UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
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February 1, 2011

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

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3 INTEGRATED INSPECTION REPORT 05000237/2010-005; 05000249/2010-005

Dear Mr. Pacilio:

On December 31, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed report documents the results of this inspection, which were discussed on January 19, 2011, with Mr. T. Hanley, and other members of your staff.

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

Based on the results of this inspection, two NRC-identified findings of very low safety significance were identified. Each of the findings involved a violation of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of these NCVs, 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 Dresden Nuclear Power Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Dresden Nuclear Power Station.

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

Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

Docket Nos. 50-237; 50-249
License Nos. DPR-19; DPR-25

Enclosure: Inspection Report 05000237/2010-005; 05000249/2010-005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000237; 05000249
License Nos:	DPR-19; DPR-25
Report No:	05000237/2010-005; 05000249/2010-005
Licensee:	Exelon Generation Company, LLC
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	Morris, IL
Dates:	October 1 through December 31, 2010
Inspectors:	C. Phillips, Senior Resident Inspector D. Meléndez-Colón, Resident Inspector J. Draper, Reactor Engineer D. Sand, Reactor Engineer W. Slawinski, Senior Health Physicist T. Go, Health Physicist F. Nestor, Reactor Engineer T. Bilik, Senior Reactor Inspector E. Sanchez, Reactor Inspector R. Jickling, Senior Emergency Preparedness Inspector
Approved by:	M. Ring, Chief Projects Branch 1 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000237/2010-005, 05000249/2010-005; 10/01/2010 – 12/31/2010; Dresden Nuclear Power Station, Units 2 & 3; Equipment Alignment, Inservice Inspection.

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 (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of Technical Specification 5.4.1 for the licensee's failure to implement the section of the high pressure coolant injection (HPCI) booster pump maintenance procedure that prescribes how to robustly mark the HPCI booster pump sight glasses to indicate the acceptable oil levels for the bearings of the Unit 2 and 3 HPCI booster pumps. Upon being informed of the condition, the licensee verified, using measurements, that the oil level for the bearings was adequate and entered the condition in the corrective action program to provide a more robust indication of the acceptable oil level.

  This finding is of greater than minor safety significance because, if left uncorrected, it has the potential to lead to a more significant safety concern. Specifically, if a more robust minimum level indication is not used, the wires could slide down the sight glass to the point that they do not prevent operators from allowing the oil level to drop below the minimum acceptable level for the pump to perform its safety function. The finding impacted the Mitigating Systems Cornerstone because it involved degradation of HPCI. It is not greater than Green because it did not result in the loss of operability of the HPCI system. The inspectors determined that this finding has a cross-cutting aspect in the area of Problem Identification and Resolution under the component Corrective Action Program because the licensee did not take appropriate corrective actions to address safety issues in a timely manner, commensurate with their safety significance and complexity. P.1(d) (Section 1R04.2)

- Green. A finding of very low safety significance (Green) and associated non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the failure to accomplish activities affecting quality in accordance with procedures. Specifically, the licensee's vendor non-destructive examination (NDE) examiner failed to perform a magnetic particle (MT) examination in accordance with procedures on the 3/2/1501-20/20-10 Unit 3 low pressure coolant injection support. The licensee initiated corrective action document Issue Report (IR) 01135770 to address the issue.

The finding was determined to be more than minor because, if left uncorrected, it would have the potential to lead to a more significant safety concern. The failure to perform an adequate MT examination could have allowed undetected flaws to remain in service. This finding is of very low safety significance (Green) because the inspectors answered "No" to all of the characterizations worksheet questions in Table 4a of MC 0609.04. Specifically, no indications were identified when the examination was re-performed. This finding has a cross-cutting aspect in the area of Human Performance for the Work Practices component because the licensee proceeded in the face of uncertainty and unexpected circumstances by continuing to perform the examination after the equipment became damaged. The licensee's examiner also elected to continue after identifying there was material present on the pipe in a location that could interfere with the exam. In addition, due to different circumstances surrounding the exam such as: component location, equipment weight, and environmental conditions, the examiner became tired. Nonetheless, the examiner elected to continue to perform the examination in this condition. H.4(a) (Section 1R08)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 2

On October 6, 2010, load was reduced to approximately 94 percent electrical output due to a high bearing temperature on 2/3 B lift pump. The unit returned to full power operation on October 7, 2010.

On October 10, 2010, load was reduced to approximately 99 percent electrical output because of a low vacuum due to two circulation water pump operation and high intake temperatures. The unit returned to full power on October 11, 2010.

On December 11, 2010, load was reduced to approximately 88 percent electrical for a control rod pattern adjustment. The unit returned to full power operation on December 12, 2010.

Unit 3

On October 1, 2010, load was reduced to approximately 96 percent electrical output for a core coastdown.

On October 3, 2010, load was reduced to approximately 95 percent electrical output for a control rod pattern adjustment. The unit resumed its core coastdown maximum power level of approximately 96 percent on the same day.

On October 11, 2010, the unit was automatically scrammed due to a nuclear power instrument equipment issue. The unit commenced startup and resumed its core coastdown on October 14, 2010.

On November 1, 2010, the unit was in planned refueling outage D3R21.

On November 29, 2010, after planned refueling outage D3R21, the unit returned to full power operation.

On December 3, 2010, load was reduced to approximately 66 percent electrical output for a loss of vacuum due to an offgas train issue. The unit returned to full power operation on December 4, 2010.

On December 16, 2010, load was reduced to approximately 92 percent electrical output for a control rod pattern adjustment. The unit returned to full power operation on the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition – Severe Thunderstorm Watch

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for October 26 and 27, 2010, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On October 25, 2010, the inspectors walked down the main power transformers, in addition to the licensee's emergency alternating current (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 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 to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. 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. The inspectors also reviewed a sample of corrective action program (CAP) items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures.

This inspection constituted one readiness for impending adverse weather condition sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

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

- Unit 2/3 cribhouse traveling screens and;
- radiation waste outdoor storage tanks.

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

b. Findings

No findings were identified.

.3 External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the UFSAR for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also walked down underground bunkers/manholes subject to flooding that contained multiple train or multiple function risk-significant cables. The inspectors also reviewed the abnormal operating procedure (AOP) for mitigating the design basis flood to ensure it could be implemented as written.

This inspection constituted one external flooding sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04Q)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Unit 3 reactor building containment cooling water (RBCCW) / Unit 2/3 RBCCW pump;
- Unit 3 low pressure coolant injection Division 1; and
- Unit 2 A instrument air system while in protected status.

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, the UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), 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 CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted three partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

.2 Closed Unresolved Item (URI) 05000237/2010003–01; 05000249/2010003–01: High Pressure Coolant Injection (HPCI) Booster Pump Bearing Oil Levels

a. Inspection Scope

Unresolved Item (URI) 05000237/2010003–01; 05000249/2010003–01, was opened in the second quarter of 2010 due to sight glasses on the high pressure coolant injection (HPCI) booster pump not conforming to the maintenance procedure guidance and the oil levels in these sight glasses potentially being outside the acceptable levels. During this inspection period, the inspectors reviewed additional information provided by the pump vendor, as well as additional corrective action program and work management documents, to determine if any operability concerns existed. This URI is closed under Section 4OA5.2 of this report. This review did not represent an inspection sample.

b. Findings

(1) Failure to Provide Robust Indication of Adequate Oil Level in High Pressure Coolant Injection Booster Pump Sight Glasses

Introduction: The inspectors identified a finding of very low safety significance (Green) and associated non-cited violation of TS 5.4.1, “Procedures,” for the licensee’s failure to provide a robust indication of adequate oil level in the sight glasses to the bearings of the Unit 2 and 3 high pressure coolant injection (HPCI) booster pumps.

