdown Safety Management program - Byron/Braidwood Annex,” the ultimate heat sink was considered available, in part, if a minimum of six cooling cells, each consisting of a fan and a riser, and the level was above the low level alarm setpoint

of 85 percent basin level. If the ultimate heat sink was not available, both units would have been in a red risk condition per the Byron's shutdown risk procedure. Since the repair plan would have required five of the eight cooling cells to be isolated and lowering of the basin level below 85 percent, a shutdown risk assessment was performed to evaluate the repair activities and the risk profile for the plant conditions.

A shutdown safety review board was convened to review the shutdown risk assessment per Procedure OU-AA-103, "Shutdown Safety Management Program." Based on the risk assessment performed, the licensee determined that it was acceptable to perform the maintenance and the overall plant risk would be yellow. The ultimate heat sink was considered available provided that a number of conditions were maintained. One of these conditions was to maintained basin level above 60 percent. Had the ultimate heat sink become unavailable during that maintenance window, the overall plant risk would become red.

On October 24, 2007, due to the excessive leak-by from the return header isolation valves, extra pumps had to be installed to prevent water flowing to the Train B risers from the basin while the repairs were in progress. These pumps took suction from the Train B return header and discharged into the Train B basin. This maintenance change was not communicated to the control room operators, nor was this change in plant conditions and in maintenance scope evaluated for risk. In addition, the inadequate isolation was not evaluated in the shutdown risk assessment. As a result, no action was initiated to monitor the basin level continuously. Subsequently, Train A basin level went down to 58 percent and Train B basin level went up to 67 percent before it was discovered by an operator during periodic walkdown of the main control room panel. The operator took immediate actions and raised the Train A basin level back to 60 percent. Given that the water inventory for the Train A basin was not lost, and that there was no change in suction pressure or temperature at the running essential service water pumps, the licensee later determined that there was no loss of safety function for the ultimate heat sink.

Analysis: The inspectors determined that the failure to conduct an adequate risk assessment of the maintenance performed at the Unit 0 Train B essential service water basin was a performance deficiency warranting a significance evaluation. This finding was more than minor because, similar to example 7e of IMC 612 Appendix E, an unplanned red risk condition was entered and the risk assessment had incorrect assumptions that had the potential to change the outcome of the assessment. The finding was related to the cross-cutting area of human performance for failure to appropriately coordinate work activities between departments to assure plant and human performance. (H.3(b))

The inspectors assessed the finding using IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria," and determined the finding to be of very low safety significance (Green) because the safety function of the ultimate heat sink was not lost. The inspector did not use IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," because that IMC is not applicable for maintenance rule findings. The inspector did not use IMC 0609, Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process," because that IMC is not applicable for shutdown conditions.

Enforcement: 10 CFR 50.65(a)(4) required, in part, that licensees assess and manage the increase in risk that may result from proposed maintenance activities. Contrary to the above, on October 29, 2007, the licensee failed to conduct an adequate risk assessment of the maintenance performed at the Unit 0 Train B essential service water basin. Because this violation was of very low safety significance and was captured in the licensee's corrective action program (IR 689055), it is treated as a NCV consistent with VI.A.1 of the NRC Enforcement Policy. (NCV 05000454/2007005-01)

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Dual Unit Outage SX Cell Mode 5 Requirements;
- Emergent Work Due to Unit 1 Train B Auxiliary Feedwater Pump Oil Leak;
- Extent of Condition Evaluation for HFB Molded Case Circuit Breaker Failures;
- Unit 1 Cycle 15 1C Safety Injection Accumulator Leakage; and
- Main Control Room Boundary Impairment.

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 UFSAR 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 also 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.

This inspection constituted five samples as defined in Inspection Procedure 71111.15.

b. Findings

Unit 1 Train B Auxiliary Feedwater Pump Lube Oil Leak

Introduction: The NRC identified a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V, "Instructions, Procedures and Drawings," having very low safety significance (Green) for the licensee's failure to classify the replacement rocker coved gasket as safety related component. This led to the use of inappropriate gasket for the Unit 1 Train B auxiliary feedwater pump diesel engine and rendered the pump unable to perform its safety shutdown function when an excessive leak developed prematurely.

Description: On October 5, 2007, a lubricating oil leak was self-revealed on the northwest valve rocker cover of the Unit 1 Train B auxiliary feedwater (AF) pump diesel engine. The leak was quantified by the licensee to be 2.85 gallons per day. According to the pump vendor, a loss of 4 gallons of oil could occur without losing diesel driver function. The licensee determined that the AF pump was operable since it met the 24 hour Technical Specifications mission time to bring the unit into hot standby. However, the diesel driven auxiliary feedwater pump was also required to mitigate several fire scenarios in the Fire Protection Report and the mission time for those fire scenarios was 72 hours at cold shutdown conditions. Therefore, the AF pump was in a degraded and non-conforming condition. The licensee took the pump out of service and repaired the gasket leak within the 72 hours of the TS allowable outage time.

Based on the failure analysis performed for the gasket, the licensee determined that the gasket had delaminated and opened up to form a gap that allowed oil to leak through the joint. These delaminations were caused by the differential thermal expansion of the valve cover and cylinder head that occurred with every engine start and stop cycle. The licensee concluded that the gasket material used was inferior. A new gasket material was specified for future replacement of the rocket cover gasket. The gasket that leaked for the rocker cover was replaced in 2005 during fuel injection maintenance.

Per Procedure SM-AA-300, “Procurement Engineering Support Activity,” piece-parts within safety related host components that are required for the host to perform its safety function, shall be classified and procured as safety related parts. The inspectors examined the procurement documents and determined that the gasket installed in 2005 was not classified and procured as a safety related part. No specifications were described in the bill of materials that maintenance used to select the replacement. As such, no receiving inspection would be performed even if a particular material was specified for procurement. The incorrect classification of the rocker cover gasket led to an inferior product being used in the safety related auxiliary feedwater system and resulted in an excessive and premature oil leak of the auxiliary feedwater pump diesel engine.

Analysis: The inspectors determined that this issue was a performance deficiency warranting a significance evaluation. This is because the licensee failed to specify the correct safety related classification for the replacement rocker cover gasket. Specifically, the lack of safety related classification led to an inferior gasket being used in the safety related diesel driven auxiliary feedwater pump. This resulted in an excessive and premature oil leak of the 1B auxiliary feedwater pump diesel engine. This oil leak would cause the engine to fail within 72 hours and the fire protection safe shutdown function could not be met.

This finding was more than minor since if left uncorrected, the finding could become a more significant safety concern that affects other cover gaskets of the auxiliary pump diesel engine.

The finding was evaluated under the SDP using Appendix F of NRC IMC 0609, “Fire Protection Significance Determination Process” since the finding affected the fire protection defense-in-depth strategies. This finding screened as very low safety significance (Green) as the finding only affected the ability to reach and maintain cold shutdown conditions.

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. Contrary to this, the licensee failed to classify the replacement rocker cover gasket as a safety related component, which led to the use of an inappropriate gasket for the 1B auxiliary feedwater pump diesel engine and rendered the pump unable to perform its safety shutdown function when an excessive leak developed prematurely.

Because this violation was of very low safety significance and was captured in the licensee's corrective action program (IR 717197), it is treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000454/2007005-02)

1R19 Post Maintenance Testing (71111.19)

.1 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance (PM) activities for review to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 Train B Centrifugal Charging Pump Work Window;
- Unit 1 Train B Auxiliary Feedwater Pump Oil Leak;
- Unit 1 Train A Residual Heat Removal Pump following Planned Maintenance;
- Unit 0 Train A Essential Service Water Makeup Pump Seal Failure;
- Unit 1 SX Return Header Crosstie Isolation Valves Replacement; and
- Alpha Air Compressor on Unit 2 Train B Diesel Generator.

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 corrective action program and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the attachment.

