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

January 29, 2015

EA-15-001

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3, INTEGRATED INSPECTION REPORT 05000237/2014005; 05000249/2014005 AND PRELIMINARY WHITE FINDING

Dear Mr. Hanson:

On December 31, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed report documents the results of this inspection, which were discussed on January 6, 2015, with Mr. S. Marik, and other members of your staff. Additionally, on January 16, 2015, the NRC discussed with Mr. S. Marik of your staff the preliminary White determination for the finding discussed below. This issue was discussed with your staff during the January 6 exit as an issue of concern.

This report discusses one NRC-identified finding, concerning the Unit 3 "E" electromatic relief valve's (ERV) inability to perform its intended safety function, which has preliminarily been determined to be a White finding with low to moderate safety significance that may require additional NRC inspections. Specifically, increased vibrations experienced on Dresden Unit 3 main steam line piping while operating at extended power uprate (EPU) power levels resulted in the degradation of multiple ERV actuator components that rendered the 3E relief valve inoperable.

This finding does not represent an immediate safety concern in that you replaced all four Unit 3 ERV actuators in November 2014 with a hardened design successfully utilized in the industry at other boiling water reactor plants which have also experienced significant steam line vibrations post EPU.

This finding with the supporting circumstances and details is documented in the enclosed inspection report. The finding was assessed based on the best available information, using the applicable Significance Determination Process. The basis for the NRC's preliminary significance determination is also described in the enclosed report. This finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the Enforcement Policy, which can be found on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

In accordance with NRC Inspection Manual Chapter 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of the date of this letter. The significance determination process is designed to encourage an open dialogue between your staff and the NRC, however, the dialogue should not impact the timeliness of the staff's final determination.

Before we make a final decision on this matter, you may choose to (1) to attend a Regulatory Conference where you can present to the NRC your perspective on the facts and assumptions the NRC used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will issue a public meeting notice and press release to announce the conference. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of your receipt of this letter. If you decline to request a Regulatory Conference or submit a written response, you relinquish your right to appeal the final Significance Determination Process determination.

Please contact Mr. Jamnes Cameron at 630–829–9833 and in writing within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. The final resolution of this matter will be conveyed in separate correspondence.

Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for the inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

This report also documents two additional findings of very low safety significance (Green). The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating these issues as non-cited violations in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of these Green findings, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission–Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532–4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and the Resident Inspector Office at the Dresden Nuclear Power Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Dresden Nuclear Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA John Giessner Acting for/

Anne T. Boland, Director
Division of Reactor Projects

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

Enclosure:
IR 05000237/2014005; 05000249/2014005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000237; 05000249
License Nos:	DPR–19; DPR–25
Report No:	05000237/2014005; 05000249/2014005
Licensee:	Exelon Generation Company, LLC
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	Morris, IL
Dates:	October 1, 2014 through December 31, 2014
Inspectors:	G. Roach, Senior Resident Inspector D. Lords, Resident Inspector J. Mancuso, Acting Resident Inspector B. Bartlett, Project Engineer T. Go, Health Physicist R. Jickling, Senior Emergency Preparedness Inspector A. Shaikh, Senior Reactor Inspector M. Porfirio, Resident Inspector, Illinois Emergency Management Agency
Observer:	E. Sanchez-Santiago, Resident Inspector, Clinton Power Station I. Khan, Reactor Engineer
Approved by:	J. Cameron, Chief Projects Branch 4 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000237/2014005, 05000249/2014005; 10/01/2014–12/31/2014; Dresden Nuclear Power Station, Units 2 & 3; Inservice Inspection Activities, Operability Determinations and Functional Assessments, and Outage Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three findings were identified by the inspectors. One of these findings was considered an apparent violation of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas" effective date January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process" Revision 5, dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and associated non-cited violation (NCV) of 10 CFR 50.55a(g)(4) was identified by the inspectors for the licensee's failure to maintain American Society of Mechanical Engineers (ASME) Code Class 2 components in accordance with ASME Code Section XI requirements. Specifically, the licensee failed to repair or replace the Unit 3A Low Pressure Coolant Injection (LPCI) heat exchanger support welds identified to have unacceptable linear flaws prior to return to service.

  The inspectors determined that the licensee's acceptance of linear flaws in the Unit 3A LPCI heat exchanger supports that are determined to be unacceptable for continued service IAW with the ASME Code Section XI, Article IWC–3000 requirements was a performance deficiency (PD). The inspectors determined that the PD was more-than-minor, and a finding, because if the PD remained uncorrected it could lead to a more significant safety concern. Absent NRC identification, the LPCI support welds with unacceptable linear flaws would have remained in service without repair or replacement. This condition could potentially lead to the failure of the Unit 3A LPCI heat exchanger supports, which in turn, could lead to a potential failure of the Unit 3A LPCI heat exchanger. The inspectors reviewed the finding using Attachment 0609.04, "Initial Characterization of Findings," Table 3–Significance Determination Process (SDP) Appendix Router. The inspectors answered 'No' to the question in Section A of Table 3; and therefore, evaluated the finding using the SDP in accordance with IMC 0609, "The Significance Determination Process for At-Power Operations," Appendix A, Exhibit 2, "Mitigating Systems Screening Questions." The inspectors answered "No" to the questions in Exhibit 2 and determined that this finding did not result in a deficiency affecting the structures, systems, and components (LPCI heat exchanger) to maintain its operability or functionality. Therefore, the finding was determined to have very low safety significance. The inspectors determined that this finding has a cross-cutting aspect in the area of Human Performance, training, for the licensee's failure to provide training and ensure knowledge transfer to maintain a knowledgeable, technically competent workforce and instill nuclear safety values. Specifically, the licensee staff dispositioned unacceptable flaws in the LPCI heat exchanger supports for continued service using an engineering evaluation because the licensee staff lacked the specific ASME Code knowledge concerning disposition of the unacceptable indications. Therefore, the licensee failed to return the LPCI heat exchanger supports to within ASME Code acceptable flaw limits via repair or replacement prior to return to service. [H.9] (Section 1R08)

- Preliminary White. An apparent violation (AV) of 10 CFR Part 50, Appendix B, Criterion III, Design Control, having a preliminary low to moderate safety significance, was self-revealed on November 6, 2014, following the discovery that one of the Unit 3 electromatic relief valves (ERVs) would not have performed its intended safety function. Increased vibrations experienced while operating at extended power uprate (EPU) power levels resulted in the degradation of multiple ERV actuator components which rendered the valve inoperable. The inspectors determined that the licensee fully implemented the Unit 3 EPU following a main generator rewind in November 2010, but failed to verify that the ERV actuator design was suitable for operation at the continuously increased vibration levels experienced at EPU power levels. This finding does not represent an immediate safety concern in that the licensee has replaced all four Unit 3 ERV actuators with a hardened design successfully utilized at the Quad Cities Generating Station, which also experienced significant steam line vibrations post EPU.

  The inspectors determined that the licensee's failure to ensure the continued operability of the Unit 3 ERVs following the establishment of EPU plant operating conditions was a performance deficiency warranting a significance evaluation. The inspectors determined that the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Mitigating Systems Cornerstone attributes of design control and equipment performance and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. A Significance and Enforcement Review Panel (SERP), using IMC 0609, Appendix A, "Significance Determination Process For Findings At-Power," dated June 19, 2012, preliminarily determined the finding to be of low to moderate safety significance (White). The inspectors determined that this finding has a cross-cutting aspect of operating experience in the area of Problem Identification and Resolution, since it involves the failure to implement relevant internal and external operating experience in a timely manner. [P.5] (Section 1R15)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and associated non-cited violation of Technical Specification (TS) 5.4.1, "Procedures," was self-revealed on November 19, 2014, for the licensee's failure to maintain configuration control in the Unit 3 containment pressure suppression system. Specifically, the licensee failed to maintain the instrument air stop valve to the actuator for Unit 3 torus vent 3–1601–60 open with the reactor in the Start-up and Run Mode following refueling outage D3R23.

  The inspectors determined that the licensee's failure to maintain configuration control of the Unit 3 containment pressure suppression system was contrary to procedures for the emergency depressurization of containment as well maintaining TS required atmospheric conditions inside the primary containment with the reactor in Mode 1 and was a performance deficiency. The inspectors determined that the finding was more than minor because it was associated with the barrier integrity cornerstone attribute of configuration control in how containment design parameters are maintained while affecting the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The inspectors determined that the finding was of very low safety significance based on answering "No" to all of the Barrier Integrity screening questions in IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 3. The finding has a cross-cutting aspect of conservative bias in the area of Human Performance because the licensee did not implement appropriate robust barriers to prevent bumping of the 3–1601–60SV in response to corrective action 511878–02. Specifically, the licensee previously evaluated 3–1601–60SV and non-conservatively determined that this particular valve did not require a seal to prevent inadvertent operation. [H.14] (Section 1R20)

Licensee-Identified Violations

- None.

REPORT DETAILS

Summary of Plant Status

Unit 2

Unit 2 began the inspection period at full power. On October 18, 2014, operators reduced reactor power to 20 percent to replace a potential transformer associated with the main generator automatic voltage regulator (AVR) feedback loop. During the evolution, the generator tripped offline due to a high water level in the 2D moisture separator; however, reactor power was below the generator trip scram setpoint, therefore the reactor remained online. Following repairs, operators synchronized the main generator back to the grid on October 19 and returned the reactor to near full power on October 20. The unit operated at or near full power for the remainder of the inspection period.

Unit 3

Unit 3 began the inspection period in coastdown to the unit's twenty-third refueling outage (D3R23) at approximately 92 percent reactor power. Coastdown continued until November 3 when the main generator was taken offline and the reactor was shut down for commencement of D3R23. Unit startup began on November 18, 2014, with the main generator synchronized to the grid on November 19, ending D3R23. The reactor returned to near full power on November 20, 2014. The unit operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment to this report. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues:

- Unit 2/3 cribhouse; and
- Unit 2/3 isolation condenser makeup pump house.

This inspection constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Condition—Severe Thunderstorms and High Winds

a. Inspection Scope

Since thunderstorms and high winds were forecast in the vicinity of the facility for October 2, 2014, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On October 2, 2014, the inspectors walked down the structures, systems, and components of the reactor and turbine buildings in addition to the licensee's emergency alternating current (AC) power systems, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of CAP items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01–05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 2/3A standby gas treatment train with 2/3B out of service;
- re-establishment of Unit 3 spent fuel pool cooling pump trips; and
- post-accident monitoring drywell pressure transducers PT 3–1625 and PT 3–1624 following replacement and relocation.

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

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

b. Findings

No findings were identified.

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:

- Unit 3 low pressure heater bay, elevation 517, Fire Zone 8.2.5D;
- Unit 3 high pressure heater bay, elevation 517, Fire Zone 8.2.5E;
- Unit 3 low pressure heater bay, elevation 538, Fire Zone 8.2.6D; and
- Unit 2 emergency diesel generator room, elevation 517, Fire Zone 9.0A.

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

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

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

- condensate pit high-high level calibration.

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

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

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance (71111.07A)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of the unit 2 and unit 3 low pressure coolant injection/ containment cooling service water heat exchangers to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. Documents reviewed for this inspection are listed in the Attachment to this document.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07–05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08)

From November 3–10, 2014, the inspectors conducted a review of the implementation of the licensee's inservice inspection (ISI) program for monitoring degradation of the reactor coolant system (RCS, risk-significant piping and components, and containment systems.

The inservice inspections described in Sections 1R08.1 and 1R08.5 below constituted one inspection sample as defined in IP 71111.08.

.1 Piping Systems Inservice Inspections

a. Inspection Scope

The inspectors observed or reviewed records of the following nondestructive examinations mandated by the ASME Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement:

- Magnetic Particle Examination of 3A LPCI Heat Exchanger Support Welds;
- Magnetic Particle Examination of Core Spray Support M–3409–09 Weld;
- Ultrasonic Examination of Reactor Pressure Vessel Shell to Isolation Condenser Nozzle N5B–1 Weld; and
- Ultrasonic Examination of Shutdown Cooling Pipe Weld SDA–04F.

The inspectors reviewed the following examination records 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. 14–129, “Magnetic Particle Examination of FW Check Valve Seat Ring 3–0220–58A;” and
- Report No. 14–202, “Liquid Penetrant Examination of FW Check Valve Seat Ring 3–0220–58B.”