Description: While performing a walkdown of the Unit 2 HPCI system on June 17, 2010, the inspectors identified that a colored wire band used to indicate the minimum acceptable oil level on the HPCI booster pump outboard bearing sight glass was below its intended position and the oil level in the sight glass was near that intended level. The inspectors questioned the licensee on the acceptability of the current oil level and the adequacy of the wire bands as oil level indicators, which were being used on all the sight glasses for the inboard and outboard bearings for both the Unit 2 and Unit 3 HPCI booster pumps (total of 4 sight glasses). The licensee measured the oil levels in each of the sight glasses and determined that the level of oil in each was adequate and that operability of the pumps was not challenged. The licensee also replaced the colored band back to its intended location and added oil to the Unit 2 HPCI booster pump outboard bearing to bring it back up to the desired level.

Because the colored wire bands were still susceptible to sliding on the sight glass, the inspectors then asked at what oil level the licensee would question the operability of the pump, and the licensee was unable to give the inspectors an answer. The licensee's vendor documents for the pump did not specify acceptable oil levels for the bearings, and the only document that specified any levels was the HPCI Booster Pump Maintenance procedure (MA-AB-734-448), which recommended a ½" band centered 2.5" below the centerline of the shaft for the inboard bearing and 2.375" below the centerline for the outboard bearing. These were based on an email from the vendor dated January 13, 2004. The licensee identified that the colored wire bands being used did not conform to this procedure, and the inspectors noted that since the high and low level indications in the field were approximately 1" apart, the non-conformance was also less conservative than the procedure in both the high and low directions.

The licensee contacted the pump vendor and requested the appropriate oil levels for the pump. In a letter to the licensee dated August 25, 2010, the vendor provided the licensee with new maximum, minimum, and design oil levels. The new vendor-recommended minimum level is lower than both the old recommended minimum level and the indicated minimum levels in the field. The letter also stated that "the minimum level is the lowest level for the pump to still be designated as operable." While only an on-shift senior reactor operator can designate equipment as operable or inoperable, this indicates that below this level, operability of the pump could be challenged.

The licensee initiated IR 1108277 to include the letter in the vendor manual for the HPCI booster pump, and WOs 1372523 and 1372526 to change the markings on the sight glass to incorporate the new levels.

Analysis: The inspectors determined that the licensee's use of the colored wire bands as the indicator of acceptable oil level on the HPCI booster pump bearings was a performance deficiency because the bands did not conform to procedure MA-AB-734-448, "HPCI Booster Pump Maintenance." This procedure directs the licensee to mill grooves at the appropriate levels into a copper sleeve around the sight glasses to provide a robust indication of the acceptable oil levels.

This performance deficiency is a finding of more than minor safety significance because, if left uncorrected, it has the potential to lead to a more significant safety concern. Specifically, if a more robust indication of the minimum acceptable level is not used, the wires could slide down the sight glass to the point that they do not prevent operators from allowing the oil level to drop below the minimum acceptable level for the pump to perform its safety function.

The inspectors performed a Phase 1 Significance Determination, using Table 2 of Attachment 4 of Inspection Manual Chapter (IMC) 0609, and determined that the finding impacted the Mitigating Systems Cornerstone because it involved degradation of High Pressure Coolant Injection, a high pressure system used for short term core decay heat removal. Using Table 4a of the same Attachment, the inspectors determined that the finding was of very low safety significance, or Green, because the finding is a design deficiency confirmed not to result in loss of operability or functionality. This was determined since the oil level in the bearings did not fall below the minimum acceptable level for the pump to perform its safety function.

The inspectors determined that this finding has a cross-cutting aspect in the area of Problem Identification and Resolution under the component Corrective Action Program because the licensee did not take appropriate corrective actions to address safety issues in a timely manner, commensurate with their safety significance and complexity. Specifically, after the licensee revised the HPCI booster pump maintenance procedure in 2004 to include instructions on marking the bearing oil sight glasses, the licensee did not initiate any actions to make those modifications until questioned by the inspectors in 2010, despite having one or more opportunities on each unit during system maintenance outages and refueling outages. P.1(d).

Enforcement: Technical Specification 5.4.1 states, in part, “Written procedures shall be established, implemented, and maintained covering the following activities: The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.” In Section 9.a of Appendix A of Regulatory Guide 1.33, it states, “Maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances.”

Contrary to the above, the licensee failed to implement Section 4.28 of the HPCI Booster Pump Maintenance procedure (MA-AB-734-448, Revision 0), which prescribes how to robustly mark the HPCI booster pump sight glasses at the vendor-recommended levels. The licensee had the opportunity to implement this section of the maintenance procedure during HPCI maintenance outages on Unit 2 in March 2009 and Unit 3 in December 2009.

The licensee initiated IR 1108277 to include the letter in the vendor manual for the HPCI booster pump, and WOs 1372523 and 1372526 to change the markings on the sight glasses to incorporate the appropriate oil levels.

Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000237/2010005-01; 05000249/2010005-01)

1R05 Fire Protection (71111.05Q and A)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 8.2.6D, Unit 3 low pressure heater bays, elevation 538';
- Fire Zone 8.2.5E, Unit 3 high pressure heater bays, elevation 517';
- Fire Zone 8.2.5D, Unit 3 low pressure heater bays, elevation 517';
- Fire Zone 8.2.2A, Unit 2 containment cooling service water pumps, elevation 495'; and
- Fire Zone 8.2.5E, Unit 3 switchgear area, elevation 517'.

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

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

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (ISI) 71111.08G

From November 1, 2010, through November 19, 2010, the inspectors conducted a review of the implementation of the licensee's ISI Program for monitoring degradation of the reactor coolant system, risk-significant piping, and components and containment systems.

The inspections described in Sections 1R08.1 and 1R08.5 below count as one inspection sample as defined in IP 71111.08-05.

.1 Piping Systems ISI

a. Inspection Scope

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

- Ultrasonic Examination of the emergency core cooling system ring header pipe weld (weld 3/2/1501-24/24-47);
- Ultrasonic Examination (UT) of the emergency core cooling system (ECCS) ring header pipe weld (weld 3/2/1501-24/24-48); and
- Magnetic Particle Examination (MT) of the U3 Low Pressure Coolant Injection (LPCI) Support 3/2/1501-20/20-10.

During the prior outage non-destructive surface and volumetric examinations, the licensee did not identify any relevant/recordable indications. Therefore, no NRC review was completed for this inspection procedure attribute.

The inspectors reviewed the following pressure boundary welds completed for risk-significant systems since the beginning of the last refueling outage to verify that the welding and any associated non-destructive examinations were performed in accordance with the Construction Code and ASME Code, Section XI.

- Weld repair of the Hydraulic Control Unit 34-03 SCRAM discharge valve (component id: 3-0305-34-03-102) FW1 and FW4; and
- Weld repair of the Hydraulic Control Unit SCRAM discharge valve (component id: 3-0305-34-03-101 FW2 and FW3.

The inspectors also reviewed the welding procedure specification and supporting weld procedure qualification records for the above, to determine if the welding procedures were qualified in accordance with the requirements of the Construction Code and the ASME Code Section XI.

b. Findings

(1) Failure to Perform Magnetic Particle Examination on the 3/2/1501-20/20-10 Unit 3 Low Pressure Coolant Injection Support in Accordance with Procedures

Introduction: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified by the inspectors for the failure of a licensee vendor NDE examiner to accomplish activities affecting quality in accordance with procedures.

Description: On November 3, 2010, the inspectors observed a licensee vendor NDE examiner performing a magnetic particle examination on the 3/2/1501-20/20-10 Unit 3 low pressure coolant injection (LPCI) Support. During the course of the examination, the magnetizing equipment lost power. The examiner attempted to determine the cause of the problem by unplugging and re-plugging the equipment into the electrical receptacle. The examiner then noticed, if he manipulated the cord, the equipment obtained power. The examiner then proceeded to manipulate and tie the cord in a position where the equipment appeared functional and proceeded with the examination using the damaged equipment. The inspectors were concerned that since the power cord was damaged the resistance applied could have been significantly different, which in turn would change the amount of current traveling through the cord, affect the magnetic flux produced by the equipment and invalidate its calibration.

