UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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February 10, 2010

Mr. Charles G. Pardee
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 05000237/2009-005; 05000249/2009-005

Dear Mr. Pardee:

On December 31, 2009, 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 inspection results, which were discussed on January 14, 2010, 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.

The report documents two NRC-identified findings and five self-revealed findings of very low safety significance (Green). All of these findings were determined to involve a violation of NRC requirements. Additionally, one licensee-identified violation is listed in Section 4OA7 of this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy.

If you contest any NCV, 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 copies to the Regional Administrator, 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 NRC Resident Inspector at Dresden. In addition, if you disagree with the characterization of 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 Dresden. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

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 made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC 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 05000237/2009-005; 05000249/2009-005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249
License Nos:	DPR-19; DPR-25
Report No:	05000237/2009-005; 05000249/2009-005
Licensee:	Exelon Generation Company
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	Morris, IL
Dates:	October 1 through December 31, 2009
Inspectors:	C. Phillips, Senior Resident Inspector D. Meléndez-Colón, Resident Inspector J. Benjamin, Project Engineer J. Draper, Reactor Engineer D. Sand, Reactor Engineer C. Moore, Operations Engineer F. Ramírez, Resident Inspector, LaSalle Station J. McGhee, Senior Resident Inspector, Quad Cities M. Holmberg, Reactor Inspector M. Mitchell, Health Physicist R. Jickling, Senior Emergency Preparedness Inspector L. Kozak, Senior Reactor Analyst
Approved by:	M. Ring, Chief Projects Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000237/2009-005, 05000249/2009-005; 10/01/2009 - 12/31/2009; Dresden Nuclear Power Station, Units 2 & 3; Equipment Alignment, Operability Evaluations, Post-Maintenance Testing, Surveillance Testing, Outage, and Event Follow-up.

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 and five findings were self-revealed. All of 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). Cross-cutting aspects were determined using IMC 0305, "Operating Reactor Assessment Program." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A self-revealed finding involving a non-cited violation (NCV) of Technical Specification 5.4.1 was identified on October 3, 2009, due to the licensee's failure to include essential information in DOP 1200-03, "RWCU System Operation with the Reactor at Pressure," Revision 51, regarding startup of the reactor water cleanup system with the reactor at pressure. This procedural deficiency caused a pressure pulse that resulted in a reactor water level Low-Low Group 1 Isolation Signal and Unit 3 reactor scram. This event was entered into the licensee's corrective action program (CAP) as Issue Report (IR) 974426. Corrective actions by the licensee included revising procedure DOP 1200-03.

  This finding was considered more than minor because it affected the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as at power operations. The finding was determined to be of very low safety significance because it did not contribute to both the likelihood of a reactor trip AND the likelihood that mitigating equipment or functions will not be available. This finding has a cross-cutting aspect in the area of Human Performance (Resources) because the licensee did not provide complete, accurate and up-to-date procedures to plant personnel.
  H.2(c) (Section 4OA3.2)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and associated NCV of Technical Specification 5.4.1 was self-revealed for the failure to meet the requirements of Clearance Order (CO) 69631 by removing shorting links instead of fuses as required by the CO on November 12, 2009. As a result, protective relaying was unintentionally removed from the Unit 2 main power transformer TR-2, the unit auxiliary transformer TR-21, and the reserve auxiliary transformer TR-22. This issue was entered into the licensee's CAP as Issue Report 992290. Corrective actions included: coaching of the individuals involved with the incorrect placing of the out-of-service and a placard on the device that was incorrectly repositioned was changed to include the specific equipment part number of the shorting links.

The finding was determined to be more than minor because the finding could reasonably be viewed as a precursor to a significant event. The finding was evaluated using the SDP in accordance with IMC 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists For Both PWRs and BWRs," Checklist 6, dated May 25, 2004. This checklist stated that for a finding to require a Phase 2 or 3 determination, it would require an increase in the likelihood of a loss of offsite power or degrade the licensee's ability to cope with a loss of offsite power. The ability of the licensee to cope with a loss of offsite power was not impacted because at least one emergency diesel generator was operable during the entire period. The inspectors determined that neither of these conditions were met so the finding screened as Green. This finding had a cross-cutting aspect in the area of Human Performance, Work Practices. H.4(a) (Section 1R04)

- Green. The inspectors identified a finding of very low safety significance and associated NCV of Technical Specification 5.4.1 for the licensee failing to follow Dresden procedure DOP 2-1500-M1, "LPCI System Mechanical Checklist," Revision 39. On September 24, 2009, the inspectors identified valve 2-1501-42A, U2 low pressure coolant injection (LPCI) A pump gland leak-off valve, was closed instead of open as required by DOP 2-1500-M1. With this valve closed instead of open, the control room alarm for LPCI pump seal leakage would not have been able to fulfill its function. The issue was entered into the licensee's CAP as IR 969490. The licensee's corrective actions included changing maintenance procedure DMP 1500-05, "LPCI Pump Maintenance," step G.25.d to include the case drain valve equipment numbers and sign offs to position and verify the valves; and Operations Department Management addressed the operations department personnel about this issue.

  The finding was determined to be more than minor because the finding, if left uncorrected, would become a more significant safety concern. Specifically, the valve isolated an alarm in the control room. The inspectors concluded this finding was associated with the Mitigating Systems Cornerstone using IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a, dated January 10, 2008. This finding has a cross-cutting aspect in the area of Human Performance, Work Practices because the licensee did not have any documentation as to how or when the valve was placed into the position it was in. The design and location of the valve precluded that the valve was accidently placed into the position it was found in. Therefore, the inspectors concluded that either the failure to use human error prevention techniques or maintaining proper documentation of activities caused the mispositioning of valve 2-1501-42A. H.4.(a) (Section 1R15)

- Green. The inspectors identified a finding of very low significance and associated NCV of 10 CFR 50 Appendix B, Criterion XI, "Test Control", because the licensee unacceptably preconditioned the Unit 2 Emergency Diesel Generator (EDG) prior to performing Technical Specification (TS) Surveillance Requirements (SR) 3.8.1.19.c.4, 3.8.1.12.c.3, and 3.8.1.10. These TS SRs involved verifying that the EDG supplied steady state frequency would be acceptable following a loss of offsite power coincident with and without a loss of coolant accident, and following the loss of the largest post-accident load. Specifically, the inspectors identified that the licensee routinely performed governor oil change outage maintenance activities which involved a section that tuned the Unit 2 diesel governor's response to a load change just prior to performing these TS SRs. This issue has been entered into the licensee's CAP as IR 1000609. The licensee had not reached a conclusion on corrective actions by the end of the inspection period.

This finding was determined to be more than minor because the finding, if left uncorrected, would become a more significant safety concern. Unacceptable preconditioning the EDG could mask latent performance issues and affect the ability of the EDG to supply safety-related power to vital loads during an event. The inspectors performed a Phase 1 SDP evaluation and determined that this issue was Green because it did not result in an inoperable Unit 2 EDG. The failure to adequately coordinate the work activity of the preventive maintenance and post-maintenance testing with the TS SR activities was the principal contributor to this finding and was reflective of recent performance. This finding had a cross-cutting aspect in the area of Work Control. Specifically, the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of the work as different job activities. The scheduling of the work activities resulted in the pre-conditioning of the EDG prior to performing the surveillance tests. H.3(b) (Section 1R19)

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion IV, "Procurement Document Control," was self-revealed for the licensee's failure to ensure a safety-related plug was ordered and installed where required in the 2/3 EDG turbo lube oil "Y" strainer. Instead, a non-conforming part was installed, which resulted in a one-half gallon per minute oil leak and removal of the diesel generator from service. The issue was entered into the licensee's CAP as IR 926605. Corrective actions included inspection of all other diesel generators to ensure the non-conforming condition did not exist on another machine, revising the procurement documents to ensure that future parts include a pressure retaining pipe plug with approved material, and adding a requirement for a quality inspection to be performed to "inspect the strainer for metallic pipe plug in blow down port." Individual procedure compliance issues were addressed through the station's performance improvement initiatives.

  The finding was determined to be more than minor because the finding was similar to IMC 0612, Appendix E, Example 5 c because an incorrect and inadequate part was installed and the system was returned to service. This performance deficiency impacted the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. A Phase 3 SDP risk evaluation was performed by the regional Senior Risk Analyst who determined the risk significance of the finding to be less than 1.0E-6/yr delta core damage frequency (CDF) and less than 1.0E-7/yr delta LERF, which represents a finding of very low safety significance. Failure of plant personnel to question the plastic shipping plug before the equipment was installed and returned to service was not in compliance with MA-AA-716-008, "Foreign Material Exclusion Program," and, therefore, inspectors determined that this event was cross-cutting in Human Performance, Work Practices, Procedural Compliance for failure of personnel to follow the procedure. H.4(b) (Section 4OA3.3)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, was self-revealed for the failure to properly move a fuel assembly to its specified location, in accordance with DFP 0800-01, “Master Refueling Procedure.” Specifically, on November 5, 2004, fuel assembly JLU569 was placed in position C4-E5, instead of C4-F5, as required by the procedure. The violation was placed into the licensee’s CAP in IR 990180. As corrective action, the licensee temporarily suspended all fuel handling activities, conducted a piece count of the spent fuel and stationed a second Senior Reactor Operator on the refueling bridge as additional oversight for follow-on fuel movements. Additionally the fuel handling crew associated with the event was suspended from future fuel moves, pending remedial training.

  Using the guidance contained in IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” dated December 4, 2008, the inspectors determined that the finding was more than minor because the finding was associated with the configuration control and human performance attributes of the Barrier Integrity Cornerstone and impacted the Barrier Integrity Cornerstone objective to provide reasonable assurance that physical design barriers (i.e., fuel cladding) protect the public from radionuclide releases caused by an accident or event. Specifically, the shutdown margin and thermal management of the spent fuel pool(s) is affected by fuel assembly placement inside the pool(s). The inspectors determined the finding could be evaluated using the significance determination process in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 3b, question 6, which directed the inspectors to Appendix M, “Significance Determination Process Using Qualitative Criteria.” Because probabilistic risk assessment tools were not well suited for this finding, the criteria for using IMC 0609, Appendix M, were met. In determining the significance of this finding, regional management reviewed the licensee's bounding analysis in the UFSAR, which demonstrated that regardless of the incorrect bundle position in the fuel pool, the design of the pool still maintained pool K_{eff} less than .95. Based on the additional qualitative circumstances associated with this finding, regional management concluded the finding was of very low safety significance (Green). This finding has a cross-cutting aspect in the area of Human Performance, Work Practices. Specifically, neither the Senior Reactor Operator (SRO), nor either of the two members of the fuel handling crew, adequately performed independent verification techniques that ensured the fuel assembly move was made in accordance with the Nuclear Component Transfer List, as required by DFP 0800-01. H.4(a) (Section 1R20)

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was self-revealed for the mispositioning of a Unit 3 control rod at power. Control rod G-11 was withdrawn one notch contrary to TS SR 3.1.3.3 requirements to insert each withdrawn control rod at least one notch. This was a performance deficiency. The violation was entered into the licensee’s CAP as IR 993634. Corrective actions included inserting control rod G-11 one notch back to the original position and suspending control rod movement while all rods were verified to be in their correct position. The operator was removed from shift duties and the oncoming shift was briefed of the event.

The finding was determined to be more than minor because the finding was associated with the Barrier Integrity Cornerstone attributes of human performance and configuration control of a control rod, and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the operator withdrew a control rod contrary to expected operation. This added positive reactivity and caused an unanticipated power increase. The inspectors evaluated the finding 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 Fuel Barrier Cornerstone. Per Table 4a, any issue that involves the fuel barrier is screened as Green. This finding had no cross-cutting aspect. (Section 1R22)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 2

On October 18, 2009, the unit began its coastdown to D2R21, and continued to downpower until the end of the month.

On November 1, 2009, the unit was shutdown for the D2R21 Refueling Outage.

On December 2, 2009, the unit began ramp-up following D2R21.

On December 9, 2009, the unit returned to full power.

Unit 3

On October 3, 2009, the unit scrammed due to a Group 1 isolation resulting from a reactor water clean-up pressure perturbation. The unit returned to full power on October 8, 2009.

On October 18, 2009, power was reduced to approximately 82 percent for a control rod pattern adjustment. The unit returned to full power on the same day.

On November 6, 2009, the main turbine was manually tripped due to an EHC fluid leak from a main stop valve. The unit returned to full power on November 10, 2009.

On November 19, 2009, power was reduced to approximately 82 percent for a control rod pattern adjustment. The unit returned to full power on the same day.

On December 12, 2009, power was reduced to approximately 70 percent for control rod testing, scram testing and quarterly valve testing. The unit returned to full power on December 13, 2009.

1. REACTOR SAFETY

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Unit 3 250V battery and DC buses during Unit 2 250V battery discharge test;
- B train of standby gas treatment when A train declared inoperable;
- U2 Division 2 low pressure coolant injection and containment cooling service water restoration after D2R21; and
- Unit 2 main power transformer clearance order error.

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, Updated Final Safety Analysis Report (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 that system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted four partial system walkdown samples as defined in Inspection Procedure (IP) 71111.04-05.

b. Findings

(1) Operating Personnel Incorrectly Placed Clearance Tags

Introduction: A finding of very low safety significance and associated Non-Cited Violation (NCV) of TS 5.4.1 was self-revealed for the failure to meet the requirements of Clearance Order (CO) 69631 by removing shorting links instead of fuses as required by the CO (Green). The inspectors determined this finding to be self-revealed because it required no active and deliberate observation by the licensee or NRC inspectors to determine whether a change in process or equipment capability or function had occurred. The licensee was in the process of restoring fuses when it was observed the fuses had not been removed.