This inspection constituted six samples as defined in Inspection Procedure 71111.19.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated outage activities for the dual unit unplanned shutdown that began on October 19, 2007 and continued through October 31, 2007. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

Both Byron units were shut down due to a leak in the SX riser pipe at the SX water Basin. The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, startup and heatup activities, and identification and resolution of problems associated with the outage. The inspectors performed assessments to verify by selected sampling that the licensee's systems were ready to support a plant restart. In addition, the inspectors performed routine tours of containment to verify their readiness for restart. In both Unit 1 and Unit 2 containments the inspectors identified indications of small packing leaks that were inactive but which were not in the licensee's corrective action system and small amounts of debris that should have been identified by licensee personnel. In all cases the material was not of a size or amount that would have significantly impacted the licensee's emergency core cooling system recirculation sump. The licensee initiated corrective action documents and removed the material.

The inspectors later reviewed the initial investigation report and observed the Plant Operating Review Committee to assess the detail of review and the adequacy of the licensee's understanding of the apparent causes and proposed corrective actions prior to restart of the units.

This inspection constituted one other outage sample as defined in Inspection Procedure 71111.20.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Routine 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:

- Surveillance Calibration of Wide Range Reactor Coolant Inlet/Outlet Temperature;
- Unit 1 Train A Solid State Protection System; and
- Unit 2 Train A Diesel Generator Monthly Surveillance.

The inspectors observed in plant activities and reviewed procedures and associated records to determine whether: preconditioning occurred; effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; acceptance criteria were clearly stated, demonstrated operational readiness, and were 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 UFSAR, 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, 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 corrective action program. Documents reviewed are listed in the attachment.

This inspection constituted three routine surveillance testing samples as defined in Inspection Procedure 71111.22.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modification(s):

- Leakby Control for SX Riser Repair.

The inspectors compared the temporary configuration changes and associated 10 CFR 50.59 screening and evaluation information against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system(s). The inspectors also compared the licensee’s information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee’s decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the

operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operations, engineering, and training personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance.

This inspection constituted one sample as defined in Inspection Procedure 71111.23.

b. Findings

No findings of significance were identified.

CORNERSTONE: EMERGENCY PREPAREDNESS

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors performed a screening review of Revisions 18, 19, 20, and 21 of the Byron Annex to the Standardized Emergency Plan to determine whether changes identified in Revisions 18, 19, 20, and 21 decreased the effectiveness of the licensee's emergency planning for the Byron Nuclear Power Station. This review did not constitute an approval of the changes, and as such, the changes are subject to future NRC inspection to ensure that the emergency plan continues to meet NRC regulations.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency preparedness drill with security aspects on October 15, 2007 to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Technical Support Center and Simulator Control Room to verify that event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package listed in the Attachment at the end of this report.

This inspection constitutes one sample as defined in Inspection Procedure 71114.06.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed licensee documentation packages for all Performance Indicator (PI) events occurring since the last inspection to determine if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. Unintended exposures >100 millirem total effective dose equivalent (or >5 rem shallow dose equivalent or >1.5 rem lens dose equivalent) were evaluated to determine if there were any regulatory overexposures or if there was a substantial potential for an overexposure.

This review represents one sample.

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring Program (REMP) And Radioactive Material Control Program (71122.03)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the most current annual Radiological Environmental Operating Report and licensee assessment results to evaluate if the REMP was implemented as required by the Radiological Effluent Technical Specifications (RETS) and the Offsite Dose Calculation Manual (ODCM). The inspectors reviewed the report for changes to the ODCM with respect to environmental monitoring and commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, interlaboratory comparison program, and data analysis. The inspectors reviewed the ODCM to identify environmental monitoring stations and evaluated licensee self-assessments, audits, licensee event reports, and interlaboratory comparison program results. The inspectors reviewed the UFSAR for information regarding the environmental monitoring program and meteorological monitoring instrumentation. The inspectors also reviewed the scope of the licensee's audit program to determine if it met the requirements of 10 CFR 20.1101(c). This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection

a. Inspection Scope

The inspectors walked down selected air sampling stations (>30 percent) and approximately 20 percent of the thermoluminescent dosimeter (TLD) monitoring stations to determine whether they were located as described in the ODCM and to determine the equipment material condition.

The inspectors observed the collection and preparation of a variety of environmental air and surface water samples. The environmental sampling program was evaluated to assess if it was representative of the release pathways as specified in the ODCM and if sampling techniques were performed in accordance with station procedures.

The inspectors evaluated the condition of the meteorological instruments using observations and record reviews, and assessed whether the equipment was operable, calibrated, and maintained in accordance with guidance contained in the UFSAR, NRC Safety Guide 23, and licensee procedures. The inspectors assessed whether the meteorological data readout and recording instruments, including computer interfaces and data loggers that measure and record wind speed, wind direction, delta temperature, and atmospheric stability measurements were available on the licensee's computer system and whether this information was available in the control room.

The inspectors reviewed each event documented in the Radiological Environmental Operating Report, which involved missed samples, inoperable samplers, lost TLDs, or anomalous measurements for the cause and corrective actions.

The inspectors reviewed the ODCM for significant changes that resulted from land use census modifications, or sampling station changes made since the last inspection. This included a review of technical justifications for changed sampling locations. The inspectors assessed whether the licensee performed reviews required to ensure that the changes did not affect their ability to monitor the impacts of radioactive effluent releases on the environment.

The inspectors reviewed the calibration and maintenance records for eight air samplers to evaluate operating parameters. The inspectors reviewed results of the vendor's inter-laboratory comparison program and quality assurance programs to assess the adequacy of environmental sample analyses performed by the licensee.

The inspectors reviewed quality assurance audit results of the REMP to determine whether the licensee met the Technical Specification/ODCM requirements.

These reviews represented six samples.

b. Findings

No findings of significance were identified.

.3 Unrestricted Release of Material From the Radiologically Restricted Area

a. Inspection Scope

The inspectors observed the access control location where the licensee monitored potentially contaminated material leaving the radiologically controlled area and inspected the methods used for control, survey, and release of material from this area. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use to verify that the work was performed in accordance with plant procedures.

The inspectors evaluated whether the radiation monitoring instrumentation was appropriate for the radiation types present and was calibrated with appropriate radiation sources that represented the expected isotopic mix. The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material and verified that there was guidance on how to respond to an alarm indicating the presence of licensed radioactive material. The inspectors evaluated the licensee's equipment to determine if radiation detection sensitivities were consistent with the NRC guidance contained in IE Circular 81-07 and IE Information Notice 85-92 for surface contamination, and Health Physics Position-221 for volumetrically contaminated material.

The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters such as counting times and background radiation levels. The inspectors assessed whether the licensee had established a "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high radiation background area.

These reviews represented two samples.

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, condition reports, and special reports related to the radiological environmental monitoring program since the last REMP inspection to determine if identified problems were entered into the corrective action program for resolution. The inspectors also assessed whether the licensee's self-assessment program was capable of identifying and addressing repetitive deficiencies or significant individual deficiencies that were identified by the problem identification and resolution process.

The inspectors also reviewed corrective action documents related to the REMP that affected environmental sampling and analysis, and meteorological monitoring instrumentation. Staff members were interviewed and documents were reviewed to

determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

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

This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the third quarter 2007 performance indicators for any obvious inconsistencies prior to its public release in accordance with IMC 0608, “Performance Indicator Program.”

This review was performed as part of the inspectors’ normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency AC Power System performance indicator for Byron Unit 1 and Unit 2 the period from the third quarter of 2006 through third quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in revision 5 of the Nuclear Energy Institute (NEI) Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” were used. The inspectors reviewed the licensee’s operator narrative logs, MSPI derivation reports, issue reports, event reports and NRC Integrated Inspection reports for the period of July 2006 through September 2007 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent

in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Specific documents reviewed are described in the Appendix to this report.