Also, the inspectors observed two instances where the magnetizing equipment was not in contact with the examination surface. In the first example, the examiner performed a portion of the test with one end of the magnetizing equipment resting on a label/tag that was located on the pipe the support was attached to. When questioned by the NRC, the examiner proceeded to demonstrate that a magnetic field could be generated through the label/tag. Though a magnetic field was apparent, there was no method of determining that it was sufficient to meet the calibration requirements to perform the test. Per ASME Section V SE-709, the technique being used is indirect magnetization; the amount of sufficient magnetization was demonstrated through direct contact with a metal plate and anything interfering with that contact can affect the magnetization strength and, therefore, not meet the calibration requirements. In such instances, the magnetization would have to be demonstrated by performing testing, similar to the case when coatings are present as described in procedure GE-MT-100, Revision 6, “Procedure for Magnetic Particle Examination.” Step 6.3.1 of that procedure establishes the requirements for examinations of sections where the area of interest is coated. After further questioning from the NRC regarding this point, the examiner proceeded to perform the test with both ends of the magnetizing equipment in contact with the examination surface versus the label/tag. In the second example, there was an instance where the test was being performed with one end of the magnetizing equipment held in the air and not in contact with the examination surface. In order for a magnetic flux line direction to be established, both ends of the magnetizing equipment need to be in contact with the examination surface. When the inspectors questioned the examiner on the failure to establish contact with the examination surface, the examiner indicated that due to the position of the component and the weight of the equipment, he had become tired and did not note he was not making contact with the surface.

The inspectors identified that the examiner had failed to perform the examination in accordance with the requirements of procedure GE-MT-100, “Procedure for Magnetic Particle Examination.” Specifically, after identifying that the magnetizing equipment was damaged, the examiner elected to continue to perform the examination with the damaged equipment and the examiner failed to ensure the magnetizing equipment was in contact with the examination surface. Also, by not ensuring proper contact existed, the requirements of the procedure, that establish the component will be placed on the surface to be examined and the examination component shall be magnetized in at least two separate magnetic flux line directions, would not be met. As a result, there was a lack of confidence whether an appropriate field was maintained throughout the examination and hence in the examination results.

In response to NRC questions, the licensee initiated IR 01135770 to address the concerns, and the examination was subsequently re-performed as required with no recordable indications.

<u>Analysis</u>: The inspectors determined that the failure to adequately perform a magnetic particle test on the 3/2/1501-20/20-10 U3 LPCI Support in accordance with procedures

was contrary to 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," and was a performance deficiency.

The performance deficiency was determined to be more than minor because, if left uncorrected, it would have the potential to lead to a more significant safety concern. Specifically, the inspector noted that the examiner that performed the magnetic particle (MT) examination would likely be used for future MT examinations. Therefore, absent NRC intervention, the licensee would have continued to perform inadequate MT examinations and could have allowed undetected cracks to remain in service. Undetected cracks would place components such as the LPCI support at increased risk for failure, which would affect the safety of an operating reactor. Based upon review of IMC 0612, Appendix B "Issue Screening," the inspectors determined the finding affected the Mitigating Systems Cornerstone attribute of Equipment Performance (reliability).

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Mitigating Systems Cornerstone. The inspectors determined that the finding was of very low safety-significance (Green) because the inspectors answered "No" to all of the worksheet questions. Specifically, no indications were identified when the examination was re-performed.

This finding has a cross-cutting aspect in the area of Human Performance for the Work Practices component. Specifically, based on the inspectors' observations and interviews with the individuals involved, the licensee proceeded in the face of uncertainty and unexpected circumstances by continuing to perform the examination after identifying the magnetizing equipment became damaged. The licensee's examiner also elected to continue after identifying that material was present on the pipe in a location that could interfere with the exam. In addition, due to different circumstances surrounding the exam such as: component location, equipment weight, and environmental conditions, the examiner became tired. Nevertheless, the examiner elected to continue to perform the examination in this condition. H.4(a)

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that, activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

Procedure GE-MT-100 "Procedure for Magnetic Particle Examination," Step 4.1 states, "The magnetizing apparatus shall be capable of inducing a magnetic field of suitable intensity in either a circular or longitudinal direction within the component examined." Step 5.1.2 states, in part, that, "Each electromagnetic yoke shall be calibrated whenever the equipment has been subjected to damage." Step 6.8.2.3 (b) states, "Position the yoke on the surface to be examined." Step 6.2.1 states, in part, "The examination component shall be magnetized in at least two separate magnetic flux line directions across each segment of the entire required examination surface area."

Contrary to the above, on November 3, 2010, the licensee failed to follow procedure GE-MT-100 when performing a MT examination on the 3/2/1501-20/20-10 U3 LPCI Support. Specifically, the licensee vendor elected to continue to perform the examination without repairing and recalibrating the equipment after it became damaged during the examination. Therefore, it was not demonstrated that the MT equipment was capable of inducing a magnetic field of suitable intensity within the component examined. Also, the licensee failed on two separate occasions to position the magnetizing equipment on the surface to be examined, which, in turn, affects the requirement to ensure the examination component is magnetized in at least two separate magnetic flux line directions across each segment of the entire required examination surface area. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as IR 01135770, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. (**NCV 05000237/2010005-02; 05000249/2010005-02**)

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI related problems entered into the licensee's corrective action program and conducted interviews with licensee staff to determine if:

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

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report. In addition, the inspectors verified that the licensee correctly assessed operating experience for applicability to the ISI group.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On October 18, 2010, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

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

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- Unit 2 Isolation condenser; and
- Unit 3 High pressure coolant injection.

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

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

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

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

b. Findings

No findings were identified.

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

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:

- Unit 3 Yellow risk due to switchyard work.

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 maintenance risk assessments and emergent work control activities constituted one sample as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- EC 381855, “OPEV 10-007/Drywell Primary Containment Isolation System – Equipment and Floor Drain Valves,” Revision 000 and Revision 001;
- IR 1136770, “3A Core Spray Fails to Start within Acceptance Criteria;” and
- EC 352794, “Affects of Loss of U2 Instrument Air on Standby Gas Treatment System,” Revision 0.

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 reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

These operability inspections constituted three samples as defined in IP 71111.15-05.

b. Findings

(1) Drywell Equipment Drain Sump Discharge Valves 2-2001-5 and 2-2001-6 Body to Diaphragm Leakage

Introduction: The inspectors identified an unresolved item regarding the operability of the Unit 2 drywell floor drain sump and drywell equipment drain sump inboard and outboard discharge air operated valves and their ability to perform their function as primary containment isolation valves.

Description: On October 19, 2010, the Unit 2 drywell floor drain sump (DWFDS) outboard discharge air operated valve (AOV), 2-2001-106, was declared inoperable due to local observation of a pinhole water leak between the body of the valve and the diaphragm while the valve was stroking closed after pumping the Unit 2 DWFDS. The licensee generated issue report (IR) 1127948, "PCIV 2-2001-106 DWFDS DISCH VLV INOP," to address this issue. The licensee determined that the cause of the leak was relaxation of the valve bolting torque. Air operated valve 2-2001-106 was repaired by torquing the bolts back to the original torque value. In addition, the licensee generated operability evaluation (OpEval) number 10-007, "Drywell Primary Containment Isolation System – Equipment and Floor Drain Valves." The licensee determined that the leakage noted was not indicative of a diaphragm leak, which would originate from between the bonnet and diaphragm or the stem and bonnet of the valve.

On October 27, 2010, the Unit 2 drywell equipment drain sump (DWEDS) pump inboard discharge air operated valve, 2-2001-5, and the Unit 2 drywell equipment drain sump pump outboard discharge air operated valve, 2-2001-6, exhibited pinhole leaks, 20 drops and 1 drop respectively, between the body of the valve and the lower side of the diaphragm while the valves were stroking closed after pumping the Unit 2 DWEDS. The licensee generated IR 1131662, "DWEDS 2-2001-5 and 2-2001-6 BODY-DIAPHRAGM LEAKAGE," to address this issue. The licensee determined that based on OpEval 10-007, the leakage was not indicative of a diaphragm leak; therefore, valves 2-2001-5 and 2-2001-6 remained operable. As a compensatory action, the licensee performs weekly inspection of the valves during the pumping operation. By the end of the inspection period, both valves continued leaking and multiple IRs had been generated as a result of the weekly inspections performed.