Description: Clearance Order 69631 was placed on November 2, 2009. The CO was to remove fuses (2-0902-29-FU1A and 2-0902-29-FU1B) for the U2 main power transformer protective relays in preparation for the replacement of the main power transformer. The fuses were located in the top of panel 902-29 in the auxiliary electric equipment room. On November 12, 2009, direction was given to restore the fuses per CO 69631. The non-licensed operators (NLOs), assigned to restore the fuses, found that fuses 2-902-29-FU1A and 2-0902-29-FU1B had not been removed, but that shorting links 2-902-29-F8 and 2-0902-29-F12 had been removed instead. These shorting links removed protective relaying from the main power transformer TR-2, the unit auxiliary transformer TR-21, and the reserve auxiliary transformer TR-22.

Two NLOs were assigned to remove the fuses. One of them was a Dresden operator, the other was a traveler from Braidwood Station. The Braidwood operator had returned to Braidwood Station by the time this issue was identified. The inspectors interviewed the Dresden operator. The NLO stated that he never saw the fuses that were to be removed. The labels for the fuses were below the fuses he was required to remove and above a fuse block that contained the shorting links that he did remove. The fuse block containing the shorting links had a placard on it stating that there were shorting links inside the fuse block. The operator stated that he had not read the placard. In addition, the operator stated that after the incorrect fuse block was removed he looked inside the fuse block and recognized that they were shorting links and not fuses. The operator stated that this did not alert him that the wrong equipment had been manipulated. The operator also stated that he had been trained to recognize the difference between shorting links and fuses.

Analysis: The inspectors determined that removal of shorting links instead of fuses was contrary to the requirements of CO 69631 and was a performance deficiency.

The finding was determined to be more than minor because the finding could reasonably be viewed as a precursor to a significant event. Specifically, the process error by the non-licensed operators involved in the performance of the CO to properly detect that the wrong piece of equipment had been removed, even after observing that the removed equipment was not what they were assigned to remove (i.e., shorting link versus a fuse), was a failure that, if left uncorrected, could lead to a significant event.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, Appendix G, Attachment 1, “Shutdown Operations Significance Determination Process Phase 1 Operational Checklists For Both PWRs AND BWRs,” Checklist 6, dated May 25, 2004. This checklist stated that for a finding to require a Phase 2 or 3 determination, it would require an increase in the likelihood of a loss of offsite power or degrade the licensee’s ability to cope with a loss of offsite power. The ability of the licensee to cope with a loss of offsite power was not impacted because at least one emergency diesel generator was operable during the entire period. The inspectors determined that neither of these conditions were met so the finding screened as Green.

This finding has a cross-cutting aspect in the area of Human Performance, Work Practices. The licensee communicates human error prevention techniques, such as self and peer checking. In addition, personnel do not proceed in the face of uncertainty or unexpected circumstances. Specifically, the NLO: 1) did not read the placard that was on the component that the NLO removed, which explained that the component was a shorting link and not a fuse; and 2) did not question why the component the NLO removed was a shorting link and not a fuse, as identified in the CO. H.4(a)

Enforcement: Technical Specification Section 5.4.1 states, in part, that “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.” Paragraph 1.c of Regulatory Guide 1.33 states, in part, that procedures for equipment control, locking and tagging shall be prepared and activities shall be performed in accordance with these procedures. The licensee established CO 69631 as the implementing procedure for tagging out-of-service the Unit 2 Main Power Transformer.

Contrary to the above, on November 2, 2009, CO 69631 was incorrectly placed, in that, fuses (2-0902-29-FU1A and 2-0902-29-FU1B) for the U2 main power transformer protective relays were not removed as required by CO 69631. Instead, shorting links 2-0902-29-F8 and 2-0902-29-F12 were removed which removed protective relaying to the U2 main power transformer, U2 reserve auxiliary transformer, and the U2 unit auxiliary transformer. Corrective actions included: coaching of the individuals involved with the incorrect placing of the out-of-service, and changing a placard on the device that was incorrectly repositioned to include the specific equipment part number of the shorting links. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as Issue Report 992290 this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (**NCV 05000237/2009005-01**)

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 1.1.1.4, Unit 3 Reactor Building Elevation570', Secondary Containment;
- Fire Zone 8.2.5.B, Unit 2 Turbine Building Elevation 517', Low Pressure Heater Bays North Turbine Cavity;
- Fire Zone 8.2.5.A, Unit 2 Turbine Building Elevation 517', High Pressure Heaters/Steam Lines; and
- Fire Zone 8.2.6.B Multiple Elevations, Low Pressure Heater Bays.

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, 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 four quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08G)

For Unit 2, from November 2, 2009, through November 13, 2009, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system, steam generator tubes, emergency feedwater systems, 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 ultrasonic examination (UT) of the following examination Category F welds (e.g., welds with known cracks approved by analysis for limited additional service without repair) to evaluate compliance with the licensee's augmented Stress Corrosion Cracking Program. Specifically, the inspectors evaluated these examinations to determine if the procedures, equipment, and personnel used were qualified in accordance with the American Society of Mechanical Engineers (ASME) Code Section XI, Appendix VIII.

- UT of the valve-to-tee weld (PS2-Tee/202-4B) on the loop B recirculation system.
- UT of the safe end-to-elbow (PS2/201-1) on the loop B recirculation system.

The inspectors observed a video record and reviewed a written report of the following containment drywell supports to evaluate compliance with the licensee's augmented inspection program for Code Class MC supports. Specifically, the inspectors evaluated this examination to determine if the VT-3 procedure, equipment, and personnel used were qualified in accordance with the ASME Code Section XI.

- Visual examination (VT-3) of eight male and female drywell shear lug stabilizers (support groups 09 and 10).

The inspectors reviewed the following examination record with relevant/recordable conditions/indications identified by the licensee to determine if acceptance of these indications for continued service was in accordance with the ASME Code Section XI or an NRC-approved alternative.

- Report No. D2R20-037, Four Indications on the Reactor Head Flange Weld (2RPV UPP HD/2-THD-FLG). The inspectors observed the following pressure boundary weld completed for a risk-significant system to determine if the licensee followed an ASME Code Section IX qualified welding procedure, maintained control of foreign material, and to determine if the welder used qualified weld filler material and base material. The inspectors also reviewed the work order for this welding to determine if the post weld nondestructive examinations required by the ASME Code were specified.
- Weld (FW-2) fabricated during installation of the component cooling service water system pump discharge elbow replacement.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities (Not Applicable)

.3 Boric Acid Corrosion Control (Not Applicable)

.4 Steam Generator Tube Inspection Activities (Not Applicable)

.5 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.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On August 3, 2009, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

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

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Unit 3 control rod drive (Z03); and
- Unit 2 Shutdown Cooling (Z10).

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 that 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 that 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 of significance 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:

- 345 kv Switchyard Bus 4 outage; and
- 345 kv Line 8014 trip.

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 Technical Specification (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 two samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- IR 957843, "Failed Flowscan on AOV [air operated valve] 3-1599-61;"
- IR 967008, "Degraded Thermal Performance of the 2A LPCI [low pressure coolant injection] Hx [heat exchanger];"
- IR 987982, "Boron Liquid Leak on 3B SBLC [standby liquid control] Pump;" and
- IR 986676, "Auto Bypass Sensors Not in Accordance with UFSAR Requirements."

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

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

b. Findings

(1) NRC Inspector-Identified Control Room Alarm Isolation Valve Out-of-Position

Introduction: A finding of very low safety significance and associated NCV of TS 5.4.1 was identified by the inspectors for the licensee failing to follow Dresden procedure DOP 2-1500-M1, "LPCI System Mechanical Checklist," Revision 39. The inspectors identified valve 2-1501-42A, U2 low pressure coolant injection (LPCI) A pump gland leak-off, was out-of-position (closed) and documented an unresolved item (URI) in inspection report 05000237/2009004; 05000249/2009004.

Description: On September 24, 2009, the inspectors identified that the 2-1501-42A valve was out-of-position. The inspectors were reviewing the 2A LPCI pump seal leak-off configuration as part of an evaluation of the mechanical seal safety classification. The inspectors reported the valve position to shift management and operations department personnel verified the valve was not in the open position as described in DOP 2-1500-M1, "LPCI System Mechanical Checklist," Revision 39. This issue was documented in IR 969490, "LPCI Gland Seal Leak-off Isolation Found Closed." With the valve closed instead of open, a control room alarm (902-3 C-6) for LPCI pump seal leakage would not have alarmed for the 2A LPCI pump had the seal failed during operation.

The issue was considered an unresolved item in Inspection Report 05000237/2009-004; 05000249/2009-004 pending NRC review of the licensee's evaluation of the valve position versus the requirements of DOP 2-1500-M1.

The licensee performed a prompt investigation into the mispositioning of the valve. The licensee was unable to determine the reason for, or the time at which the valve became mispositioned. The licensee did determine that on July 6, 2009, the 2A LPCI pump seal was replaced under Work Order 548808-01 and procedure DMP 1500-05, "LPCI Pump Maintenance," Revision 8.

The inspectors observed that the licensee took a corrective action to change maintenance procedure DMP 1500-05, "LPCI Pump Maintenance," Revision 8, step G.25.d to include the case drain valve equipment numbers. The inspectors reviewed procedure DMP 1500-05, Revision 8, step G.25.d and found that it had directed only that the case drain valves be closed with no specific equipment number designations. Since the valve that was found mispositioned was a drain valve and in close proximity to the case drain valves, it was possible that 2-1501-42A was closed at the same time that the case drain valves were closed. There was no step in DMP 1500-05 past step G.25.d to open the case drain valves.

Analysis: The inspectors determined that the as found position of 2-1501-42A was contrary to the requirement of DOP 2-1500-M1, “LPCI System Mechanical Checklist,” Revision 39 and was a performance deficiency.

The finding was determined to be more than minor because the finding, if left uncorrected, would become a more significant safety concern. Specifically, the valve isolated an alarm in the control room. The alarm warned the control room operators of a LPCI pump mechanical seal failure. A mechanical seal failure of a LPCI pump during an accident condition could result in exceeding the limits of the leakage outside the primary containment as described in TS` 5.5.2. The inspectors concluded this finding was associated with the Mitigating Systems Cornerstone.

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, dated January 10, 2008, for the Mitigating System Cornerstone. The inspectors answered “No” to all five questions on Table 4a. This issue screened as Green.

This finding has a cross-cutting aspect in the area of Human Performance, Work Practices because the licensee did not have any documentation as to how or when the valve was placed into the position it was in. The design and location of the valve precluded that the valve was accidently placed into the position it was found in. Therefore, the inspectors concluded that either the failure to use human error prevention techniques or maintaining proper documentation of activities caused the mispositioning of valve 2-1501-42A. H.4(a)

Enforcement: Technical Specification Section 5.4.1.a states, in part, that “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.” Paragraph 4 of this Regulatory Guide states, in part, that procedures for energizing, filing, venting, draining, startup, shutdown, and changing modes of operation for Emergency Core Cooling Systems shall be prepared and activities shall be performed in accordance with these procedures. The licensee established DOP 2-1500-M1, “LPCI System Mechanical Checklist,” Revision 39, as one of the implementing procedures.

Contrary to the above, on September 24, 2009, the inspectors identified that the 2-1501-42A valve was not in the open position as required by DOP 2-1500-M1, “LPCI System Mechanical Checklist,” Revision 39. The licensee took the following corrective actions: restored 2-1501-42A to the correct position; changed maintenance procedure DMP 1500-05, LPCI Pump Maintenance, step G.25.d to include the case drain valve equipment numbers and sign offs to position and verify the valves; and Operations Department Management addressed the operations department personnel about this issue. Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program as IR 969490, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000237/2009005-02) (URI 05000237/2009004-04; 05000249/2009004-04** is closed.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

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 1152490-08, "OP Perform as Left LLRT [local leak rate test] on 2-0203-2C MSIV [main steam isolation valve];"
- WO 1293386, "TSC [Technical Support Center] HVAC [heating, ventilation and air conditioning] Surveillances Failed;"
- WO 1285845, "U2 EDG [emergency diesel generator] Largest Load Reject (TSR 3.8.1.10);"
- WO 1286397, "2/3 EDG Voltage Transient;" and
- WO 1098975-02, "Perform 2B Condensate Pump Inspections."

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 five post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

(1) Preconditioning the Unit 2 EDG Prior to Performing Technical Specification (TS) Surveillance Requirements (SRs)

Introduction: The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50 Appendix B, Criterion XI, "Test Control," because the licensee unacceptably preconditioned the Unit 2 EDG prior to performing TS SRs 3.8.1.19.c.4, 3.8.1.12.c.3, and 3.8.1.10 (Green). These TS SRs involved verifying that the EDG supplied steady state frequency would be acceptable following a loss offsite power (LOOP) coincident with and without a loss of coolant accident (LOCA), and following the loss of the largest post-accident load. Specifically, the inspectors identified that the licensee performed governor oil change outage maintenance activities which involved a section that tuned the Unit 2 diesel governor's response to a load change just prior to performing these TS SRs. The licensee performed the governor oil change maintenance every six years. The SRs listed above were performed every two years.

Description: On November 13, 2009, during the performance of TS SR 3.8.1.10, under work order (WO) 00634625-01, the Unit 2 EDG did not recover fast enough to satisfy the TS SR acceptance criteria. After the largest single post-accident load was shed (i.e., a service water pump), the EDG frequency went up to 62.4 Hz and did not recover to the allowable band of 58.8-61.2 Hz until 13 seconds had passed. Technical Specification SR 3.8.1.10 requires the bus frequency to recover in less than 4 seconds. The licensee entered this condition into the corrective action program (IR 992803). A second work order (WO 01285845-01) was created, which adjusted the governor compensator by using work instructions located in station procedure DES 6600-01, "Diesel Generator Governor Oil Change and Compensation Adjustment," Revision 23. Following the adjustment, the Unit 2 EDG passed TS SR 3.8.1.10 satisfactorily.