The inspectors reviewed records of the following pressure boundary welds completed for a risk significant systems since the last Unit 1 refuelling outage to determine if the welding activities and any applicable non-destructive examination (NDE) performed were completed in accordance with the ASME Code or NRC approved alternative:

- WO 01642082, “Repair of Pinhole Leak on Unit 3 CCSW Division II Piping.”

b. Findings

Unit 3A LPCI Heat Exchanger Supports Returned to Service with Unacceptable Indications

Introduction: A finding of very low safety significance (Green) and associated NCV of 10 CFR 50.55a(g)(4) was identified by the inspectors for the licensee’s failure to maintain ASME Code Class 2 components in accordance with ASME Code Section XI requirements. Specifically, the licensee failed to repair or replace the Unit 3A LPCI heat exchanger support welds identified to have unacceptable linear flaws prior to return to service.

Description: On November 4, 2014, the inspectors reviewed a magnetic particle examination (MT) data sheet (report number 13–093) associated with work order 01140079–02. Report 13–093 identified the presence of two linear flaws and stated that the acceptance criterion for evaluating flaws was in accordance with the ASME Code Section XI, Article IWC–3000, Table 3510–3. The ASME Code Section XI, Article IWC–3000, Table IWC 3510–3 established the maximum acceptable linear flaw length as 3/16 inches for this particular support examination. The flaws identified in Report Number 13–093 were ¾ and 1 inch in length, respectively. Therefore, the identified flaws were greater than the acceptable length established by the ASME Code Section XI, Article IWC–3000 acceptance criteria. Article IWC–3122.3, “Acceptance by Analytical Evaluation”, states in part, that a component whose examination detects flaws that exceed the acceptance standards of Table 3410–1 is acceptable for continued service without repair/replacement activity if an analytical evaluation, as described in IWC–3600, meets the acceptance criteria of IWC–3600. However, the criteria of IWC–3600 are not applicable to IWC Category C–C support welds. Therefore, the use of acceptance by analytical evaluation is not allowed for the disposition of the unacceptable flaws in the LPCI support welds. Article IWC–3122.2, “Acceptance by Repair/Replacement Activity,” states in part, that a component whose examination detects flaws that exceed the acceptance standards of Article IWC–3000 is unacceptable for continued service until the component is repaired or replaced to the extent necessary to meet the acceptance standards of Article IWC–3000.

The licensee documented this condition adverse to quality into its CAP under AR 1516881. As part of the corrective actions to address these unacceptable flaws, the licensee performed an engineering evaluation, ECE 345249, that evaluated the continued use of the Unit 3A LPCI support welds with the unacceptable flaws and concluded that the LPCI system was operable and would maintain operability even with the existence of these unacceptable flaws. Therefore, the licensee accepted these flaws on the Unit 3A LPCI support welds for continued service. The inspectors questioned the licensee decision to accept the unacceptable flaws for continued service against the Code of Federal Regulations (CFR) requirement in 10 CFR 50.55a(g)(4) that requires, in part, that ASME Code Class components (including supports) shall be maintained IAW with the requirements of the ASME Code Section XI. The licensee entered the inspectors’ concern into its CAP under AR 02407379.

Analysis: The inspectors determined that the licensee’s acceptance of linear flaws in the Unit 3A LPCI heat exchanger supports that are determined to be unacceptable for continued service IAW with the ASME Code Section XI, Article IWC–3000 requirements was a PD. The inspectors determined that this PD was more-than-minor, and a finding, because if the PD remained uncorrected it could lead to a more significant safety concern. Absent NRC identification, the LPCI support welds with unacceptable linear flaws would have remained in service without repair or replacement. This condition could potentially lead to the failure of the Unit 3A LPCI heat exchanger supports, which in turn, could lead to a potential failure of the Unit 3A LPCI heat exchanger.

The inspectors reviewed the finding using Attachment 0609.04, “Initial Characterization of Findings,” Table 3 – SDP Appendix Router. The inspectors answered ‘No’ to the question in Section A of Table 3; and therefore, the finding was evaluated using the SDP in accordance with IMC 0609, “The Significance Determination Process for At-Power Operations,” Appendix A, Exhibit 2, “Mitigating Systems Screening Questions.” The inspectors answered “No” to the questions in Exhibit 2 and determined that this finding did not result in a deficiency affecting the Systems, Structures, and Components (SSC) (LPCI) to maintain its operability or functionality. Therefore, the finding was determined to have very low safety significance (Green).

The inspectors determined that this finding has a cross-cutting aspect in the area of Human Performance, training, for the licensee’s failure to provide training and ensure knowledge transfer to maintain a knowledgeable, technically competent workforce and instill nuclear safety values. Specifically, the licensee staff dispositioned unacceptable flaws in the LPCI heat exchanger supports for continued service using an engineering evaluation because the licensee staff lacked the specific ASME Code knowledge concerning disposition of unacceptable indication. Therefore, the licensee failed to return the LPCI heat exchanger supports to within ASME Code acceptable flaw limits via repair or replacement prior to return to service. [H.9]

Enforcement: Title 10 CFR 50.55a(g)(4) states that throughout the service life of a boiling or pressurized water reactor facility, components which are classified as ASME Code Class 1, 2, and 3 must meet requirements set forth in Section XI.

The ASME Code of record at Dresden Unit 3 is the 2007 Edition with 2008 Addenda. Article IWC–3000, “Acceptance Standards,” states in part, that a component whose examination detects flaws that exceed the acceptance standards of Article IWC–3000 is unacceptable for continued service until the component is repaired or replaced to the extent necessary to meet the acceptance standards of Article IWC–3000. The ASME Code Section XI, Article IWC–3000, Table 3510–3 states in part, that the maximum acceptable linear flaw for support welds is 3/16 inch.

Contrary to the above, in May 2013, the licensee identified linear flaws in excess of 3/16 inch in the Unit 3A LPCI heat exchanger supports welds and did not repair or replace these support welds and returned the supports to service with the unacceptable flaws. Because this issue is of very low safety significance, and was entered into the licensee’s CAP under AR 02407379, it is being treated as an NCV consistent with Section 2.3.2 of the NRC enforcement policy. As part of their immediate corrective actions, the licensee performed repair on the Unit 3A LPCI heat exchanger supports IAW with the ASME Code Section XI prior to plant restart. The inspectors reviewed the licensee’s repair/replacement plan and did not identify additional concerns.
(NCV 05000249/2014005–01, “Unit 3A LPCI Heat Exchanger Supports Returned to Service with Unacceptable Indications)

.2 Identification and Resolution of Problems

a. Inspection Scope

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

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

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

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Observation During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On October 18, 2014, the inspectors observed operators during a downpower to 25 percent power and containment entry in preparation for a main generator potential transformer replacement. This was an activity that required heightened awareness or was related to increased risk. 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 (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications (if applicable).

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Unit 3 shutdown cooling system.

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

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;

- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

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

This inspection constituted one quarterly maintenance effectiveness sample as defined in IP 71111.12–05.

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- protected pathways for 2/3A standby gas treatment train with unit 2 on-line risk YELLOW;
- unit 2 on-line risk YELLOW during unit 3 reactor water clean-up (RWCU) relief valve replacement; and
- protected pathways during emergent Unit 3 high pressure coolant injection (HPCI) repairs.

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

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 2 LPCI swing bus transfer did not meet acceptance criteria;
- Unit 3, 1B shutdown cooling suction isolation valve exposed to temperatures above its environmental qualification rating;
- 3A service water pump load shed functional test failure;
- Unit 3 control rod P–04 high friction force during operation indicating potential fuel channel distortion;
- 3E emergency relief valve failed to operate, historical operability review; and
- Unit 3 reactor vessel to reactor head flange inner O-ring failure.

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

This operability inspection constituted six samples as defined in IP 71111.15–05.

b. Findings

Failure to Ensure Continued Operability of Unit 3 Electromatic Relief Valve 3–0203–3E Following Implementation of Extended Power Uprate Plant Conditions

Introduction: A finding preliminarily determined to be of low to moderate safety significance (White) and an associated AV of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified for the licensee's failure to establish measures to ensure that the ERV actuator for 3–0203–3E remained suitable for operation at EPU power levels prior to fully implementing the Unit 3 EPU in November 2010.

Description: The licensee experienced a failure of the 3E ERV with the reactor shutdown in Mode 5 during surveillance testing in accordance with licensee procedure DOS 0250–07, "Electromatic Relief Valve Testing with the Reactor Depressurized" on November 6, 2014. During this surveillance, operators in the main control room (MCR) manually actuate open the ERV's. When cycling the 3E ERV, MCR operators noted that the valve position indication did not change out of the closed condition, and locally assigned equipment operators heard a click when the demand signal was given but the actuator plunger did not move, therefore the ERV did not reposition open.

The ERV actuator is a solenoid assembly that energizes to reposition the ERV pilot valve. When an open signal is sent to the ERV actuator, its solenoid energizes causing a plunger to travel downward and contact the strike lever on the pilot valve assembly. The plunger causes the ERV pilot valve to mechanically reposition relieving pressure internal to the ERV main valve causing it to open and direct steam from the main steam system to the torus suppression pool. The ERVs serve as a component of the automatic depressurization system (ADS) designed to depressurize the RCS during certain loss of coolant accidents in order for the low pressure coolant injection and core spray systems to be able to inject make-up water to the RCS. In addition, the ERVs provide RCS over pressure protection in order to minimize the likelihood that the main steam safety valve will have to actuate to protect the RCS from over pressurization.

The licensee performed an Equipment Apparent Cause Evaluation (EACE 2407705) and determined the apparent cause of the ERV failure to be that the actuator design is susceptible to vibration induced wear in conjunction with the increased vibration on the Unit 3 'B' main steam line near the 3E ERV. The increased vibration is associated with EPU steam flows as a result of full implementation of EPU plant conditions. Specifically, the actuator design installed on Unit 3 ERVs at the time of the event allowed for excessive movement of the solenoid plunger when vibrated. This excess movement resulted in friction wear on the solenoid plunger guides, spring guides, and springs. As a result of the wear on the spring and plunger guides, mechanical binding of the actuator occurred preventing the plunger from physically operating the ERV.

The licensee received a license amendment from the NRC to operate at EPU conditions increasing licensed core rated thermal power (RTP) from 2527 MWth to 2957 MWth starting with fuel cycle D3C18 which went into effect following refueling outage D3R17 in the fourth quarter of 2002. Due to limitations of the main generator, Dresden operated at higher thermal output power but was not able to consistently operate at RTP conditions. Full RTP was achieved only for short durations in the warmer summer months when plant efficiency was poorest and full thermal power resulted in a lower steam/electrical plant output which was within the capacity of the main generator. During this time, Dresden and Quad Cities Generating Station, which also received a licensee amendment to operate at EPU power levels, experienced steam dryer cracking. Quad Cities Generating Station also experienced vibration damage and failures of ERV actuators. As a result of this operating experience regarding the ERV failures at Quad Cities, the licensee performed main steam line vibration recording on Dresden Unit 3 at 2851 MWth on December 29, 2003, and 2951 MWth on October 8, 2004. The results indicated that steam line vibrations on Unit 3 were significantly lower (10–20 times) in magnitude than those experienced at Quad Cities and the licensee used engineering judgment to conclude that there was no expected increase in wear rate of the internal actuator components at Dresden.

On April 20, 2007, the licensee submitted a letter to the NRC entitled, “Request for Acceptance for Continuous Extended Power Uprate Operation.” This letter chronicled corrective actions taken at Dresden and Quad Cities Nuclear Plants with regards to steam line vibrations and committed to performing inspections of ERV actuators during the next Dresden refueling outage. Of note, was the installation of ERV hardened actuators at Quad Cities Nuclear Plant to address vibration induced failures of ERVs experienced immediately following implementation of EPU. The NRC responded to this letter on June 11, 2007, acknowledging the corrective actions and inspection that had been completed at both sites and stated that the agency had no further objection to continuous operation at full licensed thermal power of 2957 MWth and that the licensee would be expected to fulfill the commitments made in their April 20, 2007 letter.

During refueling outage D3R21 in 2010, the licensee performed a main generator rewind on Unit 3 thus permitting the main generator to supply electrical output power sufficient enough for the reactor to operate at RTP during the entire operating cycle. This upgrade meant that the main steam lines would be operating at full steam flow during the entire two year operating cycle and would be, along with attached components including the ERVs, subject to higher vibrations for a significantly greater time period.