The inspectors questioned the licensee regarding the ability of these valves to meet the local leak rate test (LLRT) acceptance criteria and Technical Specification 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)." The ability of the Unit 2 drywell equipment drain sump inboard and outboard discharge air operated valves to perform their function as primary containment isolation valves is considered an unresolved item pending further review of the licensee's response. **(URI 05000237/2010005-03)**

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification(s):

- Engineering Change 381757, "Evaluation of Procedurally Controlled Temporary Change to Bypass OPRM [overpower range monitor] Scram Contacts While Changing RPS [reactor protection system] Power Supply," Revisions 000 and 001.

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. 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. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one temporary modification sample as defined in IP 71111.18-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

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

- WO 99067063-06, "D2 20Y PM Replace 125 VDC alternate battery;"
- WO 1300627, "MOV 3-2301-6 (HPCI Suction Valve from CST) Extend Disc Guide;"
- WO 1200397, "D3 Refuel PM Replace Valve (3-2001-5) Process Diaphragm & Overhaul Air" and WO 1200398, "D3 1Rfl. PM Repl. Vlv. (3-2001-6) Process Diaphragm & Ovhl Air;"
- WO 01383671-01, "Loss of Normal Standby Pressure On 3B Core Spray System;"

- WO 01384271-01, “Disassemble and Install New Gasket”; and
- WO 1368290, “Repair Boron Liquid Lead from 3B SBLC [standby liquid control] Pump Piston.”

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

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 3 refueling outage (RFO), conducted November 1 to November 26, 2010, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment to this report.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out-of-service.
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.

- Controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of secondary containment as required by TS.
- Refueling activities, including fuel handling and sipping to detect fuel assembly leakage.
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to RFO activities.

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

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

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:

- WO 1191776-01, "D3 24M TS HPCI [high pressure coolant injection suction] LP Sys Oper Verif [low pressure system operational verification] During Startup" IST [in-service testing] surveillance;
- WO 1184443, "D3 30M/RFL TS LLRT [local leak rate test] MSIV [main steam isolation valve] 203-1A & 203-2A Dry Test;"
- DOS 1400-07, "ECCS [emergency core cooling system] venting," Revision 29;
- WO 01184397, "LLRT VLV 1201-1 and 1201-1A RWCU [reactor water clean up]," Unit 3 RWCU LLRT; and
- WO 01186610, "OP Perform as found LLRT per DOS 7000-08," Unit 3 torus/reactor building vacuum breaker header check valve.

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;

- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the 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 for in-service testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted one routine surveillance testing sample, one in-service testing sample, and three isolation valve inspection samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

(1) Adequacy of High Pressure Core Injection System Low Pressure Testing

Introduction: The inspectors identified an unresolved item regarding the low pressure testing of the HPCI system. The Technical Specifications require the testing of the HPCI system during reactor startup from a refueling outage prior to exceeding 150 psig.

Description: On November 26, 2010, during the post Unit 3 refueling outage low pressure testing of the HPCI system, the system experienced abnormal parameters. System flow cycled between about 4000 gpm to about 7000 gallons per minute (gpm). System discharge pressure cycled between 300 psig to about 500 psig. These oscillations resulted in a severe shaking of the system discharge piping. The operator in the control room did not observe the severity of these oscillations. The inspectors interviewed the control room operator performing the surveillance test. The control room operator stated that HPCI flow was observed in the control room to oscillate between 5000 and 5600 gpm. The more severe oscillations were observed by the system manager monitoring a computer point outside the control room.

The licensee documented the flow oscillations in IR 1145149, “Abnormal U3 HPCI Pump Parameters During Low Pressure Run.” In this IR the licensee stated that the oscillations appeared to be the result of pump runout. Centrifugal pump runout is a condition where the pump flow is beyond the point where net positive suction head (NPSH) required exceeds NPSH available and the pump starts to cavitate. Prolonged operation in this condition can cause damage to the pump and the piping. The inspectors observed that IR 1145149 required no actions to attempt to determine why or if the pump ran out.

The licensee accepted the test results because in the control room a flow rate of 5000 gpm was observed.

The inspectors interviewed the control room operator who performed the test. The test procedure stated that HPCI test return flow to the condensate storage tank shall be throttled such that discharge pressure shall be maintained greater than 98 psig above reactor pressure. The operator stated that he thought this meant to get discharge as close to 98 psig above reactor pressure as possible. This would have made pump discharge pressure close to 250 psig. That was why he fully opened the test return valve. The inspectors determined through interviews that in previous performances of this surveillance test operators did not normally open the test control valve fully and maintained pump discharge pressure greater than 600 psig.

The inspectors questioned licensee engineering management that if a HPCI injection occurred at a reactor pressure of 150 psig and then the HPCI injection valve fully opened without throttling, would the HPCI pump also runout? Licensee engineering management did not know the answer to this question. The licensee felt the problem was with the flow characteristics of the test valve but did not know if the injection valve would have significantly different flow characteristics. The licensee felt that the valve vendor would have to be consulted to get an assessment of the flow characteristics of the valves.

If the HPCI pump would runout during injection at a discharge pressure of 150 psig, then the testing performed would be inadequate to determine HPCI operability. The licensee evaluation of system performance at low discharge pressure is an unresolved item pending inspector review for adequacy. (**URI 05000249/2010005-04**)

(2) <u>Surveillance Testing Associated with Temporary Instruction (TI) 2515/177, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems”</u>

a. <u>Inspection Scope</u>

The inspectors verified that the high pressure core injection (HPCI) system venting procedures were acceptable following its suction swap over to the torus from the condensate storage tank (CST) in support of the Unit 3 refueling outage.

The inspectors reviewed procedures used for filling and venting following conditions which may have introduced voids into the subject systems to verify that the procedures acceptably addressed testing for such voids and provided acceptable processes for their reduction or elimination (TI 2515/177, Section 04.03.b). Specifically, the inspectors verified that:

- Gas intrusion prevention, refill, venting, monitoring, evaluation, and void correction activities were acceptably controlled by approved operating procedures (TI 2515/177, Section 04.03.c.1).
- Procedures ensured the system did not contain voids that may jeopardize operability (TI 2515/177, Section 04.03.c.2).
- Procedures established that void criteria will be reasonably ensured to be satisfied until the next scheduled void surveillance (TI 2515/177, Section 04.03.c.3).
- Procedures included independent verification that critical steps were completed (TI 2515/177, Section 04.03.c.6).

The inspectors verified the following with respect to surveillance and void detection:

- Specified surveillance frequency was consistent with TS SR requirements (TI 2515/177, Section 04.03.d.1).
- Surveillance frequency was stated (TI 2515/177, Section 04.03.d.2).
- Surveillance method was acceptably established to achieve the needed accuracy (TI 2515/177, Section 04.03.d.3).
- Surveillance procedures included up-to-date acceptance criteria (TI 2515/177, Section 04.03.d.4).
- Procedures included effective follow-up actions when acceptance criteria are exceeded or when trending indicates that criteria may be approached before the next scheduled surveillance (TI 2515/177, Section 04.03.d.5).
- Measured void volume uncertainty was considered when comparing test data to acceptance criteria (TI 2515/177, Section 04.03.d.6).
- Venting procedures and practices utilized criteria such as adequate venting durations and observing a steady stream of water (TI 2515/177, Section 04.03.d.7).
- An effective sequencing of void removal steps was followed to ensure that gas does not move into previously filled system volumes (TI 2515/177, Section 04.03.d.8).
- Surveillances were conducted at any location where a void may form, including high points, dead legs, and locations under closed valves in vertical pipes (TI 2515/177, Section 04.03.d.11).
- Revisions to fill and vent procedures to address new vents or different venting sequences were acceptably accomplished (TI 2515/177, Section 04.03.e.1).