This inspection constituted two MSPI emergency AC power system samples as defined by Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - High Pressure Injection Systems performance indicator for Byron Unit 1 and Unit 2 for the period from the third quarter of 2006 through third quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in revision 5 of the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection reports for the period of July 2006 through September 2007 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Specific documents reviewed are described in the Appendix to this report.

This inspection constituted two MSPI high pressure infection system samples as defined by Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.4 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Heat Removal System performance indicator for Byron Unit 1 and Unit 2 for the period from the third quarter of 2006 through third quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in revision 5 of the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated Inspection

reports for the period of July 2006 through September 2007 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Specific documents reviewed are described in the Appendix to this report.

This inspection constituted two MSPI heat removal system samples as defined by Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.5 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Residual Heat Removal System performance indicator for Byron Unit 1 and Unit 2 for the period from the third quarter of 2006 through third quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in revision 5 of the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection reports for the period of July 2006 through September 2007 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Specific documents reviewed are described in the Appendix to this report.

This inspection constituted two MSPI residual heat removal system samples as defined by Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.6 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Cooling Water Systems performance indicator for Byron Unit 1 and Unit for the period from the third quarter of 2006 through third quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance

contained in Revision 5 of the NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection reports for the period of July 2006 through September 2007 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. Specific documents reviewed are described in the Appendix to this report.

This inspection constituted two MSPI cooling water system samples as defined by Inspection Procedure 71151.

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. 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 corrective action program (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. 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. 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 six month period of July 1, 2007, through December 31, 2007, 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.

b. Observations

The inspectors identified an apparent trend of a number of challenges to the control room operators for the performance of work activities. The inspectors identified examples of scheduled activities that were taken to the control room to be implemented that subsequently needed to be modified or rescheduled due to poor planning. Examples included a clearance order that would have removed power to a valve needed for a flow test on the containment spray system, an electrical bus outage that would have removed power to equipment necessary for the scheduled test of the Anticipated Transient with Scram (ATWS) system, the scheduling of the monthly surveillance on the

Reactor Containment Fan Coil units when cooling flow would have been disrupted with the simultaneous scheduling of the Unit 2 SX valve stroke surveillance.

In discussions with licensee personnel the inspectors determined that an issue report (IR) had been written to perform a common cause analysis of activities that were not completed on schedule. However, the focus of this IR would not have addressed the inspectors' observed trend. The inspectors also observed that while it appeared that IRs were initiated when required that some activities were turned away from the control room due to schedule conflicts, and these types of issues may not have been documented within the corrective action program. Although this is not a violation of NRC requirements these may be missed opportunities to minimize challenges to the operators.

No findings of significance were identified.

.4 Selected Issue Follow-up Inspection: Steam Generator PORV Manual Action

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized as an issue a number of issues related to the Steam Generator Tube Rupture (SGTR) analysis in the last quarter. Specifically, an operability determination was conducted to evaluation the impact to the steam generator (SG) powered operated relief valves (PORV) due to undersized piping. The licensee determined the PORVs were operable based on the margin available from the validated operator response time. This inspectors reviewed the operability determination and documented the issue in NRC Inspection Report 05000454; 05000455/2007-004.

The licensee's SGTR analysis, as documented in the UFSAR, evaluates the two major SGTR potential consequences of concern: margin-to-overfill case and offsite dose case. The response of the operator and the ability to implement recovery actions is critical in mitigating the consequence of a SGTR event. The operator actions assumed in these two analyses are based on the plant specific emergency procedures addressing the SGTR event. Under the offsite dose case, the scenario is mitigated by isolating the stuck open SG PORV within 20 minutes, isolating the ruptured SG and depressurizing the reactor coolant system. The inspectors determined that this manual response time was not required to be validated. The inspectors selected this issue as one annual sample of the licensee's problem identification and resolution program.

Identification of Issues

The inspector reviewed the licensee's issue reports related to the SGTR and determined that the assumed manual operator action for the offsite dose case was not being evaluated. The following issues might preclude timely responses for the accident: 1) the valve must be manually operated against an 1100 psi differential pressure; 2) accessibility of the manual valve is in doubt due to steam leakage into the space; 3) the radiation dose to an operator had not been evaluated; 4) the noise level near the SG PORV may exceed dangerous levels. The inspectors questioned the licensee's justification of the response time and the licensee entered them into their corrective action program for evaluation.

Evaluation of Issues

The inspectors reviewed the issues raised by the inspectors and determined the followings:

(1) Valve Differential Pressure

The manual isolation valve is a gate valve equipped with a 10:1 bevel gear operator. Based on the licensee's calculation, the maximum pressure drop across the manual isolation valve is 1185 psid and the maximum force required to close valve at the handwheel is equal 80 lbs. This is in line with industry standard for rim pull requirement for manual valve operation. In addition, even though the valve takes 250 turns to close, the maximum pressure drop would exist when the valve is near full closure. Therefore, the inspectors determined that the operator could manually manipulate the valve to close.

(2) Accessibility of Valve

Based on the room and valve configuration, steam leakage into the space would be largely due to blowback from the valve vent. The licensee estimated that blowback would occur when steam flow was throttled to 30 percent to 40 percent of its design valve, which corresponds to 75 percent to 80 percent closed with an outlet pressure of about 100 psig. In addition, the amount of blowback steam will be relatively small due to the tortuous flow path. The licensee estimated that the blowback flow resistance would be about 10 times more than that of the normal discharge. The arrangement of the discharge cup would direct all the steam toward the ceiling with the room ventilation suction closed by. Therefore, the steam leakage would not result in the inability of the operator to operate the manual isolation valve.

(3) Radiation Dose

The licensee performed a dose calculation using the same initial iodine concentration in the RCS (fuel failure assumptions) from the SGTR analysis. This calculation also assumed a 10-minute stay time for the operator to close the valve and 1 percent safety released steam returned to room, which is conservative. The result showed a thyroid dose of 1190 mrem, which is within the yearly operational dose limit.

(4) Noise

The licensee determined that the primary sources of flow-induced noise in the room during the isolation of the PORV come from:

- Flow through the PORV ;
- Flow through the block valve while throttling; and
- Flow at the exhaust discharge as it expands to the atmosphere.

The vendor of the PORV estimated that the noise level would be 116 dBA at 420,000 lb/hr of saturated steam flow. The block valve, which is a gate valve, is not a significant noise contributor in its full open position. As the block valve is throttled closed, the noise generated from the valve would increase. However, the noise from the PORV decreases due to decreasing flow.

At the exhaust discharge to the atmosphere, the steam is expanded rapidly in a vertical direction away from roof slab; as is the sound wave from the steam expansion. The concrete roof slab is also expected to provide significant amount of noise insulation. Combining the three factors, the licensee estimated that the operator will experience 130-140 dBA at the block valve.

Using double hearing protection, the operator would experience a noise level of about 110 dBA. Normally it would take an operator 5-7 minutes to close the manual valve. Given that the OSHA standard 19 CFR 1910.95 sets an allowable stay time of no greater than 30 minutes per day at an 110 dBA environment, it is within the acceptable noise level limit for the operator to close the valve.

Based on the discussion above, the licensee determined that timely operator response was assured for the SGTR event. However, the inspector determined that the emergency operating procedures were not written to ensure that the manual isolation valve is shut within the 20 minute accident analysis time. Step 27 of Byron Emergency Operating Procedure (EOP), 1/2BEP-0, Reactor Trip or Safety Injection, directs the operator to check SG pressure. With a stuck open SG PORV, 1/2BEP-2, Faulted Steam Generator Isolation, would be entered. Step 4d of 1/2BEP-2 would direct operator to locally close the SG PORV isolation. Even though the licensee has not validated the time required to perform all these steps, the licensee needed more than 7 minutes to complete Step 15 of 1/2BEP-0, based on a required validation for the margin-to-overfill SGTR case.