The inspectors reviewed the licensee’s inspection and maintenance records of the Unit 3 ERV actuators dating back to 2004. Following required surveillance testing of the ERVs each refueling outage, the licensee performed internal inspections of the ERV actuators to identify any components that were degrading due to vibration induced wear. During the time period between 2004 and 2010, the licensee experienced no surveillance failures and noted only minor vibration induced wear of ERV actuator internal components. The licensee proactively replaced all internal components showing wear following these inspections. During the surveillance testing and inspections that have occurred in the refueling outages following the two operating cycles ending in 2012 and 2014 since the generator rewind, the licensee has experienced two failures of the 3–0203–3E, 3E, ERV, and noted significant wear damage to the actuator internals of the 3B and 3E ERV with notable but less significant wear to the 3C ERV. During refueling outage D3R22 in 2012, following multiple successful operations in the course of surveillance testing the 3E ERV actuator became mechanically bound due to significant wear induced damage and a loose bolt in the spring guide mechanism. As the ERV had performed successfully prior to that testing, the failure was considered to have occurred at the time of discovery and the licensee determined that the ERV would have performed its function during the previous cycle. The licensee made the decision to replace the actuator with a similar model actuator even though the wear degradation was significant as they planned to replace all four ERV actuators with the hardened design utilized at Quad Cities Generating Station since 2007 during the next refueling outage in 2014.

Analysis: The inspectors determined that the licensee’s failure to ensure the continued operability of the Unit 3 ERVs following the establishment of EPU plant operating conditions was a performance deficiency warranting a significance evaluation. The inspectors determined the finding was more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” dated September 7, 2012, because it was associated with the Mitigating Systems Cornerstone attributes of design control and equipment performance and adversely affected the 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, “Initial Characterization of Findings,” dated June 19, 2012, and Appendix A, “The Significance Determination Process for Findings At-Power,” Exhibit 2, “Mitigating Systems Screening Questions,” dated June 19, 2012. The finding represented an actual loss of system safety function of an ERV for greater than its TS 3.4.3.A, TS 3.5.1.H and TS 3.5.1.I allowed outage time of 14 days. Therefore, a detailed risk evaluation was performed in accordance with IMC 0609, Appendix A.

DETAILED RISK EVALUATION

The Senior Reactor Analysts (SRAs) evaluated the finding using the Dresden Standardized Plant Analysis Risk (SPAR) model version 8.21, Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) version 8.1.2.0.

Dresden SPAR Modifications

The SRAs used a change set to model the failure of ERV 3E to open. The basic event representing ERV 3E failing to open was set to TRUE.

The following SPAR Model modifications were made with the assistance of Idaho National Laboratory (INL):

a) A change was made to the success criterion for the number of SRVs (i.e., the four ERVs and the Target Rock SRV) required for reactor coolant system (RCS) depressurization following an ATWS. The present SPAR model success criterion is 5–of–5 SRVs for RCS depressurization following an ATWS. The licensee’s PRA success criterion is 3–of–5 SRVs (based on plant-specific MAAP calculations). The SPAR model was modified to use a 4–of–5 success criterion for RCS depressurization (in fault tree DEP01). Though relaxed from the present 5–of–5 success criterion, the use of a more conservative 4–of–5 SRVs for successful manual RCS depressurization in the SPAR model instead of 3–of–5 SRVs (that the licensee uses) accounts for the licensee’s analysis that 12–of–13 SRVs/safety valves are required for success to prevent RCS over-pressurization following an ATWS condition.

b) In addition to fault tree DEP01, the RCS depressurization logic found in fault trees DEP, DEP02, LI–DEP, and PPR was modified. The success criteria used is:

  - 2–of–5 SRVs for non-ATWS RCS depressurization (in fault trees DEP, DEP02, and LI–DEP). The success criteria for these fault trees were changed to make them consistent with each other for non-ATWS RCS depressurization.

  - 4–of–5 SRVs during RCS depressurization following an ATWS (in fault tree DEP01) as described above.

  - 4–of–5 SRVs for ATWS over-pressurization (in fault tree PPR) to account for the licensee’s analysis that 12–of–13 SRVs/safety valves are required to prevent RCS over-pressurization following an ATWS condition.

c) A new fault tree (DEP-CND) was created to account for successful RCS depressurization when either condenser operation is successful or there is successful operation of at least 2–of–5 SRVs.

d) All the ADS valve common cause failure (CCF) probabilities were changed as a result of modeling that reflects the ADS valves as they are actually tested; that is, in a “non-staggered” fashion over time (i.e., all at once during refueling outages). Also, the new RASP CCF “R” calculation type was used to calculate the CCF probabilities for these valves based on INL’s recommendation. Use of the “R” type calculation for the CCF probabilities is more accurate since it removes approximations when setting the failure mode of the valves in SAPHIRE to “1,” “True”, “0”, or “False”.

e) The common-cause group (CCG) for the SRVs was changed from a five-element CCG (that included the 4 ERVs and the Target Rock SRV) to a four-element CCG for the 4 ERVs (and with the Target Rock SRV separate). This is consistent with the licensee’s PRA model and is based on the differences between the ERVs and the Target Rock SRV in 1) valve design, 2) valve relief capacities, and 3) valve actuation mechanisms.

<u>**Calculation Discussion**</u>

a) Exposure Time

The exposure time was assumed to be 349 days.

For the last operating cycle between the startup of Unit 3 on December 5, 2012 (following the refueling outage) and the shutdown on November 3, 2014 (for the last refueling outage), a “T/2” evaluation provides an exposure time of 349 days (i.e., 698 days divided by 2). The “T/2” exposure time is appropriate based on RASP manual guidance because the time of the actual failure of ERV 3E cannot be determined.

b) Common Cause Failure and Extent of Condition

Common cause failure potential was assumed. The SRAs used a change set to model common cause failure with the basic event representing failure of ERV 3E to open set to TRUE. This is consistent with current SRA guidance given the circumstances that the failure matches the RASP manual guidance as discussed below:

RASP manual guidance, Section 5.1 states as “In Scope”:

Treatment of CCF dependencies among components in a Common Cause Component Group (CCCG) given one or more of the following observed conditions:

- *An observed failure of one or more components in a CCCG (i.e., the failure of ERV 3E).*

- *An observed failure of one component (i.e., the failure of ERV 3E) and observed degradation in one or more remaining components in the CCCG (i.e., the* *degradation of ERV 3B and ERV 3C, which exhibited similar wear on the spring guides and plunger as seen on the failed ERV 3E).*

c) Human Reliability

ERV 3E could not be manually operated and successful operation of the valve could be recovered. Thus, setting the failure of ERV 3E to "TRUE" in the SPAR model is a correct modeling for the failure of ERV 3E.

INTERNAL EVENTS RESULT / DOMINANT SEQUENCE

The result for the delta internal events core damage frequency ($\Delta CDF_{internal)}$ is 1.12E–6/year. The dominant sequence for internal events was a small loss-of-coolant accident (SLOCA) initiating event with a failure of the power conversion system, main feedwater, HPCI, and the failure of RCS depressurization.

CONTRIBUTIONS AND RISK ESTIMATES FROM EXTERNAL EVENTS

FIRES

A rough estimate of the fire risk contribution was obtained using information from the Dresden Individual Plant Examination of External Events (IPEEE), Revision 1, dated February 14, 2000. The following list of fire initiating events was considered in the IPEEE and were the dominant initiating events that contributed to fire risk for this issue.

- %TP - Multiple Spurious ADS Valve Opening
- %TI - Single Spurious ADS Valve Opening
- %TC - Loss of Main Condenser
- %LOOP - Single Unit Loss of Offsite Power

The delta risk from each of these fire initiating events is discussed below.

a) %TP–Multiple Spurious ADS Valve Opening

The "%TP" initiator is described in the IPEEE as a "Multiple Spurious ADS Valve Opening" initiating event. Based on the Dresden PRA system notebook for the ADS system [i.e., Reactor Vessel Pressure Control and Depressurization (ADS) System (DR–PSA–005.15 Revision 6)], each ERV can relieve about 540,000 lbm/hr at 1101 psig. This is equivalent to a flowrate of about 1080 gpm. Thus, an opening of two ERVs is equivalent to a break of about 2,000 gpm and an opening of three ERVs is equivalent to a break of about 3,000 gpm. In NUREG–1829," Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process," Volume 1, it states that medium LOCAs (MLOCAs) are historically defined over a flowrate of 1,500 to 5,000 gpm. Thus, the "%TP" initiator was modeled as a MLOCA initiating event in the Dresden SPAR model.

Using the Dresden SPAR model, the Conditional Core Damage Probability (CCDP) of a MLOCA initiating event with an ERV 3E "Fail-To-Open" failure was 1.17E–3. The nominal CCDP was 7.55E–4 (i.e., MLOCA with no failure of ERV 3E). Thus, the ΔCCDP is 4.15E–4.

From Table 4–16, “Unit 3 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total ignition frequency (IF) for the “%TP” initiating event is 3.53E–3/yr. Using the exposure time (ET) for the finding of 349 days, the ΔCDF for this fire initiating event is:

$$
\begin{aligned}
\Delta CDF_{\%TP} &= [IF] \times [\Delta CCDP] \times [ET] \\
&= [3.53E{-}3/yr] \times [4.15E{-}4] \times [349 \text{ days}/365 \text{ days}] \\
&= 1.40E{-}6/yr
\end{aligned}
$$

b) <u>%TI–Single Spurious ADS Valve Opening</u>

The “%TI” initiator is described in the IPEEE as a “Single Spurious ADS Valve Opening” initiating event. The “%TI” initiator was modeled as an Inadvertent Open Relief Valve (IORV) initiating event in the Dresden SPAR model. Since the additional equipment failures that would occur for the various affected Fire Compartments are not specified in the IPEEE, the failure of the main feedwater (MFW) system was assumed to provide limiting scenarios based on review of the SPAR model IORV event tree. Using the Dresden SPAR model, the CCDP of an IORV initiating event with loss of MFW and an ERV 3E “Fail-To-Open” failure was 5.43E–4. The nominal CCDP without the ERV 3E failure was 1.26E–4. Thus, the ΔCCDP is 4.17E–4.

From Table 4–16, “Unit 3 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total IF for the “%TI” initiating event is 5.87E–4/yr. Using the ET for the finding of 349 days, the ΔCDF for this fire initiating event is:

$$
\begin{aligned}
\Delta CDF_{\%TI} &= [IF] \times [\Delta CCDP] \times [ET] \\
&= [5.87E{-}4/yr] \times [4.17E{-}4] \times [349 \text{ days}/365 \text{ days}] \\
&= 2.34E{-}7/yr
\end{aligned}
$$

c) <u>%TC–Loss of Main Condenser</u>

The “%TC” initiator is described in the IPEEE as a “Loss of Condenser” initiating event. Thus, the “%TC” initiator was modeled as Loss of Condenser Heat Sink (LOCHS) initiating event in the Dresden SPAR model. Since the additional equipment failures that would occur for the various affected Fire Compartments are not specified in the IPEEE, the failure of the MFW system was assumed to provide limiting scenarios based on review of the SPAR model LOCHS event tree. Using the Dresden SPAR model, the CCDP of an LOCHS initiating event with loss of MFW and an ERV 3E “Fail-To-Open” failure was 8.63E–6. The nominal CCDP without the ERV 3E failure was 1.86E–6. Thus, the ΔCCDP is 6.77E–6.

From Table 4–16, “Unit 3 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total IF for the “%TC” initiating event is 1.03E–2/yr. Using the ET for the finding of 349 days, the ΔCDF for this fire-initiating event is:

$$
\begin{aligned}
\Delta CDF_{\%TC} &= [IF] \times [\Delta CCDP] \times [ET] \\
&= [1.03E{-}2/yr] \times [6.77E{-}6] \times [349 \text{ days}/365 \text{ days}] \\
&= 6.67E{-}8/yr
\end{aligned}
$$

d) **<u>%LOOP–Single Unit Loss of Offsite Power</u>**

The “%LOOP” initiator is described in the IPEEE as a “Single Unit Loss of Offsite Power” initiating event. Thus, the “%LOOP” initiator was modeled as a Loss of Offsite Power (LOOP) initiating event with the failure to recover offsite power in the Dresden SPAR model. Using the Dresden SPAR model, the CCDP of a LOOP initiating event with an ERV 3E “Fail-To-Open” failure was 2.90E–5. The nominal CCDP was 1.64E–5 (i.e., with no failure of ERV 3E). Thus, the ΔCCDP is 1.26E–5.