The licensee performed a cause evaluation and determined that the Unit 2 EDG failed the TS SR because the governor compensation was incorrectly set when performing WO 634625-01, "D2 3RFL PM D/G Governor – Change Oil/Flush/Compensate" six days earlier on November 7, 2009. The licensee determined in their extent of condition review that the other EDGs were not susceptible to the Unit 2 EDG issue because they had been successfully tested by performing TS SR 3.8.1.10 as a post-maintenance test (PMT) since their respective governor oil change outs. The inspectors identified that it was the practice for the licensee to utilize TS SR 4.8.1.10 as a PMT when performing these oil changes on a six year interval.

The inspectors questioned the practice of performing preventative maintenance (PM) activities which involved tuning the EDG governor response just prior to the EDG's biennial design basis loading/load shedding tests. Furthermore, the inspectors noted that the maintenance activity utilized to resolve the failed TS SR was to re-perform the governor compensator adjustment section of the PM activity used on November 7, 2009.

The licensee stated that, after evaluating the issue under IR 1000609, Assignment 1, that the inspector's issue was an example of acceptable pre-conditioning, primarily for two reasons. The licensee agreed that the PM and PMT could mask the as-found EDG governor's response during the performance of TS SR 3.8.1.10, but was acceptable because the TS SR is usually performed without the PM/PMT activity the majority of the time (oil change/flush every six years, and TS SR is performed every two years.). In addition the licensee determined that a second diesel run would be required, and that this run would unnecessarily stress the machine.

The inspectors disagreed with the licensee's CAP evaluation and conclusions and communicated the issue through Dresden management. The inspectors consulted the NRR Quality Assurance, Vendor Inspection, and Maintenance Branch as recommended in the NRC's Inspection Manual Part 9900 guidance regarding preconditioning. The NRR Branch agreed that this issue was not consistent with the guidance outlined in the NRC technical guidance or Information Notice 97-16, "Preconditioning of Plant Structures, Systems, and Components before ASME Code Inservice Testing or Technical Specification Surveillance Testing".

Analysis: The inspectors determined that the licensee did not establish suitable test conditions during the Unit 2 EDG TS SRs 3.8.1.19.c.4, 3.8.1.12.c.3, and 3.8.1.10. The inspectors identified that this was a performance deficiency based on the 10 CFR 50, Appendix B, Criterion XI, "Test Control" regulatory requirements and the NRC's generic communication to licensees regarding preconditioning. The failure to properly test the EDG is considered more than minor because, if left uncorrected, the finding would become a more significant safety concern. Unacceptable preconditioning of the EDG could mask latent performance issues and affect the ability of the EDG to supply safety-related power to vital loads during an event. The inspectors determined that traditional enforcement was not appropriate because it was not apparent that the performance deficiency affected the ability of the NRC to regulate. However, the inspectors noted that this issue could mask failed TS SRs, which would directly feed into the NRC assessment process. This issue was determined to be Green because it did not result in an inoperable Unit 2 EDG.

The inspectors determined that the failure to adequately coordinate the work activity of the PM/PMT and TS SR activities was the principal contributor to this finding and was reflective of recent performance. This finding had a cross-cutting aspect in the area of Work Control. Specifically the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of the work as different job activities. The scheduling of the work activities resulted in the pre-conditioning of the EDG prior to the surveillance tests. H.3(b)

Enforcement: 10 CFR 50, Appendix B, Criterion XI, "Test Control," requires, in part, "that the test is performed under suitable environmental conditions." Suitable environment conditions include conditions representative of the expected conditions when the equipment is required to perform its safety function. The adjustment of the Unit 2 EDG governor compensator affects how the EDG governor will respond when TS SRs 3.8.1.19.c.4, 3.8.1.12.c.3, and 3.8.1.10. are performed and, therefore, preconditions the EDG. The licensee agreed to change the method by which their maintenance and testing was performed, but had not reached a conclusion on corrective actions by the end of the inspection period. Because the finding is of very low safety significance, and has been entered into the corrective action program as IR 01000609, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, NUREG 1600. **(NCV 05000237/2009005-03**)

(2) 2/3 Emergency Diesel Generator (EDG) Overvoltage during Division I Undervoltage Surveillance

a. Inspection Scope

The inspectors reviewed the licensee's equipment apparent cause evaluation (EACE) in response to a 2/3 EDG overvoltage during performance of DOS 6600-06, "Bus Undervoltage and ECCS Integrated Functional Test for Unit 2/3 Diesel Generator to Unit 2," Revision 46. Documents reviewed in this inspection are listed in the Attachment to this report.

This post-maintenance testing review constituted one sample as defined in IP 71111.19.

b. Findings

Introduction: The inspectors identified an URI regarding the regulatory requirements associated with the circumstances surrounding the 2/3 EDG overvoltage event on November 16, 2009.

Description: On November 16, 2009, at 10:53 a.m., a nuclear station operator (NSO) was performing step I.11.c per DOS 6600-06, "Bus Undervoltage and ECCS Integrated Functional Test for Unit 2/3 Diesel Generator to Unit 2," Revision 46. At this time, the operator was attempting to synchronize Bus 23-1 (powered from 2/3 EDG) to Bus 23 (powered from reserve auxiliary transformer 22). The operator stated that he was only monitoring running versus on-coming bus voltage meters, which are transformed down and are only relative to actual bus voltages. The operator stated that a loud 'pop' noise was heard from the 902-3 panel. At this time, the operator noticed that the 23-1/24-1 digital volt meter read around 5600 volts (was previously around 4100 volts). The 2/3 EDG was then shutdown per DOS 6600-06 step I.12. On step I.12.c, the voltage regulator would not lower (remained upscale). The EDG stopped after the 6-minute cool down and DOS 6600-06 was stopped.

The licensee generated EACE 994101-07, "2/3 Emergency Diesel Generator (EDG) Voltage Transient," to determine the cause, extent of condition and corrective actions for this event. The inspectors reviewed EACE 994101-07 and interviewed the NSO who had performed DOS 6600-06. The inspectors raised more questions regarding the capabilities of the control room simulator used for training, procedure adequacy and the corrective actions in place. The inspectors plan to review the licensee's response to their questions to determine if there were any violations of NRC requirements and that appropriate corrective actions were applied. **(URI 05000237/2009005-04; 05000249/2009005-04)**

1R20 Outage Activities (71111.20)

.1 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for a Unit 3 forced outage that began on October 3, 2009, and continued through October 8, 2009. The forced outage was caused by a Group 1 isolation and reactor scram caused by a pressure pulse caused by the restoration of the Unit 3 reactor water clean-up system. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, startup and heatup activities, and identification and resolution of problems associated with the outage.

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

b. Findings

No findings of significance were identified.

.2 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 2 refueling outage (RFO), conducted November 1, 2009, through December 9, 2009, 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

(1) Failure to Follow the Master Refueling Procedure During Movement of Fuel Assembly JLU569

Introduction: A finding of very low significance (Green) was self-revealed involving a NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for failing to follow DFP 0800-01, "Master Refueling Procedure," Revision 45, Page 12, Step 2.b, when the licensee moved fuel assembly JLU569 to the wrong position in the Unit 2 Spent Fuel Pool during D2R21, on November 5, 2009.

Description: On November 6, 2009, during fuel shuffle 1, the fuel handling crew was moving a fuel assembly from the reactor to location C4-E5 of the spent fuel pool, per step 475 of the Nuclear Component Transfer List (Move Sheet), in accordance with DFP 0800-01, "Master Refueling Procedure." While making the move the refueling crew identified a fuel assembly was already in location C4-E5. The fuel assembly being moved was then placed in the designated "Emergency Set Down Location."

It was immediately determined that the same fuel handling crew had incorrectly performed step 294 of the Nuclear Component Transfer List the previous night, November 5, 2009, where they positioned fuel assembly JLU569 into C4-E5, vice the correct location of C4-F5, each location was located in the same fuel rack.

DFP 0800-01, "Master Refueling Procedure," Revision 45, Step 8.d directs the Senior Reactor Operator (SRO) on the refueling bridge to verify a fuel assembly is placed in the correct spent fuel pool location by observing rack coordinates in the spent fuel pool. During interviews with the inspector, it was determined that the crane operator, fuel-handling supervisor and the SRO had each independently (and incorrectly) identified spent fuel pool location C4-F5 as C4-E5.

Analysis: The inspectors determined that the licensee's failure to move fuel assembly JLU569 to the correct location in accordance with the Nuclear Component Transfer List (Move Sheet) was contrary to 10 CFR 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," which, in part, requires that activities affecting quality shall be accomplished in accordance with prescribed instructions, and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the configuration control and human performance attributes of the Barrier Integrity Cornerstone and impacted the Barrier Integrity Cornerstone objective to provide reasonable assurance the physical design barriers (i.e., fuel cladding) protect the public from radionuclide releases caused by an accident or event. Specifically, the shutdown margin and thermal management of the spent fuel pool(s) is affected by fuel assembly placement inside the pool(s).

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," Table 3b, question 6, which directed the inspectors to Appendix M, "Significance Determination Process Using Qualitative Criteria." Because probabilistic risk assessment tools were not well suited for this finding, the criteria for using IMC 0609, Appendix M, were met. In determining the significance of this finding, regional management reviewed the licensee's bounding analysis in the UFSAR which demonstrated that regardless of the incorrect bundle position in the spent fuel pool, the design of the pool still maintained pool K_{eff} less than .95. Based on the additional qualitative circumstances associated with this finding, regional management concluded the finding was very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance, Work Practices. Specifically, neither the SRO, nor either of the two members of the fuel handling crew, adequately performed independent verification techniques that ensured the fuel assembly move was made in accordance with the Nuclear Component Transfer List, as required by DFP 0800-01, Revision 45, Page 12, Step 2.b. H.4(a)

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires, in part, 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.

Dresden procedure DFP 0800-01, "Master Refueling Procedure," Revision 45 is a procedure affecting quality. Specifically, it governs fuel movements between the spent fuel pool and the reactor. Dresden Procedure DFP 0800-01 Step 2.b required the SRO to ensure that the fuel assembly was moved in accordance with the Nuclear Component Transfer List (Move Sheet).

Contrary to the above, on November 5, 2009, the licensee failed to follow DFP 0800-01, "Master Refueling Procedure," Revision 45, Step 2.b. Specifically, the fuel handling crew positioned fuel assembly JLU569 in location C4-E5 of the U2 spent fuel pool instead of location C4-F5. Because this violation was of very low safety significance and it was entered into the licensee's correction action program as IR 990180, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (**NCV 05000237/2009005-05**)

Corrective actions for this event included a temporary stand down of all fuel handling activities, a piece count of the spent fuel was performed to identify any errors associated with fuel handling up to step 475 of the nuclear transfer list, a second SRO and a fuel handling supervisor were stationed on the refuel bridge to provide additional oversight during the remaining fuel moves, and the crew associated with the event were not to resume fuel handling duties until the completion of remedial training.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- WO 1077723-01, “D2 20M/RFL [20 month/refuel] TS LLRT [local leak rate test] MSIV 203-1A & 203-2A Dry Test;”
- WO 1257282-01, “D2 QTR SBO [station black out] Diesel Generator Surveillance Test;”
- WO 1251254-01, “D3 Qtr TS Reactor Low Pressure (350 PSIG) ECCS [emergency core cooling system] Permissive Ca;” and
- WO 1277976-01, “D3 1M TS Partially Withdrawn Control Rod Drive Exercise.” (IST Sample).

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

- did unacceptable 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 frequencies 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, ASME 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 two routine surveillance testing samples, one in-service testing sample, and one isolation valve inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. <u>Findings</u>

(1) <u>Mispositioning of Unit 3 Control Rod G-11</u>

<u>Introduction</u>: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the mispositioning of a Unit 3 control rod at power.

<u>Description</u>: On November 15, 2009, during performance of DOS 0300-01, "Control Rod Exercise," Revision 48, control rod CRD G-11 was withdrawn by the reactor operator to position 16 from position 14 instead of being inserted to position 12 as required by procedure. The licensee entered DOA 0300-12, "Mispositioned Control Rod," Revision 14; and DGA 7, "Unpredicted Reactivity Addition," Revision 20. Control rod G-11 was inserted back to the initial position of 14 and DOA 0300-12 was exited.

<u>Analysis</u>: The inspectors determined that the withdrawal of the control rod was contrary to Technical Specification Surveillance Requirement 3.1.3.3 to insert each withdrawn control rod at least one notch and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Fuel Barrier Cornerstone attributes of human performance and configuration control of a control rod, and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the operator withdrew a control rod contrary to the expected operation of insertion. This added positive reactivity and caused an unanticipated power increase. No thermal or power limits were exceeded.

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 Fuel Barrier Cornerstone. Per Table 4a any issue that involves the fuel barrier is screened as Green.

This finding had no cross-cutting aspect. The inspectors determined that the licensee had taken every precaution possible to prevent this error in advance, in that, the licensee has briefed the evolution and stationed additional personnel to ensure correct movement. Notwithstanding, the operator moved the rod in the wrong direction.

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, 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.

Contrary to the above, on November 15, 2009, the licensee failed to perform an activity affecting quality in accordance with the appropriate procedure during performance of DOS 0300-01, "Control Rod Exercise," Revision 48, in that, control rod CRD G-11 was withdrawn to position 16 from position 14 instead of being inserted to position 12.