The licensee later determined that the total time to dispatch and completely close the valve would be 13 minutes and 40 seconds. Considering that there are more procedure steps to be performed before the PORV could be isolated, it would be well over 20 minutes to close the isolation valve. Therefore, the licensee would be unable to complete the required actions within the time assumed in SGTR analysis. The licensee entered this deficiency into the corrective action program as IR 713565.

Effectiveness of Corrective Actions

The inspectors determined that the licensee had not completed all the corrective actions related to this issue. However, the licensee performed a preliminary analysis of the consequences of exceeding the assumed time and determined that there was no adverse consequence to the 10 CFR 100 offsite dose calculations. The licensee also generated a training request to ensure that operators were aware of the time limitations, the actions required and the potential hazards associated with closing the PORV manual isolation valve with full steam flow. The inspectors concluded that the corrective actions were appropriate and were being completed in a timely manner.

The above constituted completion of one in-depth problem identification and resolution sample.

b. Findings

No findings of significance were identified. However, the issue was a violation of 10 CFR 50, Appendix B, Criteria III, “Design Control,” for failure to ensure that design basis information is correctly translated into procedures and instructions. This issue was

screened as minor since there was minimal effect on the safety analysis and there were no programmatic concerns identified associated with the issue.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

.1 Essential Service Water Pipe Leak and Resultant Dual Unit Shutdown

a. Inspection Scope

System Description

The Ultimate Heat Sink consists of a common eight cell mechanical draft cooling tower with safety-related water make up. There is an A train side of the tower and a B train side of the tower with each side having one common return from the associated train from each unit. Near the tower the 48 inch common return line splits into four 24 inch lines to return the water to the cooling tower. The piping is carbon steel and the 24 inch piping has a nominal thickness of 0.375 inches. As each 24 inch line comes out of the ground to go up into the tower, it is protected from tornado generated missiles with concrete walls and removable steel blocks. The portion coming out of the ground is referred to as the riser. In the room created by these walls there is only a portion of piping and one motor operated valve. The cells/risers are labeled 0A through 0H.

Degradation Description

The floor of each of the riser rooms is sloped so as to allow any water to flow into drain holes in the corners. Water in the room has historically come from cooling tower spray impingement. With a relatively warm, wetted environment, the carbon steel has rusted significantly. The visible rusted pipe was about four to six inches long and was between the concrete floor and the motor operated valve. The piping above the valve was replaced with stainless steel in 1997.

History

Every three years the licensee performs a VT-2 (visual) exam of the riser piping to look for leaks. On May 17, 2007, the licensee wrote IR 630679 documenting the protective coating was degraded to the point that there was some flaking of the carbon steel pipe for the 0A riser. It was noted in the IR that UT thickness measurements had not been taken and the observed condition was similar to what had been observed in the other risers.

On June 14, 2007, IR 640363 was written documenting the as found condition of the 0E riser. The 0E riser was the next cell to be inspected as part of a general SX system health improvement initiative. Based on the May 2007 observations, it had been decided to perform UT thickness measurements during the 0E work window. Two readings 180 degrees apart were taken with measurements of 0.122 and 0.124 inches. Adjacent areas were at 0.228 and 0.249 inches. A previous engineering evaluation had determined that wall measurements down to 0.153 inches were acceptable. A new engineering evaluation (EC 366395) determined that degradation down to 0.121 inches was now acceptable.

On October 10, 2007, the 0H riser was measured and as documented in IR 682786, the results showed the lowest reading as 0.085 inches. Other locations showed values of 0.150 and 0.154 inches. Engineering Change (EC) 367754 issued on October 12, 2007, and had a new minimum allowable value of 0.0598 inches. The licensee used American Society of Mechanical Engineer (ASME) Appendix F, Equation 10 to determine the minimum wall thickness. They also predicted a remaining life of 2.1 years.

On October 17, 2007, the 0B riser was measured and as documented in IR 685955, the results showed the lowest reading as 0.047 inches. Other locations showed values of 0.09, 0.085, 0.064, etc. The licensee used ASME equation 9D of Appendix F in EC 367754 to achieve a new minimum allowable wall thickness of 0.03 inches.

Identification of the leak

On October 18, 2007, licensee personnel began additional assessments of as-found conditions. Teleconferences between NRC and the licensee were held on October 18 to discuss operability evaluations, plans for measuring wall thickness on the remaining risers, and other topics.

On October 19, 2007, in preparations for obtaining measurements of the 0C riser a through wall leak occurred while cleaning the exterior surface of the carbon steel pipe.

Operational Consequences

The licensee entered Technical Requirements Manual 3.4.f, Condition B which required the immediate isolation of the line but the SX line was unable to be isolated. This also resulted in entry into TS 3.7.9, "UHS", condition G for each unit which required a shutdown (Mode 3 in 6 hours and Mode 5 in 36 hours).

NRC Response

The inspectors responded to the control room and obtained an understanding of plant status, equipment/personnel performance and plant management decisions to assist NRC management in making an informed evaluation of plant conditions. The inspectors observed plant parameters and status for mitigating systems/trains and fission product barriers. Information sources included drawings, system descriptions, control board indications, plant logs, computer data, recorders, and licensee personnel.

The risk significance of the as found condition is being performed as part of the inspection activities documented in Special Inspection Team Report 05000454/2007-009.

The resident inspectors observed the licensee's dual unit shutdown from the control room. While performing a dual unit shutdown within a relatively short period of time was a challenge to the licensee's control room staff the evolution was professional and controlled. Extra personnel were brought in to assist the on shift operators, management personnel observed the shut down from the control room and the Outage Control Center (OCC), Nuclear Oversight Personnel observed the shutdown from the control room, and shift qualified nuclear engineers were brought in to support the shutdown.

With the exception of a trip to the OCC and Regulatory Assurance to discuss a question regarding the TRM, the resident inspectors maintained a continuous control room presence until after the licensee had entered Mode 3.

Even though the licensee's UHS for both units was inoperable it remained available as a heat sink with a leak rate of approximately 10 gpm. This leakrate was well within the licensee's safety related and non-safety related makeup water sources to the UHS.

Restart

The inspectors performed assessments to verify by selected sampling that the licensee's systems were ready to support a plant restart. In addition, the inspectors performed routine tours of containment to verify their readiness for restart. In both Unit 1 and Unit 2 containments the inspectors identified indications of small packing leaks that were inactive but which were not in the licensee's corrective action system and small amounts of debris that should have been identified by licensee personnel. In all cases the material was not of a size or amount that would have significantly impacted the licensee's emergency core cooling system recirculation sump. The licensee initiated corrective action documents and removed the material.

The inspectors later reviewed the initial investigation report and observed the Plant Operating Review Committee to assess the detail of review and adequacy of the licensee's understanding of the apparent causes and proposed corrective actions prior to restart of the units.

This inspection constituted one sample as defined in Inspection Procedure 71153-05.

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report (LER) 05000455/2007-001 Control Rod Drive Mechanism Penetration Nozzle Weld Indication Due to Primary Water Stress Corrosion Cracking

On April 9, 2007, the licensee was performing a volumetric examination of the Unit 2 control rod drive mechanism penetration nozzle when a ultrasonic testing indication was identified. A supplementary dye penetrant examination identified two surface breaking flaws. This condition was reportable as a condition that resulted in a principal safety barrier being seriously degraded. In response to the flaws, the licensee performed a weld overlay repair on the weld and submitted, as part of the relief request submittal for the repair of the weld, analysis which addressed/bounded crack growth for the weld overlay of an embedded flaw repair. The LER was reviewed, no performance deficiencies or findings of significance were identified, and no violation of NRC requirements occurred. This LER is closed.