Documents reviewed are listed in the Attachment to this report.

This inspection effort counts towards the completion of TI 2515/177, which will be closed in a later inspection report.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

.1 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

Since the last NRC inspection of this program area, emergency action level and Emergency Plan changes were implemented based on the licensee's determination, in accordance with 10 CFR 50.54(q), that the changes resulted in no decrease in effectiveness of the Plan, and that the revised Plan continues to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. Revisions to the emergency action levels and Emergency Plan were reviewed by the inspectors in the Exelon Nuclear Radiological Emergency Plan Annex for Dresden Station, Revisions 26 and 27. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the emergency action level changes to evaluate for potential decreases in effectiveness of the Plan. However, this review does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. This emergency action level and emergency plan changes inspection constituted one sample as defined in IP 71114.04-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2RS2 Occupational As-Low-As-Is-Reasonably-Achievable (ALARA) Planning and Controls (71124.02)

This inspection constituted a partial sample as defined in IP 71124.02-05.

.1 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected the following work activities of the highest exposure significance.

- Torus Diving and Desludging Activities;
- Refuel Floor Reactor In-vessel Inspections;
- Reactor Cavity Drain Down and Decontamination, and
- Drywell Activities Associated with Control Rod Drive Exchange.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined whether the licensee reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

b. Findings

No findings were identified.

.2 Verification of Dose Estimates and Exposure Tracking Systems (02.03)

a. Inspection Scope

The inspectors reviewed the assumptions and basis (including dose rate and man-hour estimates) for the current annual collective exposure estimate for reasonable accuracy for select ALARA work packages. The inspectors reviewed applicable procedures to determine the methodology for estimating exposures from specific work activities and the intended dose outcome.

The inspectors evaluated whether the licensee had established measures to track, trend, and if necessary to reduce, occupational doses for ongoing work activities. The inspectors assessed whether trigger points or criteria were established to prompt additional reviews and/or additional ALARA planning and controls.

The inspectors evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors assessed whether adjustments to exposure estimates (intended dose) were based on sound radiation protection and ALARA principles or if they were just adjusted to account for failures to control the work. The inspectors evaluated whether the frequency of these adjustments called into question the adequacy of the original ALARA planning process.

b. Findings

No findings were identified.

.3 Radiation Worker Performance (02.05)

a. Inspection Scope

The inspectors observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice (e.g., workers are familiar with the work activity scope and tools to be used, workers used ALARA low-dose waiting areas) and whether there were any procedure compliance issues (e.g., workers are not complying with work activity controls). The inspectors observed radiation worker performance to assess whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

b. Findings

No findings were identified.

.4 Problem Identification and Resolution (02.06)

a. Inspection Scope

The inspectors evaluated whether problems associated with ALARA planning and controls were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's corrective action program.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Reactor Coolant System (RCS) Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage performance indicator for Unit 2 and Unit 3 for the period from the fourth quarter 2009 through the third quarter 2010 to determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports and NRC Integrated Inspection Reports for the period of October 1, 2009, through September 30, 2010, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two reactor coolant system leakage samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the occupational radiological occurrences PI for the period from the first quarter 2009 through third quarter 2010. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarm and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational exposure control effectiveness sample as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; 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 Attachment to this report.

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 were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of July 1, 2010, through December 31, 2010, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection Associated with Temporary Instruction (TI) 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems": ECCS venting process

a. Inspection Scope and Documentation

During a review of items entered in the licensee's CAP, the inspectors recognized corrective action items associated with ECCS venting processes. Specifically, IR 994774, "Procedures for venting ECCS/SDC systems should be revised," documented the determination to increase the venting duration requirement of existing venting procedures in response to inspector's questions about the acceptability of the original venting duration. In addition, the inspectors recognized IR 1058558, "Air ribbon discovered in 3B core spray suction," which documented the discovery of a void near the ECCS keep-fill pump. The inspectors reviewed the latter corrective action item in the context of a condition described in IR 1122533, "U3 ECCS jockey pump degraded pressure," where the keep-fill pump discharge pressure was found to be degraded.

The inspectors reviewed corrective action documents, procedures, and surveillance results documented in the List of Documents Reviewed section of this report. In addition, the inspectors interviewed plant personnel.

The inspectors verified that the selected CAP entry acceptably addressed the areas of concern associated with the scope of Generic Letter 2008-01," Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems" (TI 2515/177, Section 04.01).

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05. In addition, this inspection effort counts towards the completion of TI 2515/177, which will be closed in a later inspection report.

b. Findings

No findings were identified.

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

.1 Unit 3 Automatic Reactor Scram During Transfer of Reactor Protection System Bus

a. Inspection Scope

On October 11, 2010, at 10:04 a.m., Unit 3 scrammed during the transfer of the 'A' reactor protection system (RPS) bus from the normal to the reserve power supply. Following the scram, all systems operated as expected. Initial cause of the scram appeared to be the failure of oscillating power range monitor (OPRM) 6 power supply concurrently with the swap to reserve power on RPS bus 'A.'

The inspectors observed and reviewed the licensee's response to the event. The inspectors interviewed multiple personnel, verified that the licensee's response was appropriate and in accordance with procedures and confirmed that the event was reported per the guidance in NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73." The inspectors also verified that the scram had no impact on Unit 2.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 (Open) NRC TI 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems (NRC Generic Letter 2008-01)"

As documented in Sections 1R22 and 4OA2, the inspectors confirmed the acceptability of the described licensee's actions. This inspection effort counts towards the completion of TI 2515/177, which will be closed in a later inspection report.

.2 (Closed) Unresolved Item (URI) 05000237/2010003-01; 05000249/2010003-01: High Pressure Coolant Injection (HPCI) Booster Pump Bearing Oil Levels

This item is discussed in Section 1R04 of this report. The inspectors identified an NCV of Technical Specification (TS) 5.4.1, "Procedures." This URI is closed.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 19, 2010, the inspectors presented the inspection results to Mr. T. Hanley and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The occupational ALARA planning and controls and performance indicator verification program were discussed with Mr. T. Hanley, Site Vice President on November 12, 2010. Additionally, the inspection was re-exited on December 8, 2010, with Mr. S. Marik, the Plant Manager.
- On November 19, 2010, the inspectors presented the inservice inspection team results to the Site Vice President, Mr. T. Hanley, and other members of the licensee staff. The licensee acknowledged the issues presented. Additionally, the inspection was re-exited on January 6, 2011, via telephone with Mr. T. Hanley.
- The annual review of Emergency Action Level and Emergency Plan changes with the licensee's Acting Regulatory Assurance Manager, R. Rybak, via telephone on December 15, 2010.

The inspectors confirmed that none of the potential report input discussed was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Hanley, Site Vice President
S. Marik, Station Plant Manager
H. Bush, Radiation Protection Manager
J. Cady, Manager of RP Technical Support
R. Conley, RP Technical Specialist
D. Doggett, Emergency Preparedness Coordinator
B. Finlay, Security Manager
D. Glick, Shipping Specialist
G. Graff, Nuclear Oversight Manager
D. Gronek, Operations Director
J. Hansen, Corporate Licensing
G. Ice, Regulatory Assurance – NRC Coordinator
L. Jordan, Training Director
R. Kalb, Senior Environmental Chemistry
B. Kapellas, Work Control Manager
J. Kish, Engineering Programs, ISI Coordinator
J. Knight, Chemistry Manager
D. Leggett, Regulatory Assurance Manager
R. Laburn, Radiation Protection
P. Mankoo, Chemistry Supervisor
M. McDonald, Acting Maintenance Director
P. O'Connor, Licensed Operator Requalification Training Lead
M. Overstreet, Lead Radiation Protection Supervisor
C. Podczerwinski, Maintenance Rule Coordinator
P. Quealy, Emergency Preparedness Manager
E. Rowley, Chemistry
R. Rybak, Regulatory Assurance Manager (Acting)
J. Sipek, Engineering Director
N. Starcevich, Radiation Protection Instrumentation Coordinator