Specifically, the licensed operator moving the control rod did not follow procedure DOS 0300-01, Step I.4.a, which stated to insert the control rod one notch. The licensee took a series of corrective actions: control rod G-11 was inserted one notch back to the original position and then control room operators suspended control rod movement. All control rods were verified to be in their correct position. The operator was removed from shift duties and the oncoming shift was briefed of the event. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as IR 993634, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000249/2009005-06)**

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 Plan Annex, Revisions 24 and 25 were implemented based on licensee 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. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the Emergency Action Level (EAL) 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

(1) Changes to EAL HU6 Potentially Decrease the Effectiveness of the Plans without Prior NRC Approval

Introduction: The inspectors reviewed changes implemented to the Dresden Station Radiological Emergency Plan Annex EALs and EAL Basis. In Revision 24, the licensee changed the basis of EAL HU6, "Fire not extinguished within 15 minutes of detection within the protected area boundary," by adding two statements. The two changes added to the EAL basis stated that if the alarm could not be verified by redundant control room or nearby fire panel indications, notification from the field that a fire exists starts the 15-minute classification and fire extinguishment clocks. The second change stated the 15-minute period to extinguish the fire does not start until either the fire alarm is verified to be valid by additional control room or nearby fire panel instrumentation, or upon notification of a fire from the field. These statements conflict with the previous Dresden Station Annex, Revision 23, basis statements and potentially decrease the effectiveness of the Plans.

Description: Dresden Station Radiological Emergency Plan Annex, Revision 23, EAL HU6, initiating condition stated, "Fire not extinguished within 15 minutes of detection, or explosion, within the protected area boundary." The threshold values for HU6 were, in part: 1) Fire in any Table H2 area not extinguished within 15 minutes of Control Room notification or verification of a Control Room alarm, or 2) Fire outside any Table H2 area with the potential to damage safety systems in any Table H2 area not extinguished within 15 minutes of Control Room notification or verification of a Control Room alarm. Table H2, Vital Areas, were identified as reactor building, auxiliary electric room, control room, diesel generator rooms, 4 kilovolt emergency core cooling system switchgear area, battery rooms, control rod drive and component cooling service water pump rooms, turbine building cable tunnel, turbine building safe shutdown areas, and crib house. The basis defined fire as "combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is not required if large quantities of smoke and heat are observed."

The basis for Revision 23, EAL HU6 thresholds 1 and 2 stated, in part, the purpose of this threshold is to address the magnitude and extent of fires that may be potentially significant precursors to damage to safety systems. As used here, notification is visual observation and report by plant personnel or sensor alarm indication. The 15-minute period begins with a credible notification that a fire is occurring or indication of a valid fire detection system alarm. A verified alarm is assumed to be an indication of a fire unless personnel dispatched to the scene disprove the alarm within the 15-minute period. The report, however, shall not be required to verify the alarm. The intent of the 15-minute period is to size the fire and discriminate against small fires that are readily extinguished (e.g., smoldering waste paper basket, etc.).

Revision 24 of the Dresden Station Radiological Emergency Plan Annex, changed the threshold basis for EAL HU6 by adding the following two statements: “1) If the alarm cannot be verified by redundant control room or nearby fire panel indications, notification from the field that a fire exists starts the 15-minute classification and fire extinguishment clocks, and 2) The 15-minute period to extinguish the fire does not start until either the fire alarm is verified to be valid by utilization of additional control room or nearby fire panel instrumentation, or upon notification of a fire from the field."

The two statements added to the basis in Revision 24 conflict with the Revision 23 threshold basis and initiating condition. The changed threshold basis in Revision 24 could add an indeterminate amount of time to declaring an actual emergency until a person responded to the area of the fire and made a notification to the control room of a fire in the event that redundant control room or nearby fire panel indications were not available.

Pending further review and verification by the NRC to determine if the changes to EAL HU6 threshold basis potentially decreased the effectiveness of the Plans, this issue was considered an Unresolved Item. **(URI 05000237/2009005-07)**

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant to determine if radiological controls including surveys, postings, and barricades were acceptable:

- Drywell Nuclear Instrumentation System Maintenance;
- Drywell In-Service Inspection;
- Drywell Control Rod Drive System Maintenance and Support.

The inspectors walked down and surveyed (using an NRC survey meter) these areas to verify that the prescribed RWP, procedure, and engineering controls were in place; that licensee surveys and postings were complete and accurate; and that air samplers were properly located.

This sample was documented and credited in Inspection Report 05000237/2009003; 05000249/2009003; therefore, this review does not represent a sample.

b. Findings

No findings of significance were identified.

.2 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation safety work requirements. The inspectors evaluated whether workers were aware of any significant radiological conditions in their workplace, of the RWP controls and limits in place, and of the level of radiological hazards present. The inspectors also observed worker performance to determine if workers accounted for these radiological hazards.

This sample was documented and credited in Inspection Report 05000237/2009003; 05000249/2009003; therefore, this review does not represent a sample.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Reasonably-Achievable Planning and Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends, and ongoing and planned activities in order to assess current performance and exposure challenges. The inspectors reviewed the plant's current 3-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment.

This inspection constituted one required sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following three work activities of highest exposure significance:

- Drywell Nuclear Instrumentation System Maintenance;
- Drywell In-Service Inspection; and
- Drywell Control Rod Drive System Maintenance and Support.

This sample was documented and credited in Inspection Report 05000237/2008005; 05000249/2008005; therefore, this review does not represent a sample.

For these three activities, the inspectors reviewed the As-Low-As-Reasonably-Achievable (ALARA) work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. The inspectors also determined if the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

This sample was documented and credited in Inspection Report 05000237/2008005; 05000249/2008005; therefore, this review does not represent a sample.

b. Findings

No findings of significance were identified.

.3 Source-Term Reduction and Control

b. Inspection Scope

The inspectors reviewed licensee records to evaluate the historical trends and the current status of tracked plant source terms. The inspectors determined if the licensee was making allowances and had developing contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

This inspection constituted one required sample as defined in IP 71121.02-5.

c. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

Cornerstone: Barrier Integrity

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system (RCS) leakage performance indicator for Units 2 and 3 for the period from the fourth quarter 2008 through the third quarter 2009. 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 5, 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 January 2009 through November 2009 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report (IR) 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 of significance were identified.

Cornerstone: Occupational Radiation Safety

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences performance indicator for the period from the third quarter 2008 through the third quarter 2009, to determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. 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 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 radiological occurrences sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Items Entered Into the CAP

a. Scope

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

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

b. Findings

No findings of significance were identified.

.2 Daily CAP Reviews

a. Inspection Scope

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

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

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. Specifically, the inspectors performed a review of the licensee's corrective actions program documents related to the areas of instrument air systems, heating, ventilation and air conditioning, and instruments and controls. The inspectors' review nominally considered IRs that were generated in the six month period of July 2009 through December 2009, although some examples expanded beyond those dates where the scope of the trend warranted. In addition to reviewing the IR documents for trends, the inspectors compared their results with issues identified in the licensee's trending reports. A sample of the licensee IRs associated with trends was reviewed for corrective action adequacy.

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

b. Findings

No findings of significance were identified.

.4 In-Depth Review - Corrective Actions Associated With Tube Blockages of the Unit 2 and Unit 3 LPCI Heat Exchangers

a. Inspection Scope

The inspectors performed a focused review of root cause report (RCR) 967008-03, "Dresden 2-1503-A, 2A Low Pressure Coolant Injection (LPCI) / Containment Cooling Heat Exchanger (Hx) Failure to Meet Design Basis Heat Removal Capability due to Asiatic Clam Macrofouling resulting from 2-1501-3A Valve Leakage and Subsequent Untreated Service Water Make-up via the CCSW Keepfill Diluting the Biocide Treatment below the Asiatic Clam Lethal Concentration," revision 0, to evaluate the corrective actions that the licensee had taken to address the introduction of Asiatic clam relics into the containment cooling heat exchangers.

Containment cooling is the operating mode of the low pressure coolant injection (LPCI) subsystem initiated to cool the containment in the event of a loss-of-coolant accident (LOCA). Each containment cooling subsystem consists of two LPCI pumps, one containment cooling Hx (also called LPCI Hx), one drywell spray header and a separate suppression chamber spray header. Heat exchanger cooling water is provided by two containment cooling service water (CCSW) pumps in each containment cooling subsystem. The water source for the CCSW pumps is the cribhouse, specifically Bay 13. If the heat exchanger is significantly fouled, then the Hx may be unable to remove sufficient heat from the containment, which could result in primary containment failure.

In addition, the inspectors performed a focused review to evaluate the licensee's assessment of a number of IRs related to the failure to meet biocide residual concentration after chemical addition into the containment cooling service water system. The inspectors reviewed these issues to determine if the licensee has taken adequate corrective actions both individually and collectively. This review constituted one sample as defined in IP 71152.

The inspectors reviewed several documents that are listed in the Attachment of the report.

Issues

(1) Effectiveness of Problem Identification

The licensee's thermal performance testing of the LPCI heat exchangers has been effective in identifying heat exchanger degradation prior to the Hx becoming inoperable. On September 18, 2009, a thermal performance test was performed on the 2A LPCI Hx. The test results indicated a heat removal capability of 67.49 MBtu/hr, which was 4.9 percent below the design heat removal rate of 71 MBtu/hr at design conditions per the updated final safety analysis report (UFSAR) Table 6.2-3b, "Heat Exchanger Heat Transfer Rate." This issue was documented in IR 967008. Further evaluation determined that with a heat removal capability of 67.49 MBtu/hr the new maximum allowable inlet water temperatures for the 3 months following the test performed on September 18, were 90.2 degrees F, 89.7 degrees F and 88 degrees F, respectively. Actual CCSW temperatures for the time period, including previous summer months, were below the design basis parameter of 95 degrees F, therefore, the licensee determined that the 2A LPCI Hx, although degraded, was able to perform the required design functions. Also, the licensee reviewed the results for the most recent thermal performance tests performed for the other three heat exchangers and based on these results the licensee determined that the heat exchangers were operable.

On November 5, 2009, the 2A LPCI Hx was opened for inspection and cleaning. Approximately 50 percent of the 1256 CCSW inlet tubes were partially or fully obstructed. The primary macrofouling mechanism was Asiatic clam relics coupled with silt microfouling. Issue report 989609, "D2R21 Inspection Results for 2A LPCI Heat Exchanger," was generated to document the as-found condition. The 2A LPCI Hx was cleaned and the thermal performance testing was re-performed in December 2009. The new test results indicated a heat removal capability of 78.08 MBtu/hr at design conditions which is 10 percent above the design heat removal rate.

(2) Prioritization and Evaluation of Problems

The licensee's evaluation of the cause of the repetitive LPCI Hx blockages and prioritization of corrective actions were ineffective. This was the third blockage of a LPCI Hx by Asiatic clams. The first event occurred on the 3B LPCI Hx in September of 2006. At that time the build up of Asiatic clams was thought to be due to a change in the frequency of Bay 13 cleaning. The second event took place in March 2008, when the 3B LPCI Hx failed its thermal performance test (70.586 vice 71 MBtu/hr). Root Cause Report 776598-08, "Dresden 3-1503-B, 3B Low Pressure Coolant Injection (LPCI) / Containment Cooling Heat Exchanger (HX) Failure to Meet Design Basis Heat Removal Capability Due to Inadequate Programmatic Control of Macrofoulants," revision 0, attributed the failure of the 3B LPCI Hx to meet the design basis heat removal capability to inadequate programmatic control of macrofoulants. Specifically, the licensee failed to inject biocide into the containment cooling service water pumps' intake during normally scheduled operability surveillances and sample to verify biocide residual concentration. This was contrary to the licensee's Generic Letter 89-13 Program commitments (refer to inspection report 05000237/2008-005; 05000249/2008-005 Section 1R15 for more details). Corrective actions included injection of biocide into the containment cooling service water pumps' intake (e.g., Bay 13) during normally scheduled surveillances and sample to verify biocide residual concentration.

Root cause report 776598-08 was revised on January 9, 2009. Revision 1 included an additional causal factor which stated that a potential existed for a significant section of the CCSW pump discharge piping to not receive a lethal biocide concentration for the required contact time to ensure a 100 percent mortality rate for the control of macrofoulants. This was due to the leak-by of the 2(3)-1501-3A(B), Unit 2(3) LPCI Hx A(B) tube side discharge motor operated valves (MOVs). If leakage past these valves occurs, then the untreated service water CCSW keepfill (strained river water) will supply an equivalent volume of makeup water into the CCSW pump common discharge header and result in the dilution of any chemical biocide present in the piping. This portion of the pipe is located upstream of the LPCI Hxs and it is in this portion of the pipe where the licensee postulates the Asiatic clams are growing and eventually getting transported to the Hxs.

On May 22, 2009, RCR 776598-08 was revised again. Revision 2 added action number 776598-50 to track a Unit 2(3) biocide chemical injection configuration change to completion. This configuration change shall inject biocide into the CCSW keepfill service water to eliminate biocide dilution resulting from leak-by of the 2-1501-3A, 2-1501-3B, 3-1501-3A and 3-1501-3B valves. This configuration change is schedule to be installed in April 2010 on Unit 2 and May of 2010 on Unit 3. The purpose of this new biocide injection skid is to eliminate the Asiatic clam population residing in the Unit 2 and Unit 3 CCSW piping.

The inspectors inquired why there was such a long lead time for the injection skid modification. Through discussions with engineering management in December 2009, it became clear that the modification was thought to be for budgetary reasons only, and that the skid was to reduce the amount, and therefore the cost, of biocide that was being injected. Engineering management thought that sufficient amounts of biocide were being injected to adequately kill the Asiatic clams in the piping even though root cause report 776598-08, revision 1 dated January 9, 2009, stated that an additional causal factor potential existed for a significant section of the CCSW pump discharge piping to not receive a lethal biocide concentration for the required contact time to ensure a 100 percent mortality rate for the control of macrofoulants.