.3 Declaration of an Alert Due to the Release of an Asphyxiant Gas

a. Inspection Scope

The inspectors reviewed the licensee's entry into an Emergency Action Level (HA7) due to the release of an asphyxiant gas into a portion of the Unit 1 Auxiliary Building. On November 27, 2007, the licensee was performing maintenance activities in the Unit 1 Train B Containment Spray and RHR pump rooms. As part of this maintenance a freeze seal was being placed by the use of liquid Nitrogen. Personnel in the area had oxygen monitors and air quality reports were received indicating an oxygen deficient atmosphere of 19.4 percent which is Immediately Dangerous to Life and Health (IDLH).

The inspectors responded to the control room and obtained an understanding of plant status, equipment/personnel performance and plant management decisions to assist NRC management in making an informed evaluation of plant conditions. The inspectors observed plant parameters and status for mitigating systems/trains and fission product barriers. Information sources included drawings, system descriptions, control board indications, plant logs, computer data, recorders, and licensee personnel.

The area was evacuated, the nitrogen was isolated and an ALERT was declared in accordance with EAL HA7 which has a threshold of "Report or detection of toxic or apshyxiant gases within a Table H2 area …in concentrations that result in an atmosphere IDLH." The auxiliary building is a Table H2 area. There were no radiological releases or threats to the public, unit power levels were not affected, no offsite assistance was requested and there were no Protective Action Recommendations required.

Following the isolation of the nitrogen to the freeze seal the fans in the pump room dispersed the nitrogen and oxygen levels returned to normal in about 45 minutes. The licensee initiated a root cause analysis and determined that additional ventilation systems should have been utilized, along with additional atmospheric monitoring, and personnel briefings. Additional training was given to plant personnel, and the communications with shift personnel regarding the possibility of degraded atmospheric conditions during some maintenance evolutions was improved.

The above represents one inspection sample.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) Unresolved Items (URI) 05000454/2006003-01: Unit 1 Essential Service Water Return Isolation Valves Degraded (1SX011 & 1SX136)

On November 29, 2005, during the execution of a clearance order for planned maintenance, 1SX011, the Unit 1 Train A & B Essential Service Water Cooling Tower (SXCT) basin return header cross-tie isolation valve, and 1SX136, the Unit 1 Train B SXCT return header isolation valve failed to close on demand. The licensee determined that the failure of these isolation valves to close was a maintenance preventable

functional failure and had exceeded the maintenance rule performance criteria for the isolation function. A Maintenance Rule (a)(1) action plan was initiated to address this issue. The licensee performed an operability evaluation and determined that the SX loops could not be separated with the above valves not able to close. However, the licensee concluded that they were not required to postulate that the SX lines would crack or break and they did not have to evaluate the operability of the system in the event of a pipe crack or break. This was in direct contraction with UFSAR Table 9.2.2, Single-failure Analysis of the Essential Service Water System, which showed that upon a break of an SX return line, the remaining return line continues to service one loop in each unit. As a result of this contradiction the issue was left unresolved.

Per the Maintenance Rule (a)(1) action plan, the licensee replaced the two essential service water return isolation valves in November 2007 and returned the valves to operation. The inspectors determined that the licensee repair efforts were commensurate with safety.

Subsequently, the inspectors had additional discussions with the licensee and with the Office of Nuclear Reactor Regulations. As a result of these discussions the inspectors determined that the licensee should have evaluated the design basis requirements of the SX return line with respect to a pipe break. However, the licensee had other isolation devices to mitigate a line break and the licensee's flooding calculation did take into account an SX header failure with acceptable results. Based on this information the inspectors concluded that the operability of the SX system was maintained. The inspectors also concluded that for completeness the associated operability evaluation should have included all aspects of the current licensing bases requirements such as single failure, flooding, earthquake, and loss of coolant accident. However, since there was no regulatory requirement regarding the adequacy of operability evaluations, no violation occurred. Therefore, this URI is closed.

4OA6 <u>Management Meetings</u>

.1 <u>Exit Meeting Summary</u>

On January 15, 2008, the inspector presented the inspection results to Mr. D. Hoots, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

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

- Radiation Protection (RETS/ODCM) inspection with Mr. Hoots and other licensee staff on November 9, 2007 and Mr. Kerr on December 5, 2007;
- Licensed Operator Requalification 71111.11B with Mr. G. Wolfe, Licensed Operator Requalification Train Lead, on December 17, 2007; and
- Emergency Preparedness Inspection with Mr. D. Drawbaugh on December 18, 2007.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Hoots, Site Vice President
M. Snow, Plant Manager
B. Adams, Quad Cities Engineering Director
G. Contrady, Nuclear Oversight Manager
D. Drawbaugh, Emergency Preparedness Manager
D. Thompson, Radiation Protection Manager
C. Gayheart, Work Manager
A. Giancatarino, Engineering Director
W. Grundmann, Regulatory Assurance Manager
S. Fruin, Operations Manager
B. Spahr, Maintenance Manager
S. Swanson, Maintenance Manager
S. Kerr, Chemistry Manager
G. Wolfe, Licensed Operator Requalification Training Lead

Nuclear Regulatory Commission

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000454/2007005-01	NCV	Unit 0 Train A Essential Service Water Basin Level Drop
05000454/2007005-02	NCV	Unit 1 Train B Auxiliary Feedwater Pump Lube Oil Leak

Closed

05000454/2006003-01	URI	Unit 1 Essential Service Water Return Isolation Valves Degraded (1SX011 & 1SX136)
05000454/2007001-00	LER	Control Rod Drive Mechanism Penetration Nozzle Weld Indication Due to Primary Water Stress Corrosion Cracking
05000454/2007005-01	NCV	Unit 0 Train A Essential Service Water Basin Level Drop
05000454/2007005-02	NCV	Unit 1 Train B Auxiliary Feedwater Pump Lube Oil Leak

LIST OF DOCUMENTS REVIEWED

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

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

IR 707339; Winter Readiness Review, December 04, 2007
IR 710931; Area Heater is Leaking Water on Floor at Walkway, December 13, 2007
BOP AS-E1; Unit 1, Auxiliary Steam System Electrical Lineup, Revision 2
BOP AS-E3, Unit 0, Auxiliary Steam System electrical Lineup, Revision 3
BOP AS-M1, Auxiliary Steam System Valve Lineup, Revision 29
BOP HT-1, Heat Trace System Startup, Revision 1
BOP HT-E1, Unit 1 Heat Trace Electrical Lineup, Revision 5
BOP HT-T1, Heat Trace Locations, Revision 2

<u>1R04 Equipment Alignment</u>

Critical Control Room Drawing M-138; Diagram of Chemical and Volume Control and Boron Thermal Regeneration, Revision AV
BOP CV-1b; Unit Two Startup of the CV System, Revision 21
BOP RH-2; Securing the RH System From Recirculation, Revision 8
BOP RH-M1A; Train “A” Residual Heat Removal System Valve Lineup, Revision 6
BOP RH-E1A; Residual heat Removal System Train “A” Electrical Lineup, Unit 1, Revision 2
SX-1 System Piping Drawing; September 23, 1998, Revision 3
SX-2 System Notes; February 20, 1995, Revision 3
M-126 Diagram of Essential Service Water, Sheets 1-3
BMP 3122-4; Revision 12, Essential Service Water Make-up Repair
IR 092998; Heating Observed on 0A SX M/U Pump, January 29, 2002
IR 713008; Unplanned LCOAR Entry 0A SX MU Pump, December 18, 2007