From Table 4–16, “Unit 3 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total IF for the “%LOOP” initiating event is 2.18E–3/yr. Using the ET for the finding of 349 days, the ΔCDF for this fire-initiating event is:

$$\begin{aligned}\Delta CDF_{\%LOOP} &= [IF] \times [\Delta CCDP] \times [ET] \\ &= [2.18E{-}3/yr] \times [1.26E{-}5] \times [349\ days/365\ days] \\ &= 2.63E{-}8/yr\end{aligned}$$

<u>Total Estimated Risk From Fires</u>

The total estimated risk from fires is the sum of the risk from the above fire initiating events:

$$\begin{aligned}\Delta CDF_{Fire} = \Delta CDF_{\%TP} + \Delta CDF_{\%TI} + \Delta CDF_{\%TC} + \Delta CDF_{\%LOOP} \\ = 1.40E{-}6/yr + 2.34E{-}7/yr + 6.67E{-}8/yr + 2.63E{-}8/yr \\ = 1.73E{-}6/yr\end{aligned}$$

<u>FLOODING</u>

<u>Case 1: Internal Plant Flooding</u>–The internal plant flood risk contribution was evaluated as insignificant based on 1) the results from the Dresden Individual Plant Examination Submittal Report (IPE), dated January 1993, and 2) a previous version of IMC 0609 Appendix A, Table 3.1, “Plant Specific Flood Scenarios,” which showed that there were no significant internal flood scenarios for Dresden Station.

<u>Case 2: External Plant Flooding</u>–The external plant flood risk contribution was evaluated as insignificant based on the following:

- The initiating event frequency (IEF) for an external flood to reach grade level (i.e., 517 feet) is low (i.e., approximately 5E–5/yr based on a previous flood issue at Dresden (EA–13–079)).

- It is expected that normally there would be sufficient time available to shutdown and cooldown the plant such that the SRVs would not be needed to mitigate an external flood initiator.

- As long as off-site power and the main condenser are available, RCS cooldown can be accomplished using the bypass valves to the condenser without the need to use the SRVs.

Based on the above, the risk of this finding due to flooding is insignificant and will not be considered further.

SEISMIC

The SRAs used a seismically induced LOOP event to represent the spectrum of seismic events that could lead to a change in core damage risk. For Dresden in the RASP manual, the frequency of a seismically induced LOOP is 5.19E–5/yr as obtained from "Frequency of Seismically-Induced LOOP Events for SPAR Models," Revision 3, dated August 2011. A seismically induced LOOP can be modeled using any LOOP initiating event in the SPAR model without off-site power recovery. For the analysis, the SRAs chose to use a weather-related LOOP initiating event (IE-LOOPWR) without off-site power recovery.

For the Deficient Case, using the Dresden SPAR model with the following Change Sets: 1) Weather-Related LOOP (IE–LOOPWR) frequency set to 1.0, 2) no off-site power recovery, and 3) failure of ERV 3E (set to True), a Conditional Core Damage Probability (CCDP) of 3.24E–4 was obtained.

For the Base Case with a Change Set with IE–LOOPWR frequency set to 1.0 and 2) no off-site power recovery, a CCDP of 2.58E–5 was obtained.

Thus, the ΔCCDP was [3.24E–5 – 2.58E–5] = 6.6E–6.

The $\Delta CDF_{seismic}$ for a 349 day Exposure Time is:

$\Delta CDF_{seismic}$ = [5.19E–5/yr][6.6E–6][349 days/365 days] = 3.3E–10/yr

The seismic risk is thus 3.3E–10/yr. The risk of this finding due to seismic is insignificant and will not be considered further.

TOTAL EXTERNAL EVENTS RISK

The total external events $\Delta CDF_{external}$ is the sum of the fire, flood, and seismic risk or 1.73E–6/yr.

POTENTIAL RISK CONTRIBUTION DUE TO LARGE EARLY RELEASE FREQUENCY

The potential risk contribution due to large early release frequency (LERF) was considered using IMC 0609 Appendix H, "Containment Integrity Significance Determination Process." Dresden is a GE BWR–3 plant with a Mark I containment. Table 5.1 from Appendix H (Phase 1 screening) indicated that this issue required further evaluation since ATWS and High RCS pressure sequences were important for BWRs with Mark I containments. Table 5.2 from Appendix H (Phase 2 analysis) listed a LERF Factor of 0.3 for Anticipated Transient Without Scam (ATWS) sequences. For RCS high pressure sequences (high pressure defined as greater than 250 psi at the time of reactor vessel breach), Table 5.2 had a LERF factor of 0.6 if the drywell is flooded, and 1.0 if the drywell is not flooded.

A review of the dominant core damage sequences revealed the following:

- ATWS sequences represented a ΔCDF of 1.57E–7/yr. Based on a LERF Factor of 0.3, the ΔLERF due to ATWS core damage sequences is 4.71E–8/yr.

- High RCS Pressure sequences (i.e., the failure of RCS depressurization) represented a ΔCDF of 8.57E–7/yr. Based on the dominant core damage sequences, the sequences that flood the drywell (i.e., LOCA sequences) have a ΔCDF of 3.35E–7/yr. The non-LOCA sequences that may not result in the drywell being flooded have a ΔCDF of 5.22E–7/yr. Thus, the ΔLERF due to High RCS Pressure core damage sequences is 7.23E–7/yr (i.e., [3.35E–7/yr][0.6] + [5.22E–7/yr][1.0] = 7.23E–7/yr).

The total ΔLERF is the sum of the ΔLERF due to the ATWS core damage sequences and the High RCS Pressure sequences. The total ΔLERF is 7.70E–7/yr (White).

Total Estimated Change in Risk

- ΔCDF = 2.85E–6/yr (White)

The total change in core damage frequency (ΔCDF) is the sum of the internal and external events ΔCDF risk, or a ΔCDF of 2.85E–06/year (i.e., 1.12E–6/yr (internal) + 1.73E–6/yr (external) = 2.85E–6/yr) (White).

- ΔLERF =7.70E–7/yr (White)

The total change in LERF due to this performance deficiency is 7.70E–07/year (White).

A SERP held on January 15, 2015, using IMC 0609, Appendix A, "Significance Determination Process For Findings At-Power," dated June 19, 2012, made a preliminary determination that the finding was of low to moderate safety significance (White) based on the quantitative analysis performed during the detailed risk evaluation.

The inspectors determined that this finding has a cross-cutting aspect of operating experience in the area of Problem Identification and Resolution, since it involves the failure to implement relevant internal and external operating experience in a timely manner. (P.5)

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components.

Technical Specifications 3.4.3 and 3.5.1 require in part that the relief function of 5 relief valves shall be operable in various modes of operation. From November 29, 2010, to November 6, 2014 the licensee failed to establish measures to ensure that the application of the ERV actuators (which are essential to perform the safety-related reactor vessel depressurization and overpressure protection functions) remained suitable for operation prior to fully implementing an extended power uprate in November 2010. This resulted in multiple failures of the 3E ERV and an indeterminate period of inoperability and unavailability greater than allowed by TSs 3.4.3 and 3.5.1 during operating cycle D3C23 due to being subjected to significantly higher vibration levels during Unit 3 operation at EPU power levels. This apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Control, which has low to moderate safety significance, was identified during the inspectors' review of the licensee's ERV actuator equipment apparent cause evaluation report.

Corrective actions implemented included replacing the Unit 3 ERV actuators with hardened actuators specifically designed to withstand the increased vibrations experienced during EPU operations during refueling outage D3R23 in November 2014. In addition, the licensee inspected other main steam line components (e.g., snubbers and main steam safety valves) for indications of damage due to vibration and found no degradation. The licensee also planned to install hardened actuators the Unit 2 ERVs during D2R24 in November 2015. Historical vibration readings have been observed to be smaller on Unit 2 main steam line piping and ERV actuator components have shown significantly less wear during routine inspections. **(AV 05000249/2014005–02, Failure to Ensure Continued Operability of Unit 3 Electromatic Relief Valve 3–0203–3E Following Implementation of Extended Power Uprate Plant Conditions)**

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification:

- Unit 3 electromatic relief valve hardened actuator modification.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications was installed as directed and consistent with the design control documents; the modification operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modification did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one permanent plant modification sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

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 01562612, 3C reactor feed pump (RFP) following temperature control valve (TCV) maintenance;
- WO 01778668, following replacement of the unit 2 station blackout diesel generator 2301A governor;
- WO 01597667, Dresden 3 Technical Specification HPCI Low Pressure System Operability Verification;
- WO 01763514, Unit 3 standby liquid control following planned maintenance window; and
- WO 01794188, 2/3 diesel fire pump following cooling water line replacement.

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 TSs, 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

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 3 refueling outage (RFO) D3R23, conducted between November 2, 2014 and

November 18, 2014, 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:

- 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;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- 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; and
- licensee identification and resolution of problems related to RFO activities.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

Failure to Maintain Configuration Control in the Unit 3 Containment Pressure Suppression System

Introduction: A finding of very low safety significance and associated non-cited violation of TS 5.4.1, "Procedures", was self-revealed on November 19, 2014, for the licensee's failure to maintain configuration control in the Unit 3 containment pressure suppression system. Specifically, the licensee failed to maintain the instrument air stop valve to the actuator for Unit 3 torus vent 3–1601–60 open with the reactor in the Start-up and Run Mode following refueling outage D3R23.

Description: On November 19, 2014 at 1124, while performing DOP 1600–05, "Primary Containment Inerting and Atmosphere Control," on Unit 3, the licensee was unable to open torus vent valve 3–1601–60 from the main control room in accordance with the procedure. With the reactor mode switch in Run (Mode 1) and reactor power approximately 15 percent RTP, the licensee was attempting to inert the primary containment atmosphere with nitrogen gas in the torus and drywell in compliance with Technical Specification 3.6.3.1 which requires primary containment oxygen concentration to be below 4 volume percent within 24 hours of achieving 15 percent RTP during start-up. In addition, this condition would have prevented operators from remotely performing actions to emergency vent the primary containment using the torus main vent line in accordance with Dresden Emergency Operating Procedure DEOP 0500–04, "Containment Venting" if accident conditions were to have existed and would have required operators to respond.

With the torus vent valve unable to be operated from the main control room, an equipment operator was dispatched to the valve to investigate. The operator immediately identified that the instrument air stop valve to the valve actuator was in the closed position, and after receiving permission the equipment operator repositioned the stop valve to the open position. Once this was accomplished, the licensee was able to complete DOP 1600–05 and establish the required atmosphere in the primary containment per TS 3.6.3.1. In addition, the licensee is performing an apparent cause evaluation.

On November 12, 2014, the licensee performed TS required surveillance procedure DOS 1600–28, "Air Operated Valve Fail Safe and Accumulator Integrity Test" on torus vent valve 3–1601–60. This surveillance ensures that the torus vent valve will return to its fail-safe condition (closed) as a primary containment isolation valve in accordance with Technical Specification 3.6.1.3 upon a loss of instrument air to the valve's actuator. In order to simulate a loss of instrument air to the valve's actuator, the instrument air stop valve is closed and a fitting downstream of the stop valve is opened to bleed off air pressure to the vent valve actuator. The inspectors reviewed the licensee's as left testing of the 3–1601–60 following this surveillance and verified that the torus vent valve was successfully opened from the main control room which would indicate that the instrument air stop valve was correctly returned to its open position. The licensee's Prompt Investigation of this event identified that a local leak rate test was performed on the 3–1601–60 valve on November 16, 2014 which did not require operation of the instrument air stop valve but would have placed workers in its immediate vicinity and as such is considered the most likely opportunity for inadvertent bumping of the stop valve handle to the closed position.

The licensee commenced reactor start-up at 0232 on November 18, 2014 requiring the primary containment to be operable in accordance with Technical Specifications and reactor pressure was raised above 0 psig at 0830 on November 18, 2014 which created the conditions necessary for a loss of coolant accident to potentially require operators to vent the primary containment in order to prevent exceeding a containment design specification under certain accident conditions.

Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Section 4 of Appendix A to Regulatory Guide 1.33 lists procedures for performing Startup, Operation, and Shutdown of Safety-Related BWR Systems in particular with regards to containment integrity and containment ventilation operations. Procedure DOP 1600–M1/E1, "Pressure

Suppression System Checklist," Step 165, states, that the Unit 3 instrument air supply valve to Air Operated Valve 3–1601–60 shall be open. Procedure DOP 1600–05, "Primary Containment Inerting and Atmosphere Control," Step D.1, states, in part, that the Pressure Suppression System Checklist, DOP 1600–M1/E1 is complete. Emergency Operating Procedure DEOP 0500–04, "Containment Venting," Step D.3, states in part, that instrument air shall be available to supply motive force to operate vent valves. With reactor start-up in progress and containment integrity required, the failure to maintain configuration control of the instrument air stop valve to the torus vent valve actuator adversely affected the licensee's ability to implement each of these procedures.

Analysis: The inspectors determined that the licensee's failure to maintain configuration control of the Unit 3 containment pressure suppression system was contrary to procedures for the emergency depressurization of containment as well maintaining TS required atmospheric conditions inside the primary containment with the reactor in Mode 1 and was a performance deficiency. Specifically, the licensee failed to maintain the instrument air stop valve to the actuator for Unit 3 torus vent 3–1601–60 open with the reactor in the start-up mode following refueling outage D3R23.

The inspectors determined that the performance deficiency was more than minor, and thus a finding, in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the barrier integrity cornerstone attribute of configuration control in how containment design parameters are maintained while affecting the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, with the instrument air stop valve out of the required open position, torus hardened vent valve 3–1601–60 was unable to be remotely repositioned open while establishing inert containment conditions during a reactor start-up. In addition, this condition would have prevented the main torus vent valve from being operable from the main control room during an accident scenario with operators attempting to protect the primary containment from over pressurization.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, Table 2 the inspectors determined the finding affected the Barrier Integrity cornerstone. The inspectors determined the finding could be evaluated using Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 3, Section B, Reactor Containment, dated June 19, 2012. In Exhibit 3, the inspectors answered "No" to all of the screening questions, and therefore the inspectors determined that the finding was of very low safety significance (Green).

The finding has a cross-cutting aspect of conservative bias in the area of Human Performance because the licensee did not implement appropriate robust barriers to prevent bumping of the 3–1601–60SV in response to corrective action 511878–02. Specifically, the licensee previously evaluated 3–1601–60SV and non-conservatively determined that this particular valve did not require a seal to prevent inadvertent operation. [H.14]

Enforcement: Technical Specification Section 5.4.1.a states, in part, that "written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978." NRC Regulatory Guide 1.33, Appendix A, Section 4 addresses

"Procedures for Startup, Operation, and Shutdown of Safety-Related BWR Systems." Procedure DOP 1600–M1/E1, "Pressure Suppression System Checklist," Step 165, states, that the Unit 3 instrument air supply valve to Air Operated Valve 3–1601–60 shall be open. Procedure DOP 1600–05, "Primary Containment Inerting and Atmosphere Control," Step D.1, states, in part, that the Pressure Suppression System Checklist, DOP 1600–M1/E1 is complete. Emergency Operating Procedure DEOP 0500–04, "Containment Venting," Step D.3, states in part, that instrument air shall be available to supply motive force to operate vent valves.

Contrary to the above, between November 12 and November 19, 2014, the licensee failed to implement Step 165 of procedure DOP 1600–M1/E1 and as such Steps D.1 and D.3 of procedures DOP 1600–05 and DEOP 0500–04, respectively. Specifically, the licensee failed to maintain the instrument air stop valve to the torus vent valve in the open position, thereby preventing remote operation of the torus hardened vent line from the main control room.

This violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy because it was of very low safety significance and was entered into the licensee's Corrective Action Program as IR 2414608. The licensee's immediate corrective action was to open the instrument air stop valve to 3–1601–60. The licensee is performing an Apparent Cause Evaluation for this event and has a corrective action tracking item to report the results of this evaluation to all site personnel. **(NCV 05000249/2014005–03, Failure to Maintain Configuration Control in the Unit 3 Containment Pressure Suppression System)**

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:

- DOS 7000–01, "Local Leak Rate Testing of Main Steam Isolation Valves (Dry Tests)," Revision 07 (Containment isolation valve);
- DOS 6600–08, "Diesel Generator Cooling Water Pump Quarterly and Comprehensive/Preservice Test for Operational Readiness and In-Service Test Program," Revision 58 (Routine);
- DOS 6600–04, "Division II Bus Under voltage and ECCS Integrated Functional Test for Unit 3 Diesel Generator," Revision 46 (Routine);
- DOS 0300–15, "Control Rod Drive Scram Timing Test During Hydrostatic Test," Revision 18 (Routine); and
- DIS 0500–02, "Reactor Vessel low Water Level Scram and Low Low Water Level Isolation Master Trip Unit/Slave Trip Unit Channel Calibration and Functional Test," Revision 46 (Routine).

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, 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 four routine surveillance testing samples and one containment isolation valve samples as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

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

a. Inspection Scope

The regional inspectors performed an in-office review of the latest revisions to the Emergency Plan, Emergency Plan Annex, and Emergency Plan Implementing Procedures as listed in the Attachment to this report.

The licensee transmitted the Emergency Plan and Emergency Action Level revisions to the NRC pursuant to the requirements of 10 CFR Part 50, Appendix E, Section V, “Implementing Procedures.” The NRC review was not documented in a safety evaluation report and did not constitute approval of licensee-generated changes; therefore, this revision is subject to future inspection. The specific documents reviewed during this inspection are listed in the Attachment to this report.

This Emergency Action Level and Emergency Plan Change inspection constituted one sample as defined in IP 71114.04–06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstones: Public Radiation Safety and Occupational Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

The inspection activities supplement those documented in Inspection Report 05000237/05000249/2014003 and constitute one complete sample as defined in IP 71124.01–05.

.1 Radiological Hazard Assessment (02.02)

a. Inspection Scope

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

- RWP–10015985; D3R23 Reactor Building Internals Maintenance Activities Including Torus Diving and Desludging Activities;
- RWP–10015963; Drywell Control Rod Drives System Maintenance Activities; and
- RWP–10016007; Refuel Floor In-vessel Visual Inspection Activities.

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

- identification of hot particles;
- the presence of alpha emitters;
- the potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials (This evaluation may include licensee planned entry into non-routinely entered areas subject to previous contamination from failed fuel.);
- the hazards associated with work activities that could suddenly and severely increase radiological conditions and that the licensee has established a means to inform workers of changes that could significantly impact their occupational dose; and

- severe radiation field dose gradients that can result in non-uniform exposures of the body.

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

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors selected various containers holding non-exempt licensed radioactive materials that may cause unplanned or inadvertent exposure of workers, and assessed whether the containers were labeled and controlled in accordance with 10 CFR 20.1904, "Labeling Containers," or met the requirements of 10 CFR 20.1905(g), "Exemptions To Labeling Requirements".

The inspectors reviewed the following radiation work permits used to access high radiation areas and evaluated the specified work control instructions or control barriers:

- RWP–10015996; D3R23 Hotwell Maintenance Activities and Associated as-low-as reasonably-achievable (ALARA) Plant Activities;
- RWP–10015985; D3R23 Reactor Building Internals Maintenance Activities Including Torus Diving and Desludging Activities;
- RWP–10015963; Drywell Control Rod Drives System Maintenance Activities; and
- RWP–10016007; Refuel Floor In-vessel Visual Inspection Activities

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

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

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

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

The inspectors evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

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

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

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

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials (i.e., nonfuel) stored within spent fuel and other storage pools. The inspectors assessed whether appropriate controls (i.e., administrative and physical controls) were in place to preclude inadvertent removal of these materials from the pool.

The inspectors examined the posting and physical controls for selected high radiation areas and very-high radiation areas to verify conformance with the occupational performance indicator.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors evaluated licensee controls for very-high radiation areas and areas with the potential to become a very-high radiation areas to ensure that an individual was not able to gain unauthorized access to the very-high radiation areas.

b. Findings

No findings were identified.

.6 Radiation Worker Performance (02.07)

a. Inspection Scope

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

b. Findings

No findings were identified.

.7 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

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

b. Findings

No findings were identified.

.8 Problem Identification and Resolution (02.09)

a. Inspection Scope

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

b. Findings

No findings were identified.

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

The inspection activities supplement those documented in Inspection Report 05000237(249)/2014003 and constitute a partial sample as defined in IP 71124.02–05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the site-specific trends in collective exposures and source term measurements.

The inspectors reviewed site-specific procedures associated with maintaining occupational exposures ALARA, which included a review of processes used to estimate and track exposures from specific work activities.

b. Findings

No findings were identified.

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

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Radiation Worker Performance (02.05)

a. Inspection Scope

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

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator (MS05) for Dresden Nuclear Power Station Units 2 and 3 covering the period from the second quarter 2013 through third quarter 2014. To determine the accuracy of the performance indicator (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 7, dated August 31, 2013, and NUREG–1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance, were used. The inspectors reviewed the licensee’s operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, event reports and NRC Integrated Inspection Reports for the period of April 2013 through September 2014 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two safety system functional failures samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage performance indicator (BI02) for Dresden Nuclear Power Station Units 2 and 3 covering the period from the fourth quarter 2013 through third quarter 2014. 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 7, dated August 2013, were used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports and NRC Integrated Inspection Reports for the period of October 2013 through September 2014 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.3 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the radiological effluent TS/Offsite Dose Calculation Manual radiological effluent occurrences Performance Indicator (PR01) for the period from the first quarter 2013 through the second quarter 2014. The inspectors used Performance Indicator definitions and guidance contained in the Nuclear Energy Institute Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, to determine the accuracy of the Performance Indicator data reported during those periods. The inspectors reviewed the licensee's issue report database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one Radiological Effluent Technical Specification/Offsite Dose Calculation Manual radiological effluent occurrences sample as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of July 2014 through December 2014, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

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

.1 (Closed) Licensee Event Report 05000237/2014–003–02; "Unit 2 Reactor Scram During Automatic Voltage Regulator Channel Transfer"

On May 3, 2014 at 1209, the licensee received a unit 2 reactor scram due to a main generator trip during a planned automatic voltage regulator (AVR) channel swap. Operators immediately ensured the plant was in a safe hot shutdown (Mode 3) condition. All plant equipment subsequently operated as expected.

On April 29, 2014, the licensee noted a voltage transient on the output of Unit 2. Subsequent troubleshooting identified the AVR, which was selected to controlling channel 2, was operating with an erratic output. The licensee determined that channel 2 was failed but swapping to channel 1 would result in a trip as the erratic output of the defective channel resulted in a large difference between the channels. The licensee brought the vendor, ABB, into the troubleshooting and recovery process, having the vendor develop a procedure for swapping the AVR off of the defective channel 2. The licensee's root cause report (RCR 1655458, Dresden D2F54 Mid-Cycle Forced Outage due to Automatic Voltage Regulator Failure) after the reactor scram, identified that a failed fuse in controlling channel 2 was responsible for the voltage transient on April 29, 2014 and the inability of the AVR to respond to changes in generator output. The RCR also noted that the failed channel swap was due to an inadequate vendor developed procedure which did not account for a summing logic feedback loop. The AVR internals design, which was considered proprietary, was not shared with the licensee, therefore preventing them from identifying the missed feedback loop when reviewing the channel swap procedure. In this instance though, the failed controlling channel and the inability to swap to the functioning channel 1 without experiencing an unacceptable perturbation on the generator output prevented the licensee from avoiding a generator load reject scram. Subsequent to this event, the licensee developed new protocols for information sharing with vendors to reduce their reliance on vendor guidance and direction during the testing, installation and troubleshooting of complex structures, systems, and components. This greater information sharing was directly observed by the inspectors during troubleshooting of a failed potential transformer not associated with but affecting inputs to the AVR during August and September 2014.

This event was reported in accordance with 10 CFR 50.73(a)(2)(iv)(A), as any event or condition that resulted in manual or automatic actuation of the reactor protection system.

The inspectors reviewed and closed the original event report in Dresden NRC Integrated Inspection Report 2014003 and the first supplemental LER in Integrated Inspection Report 2014004. Documents reviewed are listed in the Attachment to this report. No findings or violations of NRC requirements were identified.

This licensee event report (LER) is closed.