(3) <u>Effectiveness of Corrective Actions to Preclude Repetition</u>

From January through September 2009, the licensee failed to take corrective actions to prelude repetition of a condition meeting the licensee's definition of a significant condition adverse to quality, associated with both Unit 2 and Unit 3 CCSW systems which affected the performance of the LPCI heat exchangers. Specifically, the licensee failed to provide a sufficient Asiatic clam lethal concentration of 8 PPM for the required minimum 18 hour contact time to ensure a 100 percent mortality rate for Asiatic clams which was necessary to ensure that the heat exchangers continued to meet their design basis heat removal requirements. The failure to perform these actions caused the blocking of the 2A LPCI Hx tubes by Asiatic clams which resulted in the degraded thermal performance of the Hx. Licensee planned corrective actions include the installation of a temporary modification to provide temporary keepfill that is expected to provide better chemical treatment of the CCSW piping upstream of the LPCI Hxs. This violation was determined to be of very low safety significance because even though the 2A LPCI Hx was degraded it was able to perform the required design safety function.

b. <u>Findings</u>

The inspectors determined that the failure to take corrective action to preclude repetition of heat exchanger blockage by providing a sufficient Asiatic clam lethal concentration of 8PPM for the required minimum 18 hour contact time to ensure a 100 percent mortality rate was a licensee-identified violation and is documented in Section 4OA7 of this report.

4OA3 <u>Follow-Up of Events and Notices of Enforcement Discretion</u> (71153)

.1 <u>(Closed) Licensee Event Report (LER) 05000237/2009-001-00; 05000249/2009-001-00, "Common Mode Failure of Reactor Building Isolation Dampers"</u>

This event, which occurred on February 6, 2009, was identified as a result of a licensee review of failures of reactor building ventilation isolation dampers at Dresden and another Exelon facility. Licensee failure analysis determined the damper failure mechanism to be the result of inadequate lubrication of internal parts and installation of upgraded solenoid valves that was completed in January of 2009. The NRC identified the slow response to identifying the common mode failure and failure to write trending condition reports to document the adverse trend. Inspectors verified replacement solenoid valves continued to perform correctly and other corrective actions put in place were appropriate to correct the procedural non-compliance issues. Documents reviewed as part of this inspection are listed in the Attachment to this report. A NCV was written in inspection report 05000237/2009002; 05000249/2009002 as 05000237/2009002-04. This LER is closed.

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

.2 <u>(Closed) LER 249/2009-001-00, “Unit 3 Group 1 Isolation and Automatic Reactor Scram”</u>

a. <u>Inspection Scope</u>

The inspectors reviewed LER 249/2009-001-00, “Unit 3 Group 1 Isolation and Automatic Reactor Scram,” to ensure that the issues documented in the report were adequately addressed in the licensee’s corrective action program. The inspectors interviewed plant personnel and reviewed operating and maintenance procedures to ensure that generic issues were captured appropriately. The inspectors reviewed operator logs, issue reports, the Updated Final Safety Analysis Report, and other documents to verify the statements contained in the LER. This LER is closed.

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

b. <u>Findings</u>

<u>Introduction</u>: A finding of very low significance (Green) involving a NCV of TS 5.4.1 was self-revealed when Unit 3 experienced an automatic reactor scram and Group 1 primary containment isolation signal (PCIS) when operators were restoring the reactor water cleanup (RWCU) system with the reactor at pressure. Station procedure DOP 1200-03, “RWCU System Operation with the Reactor at Pressure,” Revision 51, failed to identify the correct position of motor operated valve (MOV), 3-1201-7, RWCU System Return to Reactor. This procedural deficiency caused a pressure pulse that resulted in a reactor water level Low-Low Group 1 Isolation Signal and Unit 3 reactor scram.

<u>Description</u>: On October 3, 2009, Unit 3 experienced an automatic reactor scram and Group 1 PCIS. Due to the Group 1 PCIS, the inboard and outboard main steam isolation valves closed as designed. In addition, PCIS Group 2 and Group 3 isolations were received and verified complete. Operators manually initiated the isolation condenser to control reactor pressure within limits.

The RWCU system had tripped earlier on October 2, 2009. On October 3, 2009, prior to the reactor scram, operators were restoring the reactor water cleanup system per station procedure DOP 1200-03, “RWCU System Operation with the Reactor at Pressure,” Revision 51. Per the procedure, RWCU was being filled and heated in the blowdown mode with a flow path from the reactor pressure vessel (RPV) to the main condenser.

While the fill was being performed, the 3-1201-7 valve, Unit 3 RWCU System Return to Reactor, was closed. Reactor water cleanup system operation in the blowdown mode with the 3-1201-7 valve closed resulted in: (1) heat up and expansion of the water volume upstream of the 3-1201-7 valve (area of high pressure), and (2) cooling and contraction of the water volume downstream of the 3-1201-7 valve (area of low pressure). This condition created a high differential pressure across the valve.

A root cause investigation determined that under these conditions, when the 3-1201-7 valve was opened, the pressurized water upstream of the valve flashed to steam in the lower pressure region downstream of the valve. The resulting pressure pulse was sensed by the RPV level transmitters, resulting in a Reactor Water Level Low SCRAM Signal and Reactor Water Level Low-Low Group 1 Isolation Signal.

The licensee determined that the probable cause for the pressure pulse initiating the Reactor Water Level Low-Low Group 1 Isolation Signal and Unit 3 Reactor SCRAM was a latent procedural deficiency. DOP 1200-03 provided inadequate guidance for the 3-1201-7 valve position during system startup with the RPV at pressure. In GEK-32399, "Dresden 3 Instrumentation Subsystem of the Reactor Water Cleanup System," Section 3-11, "Normal Operation," Table 3-6, "Valve Positions for Cleanup System Startup during Normal Operations," the reactor vendor, General Electric, recommended that the Reactor Return Isolation Valve 1201-7 be in the open position for RWCU system startup when the reactor is at power. This recommendation was not incorporated in DOP 1200-03. Procedure DOP 1200-03, step G.1.g.(2) , gave the option to the operator to open MOV 3-1201-7 at that step or later on in the procedure. During this event, the 3-1201-7 valve was opened later on in the procedure.

<u>Analysis</u>: The inspectors determined that the licensee's failure to include pertinent information regarding valve position during RWCU system startup with the RPV at pressure in DOP 1200-03 was a performance deficiency warranting a significance evaluation. Using IMC 0612, Appendix B, "Issue Screening," issued on December 4, 2008, the inspectors determined that this finding was more than minor because it impacted the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as at power operations. The failure to maintain adequate procedures for the restoration of systems can result in events (i.e., reactor scram) that upset plant stability. This condition caused a pressure pulse that was sensed by the RPV level transmitters, resulting in a Reactor Water Level Low SCRAM Signal and Reactor Water Level Low-Low Group 1 Isolation Signal. This finding had a cross-cutting aspect in the area of Human Performance Resources because the licensee did not provide complete, accurate and up-to-date procedures to plant personnel. H.2(c)

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process," Attachment 0609.04, dated January 10, 2008. The inspectors determined that the finding impacted the Initiating Events Cornerstone. The inspectors answered "No" to the question on Transient Initiators under the Initiating Events Cornerstone column on Table 4a because the finding did not contribute to <u>both</u> the likelihood of a reactor trip AND the likelihood that mitigating equipment or functions will not be available. Therefore, the issue screened as having very low safety significance (Green).

<u>Enforcement</u>: The inspectors determined that the licensee's failure to include pertinent information, regarding valve position during RWCU system startup with the RPV at pressure, in DOP 1200-03 was a violation of Dresden Nuclear Power Station Technical Specification Section 5.4.1, "Procedures." Section 5.4.1 states, in part, that written procedures shall be established, implemented, and maintained covering applicable

procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, issued February 1978. Procedures addressing startup of boiling water reactor (BWR) systems, including the reactor cleanup system, are recommended in Section 4. of Appendix A to this Regulatory Guide.

Contrary to the above, on October 3, 2009, the licensee failed to include pertinent guidance regarding 3-1201-7 valve position during system startup with the RPV at pressure. This failure resulted in an automatic reactor scram and Group 1 primary containment isolation signal. This event was entered into the licensee's corrective action program as IR 974426, "U3 Group 1 Isolation and Reactor Scram." Corrective actions by the licensee included revising procedure DOP 1200-03, requiring the 3-1201-7 valve to be open prior to initiating RWCU system fill and vent activities. 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 a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000249/2009005-08)**

.3 <u>(Closed) Licensee Event Report (LER) 05000237/2009-003-00; 05000249/2009-003-00, "Emergency Diesel Generator Oil Leak" and Unresolved Item (URI) 05000237/2009003-01; 05000249/2009003-01, "Failure of 2/3 Emergency Diesel Generator Due to Lube Oil Leak on Y Strainer"</u>

This event, which occurred on June 2, 2009, during performance of the monthly surveillance on the Unit 2/3 Emergency Diesel Generator (EDG), resulted in an oil leak of approximately one-half gallon per minute from the turbocharger lubricating oil "Y" strainer end cap plug. The initial event was documented in Section 1R12 of report 05000237/2009003; 05000249/2009003 as an Unresolved Item **(URI 05000237/2009003-01; 05000249/2009003-01.)**

Documents reviewed as part of this inspection are listed in the Attachment to this report. Both the above referenced URI and this LER are closed.

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

<u>Introduction</u>: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion IV, "Procurement Document Control," was self-revealed for the failure to ensure a safety-related plug was ordered and installed where required in the 2/3 EDG turbo lube oil "Y" strainer.

<u>Description</u>: On June 02, 2009, the 2/3 EDG was operating in support of the monthly surveillance run in accordance with DOS 6600-01, "Diesel Generator Surveillance Tests." At approximately 3:39 am the 2/3 EDG was 25 minutes into the loaded run when an oil leak of approximately ½ gallon per minute was identified at the Turbo Lube Oil System "Y" strainer.

The 2/3 EDG was secured at approximately 3:47 a.m., and the turbo oil circulating pump was secured approximately 45 minutes after the engine shutdown to allow heat removal from the engine's turbo charger to prevent damage. Inspection of the turbo lube oil system "Y" strainer identified the source of the leakage to be coming from a pipe plug on the "Y" strainer end cap. Further investigation revealed the pipe plug installed in the strainer end cap to be a black 3/8 inch NPT "plastic" shipping plug instead of the safety-related steel plug required by design documents.

As immediate corrective action, the licensee installed a 3/8 inch NPT ASTM A-105 carbon steel hex head threaded pipe plug, Cat ID 43255-1 in the strainer end cap of the 2/3 EDG using work order (WO) 1240346-01 and approximately 30 gallons of oil were added to the engine reservoir. Surveillance procedure DOS 6600-01, "Diesel Generator Surveillance Tests," was completed satisfactorily with no leakage observed from the Turbo Lube Oil System "Y" strainer. The 2/3 EDG was declared operable at 11:05 p.m. on June 2, 2009. Extent of condition reviews were performed on the four other similar diesel generators; two safety-related and two station blackout emergency diesels. No other non-conforming conditions were identified.

During the subsequent root cause investigation, the licensee determined that the Unit 2/3 EDG Turbo Lube Oil "Y" Strainer (EPN 2/3-6661) and Circulating Oil "Y" Strainer (EPN 2/3-6672) were replaced on March 24, 2008, under WO 922770-01 due to wear on the strainer blowdown caps. On March 24, 2008, the licensee completed steps 8, 9 and 10 of WO 922770-01. This work scope removed the old lube oil strainer 2/3-6661 from the system, cleaned piping and pipe nipples prior to installing the strainer (replacing pipe nipples as required), and installed the new Mueller strainer snug tight using site approved sealant. On March 25, 2008, the license performed step 11 of the work package requiring the strainers to be painted with designated orange paint once the strainers have been installed. The painting step was important because from this step on there is no way to visually identify the non-conforming condition. Interviews with the individual performing the installation and painting indicated that they did not identify the plug as a plastic foreign material exclusion (FME) plug and therefore took no action to replace it as was required by procedure MA-AA-716-008, "Foreign Material Exclusion Program."

The post-maintenance test (PMT) was performed on the "Y" strainers on March 27, 2008, per WO 922770-02. The licensee performed visual inspections of the "Y" strainers at system pressure. The inspections passed with no identified leakage. Subsequent investigation revealed that Turbo Lube Oil Strainer replaced under WO 922770-01 in March 2008 was assigned Exelon Catalog Identification Number 38412-1. The "Y" strainer was manufactured commercial grade by Mueller Steam Specialty under Model No. 352M. Exelon purchased the 'Y' strainer from Engine Systems Incorporated (ESI) under Purchase Order (PO) 00000703 Revision 001 as a Quality Level 1 Nuclear Safety-Related Item. The PO stated, Strainer, Y-Type, 1 IN, Bronze ASTM B62, Threaded (FNPT), Class 250, 20 Mesh Size Stainless Steel Screen, supplied with threaded gasketed cap and plug; and rated for 400 PSI @ 150 F (WOG); and seismically qualified per Report Number ST-MSS-352M-1 issued by ESI.

The Mueller Steam Specialty catalog "Cut Sheet" that was pasted in the supply database for CAT ID 38412-1 on July 3, 2006, indicated "Y" strainer Blowoff Outlets are unplugged. Additionally, the current Mueller Steam Specialty "online" specification sheet for "Y" Strainers (ES-MS-351M-358) states Blow Off Outlets: "Not normally furnished with plug. Plug available, specify with order."