<u>1R05 Fire Protection</u>

Pre-Fire Plan - Zone 11.4A-1; 1B Auxiliary Diesel Feedwater Pump, January 31, 2007
Pre-Fire Plan - Zone 5.6-2; Division 21, Miscellaneous Electrical Equipment and Battery Room, January 31, 2007
Pre-Fire Plan – Zone 5.1-1; Elevation 426’ -0”, Division 12 ESF Switchgear Room, January 31, 2007
Pre-Fire Plan – Zone 8.5-2; Elevation 426’-0”, Unit 2 Turbine Building Elevation, January 31, 2007
Main Control Room Pre-Fire Plan; Zone 2.1-0”, January 31, 2007
Auxiliary Building Elevation Pre-Fire Plan; Zone 11.3-0, 364’-0”, January 31, 2007
IR 687892; Alarm Failure Associated with 0BOSR 10.C 2-1, October 22, 2007
IR 690182; FSIC Trouble Unit 2 FP Panel, October 26, 2007
Pre-Fire Plan – Zone 11.6-0 South, Zone 11.6-0 North, Zone 11.6-0 West, Revision 5

Corrective Action Documents as a Result of NRC Inspection

IR 694664; Pre-Fire Plan Discrepancies Within Plant Locals, November 05, 2007
IR 704156; Restricted Extinguisher Access, November 27, 2007

1R07 Heat Sink Performance

IR 699482; CO# 57609 Final Clear Delayed Due to 2A CV PP Lube Oil Breaker Removed, November 15, 2007
IR 696326; SX System Breech Could Put SXCT Basin in the Auxiliary Building Basement, November 08, 2007
IR 698926; Pitting Discovered on 2A CV PP Cubicle Cooler Channel Heads, November 14, 2007
IR 706828; 2B DG JW Cooler Upper Divider Plate Accept Criteria Not Met, December 04, 2007
IR 706829; 2B DG JW Cooler Lower Divider Plate Accept Criteria Not Met, December 09, 2007
IR 706862; 2B DG JW Cooler Upper Cover Plate Accept Criteria Not Met, December 09, 2007
IR 706863; 2B DG JW Cooler Lower Cover Plate Accept Criteria Not Met, December 09, 2007
UFSAR – Table 9.2-11; Essential Service Water Component Nominal Design Flow Rates, Revision 10
WO 929534 02; GL 89-13 HX JW Upper and Lower Inspection for DG, December 04, 2007

1R11 Licensed Operator Requalification Program

Cycle 07-5, Out of the Box Evaluation 07-45, Revision 3, September 18, 2007

1R12 Maintenance Effectiveness

Plant Barrier Impairment Permit No. 07-292; October 11, 2007
IR 544395; 1B FW Pump HP Stop Valves Failed Closed During Startup, October 16, 2007
IR 545519; IR 544395 Not Accurate (Unit 1 Loss of Feedwater Flow event), October 18, 2007
IR 545992; FW Pump High Pressure Stop Valve Solenoid Orientation, October 19, 2007
IR 685092; VA Duct to be Removed by WO 401976-27, October 15, 2007
IR 687083; 1B FW Pump HP Stop Valve Failed Closed, October 20, 2007
IR 703640; Unit 1 FW System Exceeds Maintenance Rule Reliability Criteria, November 26, 2007
Functional Failure Cause Determination Evaluation; Feedwater (FW) FW1, November 20, 2007
Apparent Cause Report; Trip of the 1B Feedwater pump During Plant Shutdown, November 29, 2007
Unit 1/0/2 Standing Order 07-049, October 12, 2007
Essential Service Water System Maintenance Rule Monthly Evaluation, November 2007
Design Change Package EC # 364470, Revision 000
IR 094130; Assign # 01; 2B FW Pump HP Stop Valve Closed on Startup
EC 367916, Installation of a Line Stop on Line 0SX97AA-24", Revision 0
EC 367918, Installation of a Line Stop on Line 0SX03CA-48" to Support Replacement of Line 0SX97AD-24"

1R13 Maintenance Risk Assessments and Emergent Work Control

Protected Equipment Log; November 14, 2007
Protected Equipment Log; November 26, 2007
Unit 1 Risk Configurations, Week of October 01, 2007, Revision 2

Unit 1 Risk Configurations, Weeks of November 15 and 26, 2007
BB PRA-017.66B; Risk Assessment – Heavy Load Lift for SX Valve Replacement, Revision 3
ER-AA-600-1012; Risk Management Documentation, Revision 7
IR 683242; Unable to Perform 0B VC Monthly Due to Chiller Work Window, October 11, 2007
IR 685745; Standing Order 07-049 for SX Valve Replacement Questions, October 17, 2007
IR 689055; 0A SX Basin Level Drop, October 24, 2007
IR 697876; Incomplete OLR Evaluation, November 12, 2007
Shutdown Safety Approval, B1F24/B2F25, October 21, 2007
OU-AA-103; Shutdown Safety Management Program, Revision 7
Unit 1 and Unit 2 Risk Configurations, Week of 12/17/07, Revision 1
Byron's Operations Narrative Logs, December 18, 2007 – December 19, 2007

Corrective Action Documents as a Result of NRC Inspection

IR 690214; Concerns with B1F24/B2F25 SSRB, October 26, 2007

1R14 Personnel Performance During Nonroutine Evolutions

0B0A Security – 1; Security Threat Unit 0, Revision 8

1R15 Operability Evaluations

Plant Barrier Impairment Permit No. 07-419; Dirt Removal, Revision 6
EC 367082 002; Operation Evaluation 07-008, UHS Capability with Failure of SX Fans
EC 367914; Dual Unit Outage SX Cell Mode 5 Requirements, Revision 0
Design Analysis ATD-0063; Heat Load to the Ultimate Heat Sink During a Loss of Coolant Accident, Revision 004A
Unit 1 Cycle 15 Accumulator Leakage, Revision 0, December 22, 2007
BOP VV-3; Control Room Offices HVAC System Startup and Shutdown, Revision 7
Project No. BYR-68853; Failure Analysis (2) Westinghouse HFB-3125 Molded Case Circuit Breakers, October 26, 2007
Project No. BYR-69850; Failure Analysis (4) Westinghouse Breakers, October 26, 2007
Project No. BYR-70817; Failure of 1B AF Diesel Valve Cover Gasket, November 12, 2007
IR 564358; Small Leak on the 1B AF Pump Southwest Valve Cover, December 01, 2006
IR 626301; Oil Leak on Northeast Valve Cover on 1B AF Diesel, May 07, 2007
IR 680189; Failures of Unit 1 Pressurizer Heater Molded Case Circuit Breakers, October 04, 2007
IR 680840; Oil Leak on Northeast Valve Cover on 1B AF Diesel, October 06, 2007
IR 680854; 1B AF Pump Operable with 2.85 GPD Oil Leak, October 06, 2007
IR 681075; 1B AF Pump Valve Cover Gasket Appears to be Separating, October 06, 2007
IR 681107; Oil Leak From Southeast Valve Cover on 1B AF Diesel, October 07, 2007
IR 714970; Degraded Control room Ventilation and Fire Barrier, December 22, 2007
SM-AA-300; Procurement Engineering Support Activities, Revision 3
SM-AA-330-1002; Procurement engineering Process and Responsibilities, Revision 7
SM-AA-330-1002; Bill of material Development and Right Parts Selection for Maintenance, Revision 4

Corrective Action Documents as a Result of NRC Inspection

IR 698399; MRC Comments on Shift Review of IR, November 13, 2007
IR 717197; NRC Question Regarding CAT ID Safety Classification, January 02, 2008
IR 717552; Attention to Detail Discrepancies in Surveillances, January 03, 2008