Nuclear Regulatory Commission

M. Ring, Chief, Division of Reactor Projects, Branch 1
B. Dickson, Plant Support Team Branch Chief, DRS/RIII

IEMA

R. Zuffa, Illinois Emergency Management Agency
R. Schulz, Illinois Emergency Management Agency

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000237/2010005-01 05000249/2010005-01	NCV	Failure to Provide Robust Indication of Adequate Oil Level in High Pressure Coolant Injection Booster Pump Sight Glasses (1R04)
05000237/2010005-02 05000249/2010005-02	NCV	Failure to Perform Magnetic Particle Examination on the 3/2/1501-20/20-10 U3 LPCI Support in Accordance with Procedures (1R08)
05000237/2010005-03	URI	Drywell Equipment Drain Sump Discharge Valves 2-2001-5 and 2-2001-6 Body to Diaphragm Leakage (1R15)
05000249/2010005-04	URI	Adequacy of High Pressure Core Injection System Low Pressure Testing (1R22)

Closed

05000237/2010005-01 05000249/2010005-01	NCV	Failure to Provide Robust Indication of Adequate Oil Level in High Pressure Coolant Injection Booster Pump Sight Glasses (1R04)
05000237/2010005-02 05000249/2010005-02	NCV	Failure to Perform Magnetic Particle Examination on the 3/2/1501-20/20-10 U3 LPCI Support in Accordance with Procedures (1R08)
05000237/2010003–01; 05000249/2010003–01	URI	High Pressure Coolant Injection (HPCI) Booster Pump Bearing Oil Levels (4OA5)

Discussed

2515/177	TI	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems (NRC Generic Letter 2008-01) (1R22 and 4OA2)

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 (71111.01)</u>

- IR 1113984, “Discharge and Ice Melting Line Hit While Drilling CP1”
- DOA 4400-06, “2/3 Crib House Screen Plugging,” Revision 6
- DOP 4400-07, “Circulating Water De-Icing Operation,” Revision 14
- M-36, “Diagram of Circulating Water and Hypochlorite Piping,” Revision RN
- OP-AA-108-111-1001, “Severe Weather and Natural Disaster Guidelines,” Revision 5
- IR 1019600, “’A’ Floor Drain Sample Tank Recirculation Line Rupture”
- DOS 0010-28, “Preparation for Cold Weather for Radwaste,” Revision 23
- WO 1374338-01, “CE Replace 2/3-2001-424A FDST Heat Trace”
- WO 1325389, “D2/3 QTR PM Emergency Diesel Pump (Flood Pump) Operation”
- IR 1070256, “NRC CDBI – Calculation 8.11.6-11 Enhancement Opportunity”

<u>1R04 Equipment Alignment (71111.04Q)</u>

- DOP 4700-01, Rev 52, “Unit 2(3) Instrument Air System Startup”
- DOP 3700-M2/E2 Rev 14, “U3 RBCCW System Checklist”
- M-360, “Diagram of L.P. Coolant Injection System,” Unit 3
- 20300-001, “Low Pressure Coolant Injection (LPCI) System and Instrumentation,” Revision 0
- DOP 1500-E1, “Unit 3 LPCI and CCSW System Electrical,” Revision 13
- DOP 1500-M1, “Unit 3 LPCI and Containment Cooling Valve Checklist,” Revision 31
- OP-AA-108-117, “Protected Equipment Program,” Revision 1
- OU-DR-104, “Shutdown Safety management Program,” Revision 11
- OU-AA-103, “Shutdown Safety Management Program,” Revision 11
- IR 01138087, “Shutdown Risk Equipment Protection”
- Shutdown Safety Approval / Notification Form, “New revision to Dresden Shutdown Safety Management Program, OU-DR-104,” October 6, 2010
- MA-AB-734-448, “HPCI Booster Pump Maintenance,” Revision 0
- IR 1081187, “NRC Concerns – MCC 29-1 Light, U2 HPCI Oil Sightglass”
- IR 1081750, “NRC Concern – U2 HPCI Booster Pump Oil Level”
- IR 1085361, “Unit 3 HPCI Booster Pump Sight Glass Markings”
- IR 1085422, “NRC Inspector Questions HPCI Booster Pp Oil Level Impact”
- IR 1108227, “Flowserve Issues HPCI Booster Pump Oil Level Change”
- IR 1127778, “U2 HPCI Booster Pump OB Bearing Housing Oil Leak”

<u>1R05 Fire Protection (71111.05)</u>

- IR 1138221, “NRC Identified Concern In The Unit 3 Low Pressure Heater Bay.” 11/9/2010
- IR 1136389, “Drained Turbine Oil Stored Behind Bus 36 Without TCP”

1R08 Inservice Inspection Activities (ISI) 71111.08G

- ER-AA-335-016; VT-3 Visual Examination of Component Supports, Attachments, and Interiors of Reactor Vessels; Revision 5
- GE-MT-100; Procedure for Magnetic Particle Examination (Dry Particle, Color Contrast or Wet Particle, Fluorescent); Version 6
- GEH-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds; Revision 7
- GE-PT-100; Procedure for Liquid Penetrant Examination Using Fluorescent and Visible Dye Liquid Penetrant Inspection Methods; Version 5
- WO 00951307-1; HCU VLV 3-0305-22-15-101 Valve 101 Cut and Replace; July 18, 2008
- WO 00974094-1; HCU 34-03 J1 – Cut Out and Replace 34-03-102 Valve; July 18, 2008
- 08-567; Liquid Penetrant Examination Data Sheet; Component 3-0305-34-03-102 FW1 and FW4; November 6, 2008
- 08-573; Liquid Penetrant Examination Data Sheet; Component 3-0305-34-03-101 FW2 and FW3; November 7, 2008
- WPS 8-8-GTSM; GTAW and SMAW Manual P-8 to P-8 Material Welding Procedure; Revision 2
- A-003; PQR, GTAW Manual P-8 to P-8 Material; Revision 0
- 1-51A; PQR, GTAW Manual P-8 to P-8 Material; Revision 0
- 4-51A; PQR, GTAW/SMAW Manual P-8 to P-8 Material; Revision 0
- A-004; PQR SMAW Manual P-8 to P-8 Material; Revision 0
- AR 01093003; SBLC 3A Accumulator Leakage Not Identified as Code Leakage; July 21, 2010
- AR 01055270; Leakage Update for 3A SBLC Discharge Piping; April 11, 2010
- AR 01030537; Code Leakage Identified After Unit 2 Class 1 Leakage Test; February 15, 2010
- AR 00988019; Thru Weld Leak on ¾" Line to 2-0202-5B; November 3, 2009
- AR 00987982; Boron Liquid Leak on 3B SLBC Pump; November 3, 2009
- AR 00898594; Code Class III Piping Leak on CCSW Vault Cooler; March 27, 2009
- AR 00964688; LR: Work Orders Needed for U2 Nonexempt Piping Support Exams; September 14, 2009
- AR 00879567; Leak on Bolted Connection of Isolation Condenser; February 11, 2009
- AR 00957289; License Renewal B.1.7 BWR Stress Corrosion Cracking Issue; August 25, 2009
- AR 00976300; Leaks Identified During Repair Replacement Test; October 7, 2009
- AR 00992769; D2R21 ISI Scope Expansion; November 13, 2009
- AR 00991642; Vendor did not Follow ASME Repair Plan 2-09-060; November 10, 2009
- AR 00888550; NOS ID Weld Modified by MMD after QV and NDE Inspections; March 4, 2009
- AR 00991109; U2 HPI Steam Line Support Pulled Away From Ceiling; November 9, 2009
- AR 01116812; HPCI Whip Restraints Included in ISI Program and Drawings; September 23, 2010
- AR 01131020; Indication Identified on U3 LPCI Support 3/2/1501-20/20-12; October 26, 2010

AR 00911408; Discrepancy Regarding ASME Section XI Code Class; April 24, 2009

1R11 Licensed Operator Requalification Program (71111.11Q)