Since the part number specified by Dresden in the procurement document does not include a plug in the end cap, Engine Systems Incorporated (ESI) included the plastic plug for FME purposes. The plug is black only because that was the color that ESI had on hand at the time. Personnel from ESI stated that when performing the qualification testing for the part two strainers are ordered, one for the testing and one to ship to the customer. An appropriate plug is installed in the one used for qualification testing.

The strainer purchased for WO 922770-01 was shipped to Dresden Site Supply and had a receipt inspection performed on December 19, 2007. The inspection accepted the strainer with no discrepancies noted in the Quality Receipt Inspection Package and without questioning if the plug installed in the strainer end cap should have been a suitable pressure retaining pipe plug or a shipping plug.

The licensee concluded from their investigation that the root cause for this issue was the failure to have a purchase order that clearly documented the need for the safety-related strainer cap plugs.

Analysis: The inspectors determined that the failure to document the requirement for a safety-related strainer cap plug in the purchase order was a performance deficiency. The finding was determined to be more than minor because the finding was similar to IMC 0612, Appendix E, Example 5 c, in that, an incorrect and inadequate part was installed and the system was returned to service. Therefore, this performance deficiency also impacted the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

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, dated January 10, 2008, for Mitigating Systems because the 2/3 EDG is a mitigating system that could impact the long term or short term decay heat removal capability during a loss of offsite power event. The inspectors answered "yes" to the question, "Does the finding represent actual loss of safety function of a single train for greater than its Technical Specification Allowed Outage Time?" The inspectors performed a SDP phase 2 evaluation using the pre-solved spreadsheet for the Risk-Informed Inspection Notebook for Dresden Nuclear Power Station. The assumption that EDG 2/3 was unavailable for greater than 30 days resulted in a finding of low to moderate risk significance (White). The Region III senior reactor analyst (SRA) performed a SDP phase 3 evaluation of the EDG 2/3 failure to run. The SRA used the Dresden Standardized Plant Analysis Risk (SPAR) Model, Revision 3.50, and assumed that the EDG would have failed to run in response to any demand that would have occurred since the last successful 24 hour endurance run. This exposure period was approximately 89 days. The delta CDF for internal events was estimated to be 4.0E-7/yr. The dominant sequence was a loss of offsite power event followed by common cause failure of all emergency power and the failure to recover either offsite or onsite power.

Since the delta CDF was greater than 1.0E-7/yr, the SRA evaluated the risk contribution from external events. The risk contribution from seismic events was determined to be negligible because the frequency of seismically-induced loss of offsite power events was estimated to be much less than plant-centered, switchyard-centered, or grid-related loss of offsite power events. The fire risk contribution was estimated using information from the licensee's Individual Plant Examination for External Events (IPEEE) submitted in 2000. Fire-induced loss of offsite power events were assumed to occur for fires in control room panel 902-8 (Unit 3 panel 903-8), panel 923-2, and for fires in the auxiliary electric equipment room (AEER). The SRA used the fire ignition frequencies from the IPEEE and calculated conditional core damage probabilities using the SPAR model for plant-centered loss of offsite power events with the failure of the 2/3 EDG to estimate the change in core damage frequency for fire events that did not result in control room evacuation. Fires in the AEER contributed less than 1.0E-7/yr to the change in CDF. For the control room, fires in panel 902-8 (903-8) were evaluated and determined to be potential risk contributors because the fire damage caused a loss of offsite power and resulted in the unavailability of the Division II power supplies. For panel fires that were not suppressed within 15 minutes, the SRA used a non-suppression probability of 3.4E-3 from the licensee's IPEEE and concluded that operators would evacuate the control room and use the fire-specific safe shutdown procedures. With the 2/3 EDG unavailable due to the performance deficiency, only the station blackout (SBO) diesel generator would remain available to provide power. The SRA used SPAR-H to estimate the human error probability (HEP) for aligning the SBO diesel generator during fire scenarios and estimated a value of 0.4 assuming that diagnosis of the loss of power and need for the SBO diesel generator would dominate the HEP. The performance-shaping factors for stress and procedures were adjusted in the HEP calculation. The procedures for using the SBO DG were considered to be incomplete because the Dresden fire safe shutdown procedures do not address the use of the SBO diesel generator and operators would be required to use separate procedures for non-fire scenarios to line-up the SBO DG. Also, the stress of the fire-induced LOOP with failure of the 2/3 EDG was assumed to be high. The risk contribution from control room fire scenarios was estimated to be approximately 4.0E-7/yr. The total delta CDF from internal and external scenarios was estimated to be approximately 8.0E-7/yr. The risk estimate is conservative because it does not account for any successful run time of the diesel generators and provides only limited credit for the use of SBO diesel generators in fire scenarios.

The risk contribution from large early release frequency (LERF) was also evaluated. IMC 0609, Appendix H, "Containment Integrity Significance Determination Process" assigns a screening LERF factor of 1.0 to station blackout core damage sequences for BWRs with Mark I containments. This would result in a delta LERF estimate of 8.0E-7/yr, which represents low to moderate significance. However, based on a previous Dresden phase 3 SDP evaluation and other SDP evaluations of plants with Mark 1 containments, a much lower LERF factor of 0.1 is judged to be appropriate for this SDP phase 3 evaluation. As a result, the risk significance of the finding is estimated to be less than 1.0E-6/yr delta CDF and less than 1.0E-7/yr delta LERF, which represents a finding of very low safety significance (Green).

In addition, the failure of plant maintenance personnel to identify and remove the plastic foreign material exclusion plug prior to equipment return to service was a significant contributor to the finding. Step 4.2.5.3.B of MA-AA-716-008, "Foreign Material Exclusion Program," states, in part, "New parts/components/equipment to be installed in the plant should be carefully inspected to ensure that no foreign material (e.g., packaging material, shipping plugs, desiccants, and lubricant/preservatives used for shipping or storage) are present to prevent introduction to the system." Failure of plant personnel to question the plastic shipping plug before the equipment was installed and returned to service was not in compliance with the procedure and, therefore, inspectors determined that this event was cross-cutting in Human Performance, Work Practices, Procedural Compliance for failure to follow of personnel to follow the procedure. H.4(b)

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion IV, "Procurement Document Control," requires, in part, that measures shall be established to assure that applicable regulatory requirements, design bases, and other requirements which are necessary to assure adequate quality are suitably included or referenced in the documents for

procurement of material, equipment, and services, whether purchased by the applicant or by its contractors or subcontractors.

Contrary to the above, from December 2007 until June 2009, the licensee did not include a requirement which was necessary to assure adequate quality in the document for procurement of the 2/3 EDG Turbo Lube Oil "Y" Strainer, CAT ID 38412-1. Specifically, the purchase order did not specify what type of plug was required to be supplied and installed in the strainer cap prior to installation. The strainer was supplied with a plug installed that was neither designed nor constructed sufficiently to prevent a leak that resulted in the inoperability of the 2/3 EDG for greater than 30 days. Immediate corrective action to correct the leak included installation of a qualified plug in the strainer, post-maintenance testing of the 2/3 EDG, and inspection of all other diesel generators to ensure the same condition did not exist on another machine. The catalogue ID was revised to include a pressure retaining pipe plug with approved material and a requirement was added for a quality inspection to be performed to "inspect the strainer for metallic pipe plug in blow down port." Individual procedure compliance issues were addressed through the station's performance improvement initiatives. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as IR 926605, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000237/2009005-09; 05000249/2009005-09)

.4 <u>Electro-Hydraulic Control (EHC) Fluid Leaking From Stop Valve 3-5699-MSV4-FA Resulting in Forced Outage D3F49</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the plant's response to an EHC leak on Dresden Unit 3 that caused the unit to come offline. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. <u>Findings</u>

<u>Introduction</u>: The inspectors identified an unresolved item regarding the regulatory requirements associated with the circumstances surrounding the Unit 3 turbine trip on November 6, 2009.

<u>Description</u>: On November 5, 2009, at 8:53 p.m., Unit 3 Control Room received the following alarm: 903-7 B-6, EHC [electro-hydraulic control] RESERVOIR LVL HI/LO (reference IR 989641) indicating a rate of change in the EHC reservoir at 1.3" in 100 hrs or greater. A non-licensed operator (NLO) was dispatched to stage a barrel of EHC fluid for addition. Preparations were made for a heater bay entry to look for leaks.

A Unit 3 heater bay entry was made and it was determined that the Unit 3 Main Turbine Stop Valve (MSV) # 4 had an EHC leak from the fast-acting solenoid valve (3-5699-MSV4-FA). The leak was determined to be approximately 4-5 gallons of fluid per hour. A report from the field was that reservoir level had dropped about 1.1" in the last 12 hours. Between 12:50 a.m. and 3:43 a.m. on November 6, 2009, the licensee added two barrels of EHC fluid to the EHC reservoir.

On November 6, 2009, between 9:00 a.m. and 2:00 p.m., licensee management conducted meetings regarding the repair of the leak on MSV #4. The plan called for starting to down power Unit 3 to 650 Mwe for a planned 3:00 p.m. entry into the heater bay to repair the valve. The decision to go to 650 Mwe was to reduce the dose rate in the area and extend stay time for the repair.

At approximately 3:00 p.m., while staging for entry to repair the leak, Operations personnel informed the NLO, staged to isolate the oil supply to the leaking valve, that level in the EHC reservoir was dropping quickly, and requested the NLO to enter the pipeway as soon as possible.

At approximately 3:05 p.m., the NLO observed oil spraying profusely from the bottom area of #4 Main Stop Valve and the area of the solenoid that was going to be changed out. The NLO immediately contacted the control room to report what was observed and a decision was made to take the turbine offline. At 3:32 p.m., the Unit 3 Turbine was tripped.

The licensee had not completed their root cause investigation by the end of the inspection period. The inspectors planned to review the root cause investigation to determine if there were any violations of NRC requirements and that appropriate corrective actions were applied. (**URI 05000249/2009005-10**)

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the interim report for the INPO plant assessment of Dresden Station conducted in September 2009. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

On November 10, 2008, the inspectors conducted a walkdown of the Unit 2 High Pressure Coolant Injection (HPCI) discharge piping inside the Unit 2 X-Area in sufficient detail to reasonably assure the acceptability of the licensee's walkdowns (TI 2515/177, Section 04.02.d). The inspectors also verified that the information obtained during the licensee's walkdown was consistent with the items identified during the inspectors' independent walkdown (TI 2515/177, Section 04.02.c.3).

The inspectors verified that Piping and Instrumentation Diagrams (P&IDs) accurately described the subject system, that the P&IDs were up-to-date with respect to recent hardware changes, and any discrepancies between as-built configurations and the P&IDs were documented and entered into the CAP for resolution (TI 2515/177, Section 04.02.b).

In addition, the inspectors reviewed the licensee's isometric drawings that describe the HPCI system configurations to verify that the licensee had acceptably confirmed the accuracy of the drawings (TI 2515/177, Section 04.02.a). The inspectors considered the following related to the isometric drawings:

- High point vents were identified.
- High points that do not have vents were acceptably recognizable.
- Other areas where gas can accumulate and potentially impact subject system operability, such as at orifices in horizontal pipes, isolated branch lines, heat exchangers, improperly sloped piping, and under closed valves, were acceptably described in the drawings or in referenced documentation.
- Horizontal pipe centerline elevation deviations and pipe slopes in nominally horizontal lines that exceed specified criteria were identified.
- All pipes and fittings were clearly shown.
- The drawings were up-to-date with respect to recent hardware changes and that any discrepancies between as-built configurations and the drawings were documented and entered into the CAP for resolution.

The licensee indicated that even though they possess isometric drawings of the HPCI system, they do not rely upon any isometric drawings for gas management in that system. Therefore, the inspectors were unable to verify the above considerations.

In their review, the inspectors did identify discrepancies in the available isometric drawings between what was shown on the drawing and the as-built condition of the system. The discrepancies identified were in drawings M-1151C-2 and ISI-510 Sheet 2 and were associated with the 2-23126-3/4"-L vent line. The licensee determined that drawing M-1151C-2 does not need to be updated because it was created to support a seismic analysis done before the 2-23126-3/4"-L vent line was installed and was not intended to be updated. They determined that drawing ISI-510 Sheet 2 does not need to be updated because it is a system pressure testing walkdown isometric drawing, therefore, the discrepancy does not impact the purpose and use of the drawing. These conclusions were documented in AR 1014280.

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.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 14, 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 Meeting

Interim exits were conducted for:

- The results of the inservice inspection with Site Vice-President T. Hanley on November 13, 2009.
- The results of the As-Low-As-Reasonably-Achievable Planning and Controls inspection with the Site Vice President, Mr. T. Hanley, on November 17, 2009.
- The annual review of Emergency Action Level and Emergency Plan changes with the licensee's Emergency Preparedness Manager, Mr. P. Quealy, via telephone on December 21, 2009.