1R19 Post Maintenance Testing

WO 401976; Replace Valve Due to High Torque Required to Operate Valve, November 30, 2007
WO 401976 22; OPS PMT-Functional, Partial Stroke 1SX136, November 20, 2007
WO 401976 23; Diagnostic Testing – 1SX136, November 16, 2007
WO 401976 46; PMT VT2 System Leakage at NOP/NOT, November 10, 2007
WO 401976 47; PMT VT2 System Leakage at NOP/NOT – OFPC2BD-6, November 26, 2007
WO 662363; Replace 1SX011 Due to High Torque Required to Operate Valve, December 07, 2007
WO 663363 27; OPS PMT Verify Removable VA Duct is Installed, December 06, 2007
WO 663363 38; VT2 VIS of 1SX011 and Replaced Pipe Spool, November 15, 2007
WO 663363 39; VT@ System Leakage at NOP/NOT, November 14, 2007
WO 663363 47; Remove Pumping Skid For Draining of 42” SX Piping, November 15, 2007
WO 854882 02; OP PMT: Verify Proper CV Pump/Motor Oil Level
WO 99040347 02; SEP Perform 2B CV Pump ASME PER 2BVSR 5.5.8.CV.5-2A
WO 99040347 06; ST CMO Vibration Testing for Uncoupled Motor Run
WO 992403; Operations PMT, Cycle Breaker Bus 141-Cub4
WO 999953; Operations PMT, Visually Verify No Leakage from Flange
WO 772997 03; SEP Visual on Gear Oil Pins and Oil Leaks
WO 1028181 03; Replace Northeast/Southwest Valve Cover Gaskets, October 06, 2007
WO 1028181 04; OPS PMT Check for Oil Leaks on Valve Covers, October 07, 2007
WO 1045328 01; 2CV01PB Group A IST Requirements for CV Pump, October 10, 2007
WO 1092234 02; Change in Status of 2B DG “A” Air Compressor, December 28, 2007
IR 701946; Found Fasteners Bottomed Out, November 20, 2007
IR 713008; Unplanned LCOAR Entry 0A SX Makeup Pump, December 18, 2007
IR 714757; Critical Spare Not in “Ready to Install” Condition, December 20, 2007
0BOSR 7.9.6-1; Essential Service Water Makeup Pump 0A Monthly Operability Surveillance, Revision 21
0BVSR 5.5.8.SX.5-1a; Unit 0 Group A Inservice Testing (IST) Requirements for Essential Service Water Makeup Pump 0A, Revision 1
Procedure BOP RH-5, Revision 23, Residual Heat Removal System Startup for Recirculation
NDE Report No. 2007-472; 1SX03B-42, October 09, 2007

Corrective Action Documents as a Result of NRC Inspection

IR 715552; Deficiency in Surveillance Procedure for SX Makeup Pump Auto Start, December 26, 2007

1R20 Outage Activities

IR 676679; 0SX163D Vault Leaking Approximately 1 GPM to Ground, September 27, 2007
IR 685585; Standing Order Being Used as a Substitute for Procedures, October 16, 2007
IR 685955; Min Wall on SX Riser Piping, 0SX97AB-24, October 17, 2007
IR 687374; Oversimplification of SX TS Applicability, October 21, 2007

IR 687409; I don't Like What the Plan Is, October 21, 2007
IR 688752; Not Fixing SX Problems Before Startup, October 24, 2007
IR 690980; Lack of Direction and Poor Process Control for SX Aggregate, October 29, 2007
IR 693606; Linestop Equipment Damaged During Removal From 0D SX Pipe, November 02, 2007
IR 691623; Material in Bottom of a SX Underground Header Supplying a SX, October 07, 2007
IR 691915; 0SX163A – Visual Inspection Determined Valve Will Leak, October 30, 2007.
IR 703348; B1F24/B2F25 Outage Critique, November 02, 2007
2BGP 100-2, Revision 33; Plant Startup
2BGP 100-2A1, Revision 21; Reactor Startup
2BVSR XPT-2, Revision 6; Checkout of the Bank Overlap Unit
Unit 0 Standing Order; Log No. 07-050 SX Cooling Tower Operations, October 27, 2007
Unit 0/1/2 Standing Order; Log No. 07-051; Contingency Actions for Installed SX Riser Line Stops, October 28, 2007
Unit 0/1/2 Standing Order; Log No. 07-057; 0SX162C Piping Replacement Contingencies, November 14, 2007
Unit 0 Standing Order; Log No. 07-056 Contingencies During Repair of Line Downstream of 0SX162C, November 03, 2007
Selected B1F24/B2F25 OCC Turnover
Selected Outage Risk Status

Corrective Action Documents as a Result of NRC Inspection

IR 680740; Concern Past Boric Acid Leakage 2SI8920, October 05, 2007
IR 691554; 0A and 0D UHS Riser Piping Inoperable, October 30, 2007
IR 691623; Material in Bottom of A SX Underground Header Supplying A SX, October 07, 2007
IR 691772; NRC Senior Resident Inspector Unit 2 Mode 3 Walkdown Results, October 30, 2007
IR 691990; 2RC030 Minor Valve Packing Leak (Boric Acid), October 30, 2007
IR 691955; NRC Walkdown of Unit 1 Containment, October 30, 2007

1R22 Surveillance Testing

1BOSR 3.1.5-1; Unit 1 Train A Solid State Protection System Bi-Monthly Surveillance, Revision 26
2BOSR 8.1.2-1; 2A DG Operability Surveillance, Revision 20
Drawing 6E-2-4031RC28; Loop Schematic Diagram Wide Range Temperature (Cold Leg) Protection II (2TE-RC024B & RC025B) Protection Cabinet II (2PA02J), Revision L
Drawing 6E-2-4031RC26; Loop Schematic Diagram Reactor Coolant System Cold Overpressurization System Control 2A & 2D Control Cabinet 5 & 8 (2PA05J & 2PA08J), Revision 0
BISR 3.3.2-202; Surveillance Calibration of Wide Range Reactor Coolant Inlet/Outlet Temperature, Revision 9
BwISR 3.3.3.2-203; Surveillance Calibration of Wide Range Reactor Coolant Cold Leg (Inlet) Temperature and Loop A Hot Leg Pressure, Revision 9

Corrective Action Documents as a Result of NRC Inspection

IR 713512; Potential Discrepancy in B.5.B Training Commitment, December 18, 2007
IR 713778; Questions on Prudency on Performing Surveillance on Line, December 13, 2007

1R23 Temporary Plant Modifications

CC-AA-320-001; Dynamic (Seismic) Qualification of Equipment, Revision 4
MA-BY-716-026-1001; Seismic Housekeeping, Revision 0
EC 367928 001; Leakby Control in Line 2SX03B-42" Utilizing Valves 0SX241, 0SX242, 1SX265A and 1SX265B and De-Watering Pumps

Corrective Action Documents as a Result of NRC Inspection

IR 691655; Technical Rigor Associated with EC 364470, October 30, 2007

1EP4 Emergency Action Level and Emergency Plan Changes

Byron Station Annex of the Exelon Standardized Emergency Plan; Revisions 17, 18, 19, 20 and 21

2PS3 Radiological Environmental Monitoring Program And Radioactive Material Control Program

Radiological Environmental Monitoring Program (REMP) and Radioactive Material Control Program
CY-BY-170-301; Byron Station Offsite Dose Calculation Manual, Revision 5
Sample Collection Manual; Environmental Incorporated Midwest Laboratory, Revision 10, January 6, 2006
Functional Area Self-Assessment; Check-in REMP/RAM Control; Action Tracking/Assignment No. 00558566-05, October 1, 2007
Byron 2006 Annual Radiological Environment Operating Report, May 2007
Technical Requirements Manual; Section 3.12; Radiological Environmental Monitoring Program, Revision 46
Chemistry, Radwaste, Effluent and Environmental Monitoring Program Audit Report, NOSA-BYR-06-04; AR 437597, April 5, 2006
Energy Northwest Audit of Teledyne Brown Engineering Environmental Services (TBE-ES); Audit No. 05-A-09; NUPIC Audit No. 19309; and Supplier No. 2427, December 15, 2005
NUPIC Audit/Survey Number 19238; Environmental Inc. Northbrook, IL, January 18, 2006
Monthly Report on the Meteorological Monitoring Program at the Byron Nuclear Station, August 2007
Monthly Report on the Meteorological Monitoring Program at the Byron Nuclear Station, September 2006
Monthly Report on the Meteorological Monitoring Program at the Byron Nuclear Station, May 2007
IR 526171; REMP Lab Misses LLD for Low level Iodine in Cow Milk, August 7, 2007
IR 562730; Hour Meter Malfunction on BY-04 REMP Air Sample Station, November 28, 2006
IR 475120; Duplicate Environmental TLD's/Global Dosimetry Error, March 31, 2006
IR 481720; Missed REMP Samples in January 2006, April 21, 2006
IR 483012; Surface Water Samples Unobtainable in February 2006, April 25, 2006
IR 561302; Unable to Obtain Goat Milk Sample BY-38, November 7, 2006
IR 526017; Unable to Obtain Goat Milk Sample BY-38, August 25, 2006
IR 562714; No Root Vegetable Sample Obtained in Quadrant No. 3, November 2006
IR 579820; Missed REMP Samples in December 2006, January 17, 2007
RP-AA-214; Area TLD Surveillance, Revision 2