- OPEX-AB (Loss of U2 125 VDC Reactor Building Bus; Small Steam Leak in Drywell; Emergency Depressurization), Revision 07

1R12 Maintenance Effectiveness (71111.12)

- Maintenance Rule Expert Panel Meeting Notes for 8/20/2009 and 10/15/2009
- ER-AA-310-1003, “Maintenance Rule – Performance Criteria Selection,” Revision 3
- RM Documentation No. SA-1109, “PRA Basis for Dresden Maintenance Rule Reliability Performance Criteria,” Revision 0
- RM Document No DR-MR-005, “PRA Basis for Dresden Maintenance Rule Availability Performance Criteria and Reliability Performance Criteria,” Revision 0
- U2 Isolation Condenser System Health Report, 2009 – 2010
- IR 1105464, “2/3 ‘B’ ISO Condenser Day Tank Not Property Grounded.” 8/24/2010
- IR 01091794, “ISO Condenser Procedure(s) Inconsistent/Needs Clarification.” 7/18/2010
- IR 01079816, “2/3 B ISO Condenser makeup Pump Coolant Hose Sheared.” 6/12/2010
- IR 01071706, “2/3 B ISO Condenser makeup Pump Leak.” 5/20/2010
- IR 01060591, “MSOPS 4Q: ISO Condenser – Cross-Connect Valve on MKUP Line.” 4/23/2010
- IR 01037281, “2/3 B ISO Condenser Make Up Pump Trouble Alarm In.“ 3/1/2010
- IR 01032659, “U2 Leak on ISO Condenser West End.” 2/19/2010
- IR 01010350, “U2 ISO Condenser Shell Side Level Steadily Rising.” 12/29/2009
- IR 998503, “Spurious ARM HI Alarm ISO Condenser Area.” 11/25/2009
- IR 992743, “Confined Space / ISO Condenser.” 11/12/2009
- IR 990620, “U2 ISO Condenser Shell Side Inspection Results – FME.” 11/08/2009
- IR 989006, “ISO Condenser Pip in Drywell Covered With Wrong Insulation.” 11/04/2009

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

- IR 1132279, “U3 East LPCI Corner Room Door Not Completely Dogged Closed”

1R15 Operability Evaluations (71111.15)

- IR 1127544, “DWEDS/DWFDS Diaphragm Valve EACE Results Changed”
- IR 1127948, “PCIV 2-2001-106 DWFDS Disch Vlv Inop”
- IR 1136649, “Retorque Body to Bonnet Bolting”
- IR 1131662, “DWEDS 2-2201-5 and 2-2001-6 Body-Diaphragm Leakage”
- IR 1132061, “NOS IDS Incomplete Op Eval for DWEDS and DWFD Valves”
- Regulatory Guide 1.52, “Design Testing, and Maintenance Criteria For Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants,” Revision 2
- UFSAR Section 6.5 Fission Product Removal and Control Systems
- Technical Specification 5.5.7 Ventilation Filter Testing Program

1R18 Plant Modifications (71111.18)

- Drawing 12E-3464, Sheet 1, “Schematic Diagram Reactor Protection System Channel “A” Trip Aux. Relays”
- Drawing 12E-3464, Sheet 2, “Schematic Diagram Reactor Protection System Channel “B” Trip Aux. Relays”
- Drawing 12E-2464, Sheet 1, “Schematic Diagram Reactor Protection System Channel “A” Trip Auxiliary Relays”
- Drawing 12E-2464, Sheet 2, “Schematic Diagram Reactor Protection System Channel “B” Auxiliary Relays”

1R19 Post-Maintenance Testing (71111.19)

- WO 99067063-06, “D2 20Y PM Replace 125 VDC alternate battery.”
- DES 8300-52, Rev 14, “Unit 2 Alternate 125 VDC Station Battery Modified Performance Test 2-83125-2A”
- IR 1086387, “U2 Alt Battery Replacement”
- WO 930345-04, “Fill and Vent The 3B Core Spray Piping After Maintenance Per DOP-1400-03”
- IR 1134571, “Indications of 3-1402-8B Stop Check Valve Not Seated”
- IR 1140240, “3B Core Spray Pump Failed to Trip”
- WO 1300627, “MOV 3-2301-6 (HPCI Suction Vlv. from CST) Extend Disc Guide”
- IR 1141157, “WO 1300627 Being Completed Without Replacing Valve Stem”
- IR 1142530, “3-2301-6 Stroke Time in Alert Range”
- WO 1200397, “D3 Rfl. PM Replace Vlv. (3-2001-5) Process Diaphragm & Ovhl. A”
- WO 1200398, “D3 1Rfl. PM Repl. Vlv. (3-2001-6) Process Diaphragm & Ovhl Air”
- MA-DR-MM-4-20002, “Disassembly, Reassembly of Dresden Stations Drywell Sump ITT Grinnell Diaphragm Valves,” Revision 5
- IR 1145875, “NRC Identified Procedure Error in MA-DR-MM-4-20002”
- WO 01384271-02, “Verify No Leaks at System Pressure”
- WO 1368290, Repair Boron Liquid Lead from 3B SBLC Pump Piston
- DOS 1100-04, “Standby Liquid Control System Quarterly/Comprehensive Pump Test For The Inservice Test (IST) Program.” Rev 44

1R22 Surveillance Testing (71111.22)

- WO 1184443, “D3 30M/RFL TS LLRT MSIV 203-1A & 203-2A Dry Test”
- WO 1184444, “D3 30M/RFL TS LLRT MSIV 203-1B & 203-2B Dry Test”
- WO 1188712, “D3 30M/RFL TS LLRT MSIV 203-1C & 203-2C Dry Test”
- WO 1184442, “D3 30M/RFL TS LLRT MSIV 203-1D & 203-2D Dry Test”
- WO 1184436, “D3 30M/RFL TS LLRT MSIV 203-2A Wet Test”
- WO 1184438, “D3 30M/RFL TS LLRT MSIV 203-2B Wet Test”
- WO 1184439, “D3 30M/RFL TS LLRT MSIV 203-2C Wet Test”
- WO 1184437, “D3 30M/RFL TS LLRT MSIV 203-2D Wet Test”
- DOS 7000-01, “Local Leak Rate Testing Of Main Steam Isolation Valves (Dry Tests),” Revision 06
- DOS 7000-02, “Local Leak Rate Testing Of Main Steam Isolation Valves (Wet Test),” Revision 02
- IR 1133829, “D3R21 LLRT On 3-0203-1C Leakage Exceeded 34 SCFH”
- IR 1133832, “D3R21 LLRT 3-0203-1D Leakage Exceeded 34 SCFH”
- IR 1133833, “D3R21 LLRT 3-0203-2D Leakage Exceeded 34 SCFH Limit”
- IR 1134866, “D3R21 MSIV Total Leakage Approaching Limit of <86 SCFH”
- DOS 1400-07, “ECCS venting,” Revision 29
- DOP 2300-01, “HPCI standby operation,” Revision 45
- DAP 09-11, “Swap U2 HPCI suction to the torus from the CST,” 11/2/2010
- ER-DR-200-101, “Periodic monitoring for gas accumulation in ECCS systems,” Revision 4
- WO 01184397, “LLRT VLV 1201-1 and 1201-1A RWCU,” 11/4/10
- IR 1135334, “D3R21 LLRT on 3-1201-1 exceeded admin alarm limit,” 11/04/2010
- DTP 47A, “Containment boundary repair deferral form - RWCU 3-1201-1 & 3-1201-1A,” 11/18/2008
- IR 1138793, “3-1601-31B – U3 TORUS/RB VAC BKR HDR CK VLV EXCEEDED ADMIN ALARMT LIMIT,” 11/11/10

- EACE 1135334, Evaluation of LLRT failures
- WO 01186610, “OP Perform as found LLRT per DOS 7000-08” 10/20/10
- DOS 7000-08, “Local leak rate testing of primary isolation valves,” Revision 09