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

4OA7 Licensee-Identified Violations

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

- Title 10 of the Code of Federal Regulations, Part 50, Appendix B, Criterion XVI, “Corrective Action,” states, in part, “Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.” A significant condition adverse to quality for both Unit 2 and Unit 3 containment cooling service water

(CCSW) systems was identified by the licensee in RCR 776598-08, "Dresden 3-1503-B, 3B Low Pressure Coolant Injection (LPCI) / Containment Cooling Heat Exchanger (HX) Failure to Meet Design Basis Heat Removal Capability Due to Inadequate Programmatic Control of Macrofoulants," Revision 1, on January 9, 2009. Procedure LS-AA-125, "Corrective Action Program (CAP) Procedure," revision 13, defines significant condition adverse to quality (SCAQ), in part, as "A condition which, if left uncorrected, could have a serious effect on safety or reliability." In addition, "recurring deficiencies or errors that cannot be dispositioned or brought into conformance by established corrective action systems," are considered SCAQs. The inspectors determined that the conditions described in RCR 776598-08, met the licensee's definition of a significant condition adverse to quality. Contrary to the above requirements, from January through September 2009, the licensee failed to take measures to assure that the cause of the condition (blockage of the LPCI heat exchangers) was determined and corrective action taken to preclude the repetition for a significant condition adverse to quality on both Unit 2 and Unit 3 CCSW systems. Specifically, the licensee failed to prevent the recurrence of Asiatic clam blockage in the 2A LPCI Hx tubes which resulted in the degraded thermal performance of the Hx. Licensee planned corrective actions included installation of a temporary modification to provide temporary keepfill that was expected to provide better chemical treatment of the CCSW piping upstream of the LPCI Hxs, and a permanent injection skid for biocide to provide for long term assurance of effective chemical treatment. This violation was determined to be of very low safety significance because even though the 2A LPCI Hx was degraded it was able to perform the required design safety function.

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
B. Casey, Engineering Programs (Braidwood)
H. Do, Exelon Corporate ISI
B. Finley, Security Manager
D. Glick, Shipping Specialist
T. Green, Nondestructive Examination Services
J. Griffin, Regulatory Assurance - NRC Coordinator
D. Gronek, Operations Director
J. Hansen, Corporate Licensing
L. Jordan, Training Director
R. Kalb, Chemistry
P. Karaba, Maintenance Director
J. Kish, Engineering Programs
M. Kluge, Design Engineer
D. Leggett, Nuclear Oversight Manager
R. Laburn, Radiation Protection
M. Marchionda, Regulatory Assurance Manager
J. Miller, Nondestructive Examination Services
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
J. Sipek, Engineering Director
N. Starcevich, Radiation Protection Instrumentation Coordinator
J. Strmec, Chemistry Manager
S. Vercelli, Work Management Director

NRC
M. Ring, Chief, Division of Reactor Projects, Branch 1

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened:

05000237/2009005-01	NCV	Operating Personnel Incorrectly Placed Clearance Tags (Section 1R04)
05000237/2009009-02	NCV	NRC Inspector-Identified Control Room Alarm Isolation Valve Out-of-Position (Section 1R15)
05000237/2009005-03	NCV	Preconditioning the Unit 2 Emergency Diesel Generator Prior to Performing TS Surveillance Requirements (Section 1R19)
05000237/2009005-04 05000249/2009005-04	URI	2/3 Emergency Diesel Generator (EDG) Overvoltage During Division I Undervoltage Surveillance (1R19)
05000237/2005009-05	NCV	Failure to Follow the Master Refueling Procedure During Movement of Fuel Assembly JLU569 (Section 1R20)
05000249/2009005-06	NCV	Mispositioning of a Unit 3 Control Rod at Power (Section 1R22)
05000237/2009005-07	URI	Changes to EAL HU6 Potentially Decreased the Effectiveness of the Plans without Prior NRC Approval (1EP4)
05000249/2009005-08	NCV	Procedural Deficiency Causing a Pressure Pulse Resulting in a Reactor Water Level Low-Low Group 1 Isolation Signal and Unit 3 Reactor Scram (Section 4OA3.2)
05000237/2009005-09 05000249/2009005-09	NCV	Failure to Ensure a Safety-Related Plug was Ordered and Installed in the 2/3 Emergency Diesel Generator Turbo Lube Oil “Y” Strainer (Section 4OA3.3)
05000249/2009005-10	URI	Electro-Hydraulic Control (EHC) Fluid Leaking From Stop Valve 3-5699-MSV4-FA Resulting in Forced Outage D3F49 (Section 4OA3.4)
Temporary Instruction 2515/177		Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems (NRC Generic Letter 2008-01) (Section 4OA5.3)

Closed:

05000237/2009005-01	NCV	Operating Personnel Incorrectly Placed Clearance Tags (Section 1R04)
05000237/2009009-02	NCV	NRC Inspector-Identified Control Room Alarm Isolation Valve Out-of-Position (Section 1R15)
05000237/2009005-03	NCV	Preconditioning the Unit 2 Emergency Diesel Generator Prior to Performing TS Surveillance Requirements (Section 1R19)
05000237/2005009-05	NCV	Failure to Follow the Master Refueling Procedure During Movement of Fuel Assembly JLU569 (Section 1R20)
05000249/2009005-06	NCV	Mispositioning of a Unit 3 Control Rod at Power (Section 1R22)
05000249/2009005-08	NCV	Procedural Deficiency Causing a Pressure Pulse Resulting in a Reactor Water Level Low-Low Group 1 Isolation Signal and Unit 3 Reactor Scram (Section 4OA3.2)
05000237/2009005-09 05000249/2009005-09	NCV	Failure to Ensure a Safety-Related Plug was Ordered and Installed in the 2/3 Emergency Diesel Generator Turbo Lube Oil “Y” Strainer (Section 4OA3.3)
05000237/2009004-04 05000249/2009004-04	URI	Inspector Identified Control Room Alarm Isolation Valve Out-of-Position (1R15)
05000237/2009003-01 05000249/2009003-01	URI	Failure of 2/3 Emergency Diesel Generator (EDG) Due to Lube Oil Leak On Y-Strainer (4OA3.3)
05000237/2009-001-00 05000249/2009-001-00	LER	Common Mode Failure of Reactor Building Isolation Dampers (4OA3.1)
05000249/2009-001-00	LER	Unit 3 Group 1 Isolation and Automatic Reactor Scram (4OA3.2)
05000237/2009-003-00 05000249/2009-003-00	LER	Emergency Diesel Generator Oil Leak (4OA3.3)

Discussed:

Inspection Report 05000237/2008005; 05000249/2008005, Section 1R15 (4OA2.4)

05000237/2009002-04	NCV	Failure to Take Corrective Actions to Replace a Degraded Valve in a Timely Manner (4OA3.1)

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.

1R04 Equipment Alignment (71111.04)

- WO 1079566-01, "Perform 250V Station Battery Service Test"
- C/O 76319, "(ASSY) Battery 250V U2"
- DOP 7500-M1/E1, "Unit 2/3 Standby Gas Treatment," Revision 6

1R05 Fire Protection (71111.05)

- IR 976782, "NRC Observations from U3 Rx Bldg. 570' Pre-Plan Review"

1R08 Inservice Inspection Activities (71111.08G)

- IR 00992912; Material Certification of Recirc Piping Could not be Found; November 13, 2009
- IR 00911408; Section XI Class 2 Boundary; April 28, 2009
- IR 00889729; LPCI Heat Exchanger Recordable Indications; March 6, 2009
- IR 00782956; Corrosion Pipe Elbow B CST Tank; June 6, 2008
- IR 00755744; 2/3 EDG Leak on Engine Block; March 28, 2008
- IR 00711323; 2/3 DGCW Pump Suction Pipe Corrosion; December 14, 2007
- IR 00705912; Unit 2 CCSW System Corrosion; December 2, 2007
- IR 00705639; DGCW Pipe Corrosion; December 2, 2007
- IR 00695137; Unit 2 Reactor Head Flange MT Indication; November 8, 2007
- IR 00691069; Loose Anchor Bolt on CS Line; October 31, 2007
- IR 00681657; PT Rejectable Indication; October 22, 2007
- ASME Section XI Repair/Replacement Plan 2-1505A-12"-0; April 1, 2009
- Certified Mill Test Report (Consolidated Power Supply); 12" Safety-Related 90 Elbow; September 15, 2009
- EC 368360; Evaluation of Leakage at Bolted Connections and other Recordable Indications; Revision 0
- Examination Summary Sheet; D2R21-028 UT of PS2/201-1; November 7, 2009
- Examination Summary Sheet; D2R21-029 UT of PS2-Tee/202-4B; November 7, 2009
- NDE Report No. 09-294; VT-3 Visual Examination; November 13, 2009
- NDE Certification; Scott R. Erickson; UT Level III; October 6, 2009
- Procedure GE-PDI-UT-2; PDI Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds; Revision 4
- Procedure GE-PDI-UT-3, PDI Generic Procedure for the Ultrasonic Thru Wall Sizing in Piping Welds, Revision 2
- Procedure ER-AA-335-018, Detailed General VT-1, VT-1C, VT-3 and VT-3C Visual Examination of ASME Class MC and CC Containment Surfaces and Components; Revision 5
- Procedure ER-AA-335-1008; Code Acceptance and Recording Criteria for Nondestructive Surface Examination; Revision 1
- Procedure Qualification Record; A-001; October 19, 1998
- Procedure Qualification Record; A-002; March 9, 1997
- Procedure Qualification Record; 1-50C; January 3, 1984

- Report No. D2R20-037; Four Indications on the Reactor Head Flange Weld (2RPV UPP HD/2-THD-FLG); November 11, 2007
- Weld Procedure Specification; 1-1-GTSM-PWHT; Revision 1
- Welder Qualification Record; W2677; October 5, 2009
- Work Order 01189798; Replace Degraded Elbow on 2A CCSW Pump; October 22, 2009

1R12 Maintenance Effectiveness (71111.12)

- Z03, "Control Rod Drive Maintenance Rule Performance Criteria"
- IR 845878, "Scram Dump Valve Leaking", 11/17/2008
- IR 763023, "Review Maintenance Rule Functions Perform review described in In-Progress Notes", 5/30/2008
- IR 842585, "Handwheel Spins with no Valve Movement", 11/09/2008
- IR 842587, "Valve Handwheel Broken", 11/09/2008
- IR 843592, "HCU P6 Scram Valve Packing Leak", 11/11/2008
- IR 700134, "Relief Valve Continuously Lifted", 11/16/2007
- IR 976292, "CRD Exercising and Condenser Vacuum Scram Impact U3 Restart", 10/05/2009
- WO 1186809, "Scram Dump Valve Leaking", 11/17/2008
- M-34, "Diagram of Control Rod Drive Hydraulic Piping", Revision W
- TS 3.1.3, Control Rod Operability
- TS 3.1.4, Control Rod Scram Times
- TS 3.1.5, Control Rod Scram Accumulators

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

- IR 1009039, “345 kv Line 8014 trip”

1R15 Operability Evaluations (71111.15)

- Operability Evaluation No. 09-007, 2A LPCI Heat Exchanger (2-1503-A)
- EC 372200, “Perform Evaluation of Thermal Performance Test Data of 2A LPCI Hx”
- EC 377036, “2A LPCI Heat Exchanger September 18, 2009 Thermal Performance Test”
- IR 978203, “GL 89-13 Program Health Color Change”
- IR 989609, “D2R21 Inspection Results for 2A LPCI Heat Exchanger”
- IR 990189, “2A LPCI Heat Exchanger Tubesheet Corrosion”
- IR 990209, “2A LPCI Hx Top Coverplate Coating Bubbled”
- IR 996991, “’A’ LPCI HT Exchanger Shell Side RV Lifting”
- CY-DR-110-220, “LPCI Service Water (CCSW) and Torus Water Sampling,” Revision 3
- CY-DR0120-413, “Cooling and Service Water Chemical Injection System,” Revision 8
- Root Cause Report 967008-03, “Dresden 2-1503-A, 2A Low Pressure Coolant Injection (LPCI)/Containment Cooling Heat Exchanger (Hx) Failure to Meet Design Basis Heat Removal Capability due to Asiatic Clam Macrofouling Resulting from 2-1501-3A Valve Leakage and Subsequent Untreated Service Water Make-Up via the CCSW Keepfill Diluting the Biocide Treatment below the Asiatic Clam Lethal Concentration”
- Focus Area Assessment, Dresden Station, CCSW System Asiatic Clam Fouling. Performed by Water Technology Consultants, Inc.
- EC Evaluation 373443, “Evaluation of Leakage From Cylinder Head Covers on 2A SBLC Pump”
- WO1001541-76, “3B SBLC System Pump Test for Operability Verification”

1R19 Post-Maintenance Testing (71111.19)

- IR 1003797, "TSC HVAC Surveillances Failed"
- WO 1294151, "D1/2/3 SAN PM Operability Surv for the TSC AFU's"
- DOS 5750-05, "Semi-Annual Technical Support Center (TSC) Air Filtration Unit (AFU) Operability Test," Revision 15
- IR 348426, "FIC-2/3-5748-93 Airflow Indication Not Actual Airflow"
- WO 826129, "FIC-2/3-5748-93 Airflow Indication Not Actual Airflow"
- IR 1005336, "TSC Flow Controller Range Issue"
- EP-AA-1000, "Standardized Radiological Emergency Plan," Revision 19
- EP-AA-112-200-F-01, "Station Emergency Director Checklist," Revision F
- NUREG-0696, "Functional Criteria for Emergency Response Facilities," February 1981
- NUREG-0737, "Clarification of TMI Action Plan Requirements," Supplement No. 1, January 1983.
- M-3006, "Technical Support Center HVAC & Plumbing Layout," Revision F
- DOS 6600-01, "Diesel Generator Governor Oil Change and Compensating Adjustment," Revision 23
- IR 992803, "U2 EDG Largest Load Reject (TSR 3.8.1.10)"
- IR 994101, "2/3 EDG Voltage Transient"
- DOS 6600-06, "Bus Undervoltage and ECCS Integrated Functional Test for Unit 2/3 Diesel Generator to Unit 2," Revision 46
- IR 997244, "Recirc Pump Instruments not Functioning Req'd for Hydro"
- IR 997142, "CCP: MCR Panel 923-5 Lost Ventilation Equip Indications"
- EC 378040, "2/3 EDG Overvoltage during Division I Undervoltage Surveillance," Revision 0
- IR 1005291, "Inaccurate Information Included in IR 994101"
- IR 1006989, "Control Room Indicators Deenergized"
- EACE 994101-07, "2/3 Emergency Diesel Generator (EDG) Voltage Transient"
- IR 987850, "D2R21 As Found LLRT on 2-0203-2C Exceeded Leakage Limit"
- DOS 0250-02, "Full Closure Timing and Exercising of Main Steam Isolation Valves," Rev 26
- DOS 0250-03, "Main Steam Isolation Valve Fail-Safe Closure Test," Rev 21
- IR 1001725, "Higher than Expected Vibrations on 2B Cond Pp."
- IR 1002609, "FME: Found in 2B Condensate Pump Suction Piping"
- ER-AA-2006, "Lost Parts Evaluations," Revision 6
- WO 1098975, "2B Condensate Booster Motor Alignment"
- DOP 3300-02, "Condensate System Startup," Revision 50
- M-15, "Diagram of Condensate Piping," Revision J
- MA-AA-716-012, "Post-Maintenance Testing," Revision 11
- MA-AA-716-230-1002, "Vibration Analysis/Acceptance Guideline," Revision 2