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

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 6, 2015, the inspectors presented the inspection results to Mr. S. Marik, 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. Additionally on January 16, 2015, the inspectors presented the preliminary determination results of the significance of the ERV issue (Section 1R15) to Mr. S. Marik. This issue had been addressed during the January 6 exit as an issue of concern.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the areas of radiological hazard assessment and exposure controls; occupational ALARA planning and controls; and RETS/ODCM radiological effluent occurrences performance indicator verification with Mr. S. Marik, Site Vice President, on November 7, 2014.
- The results of the inservice inspection with Mr. J. Washko on November 10, 2014
- The annual review of Emergency Action Level and Emergency Plan changes with the licensee's Emergency Preparedness Coordinator, Mr. D. Doggett, via telephone on December 3, 2014.

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

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Marik, Site Vice President
J. Washko, Station Plant Manager
D. Anthony, NDES Manager
L. Antos, Security Manager
G. Baxa, Regulatory Assurance
J. Biegelson, Engineering
H. Bush, Radiation Protection
P. Chambers, Dresden Licensed Operator Requalification Training Lead
P. DiGiovanna, Training Director
P. DiSalvo, GL 89–13 Program Owner
H. Do, Engineering Manager
D. Doggett, Emergency Preparedness Manager
B. Franzen, Regulatory Assurance Manager
D. Glick, Radioactive Material Shipping Specialist
F. Gogliotti, Director, Site Engineering
G. Graff, Nuclear Oversight Manager
M. Hosain, Site EQ Engineer
J. Humenik, Manager Maintenance Planning
M. Jesse, Corporate Regulatory Assurance Manager
R. Johnson, Chemistry
B. Kapellas, Maintenance Director
D. Ketchledge, Engineering
M. Knott, Instrument Maintenance Manager
J. Kish, ISI Programs Engineering
S. Kvasnicka, Site NDE Level III
T. Leffler, Senior Staff Engineer, Dresden Engineering
S. Matzke, Senior Emergency Preparedness Specialist
G. Morrow, Operations Director
P. O'Brien, Regulatory Assurance—Corrective Action Program Coordinator
M. Overstreet, Radiation Protection Manager
W. Painter, Radiological Engineering Manager
T. Palanyk, Manager Operations Support
M. Pavey, Radiation Protection Manager
P. Prater, Manager Operations Training
E. Rogers, NOS Lead Assessor
D. Schiavoni, Engineering
R. Schmidt, Chemistry Manager
J. Sipek, Work Control Director
R. Stachniak, Engineering
R. Sisk, Buried Pipe Program Owner
D. Walker, Regulatory Assurance—NRC Coordinator
P. Wojtkiewicz, Senior Manager Site Engineering

Nuclear Regulatory Commission

A. Boland, Director, Division of Reactor Projects
J. Cameron, Chief, Division of Reactor Projects, Branch 4

IEMA

M. Porfirio, Resident Inspector, Illinois Emergency Management Agency

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000249/2014005–01	NCV	Unit 3A LPCI Heat Exchanger Supports Returned to Service with Unacceptable Indications (1R08)
05000249/2014005–02	AV	Failure to Ensure Continued Operability of Unit 3 Electromatic Relief Valve 3–0203–3E Following Implementation of Extended Power Uprate Plant Conditions (1R15)
05000249/2014005–03	NCV	Failure to Maintain Configuration Control in the Unit 3 Containment Pressure Suppression System (1R20)

Closed

05000249/2014005–01	NCV	Unit 3A LPCI Heat Exchanger Supports Returned to Service with Unacceptable Indications (1R08)
05000249/2014005–03	NCV	Failure to Maintain Configuration Control in the Unit 3 Containment Pressure Suppression System (1R20)
05000237/2014–003–02	LER	Unit 2 Reactor Scram During Automatic Voltage Regulator Channel Transfer

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.

1R01 Adverse Weather Protection (71111.01)

- IR 2389944, “Potential Missile Hazards Identified”
- IR 2395997, “NOS ID: Winter Readiness Meeting Observation”
- IR 2404998, “2B Recombiner Room Heating Coil Leaks”
- IR 2405124, “ 2A Recombiner Supply Fan Failed to Trip”
- IR 2410428, “NOS ID: MCCS 20-1 and 30-1 Cross-tied During Low Temperature”
- IR 2412850, “Unit 1 Cold Weather DOS 0010-19 Revision Needed”
- IR 2415653, “Insulation Missing From Piping”
- IR 2416427, “When Try to Adjust Switch it Grinds”
- IR 2417755, “NRC Identified Issues with DOS 0010-25”
- IR 2417779, “NRC Questions on Winter Readiness Prep Work Orders”
- IR 1183582, “Excessive Noise Vibration”
- WO 1695075, “D3 AN COM Preparation for Cold Weather For Unit 3”
- WO 1716914, “D2 AN COM Preparation for Cold Weather for Unit 2”
- WO 0360751, “Excessive Noise Vibration”
- WO 0358349, “Subcooler Fan Vibrating”
- WO 1409114, “Subcooler Fan Vibrating”
- WO 0481365, “Insulation Missing From Piping”
- WO 0479144, “2A Recombiner Supply Fan Failed to Trip”
- WO 0479347, “2B Recombiner Room Heating Coil Leaks”
- DOA 5700-01, “Loss of Heating Boilers,” Revision 16
- DOP 5750-02, “Reactor Building Ventilation,” Revision 42
- DOP 4400-07, “Circulating Water De-Icing Operation,” Revision 14
- DOS 0010-25, “Preparation for Cold Weather operations for Unit 3,” Revision 21
- DOS 0010-22, “Preparation for Col Weather Operations for Unit 2,” Revision 23
- OP-AA-108-111, Attachment 1, “Adverse Condition Monitoring and Contingency Plan,” Revision 9, for U2 Main Generator Megawatt Spikes
- Memorandum dated November 10, 2014 from S. Marik to T. Hanley, Subject: Certification of 2014-2015 Winter Readiness

1R04 Equipment Alignment (71111.04)

- WO 1704363, “D3 Pre/Rfl Disable Pump Trips for FPC Pumps/Enable Post/Rfl
- IR 2416845, “Wiring Discrepancy on 12E-2830E Found During DOP 1900-16”
- EC 416945, Wiring Discrepancy on Drawing 12E-2830E”
- DOP 1900-16, “Disable Fuel Pool Cooling Pump Trips,” Revision 01
- IR 2406638, “NRC Identified Excessive Amount of Grease on MOV Motor Casing”
- DIS 1600-10, “PT 2(3)-1625 Transmitter Loop Calibration,” Revision 26
- DIS 1600-10, “PT 2(3)-1625 Transmitter Loop Calibration,” Revision 27
- WO 1411686, “Relocate PT 3-1624 and PT 3-1625 Drywell Pressure Transmitter”
- Design Attribute Review (DAR) for Engineering Change 383319, Revision 000, “Relocate the U3 PT 3-1624 and 3-1625 Drywell Pressure Transmitters”

- Work Planning Instructions for EC 383319, Rev. 000, “Relocate the U3 Drywell Pressure Transmitters PT 3-1624 and 3-1625”
- IR 1135870, “Press Xmitters 2(3)-1625 and 2(3)-1624 are not Properly Inst”
- AR 1135870-04, “Revise DIS 1600-10 Per the Attached Mark up”
- <u>Drawings</u>:
- 12E-3493, Schematic Diagram – Process Instrumentation – RX Temperature Monitoring, N2 Inerting Sys Vessel Process and Pressure Suppression
- 12E-3771D, Wiring Diagram Instrument Rack 2203-7 Section D Jet Pump Recirc. System
- 12E-3771A. Wiring Diagram Instrument Rack 2.203-7 Section A Jet Pump Recirc. System
- 12E-3751, Wiring Diagram Process Instrumentation Panel 903-19

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

- Pre-Fire Plan, Fire Zone 8.2.5D, Revision 1
- Pre-Fire Plan, Fire Zone 8.2.5E, Revision 1
- Pre-Fire Plan, Fire Zone 8.2.6D, Revision 1
- Pre-Fire Plan, Fire Zone 9.0A, Revision 3
- Fire Load Calculation Sheet, No. DRE97-0105, Revision 09, Amendment 18

<u>1R06 Flooding</u> (71111.06)

- WO# 1663814, “D3 AN TS CDSR Pit Hi/Hi Water Level Switch Func Check”
- DIS 4400-01, “Condenser Pit High and High-High Water Level Switch Functional Check,” Revision 18

<u>1R07 Annual Heat Sink Performance</u> (71111.07)

- ER-AA-340-1002, “Service Water Heat Exchanger inspection Guide,” Revision 6
- DMP 1500-03, “Containment Cooling (LPCI) Heat Exchanger Maintenance,” Revision 32
- WO 1407044, “D3 RFL Com Clean/Insp/Hydro/Eddy Current ‘B’ LPCI HX”

<u>1R08 Inservice Inspection Activities</u> (71111.08G)

- NDE Report No. 13-093, Magnetic Particle Examination of Unit 3 LPCI HX Support 3A Welds, May 22, 2013
- IR 01585328, Re-Visit Corrective Action on LPCI System, November 14, 2013
- IR 01638395, Plan to Determine Crack Propagation Rates in LPCI HX Support, March 25, 2014
- IR 01662025, PHC Deliberates on Cracked Welds in LPCI HX Supports, May 20, 2014
- IR 02408070, Clarification to AR 2407379, November 6, 2014
- IR 02407379, NRC Concern: LPCI HX Weld Indication, November 5, 2014
- IR 02406800, Unacceptable Indications HPCI Control Valve Chest Spare Cover, November 5, 2014
- Engineering Change Evaluation No. 345249, Assess Capacity of Upper Support of 2A LPCI HX With Missing Section of Attachment Weld
- NDE Report No. 14-129, Magnetic Particle Examination for Unit 3 FW Check Valve Seat Ring 3-0220-58A, July 8, 2014
- NDE Report No. 14-202, Liquid Dye Penetrant Examination for Unit 3 FW Check Valve Seat Ring 3-0220-58B, September 16, 2014
- NDE Report No. D3R23-UT-009, Ultrasonic Examination of Shutdown Cooling Pipe Weld SDA-04F, November 5, 2014

- NDE Report No. D3R23-GEH-012, Ultrasonic Examination of RPV Shell to ISO Condenser Nozzle Weld N5B-1, November 6, 2014
- NDE Procedure ER-AA-335-003, Magnetic Particle Examination, Revision 6
- Engineering Evaluation 0000393467, Evaluation of Wall Thinning of 3C and 3D CCSW Vault Cooler Header, April 26, 2013
- IR 01513772, Pin Hole Leak Identified on Unit 3 CCSW DIV II Piping, May 14, 2013
- IR 01559946, Repair Wall Thinning in 3C CCSW Vault Cooler Header, September 17, 2013
- IR 01559950, Repair Wall Thinning in 3D CCSW Vault Cooler Header, September 17, 2013
- NDE Procedure, GEH-UT-311, Procedure for Manual Ultrasonic Examination of Nozzle Inner Radius, Bore and Selected Nozzle to Vessel Regions, Revision 19
- Work Order No. 01642082, Repair Pin Hole Leak Identified on Unit CCSW DIV II Piping, dated May 16, 2013

<u>1R11 Licensed Operator Requalification Program</u> (71111.11)

- DGP 03-01, "Power Changes," Revision 128
- DGP 03-04, "Control Rod Movements," Revision 71

<u>1R12 Maintenance Effectiveness</u> (71111.12)