1EP4 Emergency Action Level and Emergency Plan Changes

- Exelon Nuclear Radiological Emergency Plan Annex for Dresden Station; Revisions 25, 26, and 27

2RS2 Occupational ALARA Planning and Controls (71124.02)

- RP-AA-460-002; Additional High Radiation Exposure Control; Revision 0
- RP-AA-400; ALARA Program; Revision 7
- RP-AA-401; Operational ALARA Planning and Control; Revision 11
- RP-AA-203-1001; Personnel Exposure Investigations; Revision 6
- RP-AA-210; Dosimetry Issue, Usage and Control; Revision 17
- RP-AA-211-2001; RP Position Paper; Performance Verification of Vendor Supplied Thermo-luminescent Dosimeters (TLD) Relative to ANSI N13.11-2001; Revision 1
- RP-AA-214; Area TLD Surveillance; Revision 3
- RP-AA-220; Intake Investigation; Revision 6
- RP-AA-250; External Dose Assessments from Contamination; Revision 4
- RP-AA-350: Personnel Contamination Monitoring, Decontamination and Reporting; Revision 0
- RP-AA-461; Radiological Controls for Contaminated Water Diving Operation; Revision 02
- AR-01109705; Individual Contaminated While Doing NDE on Refuel Floor; dated September 3; 2010
- Dresden Survey Form No. 0102797; 0102798; dated September 3, 2010
- Personnel Contamination Events D3R21; dated November 10, 2010
- AR-01109756; Unexpected Alarm at Main Steam Line Radiation Monitor; dated September 3, 2010
- AR-01127553; Dresden Station Weekly Exposure Trend; dated October 17, 2010
- AR-01136613; D3R21 Micro ALARA Plan Documentation; dated November 6, 2010
- AR 01137277; Level One PCE on GE Technician in CRD Pit 5K on Beard; dated November 8, 2010
- AR-01138137; Level II Personnel Contamination Event (PCE); dated November 11, 2010
- AR-01137268; Level I PCE on GE Technician from Under Vessel with 5K on Right Hand; dated November 8, 2010
- ALARA Plan 100011601; Dresden 3 R21 Torus Desludging Activities
- RWP-10011598; D3R21 Reactor Water Clean Up (RWCU) System Maintenance Activities; Revision 0
- RWP-10011581; Dresden 3 R21 Drywell Control Rod Drive Exchange; Revision 0
- RWP-10011577; Dresden 3 R21 Drywell Safety’s Electromagnetic Target Rock Maintenance; Revision 0
- RWP-10011623; Dresden 3 R21 Cavity Drain Down and Decontamination; Revision 0
- RWP-10011622; Dresden 3 R21 Refuel Floor Reactor In-vessel Inspection; Revision 0
- RWP-10011085; Dresden 3 R21 Refuel Floor Preparations and Maintenance; Revision 0

4OA1 Performance Indicator Verification (71151)

- IR 1132112, “NRC RI Questions RCS Leakage Data”
- IR 1132440, “NRC Identified Inaccurate PI Data Reported”
- Monthly Data Elements for Occupational Control Effectiveness Ocurrences from February 2009 through September 2010

4OA2 Identification and Resolution of Problems (71152)

- “D2R21 10CFR50 Appendix J, Total Leakage Summation” 11/30/2009
- “D3R20 10CFR50 Appendix J, Total Leakage Summation” 11/26/ 2008
- IR 999625, “Air found in HPCI discharge piping during UT.” 11/30/2009
- IR 999762, “Air found in second location in HPCI discharge piping.” 12/1/2009
- IR 1029105, “Air void identified on U2 HPCI discharge piping above TORUS.” 2/11/2009
- IR 1057049, “Air void U2 HPCI discharge piping above acceptance criteria.” 4/15/2010
- IR 1058448, “NRC resident inquiry for U2 HPCI UT inspections.” 4/19/2010
- IR 1076194, “HPCI event notification EN45844 retraction.” 6/2/2010
- IR 1081055, “NRC Question: GL 2008-01 HPCI piping.” 6/16/2010
- IR 1066886, “U2 HPCI discharge piping air void increased in size.” 5/7/2010
- IR1086945, “U2 HPCI air void increase.” 7/1/2010
- IR 1098512, “U2 HPCI air void increase.” 8/5/2010
- IR 1113218, “MOV 3-2301-4 failed to fully open.” 8/15/2010
- IR 994774, “Procedures for Venting ECCS/SDC Systems Should Be Revised”
- IR 999625, “Air Found in HPCI Discharge Piping During UT”
- IR 1058558, “Air ribbon discovered in 3B core spray suction,” 04/19/2010
- IR 1122533, “U3 ECCS jockey pump degraded pressure,” 10/05/2010
- WO 1314385, “UT 3B core spray suction line,” 6/29/2010
- DOP 1000-01, “Fill and vent of SDC,” Revision 34
- DOP 1400-03, “ECCS fill system,” Revision 53
- DOS 1400-07, “ECCS vent,” Revision 29
- DOP 2300-01, “HPCI standby operation,” Revision 45
- IR 1132112, “NRC RI Questions RCS Leakage Data”
- IR 1132440, “NRC Identified Inaccurate PI Data Reported”

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

- EC 374991, “Evaluate HPCI System Function with 2-2301-6 Valve Failed to Close,” Revision 001
- EC 374707, “OP EVAL 09-002: Evaluate Operability of MOV 2-2301-6 due to Closure Issues,” Revision 002
- IR 893211, “While Placing C/O 71240, MO 2-2301-6 Did Not Fully Closed”
- IR 894450, “MOV 2-2301-6 Valve Binding Observed”
- MA-AA-716-210, “Performance Centered Maintenance (PCM) Process,” Revision 10
- MA-AA-716-210-1001, “Performance Centered Maintenance (PCM) Templates,” Revision 9
- IR 1125022, “U3 Scram”
- IR 1124863, “D3 OPRM Power Supply 5V Section Failed”
- IR 1125016, “2/3 EDG Autostarted on U3 Scram (Start Signal Unknown)”
- IR 1125133, “CRD 30-15 (N-4) Showing Signs of Distortion”
- IR 1125141, “CRD 10-15 (C-4) Showing Signs of Distortion”
- IR 1125973, “Follow-Up to IR 1123230 on GE Interim Part 21”
- IR 1128719, “ENS Posted on Website Inaccurate”
- IR 1128599, “Potential Incorrect RPS Breakers for APRM/OPRM/RBM Loads”

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
AOP	Abnormal Operating Procedure
AOV	Air Operated Valve
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CCSW	Containment Cooling Service Water
CFR	Code of Federal Regulations
CRD	Control Rod Drive
CST	Condensate Storage Tank
DWEDS	Drywell Equipment Drain Sump
DWFDS	Drywell Floor Drain Sump
EACE	Equipment Apparent Cause Evaluation
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
FW	Feedwater
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
ISI	Inservice Inspection
IST	In-Service Testing
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
LLRT	Local Leak Rate Test
MCC	Motor Control Center
MOV	Motor-Operated Valve
MT	Magnetic Particle
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NDE	Non-Destructive Evaluation
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulations
OSP	Outage Safety Plan
PARS	Publicly Available Records System
PCIV	Primary Containment Isolation Valves
PI	Performance Indicator
PM	Planned, Preventative Maintenance, or Post-Maintenance
PMT	Post-Maintenance Testing
RBCCW	Reactor Building Closed Cooling Water
RCS	Reactor Coolant System
RFO	Refueling Outage
RP	Radiation Protection
RPS	Reactor Protection System
SDC	Shutdown Cooling

SDP	Significance Determination Process
SR	Surveillance Requirement
SSC	Structures, Systems, and Components
TLD	Thermo-Luminescent Dosimeter
TS	Technical Specification
U2	Unit 2
U3	Unit 3
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VOC	volts Direct Current
WO	Work Order

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Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

Docket Nos. 50-237; 50-249
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Letter to M. Pacilio from M. Ring dated February 1, 2011

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3 INTEGRATED INSPECTION REPORT 05000237/2010-005; 05000249/2010-005

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