1R20 Outage (71111.20)

- DGP 01-01, "Unit Startup," Revision 153
- IR 975280, "3B CRD FCV Failed to Operate Remotely"
- IR 975813, "D3F48LL: DEHC Alarms During U3 Chest Warming"
- IR 975830, "D3F48LL: DEHC Issues During Turbine Roll"
- IR 976410, "CIV #1 Indicates 57% Open. LVDT Position Indication Failure"

1R22 Surveillance Testing (71111.22)

- IR 984934, “DOS 6620-07 SBO Surveillance Need Revision”
- IR 745855, "Unable to Close SBO Diesel Onto Bus"
- IR 984179, "Unit 2 SBO Preparation for Standby Readiness Deficiency"
- DOS 6620-07, "SBO 2(3) Diesel Generator Surveillance Tests,” Revision 28
- DOP 6620-20, "SBO D/G 2(3) Prelubrication and Barring for Normal Start", Revision 06
- DOA 6500-11, "4 KV Bus Overvoltage," Revision 05
- WO 1257282, "Perform DOS 6620-07, D2 SBO Surveillance," 10/26/2009
- WO 1079209-01, “D2 30M/RFL TS LLRT MSIV 203-1B & 203-2B Dry Test”
- WO 1077724-01, “D2 30M/RFL TS LLRT MSIV 203-1C & 203-2C Dry Test”
- WO 1077725-01, “D2 30M/RFL TS LLRT MSIV 203-1D & 203-2D Dry Test”
- WO 1081285-01, “D2 20M/RFL TS LLRT MSIV 203-2A Wet Test”
- WO 1079266-01, “D2 30M/RFL TS LLRT MSIV 203-2B Wet Test”
- WO 1081288-01, “D2 30M/RFL TS LLRT MSIV 203-2C Wet Test”
- WO 1081313-01, “D2 30M/RFL TS LLRT MSIV 203-2D Wet Test”
- DOS 7000-01, “Local Leak Rate Testing of Main Steam Isolation Valves (Dry Tests),” Rev 5
- DOS 7000-02, “Local Leak Rate Testing of Main Steam Isolation Valves (Wet Test),” Rev 2
- IR 987850, “D2R21 As Found LLRT on 2-0203-2C Exceeded Leakage Limit”
- IR 987852, “D2R21 As Found LLRT on 2-0203-1D Exceeded Leakage Limit”
- DIS 1500-01, “Reactor Low Pressure (350 PSIG) ECCS Permissive,” Revision 27
- IR 944688, “Test Valves Not Installed on CST Level Switches (HPCI Logic)”

1EP4 Emergency Action Level and Emergency Plan Changes

- Dresden Station Radiological Emergency Plan Annex; Revisions 23, 24, and 25

2OS1 Access Control to Radiologically Significant Areas (71121.01)

- AR 987949; Operator PCE in Clean Area above Drywell Bullpen; November 3, 2009
- AR 993194; Responding to Guardhouse Portal Monitor Alarm; November 13, 2009
- RP-AA-203-1001; Personnel Exposure Investigation, Revision 6
- RP-AA-210; Dosimetry Issue, Usage and Control; Revision 15
- RP-AA-220; Intake Investigation, Revision 5
- RP-AA-350-1001; Response to Guardhouse Portal Monitor Alarms, Revision 0
- Underwater Construction Corporation Safe Practices Manual, Attachment A: Safety Hazard Analysis/Dive Plan; November 3, 2009

2OS2 As-Low-As-Reasonably-Achievable Planning and Controls (71121.02)

- RWP 10010408; D2R21 Drywell Nuclear Instrumentation System Maintenance; Revision 0
- RWP 10010420; D2R21 Drywell Control Rod Drive System Maintenance; Revision 0
- RWP 10010421; D2R21 Drywell Control Rod Drive System Support; Revision 0
- RWP 10010426; D2R21 Drywell In-Service Inspection; Revision 0
- RWP 10010437; D2R21 Torus Diving Activities; Revision 1
- RWP 10010452; D2R21 Reactor Disassembly/Reassembly and Related Activities; Revision 1
- AR 870602-03; Focused Area Self-Assessment: ALARA Planning for Outage Readiness and Preparation; August 27, 2009
- AR 988447; Unit 2 Refuel Floor and Reactor Building Low Level Contamination; November 3, 2009

- AR 990061; Under Vessel General Electric Worker Receives Small Ingestion; November 5, 2009
- AR 993319; Shaw Laborer Wiping Down cords on RB 613 300K Particle on Scrubs; November 11, 1009
- RWP-WIP-10010388; D2 R21 Scaffold Installation/Removal Activities (Excluding Drywell); November 7, 2009
- RP-AA-461; Radiological Controls for Contaminated Water Diving Operations; Revision 2
- RWP-WIP-10010403; D2 R21 Drywell Radiation Protection Department Activities; November 6, 2009
- RWP-WIP-10010403; D2 R21 Drywell Radiation Protection Department Activities; November 10, 2009
- RWP-WIP-10010437; D2 R21 Torus Diving Activities; November 10, 2009
- RWP-WIP-10010453; D2 R21 Refuel Floor IVVI Activities; November 7, 2009

<u>4OA1 Performance Indicator (PI) Verification (71151)</u>

- LS-AA-2140; Monthly Data Elements for NRC Occupational Exposure Control Effectiveness; Revision 4

<u>4OA2 Identification and Resolution of Problems (71152)</u>

- RCR 776598-08, “Dresden 3-1503-B, 3B Low Pressure Coolant Injection (LPCI) / Containment Cooling Heat Exchanger (HX) Failure to Meet Design Basis Heat Removal Capability Due to Inadequate Programmatic Control of Macrofoulants,” Revision 0
- IR 868703, “2A and 2B LPCI Heat Exchanger Samples Tested 0 PPM Biocide”
- IR 871271, “Biocide Injection Unavailable for CCSW System PMT Run”
- IR 877889, “Biocide Injection Not Available During U3 CCSW Run”
- IR 880708, “CCSW Biocide/Clam-Trol Chemical Injection Result Low”
- IR 881043, “CCSW Biocide/Clamtrol Chemical Injection Result Low”
- IR 883155, “3A and 3B LPCI Fail Clam-Trol Test”
- IR 884613, “2B LPCI Failed Clam-Trol Test”
- IR 887406, “Inadequate Biocide Retention”
- IR 888462, “0 PPM Biocide Results for 2/3 EDG”
- IR 889598, “No Biocide Found in Unit 2B LPCI CCSW Hx Lay-up Sample”
- IR 891286, “No Biocide Found in 2B LPCI CCSW Hx Lay-up Sample”
- IR 892241, “Procedure change and Eval of Biocide Injection to DGCWP’s”
- IR 905027, “2B LPCI No Clamtrol Present”
- IR 905224, “No Biocide Detected in 2/3 DGCSW”
- IR 908886, “2A LPCI Biocide Results Less than 8 PPM”
- IR 914398, “Revision to RCR 776598-08, 3B LPCI Hx Macrofouling Required”
- IR 915033, “2A LPCI SW Biocide 24 hr. Sample < 8PPM”
- IR 917133, “2B LPCI Failed Clam-Trol Test”
- IR 920498, “2A and 2B LPCI SW Biocide <8PPM (24hr Sample)”
- IR 923788, “Clam-Trol Analysis Failed on 3DGCSW”
- IR 999766, “2B LPCI Failed for Biocide”
- IR 1000791, “2B LPCI Heat Exchanger Failed Clam-Trol Analysis”
- IR 1006553, “No Biocide Detected in CCSW from 3B LPCI Hx”
- IR 1007918, “Unit 2 A and B LPCI Heat Exchangers Fail 18-24 hr Biocide”

4OA3 Follow-Up of Events (71153)

- Licensee Event Report 237/2009-003-00, “Emergency Diesel Generator Oil Leak”, Revision 00
- IR 926605, “Oil Leak on the 2/3 DG Turbo Lube Oil Y-strainer”
- MA-AA-716-008, “Foreign Material Exclusion Program,” Revision 4
- Licensee Event Report 237/2009-001-00, “Common Mode Failure of Reactor Building Isolation Dampers,” Revision 00
- IR 877591, “Potential 10CFR50 Part 21 Notification of Versa Air Solenoid”
- IR 838034, “RBV Damper 2-5742-A Slow to Close”
- IR 842305, “3-5742-B Damper 90 Seconds to Close”
- IR 888338, “RBV Isolation Damper Solenoid Valve Incorrect Component Classification”
- IR 975779, “Post Transient/Scram Walkdown Observation by NRC”
- IR 975076, “U2/3 EDG Started on Rx Trip when Aux Power Transferred”
- IR 974426, “U3 Group 1 Isolation and Reactor Scram”
- IR 973968, “3A RWCU Pump Tripped and DOA Entry”
- IR 973144, “RWCU Isolate on High Temperature”
- IR 973104, “3A RWCU Tripped”
- Root Cause Report 974426-04, “U3 Reactor SCRAM and Group 1 Isolation Resulting in Forced Outage D3F48 Due to DOP 1200-03, titled RWCU System Operation with the Reactor at Pressure Latent Procedural Deficiency”
- LER 249/2009-001-00, “Unit 3 Group 1 Isolation and Automatic Reactor Scram”
- IR 990113, “U3 from 650 MWe to 0 and a Turbine Trip”
- IR 990160, “2/3 EDG Auto Started when U3 Main Generator was Tripped”
- IR 990112, “Need WO Rolled for Repair to U3 EHC Filter Pump Bkr”
- IR 990110, “U3 EHC Filter Pmp Trip”
- IR 990661, “ MSV #4 Did Not Open During Initial Turbine Roll“

4OA5 Other Activities (TI 2515/177)

- IR 994774, “Procedures for Venting ECCS/SDC Systems Should Be Revised”
- IR 999625, “Air Found in HPCI Discharge Piping During UT”
- IR 999762, “Air Found in Second Location in HPCI Discharge Piping”
- IR 1014280, “Question from NRC Inspector on ISI Drawing”
- EC 371153, Rev 2, “NRC GL 2008-01 HPCI System Evaluation”
- DOP 2300-01, “HPCI Standby Operation,” Rev 41
- M-51, “Diagram of High Pressure Coolant Injection Piping,” Rev CL
- ISI-504, “System Pressure Test Walkdown Isometric MSIV Room – X Area,” Rev B
- ISI-510, “System Pressure Test Walkdown Isometric H.P. Coolant Injection Piping,” Sheet 2, Rev D
- M-1151C-2, “Computer Math Model High Pressure Coolant Injection System,” Sheet 1, Rev 2
- M-4455, “HPCI High Point Vent Line,” Sheet 3, Rev A

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
AEER	Auxiliary Electric Equipment Room
ALARA	As-Low-As-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CCSW	Containment Cooling Service Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CO	Clearance Order
CRD	Control Rod Drive
D2	Dresden Unit 2
DRP	Division of Reactor Projects
EACE	Equipment Apparent Cause Evaluation
EAL	Emergency Action Level
EC	Engineering Change
EDG	Emergency Diesel Generator
ESI	Engine Systems Incorporated
FME	Foreign Material Exclusion
GE	General Electric
HEP	Human Error Probability
HEPA	High Efficiency Particulate Air
HPCI	High Pressure Coolant Injection
HCU	Hydraulic Control Unit
Hx	Heat Exchanger
IPEEE	Individual Plant Examination for External Events
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
IP	Inspection Procedure
IR	Issue Report
ISI	Inservice Inspection
IST	In-service Test
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of OffSite Power
LPCI	Low Pressure Coolant Injection
MOV	Motor Operated Valves
MSV	Main Stop Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	Non-Licensed Operator
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSO	Nuclear Station Operator
OSF	Outage Safety Plan
PARS	Publicly Available Records
PCIS	Primary Containment Isolation Signal
PI	Performance Indicator

P&ID	Piping and Instrumentation Diagrams
PM	Planned or Preventative Maintenance, or Post-Maintenance
PO	Purchase Order
RCR	Root Cause Report
RCS	Reactor Coolant System
RFO	Refueling Outage
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Cleanup
SBLC	Standby Liquid Control
SBO	Station Blackout
SCAQ	Significant Condition Adverse to Quality
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SR	Surveillance Requirements
SRO	Senior Reactor Operator
SSC	Structures, Systems and Components
TS	Technical Specification
U2	Unit 2
U3	Unit 3
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
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
License Nos. DPR-19; DPR-25

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SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
INTEGRATED INSPECTION REPORT 05000237/2009-005;
05000249/2009-005

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