RP-AA-214, Attachment 2; Area TLD Worksheet, January 1, 2006 through June 30, 2006, dated August 29, 2006
RP-AA-214, Attachment 2; Area TLD Worksheet, July 1, 2006 through December 31, 2006, dated January 25, 2007
IR 582299; 2006 Year End Results for Area TLDs, dated January 23, 2007
Unconditional Release Detection Thresholds and Dose Consequences, December 9, 2005
BRP 5822-11; Calibration of Nuclear Enterprises Small Articles Monitor (SAM), Revision 13
BCP 300-92; NPDES/Compositor Performance Check, Revision 6
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RP-BY-503-1002; Release of material from RWP Exempt RCAs, Revision 0
RP-BY-500; Radioactive material (RAM) Control, Revision 13
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IR 696773; REMP TLD Location Further Than Closest Resident, November 8, 2007

4OA1 Performance Indicator Verification

IR 683378 4D; MSPI and Maintenance Rule CDE Correction Requirement Missed in IR, October 11, 2007
Selected Byron Operations Narrative Logs, July 1, 2006 to September 30, 2007
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Completed Monthly Report, LS-AA-2200, Attachment 2, High Pressure Safety Injection Function, July 2006 to September 2006
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Completed Monthly Report, LS-AA-2200, Attachment 5, Emergency AC Power Function, October 2006 to December 2006
Completed Monthly Report, LS-AA-2200, Attachment 6, Cooling Water Support Function, January 2007 to March 2007
MSPI Derivation Report; Byron Unit 1, High Pressure Injection System, Unreliability Index, September 2006
MSPI Derivation Report; Byron Unit 1, High Pressure injection System, Unavailability Index, September 2006
MSPI Derivation Report; Byron Unit 2, Heat Removal System, Unreliability Index, June 2007
MSPI Derivation Report; Byron Unit 2, Heat Removal System, Unavailability Index, June 2007
MSPI Derivation Report; Byron Unit 2, Residual Heat Removal System, Unreliability Index, September 2007
MSPI Derivation Report; Byron Unit 2, Residual Heat Removal System, Unavailability Index, September 2007
MSPI Derivation Report; Byron Unit 1, Emergency AC Power System, Unreliability Index, December 2006
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IR 714087; Frequently Asked Question Process Improvement Needed, December 20, 2007
IR 714821; Question on MSPI Start Demands and PMT Testing, December 21, 2007
IR 715555; Issue with MSPI Demand Counting, December 26, 2007

4OA2 Problem Identification and Resolution

IR 665859; Inconsistent Procedure Application of a Faulted/Ruptured SG, August 29, 2007
IR 685707; NOS Identified 3Q07 Yellow Rating for Engineering, October 11, 2007
IR 695353; NOS Identified Discrepancies in an Engineering Evaluation, November 06, 2007
IR 703821; FHB Overhead Crane PM's Conflict with New Fuel Receipt, November 20, 2007
IR 712524; Fleed-Wide Scaffold Issues, December 13, 2007
1BOSR MS-R1; U-1 Manual Stroke of the SG PORVS 18 Month Surveillance, Revision
Drawing 93-14798; 8" – 1500 Weld Ends Carbon Steel Flex Wedge Gate Valve With 10:1 Bevel Gear Operator, Revision D
IR 662494; SGTR Analysis Input Error, August 20, 2007
IR 673669; Is a Contingency Plan Needed for SGTR Analysis Revision, September 20, 2007
IR 680419; SG PORV TS Inappropriately Credits Local OPS for SGTR, October 05, 2007
IR 685058; Concerns with SGTR Analysis Input Assumptions, October 15, 2007
IR 687783; B1F24/B2F25 SG PORV Operability Concern, October 22, 2007
IR 691095; Inoperability of SG PORVs in Local Mode, October 29, 2007
IR 713620; Request for OPS Support – Time Validate SGTR Local Actions, December 19, 2007
IR 713904; Independent Review of Byron/Braidwood SGTR Analysis, December 19, 2007
HU-AA-1211; Briefings – Pre-job, Heightened Level of Awareness, Infrequent Plant Activity and Post-Job Briefings, Revision 3
SA-AA-112; Hearing Conservation, Revision 3
Log No. 07-053; Timeliness of Local Operator Actions, October 29, 2007
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ASME F1030-86; Standard Practice for Selection of Valve Operators, 2004
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IR 705978; SGTR Manual Actions UFSAR Assumed Time Response Question, November 30, 2007
IR 713565; SGTR Offsite Dose Case Issue, December 19, 2007
IR 680740; Concern Past Boric Acid Leakage 2SI8920, October 05, 07

4OA3 Followup of Events and Notices of Enforcement Discretion

EC 367916; Line Stop Installation at Line 0SX97AA-24", Revision 0
EC 367915; Line stop Installation at Line 0SX97AB-24", Revision 0
WO 01047835-04; Remove/Reinstall Missile Barrier to Support Temporary Repair Activities, Revision 0
IR 689944; Debris at SXCT Jobsite, Debris Retrieved from SXCT Basin, October 26, 2007
IR 689446; Different Day- Same SX Level Control Problem, October 25, 2007

IR 703919; Alert (HA7) Declared Due to Low Oxygen Levels in 1B CS Pump Room, November 27, 2007
Event Summary Report; Alert Declared at the Exelon Nuclear Byron Generating Station, November 27, 2007
Plant Barrier Impairment Permit # 07-476; Door AB1 from 1CS01PA RM A-210
Plant Barrier Impairment permit # 07-477; Door 1CS01PA from 1CS01PB Rm A-212
Hourly Fire/Flood Watch Inspection Log; 1BCS Pump Room, November 27, 2007
LER 455/2007-001-00, April 09, 2007
Byron Station Alert Event Report from November 27, 2007, Report dated December 26, 2007
Event Review Checklist, Byron Station November 27, 2007

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IR 692799; Contingency Plans for SXCT Risers Not Evident, October 30, 2007
IR 708353; 1CS043A Requires Cleaning, NAOH Is On the Valve Body, December 06, 2007
IR 708906; Follow-up Question – 11/27/07 Alert, December 07, 2007
IR 713512; Potential Discrepancy in B.5.B Training Commitment, December 18, 2007
IR 701830; Question on Identification of Plant Thin Wall Piping, November 20, 2007
IR 691772; NRC Senior Resident Inspector Unit 2 Mode 3 Walkdown Results, October 30, 2007

LIST OF ACRONYMS USED

AF	Auxiliary Feedwater System
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
CAP	Corrective Action Program
CFR	Code of Federal Regulations
EC	Engineering Change
IMC	Inspection Manual Chapter
IR	Inspection Report
IR	Issue Report
LER	Licensee Event Report
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PI	Performance Indicator
PM	Planned or Preventative Maintenance
PORV	Powered Operated Relief Valve
REMP	Radiological Environmental Monitoring Program
RETS	Radiological Effluent Technical Specification
RHR	Residual Heat Removal
SDP	Significance Determination Process
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SX	Essential Service Water System
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item