- Engineering Change (EC) 383671, "Evaluation of MOV Actuators 3-1001-1A and 3-1001-1B for Elevated Ambient Temperature of 151°F," Revision 0
- WO 647053-01, "IM D3 8Y PM&C SDC Pump B Suction Pressure Switch"
- IR 1439716, "D3R22LL Improper Test EQOT Specified for SDC Flow Measurements"
- IR 1444368, "Borescope Inspection Showed Cracked Coating"
- IR 1444424, "3C SDC Pump made Available for Shutdown Safety"
- IR 1448060, "FME: Gasket Coming Apart in Rotating Spectacle Flanges"
- IR 1459432, "CA's 987500-21/22 Not Fully Implemented"
- IR 1466314, "MRC Decision: CAS 987500-21(22)"
- IR 1472144, "Calculation DRE96-0073 Not Revised for New Stem Material"
- IR 1494273, "Broken Wire Found on Potentiometer of 3-1001-4B"
- IR 1525007, "U3 DW Temp Monitoring Shows EQ Limit Exceeded for SDC MOV"
- IR 1574072, "3-1001-24B Could Not Be Opened"
- IR 1579397, "Unavailability Review for U3 B SDC Train"
- IR 1599492, "Pressure Gage Broken for 3B SDC Pump"
- IR 2059932, "U3 Maintenance Rule Function 10-4 IS (A)(2) at Risk"
- IR 1672800, "Pressure Switch Found O.O.T. Unable to Calibrate"
- IR 2392600, "U3 DW Temp Monitoring Shows EQ Limit Exceeded for 1B SDC MOV"
- IR 1695472, "3B SDC Pump Did Not Start"
- IR 1614724, "Reactor Recirculation and ASD Systems MRule (A)(2) at Risk"
- IR 1679382, "Unavailability Accruing for MR Functions 14-4 & 15-10"
- IR 1620462, "Braidwood OPEX Potential Applicability (NER BW-14-004)"
- IR 1692932, "Action for Maint Rule Function Review Repeated Extensions"
- IR 1649632, "Adverse Trend LPRM"
- IR 1603434, "U3 Maintenance Rule Function Z0702-1 is (A)(2) at Risk"
- IR 1487752, "Maintenance Rule Function Z89-1 Needs (A)(1) Determination"
- WO 1763891, "3B SDC Did Not Start"
- Maintenance Rule Expert Panel Meeting Notes, "A1AP PCIV to Provide Primary Containment Boundary," March 10, 2014
- <u>Drawings</u>:
- M-363, Diagram of Shutdown Reactor Cooling Piping

- 12E-3517, Schematic Diagram Reactor Shutdown Cooling System Pump Control Circuits
- M-494, Instrument Installation Details

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

- OU-AA-103, "Shutdown Safety Management Program," Revision 15
- OU-OR-104, "Shutdown Safety Management Program," Revision 19
- WO 1200781-01, "Replace Relief Valve 3-1299-69"
- Secondary Containment Restoration Contingency Plan for WO 1200781-01
- DAP 07-44, "Control of Temporary Openings in Secondary Containment During Performance of Work packages, Surveillances, or Other Procedures," Revision 14
- IR 2415222, "NRC Questioned PPW"
- Protected Equipment List for U3 Div II LPCI
- Protected Equipment List for Unit 3 Isolation Condenser
- Protected Equipment List for Unit 3 Div II Core Spray
- Protected Equipment List for Unit 3 ADS [automatic depressurization system]
- Protected Equipment List for Unit 3 Div I LPCI
- Protected Equipment List for Unit 3 Div I Core Spray

1R15 Operability Determinations and Functional Assessments (71111.15)

- IR 2390640, "NRC Question From SRI"
- IR 2389466, "U2 Swing Bus Transfer Time Did Not Meet Acceptance Criteria"
- IR 1164417, "Proposed NRC Minor Violation for LPCI Swing Bus"
- IR 1122737, "Transfer of Feed to MCC38-7/39-7 From Bus 39 to Bus 38"
- Prompt Investigation, "LPCI Swing Bus Transfer Did Not Meet Acceptance Criteria"
- Apparent Cause Report (ACE) for IR 122737-01, "Low Pressure Coolant Injection Time Delay Relay Out of Tolerance Due to Ineffective Calibration Method"
- DOS 6600-07, "Testing LPCI Swing Bus Protective Relays and Auto Transfer Function," Revision 27
- IR 2392600, " U3 DW Temp Monitoring Shows EQ Limit Exceeded for 1B SDC MOV"
- IR 2412713, "3A SW Pump Did Not Trip During DOS 6700-03"
- DOS 6700-03, "Circ WTR and SW Pump Load Shed Logic Test," Revision 02
- IR 2413467, "Unit 3 CRD P04 Has High Calculated Friction Value"
- DOS 0300-16, "Fuel Channel Distortion Monitoring," Revision 17
- NF-DR-135-1000, "Channel Distortion Monitoring Data Review and Test Frequency Determination," Revision 7
- NF-AB-730, "Cell Friction Computation Results [for P04]," Revision 3, dated 11/19/2014
- Event Notice 46230, GE Hitachi Nuclear Energy, "Part 21 – Failure to Include Seismic Input in Reactor Control Blade Customer Guidance"
- SC 11-05 10 CFR Part 21 Communication, "Failure to Include Seismic Input in Channel-Control Blade Interference," Revision 2
- OP-AA-108-111. Attachment 1, "Adverse Condition Monitoring and Contingency Plan,"Revision 9, for Unit 3 Head Seal Leak Detection Pressure dated 11/25/2014
- IR 0861492, "Reactor Vessel Head Flange Leakage Results in Unit Shutdown"
- IR 2416131, "Unexpected Alarm"
- IR 199861, "RPV flange leakage alarm during hydro"
- IR 2429183, "Historical Operability Determination Assignment Extended"
- Drawings:
- 12E-2662A, Part 1, Schematic & Wiring Diagram 480V AC Reactor Building MCC 28-7 (2-7828-7)

- 12E-2662B, Part 2, Schematic & Wiring Diagram 480V AC Reactor Building MCC 28-7 (2-7828-7)
- 12E-2662D, Part 2, Schematic & Wiring Diagram 480V AC Reactor Building MCC 29-7
- 12E-2662E, Part 3, Schematic & Wiring Diagram 480V AC Reactor Building MCC 29-7
- 12E-3508, Primary Containment Isolation Sys. Shutdown Cooling System Isolation Logic
- 205LN001-01, Shutdown Cooling System
- 223LN005-006, Group 3 PCIS Shutdown Cooling Valve Control Logic
- Apparent Cause Investigation Report for: 3E ERV Failed to Actuate During D3R23, dated November 15, 2014
- AT 203507-02, "Comparison of Full Thermal Vibration data (2951 MWth) for Dresden Unit 3 to previously evaluated data (From EC 347006)"
- Letter from Structural Integrity Associates, Inc., K. Fujikawa to S. Eldridge, Lead Project Engineer, Exelon Nuclear, dated January 21, 2004, Subject: Dresden Unit 3 Main Steam Line and Component Vibration Assessment
- EC 347006, "Evaluation of Dresden Unit 3 Main Steam Line Vibrations at EPU Power Levels"
- EC 357589, "Final disposition of vibration data for Quad Cities MSL Components Units 1 & 2"
- IR 2408995, "Details Inspections Needed From 3E ERV Failure to Actuate"
- IR 2407705, "ERV Failed to Actuate During DOS 0250-07"
- IR 2413662, "MRule A1 Action Plan Revision to U3 Function 0203-1"
- IR 2413664, "MRule A1 Action Plan Revision to U3 Function 30-3"
- IR 2415209, "NRC Discussion Requested"

<u>1R18 Plant Modifications</u> (71111.18)

- IR 2410948, "Installation of New ERV Actuator Cover Bolts for Unit 3"
- WO 1661343, "Benchtest (4) Replacement ERV Solenoids"
- WO 1661343-02, Replace ERV Solenoid Valve 3-0203-3B (EC 394702)
- WO 1661343-03, Replace ERV Solenoid Valve 3-0203-3C (EC 394702)
- WO 1661343-04, Replace ERV Solenoid Valve 3-0203-3D (EC 394702)
- WO 1661343-05, Replace ERV Solenoid Valve 3-0203-3E (EC 394702)
- WO 1661343-07, "PMT ERV Solenoid Valve 3-0203-3B"
- WO 1661343-08, "PMT ERV Solenoid Valve 3-0203-3C"
- WO 1661343-09, "PMT ERV Solenoid Valve 3-0203-3D"
- WO 1661343-10, "PMT ERV Solenoid Valve 3-0203-3E"
- WO 1661343-11, "PMT ERV Solenoid Valve 3-0203-3B"
- WO 1661343-21, "SEP Acceptance of Test Results by System Manager (EC 394702)"
- WO 1700572-23, "Main Steam PMTs Required for mode 2"
- EC 394702, "Main Steam ERV Actuator Upgrade – U3," Revision 00
- DOS 0250-08, "Target Rock Safety Relief Valve Testing With the Reactor Depressurized," Revision 04
- DOS 0250-07, "Electromatic Relief Valve Testing With the Reactor Depressurized," Revision 04

<u>1R19 Post-Maintenance Testing</u> (71111.19)

- WO 1562612, "3C RFP TCV Anomaly Compared to 3A and 3B RFP TCV's"
- IR 2399169, "TIC 3-3841-31C One Point Calibration Needed"
- IR 2401953, "Re-Perform PMID 00165770-02"
- IR 2402013, "Replace U2 SBO Freq Transducer 2-6620-184"
- IR 2402028, "U2 SBO DG Starting Time Needs Re-Verified"
- IR 2402017, "U2 SBO Failed to Meet Acceptance Criteria of DOS 6620-07"

- IR 2402042, “U2 SBO Engine A Lube Oil Sump Level Low During Run”
- IR 2402044, “U2 SBO Cooldown Speed High”
- IR 2402285, “SBO Diesel Logic Discrepancies”
- IR 2414260, “Abnormal Vibration Indication on U3 HPCI Turbine Test (D3R23)”
- IR 2414258, “Improved Torque Needed on HPCI Control VLV Casing”
- IR 2414245, “Two Leaks on the Flanged Areas of HPCI Inlet Steam Piping”
- IR 2414232, “U3 HPCI Leaks Discovered During Runs per DTP 09”
- IR 2414229, “Leak Identified on the 3-2303-STPV”
- IR 2413929, “Request REV to DOS 2300-03 for Inclusion of Overspeed Test”
- DOS 2300-03, “High Pressure Coolant Injection System operability and Quarterly IST Verification Test,” Revision 105
- WO 1778668, “EM PMT U2 SBO Governor”
- WO 1763514, “D3 QTR TS 3A SBLC Pump Test for IST”
- WO 1794188, “Operations PMT 2/3 Diesel Fire Pump to Check for Leaks at System Pressure”
- DOS 1100-04, “Standby Liquid Control System Quarterly / Comprehensive Pump Test for the Inservice Testing (IST) Program”
- DFPS 4123-05, “2/3 Diesel Fire Pump Operability,” Revision 52

<u>1R20 Outage Activities</u> (71111.20)

- IR 2408231, “U3 Main Turbine LP Bearing #6 Inspection/Repair/Reset Tilt”
- IR 2409100, “1D MSIV Manifold Block Leaking Air”
- IR 2409273, “IRM 12 Spiking”
- IR 2411062, “LPRM 16-41 B”
- IR 2410671, “D3R23: FME: ECCS Suction Strainer Inspection Results”
- IR 2408805, “U3 B Channel Half Scram”
- IR 2404461, “NRC ID: Scaffold Resting on 3-1501-5B Valve Body”
- IR 2411688, Leaking by Through Relief Valve Drain Piping”
- IR 2411556, “Unexpected Water Enters U3 Main Condenser”
- IR 2411060, “LPRM 48-09C Connector Problem”
- IR 2411062, “LPRM 16-41 B”
- IR 2411065, “LPRM 48-33 D Connector Problem”
- IR 2399625, “U2 Main Turbine Trip on Unit Downpower 4.0 Critique”
- IR 2399384, “Voltage Regulator Troubleshooting Results”
- OU-DR-104, “Shutdown Safety Management Program,” Revision 19
- OU-AA-103, “Shutdown Safety Contingency Plan,” Revision 14
- DOP 0201-04, “Operations with the Potential to Drain the Reactor Vessel,” Revision 12
- DOS 1000-02, “Alternate Decay heat Removal using Shutdown Cooling and Fuel Pool Cooling,” Revision 18
- DOP 1000-09, “Bypassing Shutdown Cooling Isolation,” Revision 00
- Core Operating Limits Report for Dresden Unit 3 Cycle 24, Revision 0
- IR 2413963, “U3 IRM 18 Bypassed Due to Erratic Recorder Indication”
- IR 2413522, “D3R23: FME Drywell Closeout Inspection by NRC”
- IR 2413374, “North Center, South Center, Southwest Waterboxes leaking”
- IR 2413098, “U3 X-Area INTLK Doors INOP/BYP Did Not Clear”
- IR 2413429, “IR Written For Oil Addition to 3B RR Pump Motor Lower Bearing”
- IR 2413426, “Perform Monthly ACMP Readings on the Unit 3 Exciter Bearing”
- IR 2413416, “Perform Post D3R23 ACMP Readings on the U3 Exciter Bearings”
- IR 2413317, “Bad Flows”
- IR 2413109, “U3 Alterex Bearing #12 is Grounded”
- IR 2412921, “D3R23 LLRT Complete with 3 Components Leaking > Admin Limit”

- IR 2412918, “NOS ID: D3R23 Drywell Walkdown Items”
- MA-AA-716-008-1008, “Reactor Services, Refuel Floor FME Plan,” Revision 9
- OP-AA-106-101-1006, Issue Resolution Documentation Form, ODM Issue, “U3 RPV Head Spray Pipe Flange Indications / Damage (IR 2406384),” Revision 14
- IR 2406384, “D3R23LL: U3 PRV Head Spray Pipe Flange Indications / Damage”
- WO 1595080, “TESCO Machine Surface to Remove Groove Indications”
- DEOP 0500-04, “Containment Venting,” Revision 15
- IR 24104608, “3-1601-60 Failed to Operate From MCR”
- DOS 1600-28, “Air Operated Valve Fail Safe and Accumulator Integrity Test,” Revision 17
- DOP 1600-05, “Primary Containment Inerting and Atmosphere Control”
- DOA 1600-09, “Emergency Venting,” Revision 06
- DOP 1600-M1/E1, “Unit 3 Pressure Suppression System Checklist,” Revision 28
- NRC Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operations),” Revision 2
- Dresden Configuration Control Alert for IR 2414608, “3-1601-60 Failed to Operate From MCR”
- DAN 902(3)-5 E-5, “Group 2 Isolation Initiated,” Revision 33
- DAN 902(3)-3 F-3, “VLV 1601-23/24 1601-60-60 Group 2 Override,” Revision 4
- DOA 4700-01, “Instrument Air System Failure,” Revision 47
- Computer Setpoint Value F136, Torus Vent Valve 1601-60, Start Time 11/12/2014 11:00:00, End Time: 11/12/2014 12:00:00

<u>1R22 Surveillance Testing</u> (71111.22)

- DOS 7000-01, “Local Leak Rate Testing of Main Steam Isolation Valves (Dry Tests),” Revision 07
- WO 1592123, “D3 30M/RFL TS LLRT MSIV 203-1B & 203-2B Dry Test”
- WO 1592124, “D3 30M/RFL TS LLRT MSIV 203-1A & 203-2A Dry Test”
- WO 1592125, “D3 30M/RFL LLRT MSIV 203-1D & 203-2D Dry Test”
- WO 1592128, “D3 30M/RFL TS LLRT MSIV 203-2A West Test”
- IR 2407046, “Use of IM Technicians for MCR Manipulation Peer Checks”
- IR 2406387, “D3R23 LLRT on 0203-1A Exceeded Tech Spec Limit of <34 SCFH”
- IR 2406385, “D3R23 LLRT on 203-1D Exceeded Tech Spec Limit of <34 SCFH”
- DOS 6600-08, “Diesel Generator Cooling Water Pump Quarterly and Comprehensive/Preservice Test for Operational Readiness and In-Service Test Program,” Revision 58
- WO 1767875, “D2/3 45D TS Diesel Generator Cooling Water Pump Test for IST Program Surveillance”
- IR 1660862, “2/3 Diesel Generator Cooling Water Pump Post Maintenance Test”
- IR 1655191, “2/3 DGCWP Vibrations Found in Alert Range During DOS 6600-08”
- IR 2396775, “NRC Identified Spalled Concrete on Unit 2/3 EDG Pump Foundation”
- MA-AA-716-230-1002, “Vibration Analysis / Acceptance Guideline,” Revision 2
- DOC 6600-04, “Bus Under voltage and ECCS Integrated Functional Test for Unit 3 Diesel Generator,” Revision 46
- IR 2410517, “U3 Swing Bus relay Requires CAL Prior to D3R23 Startup”
- IR 2411305, “D3R23 LL: U2 and U3 Division 1 UV Testing Procedure”
- WO 1597351, “D3 24M/ RFL TS Bus 34-1 UV and ECCS Integrated Func Test”
- WO 1599619, “D3 Post/ Refuel TS Perf 100% CRD Test Refuel Outage Before 40% Power”
- WO 1700575, “D3R23 PMTS for CRD System”
- IR 2413401, “U3 CRD H-04 Difficult to Unlatch, Move out”
- IR 2413402, “U3 CRD D-11 Difficult to Unlatch”
- IR 2403406, “U3 CRD RPIS Issue on CRD F-15”

- IR 2412578, “CRD 30-15 (H-4) Declared Slow During Scram Timing”
- IR 2412580, “CRD 22-23 (F-6) Declared Slow During Scram Timing”
- IR 2414695, “CRD F-14 Difficult to Unlatch”
- IR 2414502, “Rod Drift Alarm”
- IR 2414491, “Rod Need Notch Timing”
- OP-DR-300-101, “Operating Limit Minimum Critical Power Ratio (OLMCPR) Determination,” Revision 1
- DOS 0300-14, “Control Rod Drive Scram Testing At Power,” Revision 38
- DOS 0300-15, “Control Rod Drive Scram Timing Test During Hydro,” Revision 18
- DOS 0300-16, “Fuel Channel Distortion Testing,” Revision 17
- DGP 03-04, Control Rod Movements,” Revision 71
- DIS 0500-02, “Reactor Vessel low Water Level Scram and Low Low Water Level Isolation MTU/STU Channel Calibration and Functional Test,” Revision 46
- WO 1766072, “D2 QTR TS Reactor Low Level Scram / Low Low Level Isolation ATS Function”
- Drawings:
- M-262 Arrangement and Details of Equipment Foundations Crib House and Heater Boiler Building
- M-241 Equipment Foundations Anchor Bolt Schedule, Sheets 1 and 2

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

- EP-AA-1000, Exelon Nuclear Standardized Radiological Emergency Plan, Revisions 24 and 25
- EP-AA-1004, Radiological Emergency Plan Annex for Dresden Station, Revisions 33 and 34
- EP-AA-110-200, Dose Assessment, Revisions 4, 5, 6, and 7
- EP-AA-110-200-F-01, Dose Assessment Input Form, Revision B
- EP-AA-110-201-F-01, On-Shift Dose Assessment Input Sheet, Revision B
- EP-AA-112-100-F-02, Shift Dose Assessor, Revision F
- EP-AA-120-F-01, Core Damage Assessment BWR, Revisions 9 and 10

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

- RP-AA-210, Dosimetry Issue, Usage, and Control, Review 23
- RP-AA-301, Radiological Air Sampler Program, Revision 8a
- RP-AA-301, Radiological Air Sampler Program; Air Sample Calculations, Revision 8
- RP-AA-302, Determination of Alpha Levels and Monitoring, Revision 5
- RP-AA-700-1246, Operation of Air Samplers, Revision 2
- RP-AA-401-1003, Contamination Control Best Practice Application, Revision 1
- RP-AA-460, Control for High and Locked High Radiation Areas, Revision 26
- RP-AA-461, Radiological Controls for Contamination Water Diving Operations, Revision 5
- TID-2008-002, TIP Dose Rate Evaluation, April 22, 2008
- RWP-10015959, D3R23 Drywell Main Steam Safety, Electromatic and Target Rock Valve Maintenance, Revision 1
- RWP-10015996, D3R23 Hotwell Maintenance Activities and Associated ALARA Plant Activities, Revision 1
- RWP-10015985, D3R23 Reactor Building Internals Maintenance Activities – Including Torus Diving and Desludging Activities, Revision 2
- RWP-10015963, Drywell Control Rod Drives System Maintenance Activities, Revision 1
- RWP-10016007, Refuel Floor In-vessel Visual Inspection Activities, Revision 1
- RWP-10015985, Initial Underwater Survey of Unit 3 Reactor Elevation 490’ Torus Proper, November 6, 2014

- IR-02405886, “General Area Safety Walkdown,” November 5, 2014
- IR-02407429, “Level 1 PCE to Performing By-pass Valve Disassembly on Elevation 591’,” November 5, 2014
- IR-02407168, “Level One PCE on Shoe,” November 5, 2014
- IR-02406214, “Doffing Issues While Performing General Walkdown,” November 4, 2014
- IR-02406255, “Radiation Protection Smart Turnstile was not Programmed Correctly,” November 4, 2014
- IR-02406986, “Contamination of Worker Right Hand Less than 1K dpm,” November 5, 2014
- IR-02408292, “NRC Observation of Refuel Floor Work of Individual Removing Camera from the Cavity,” November 6, 2014
- IR-02407965, “NRC Observed Cords Hanging Loose at CA Boundary at Unit-3 Torus,” November 6, 2014

<u>2RS2 Occupational ALARA Planning and Controls</u> (71124.02)

- CC-AA-401, Temporary Contact Shielding Permit; ALARA Plan, Revision 10
- ALARA-10015996, D3R23 Hotwell Maintenance Activities and Associated ALARA Plant Activities, Revision 1
- ALARA-10015985, D3R23 Reactor Building Internals Maintenance Activities – Including Torus Diving and Disludging Activities, Revision 2
- ALARA-10015963, Drywell Control Rod Drives System Maintenance Activities, Revision 1
- ALARA-10016007, Refuel Floor In-vessel Visual Inspection Activities, Revision 1

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

- LSAA-2150, Monthly Data Elements for RETS/ODCM Radiological Effluent Occurrences, Revision 5
- Data Elements from January 2013 through June 2014
- IR-02401911, December 20113 LS-AA-2150 Data Elements Were Not Located in the EDMS Data System, Dated October 27, 2014
- IR 2395903, “PMC-D2 Isolation Condenser level Increase”
- IR 2395050, “U2 Isolation Condenser High Level”
- EC 397055, “SSF Evaluation for Loss of Secondary Containment via Interlock Door Breach,” Revision 01
- LER 05000237/2013-004-00, “Secondary Containment Inoperable Due to Two Interlock Doors Being Open Simultaneously”
- LER 05000237/2013-003-00, “Secondary Containment Inoperable Due to Two Interlock Doors Being Open Simultaneously”
- IR 1639014, “Unexpected Alarm-Unit 2/3 Diesel generator Interlock Doors Inoperable/Bypassed”

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

- IR 1689234, “Vibration Increasing on 2C RFP Motor”
- IR 1692240, “High Vibes 3A Stator Cooling Water Pump”
- IR 1697947, “U2 ECCS Jockey Pump Elevated Vibration”
- IR 1686037, “3A CRD Pump Discharge Throttled Position”
- IR 1684809, “Trend IR – 8 DCV’s Failed Bench Test”
- IR 2428849, “NRC Communication of Observed Unit 2 Drywell Leakage”

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

- Root Cause Investigation Report, “Dresden D2F54 Mid-Cycle Force Outage Due to Automatic Voltage Regulator (AVR) Failure,” dated August 26, 2014
- IR 1655458, “U2 Reactor Scram”

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ADS	Automatic Depressurization System
ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scam
AV	Apparent Violation
AVR	Automatic Voltage Regulator
CAP	Corrective Action Program
CCDP	Conditional Core Damage Probability
CCF	Common Cause Failure
CCCG	Common Cause Component Group
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EACE	Equipment Apparent Cause Evaluation
EPU	Extended Power Uprate
ERV	Electromatic Relief Valve
ET	Eddy Current Testing
HPCI	High Pressure Coolant Injection
IF	Ignition Frequency
IMC	Inspection Manual Chapter
IORV	Inadvertent Open Relief Valve
INL	Idaho National Laboratory
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Issue Report
ISI	Inservice Inspection
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOCHS	Loss of Condenser Heat Sink
LPCI	Low Pressure Coolant Injection
MCR	Main Control Room
MFW	Main Feedwater
MT	Magnetic Particle
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PARS	Publicly Available Records System
PD	Performance Deficiency
PI	Performance Indicator
PMT	Post-Maintenance Testing
RCR	Root Cause Report
RCS	Reactor Coolant System

RFO	Refueling Outage
RFP	Reactor Feed Pump
RPV	Reactor Pressure Vessel
RTP	Rated Thermal Power
SDP	Significance Determination Process
SERP	Significance and Enforcement Review Panel
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSCs	Systems, Structures, and Components
TCV	Temperature Control Valve
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	Work Order

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Sincerely,

/RA John Giessner Acting for/

Anne T. Boland, Director
Division of Reactor Projects

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