February 12, 2008

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

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
NRC INTEGRATED INSPECTION REPORT 05000237/2007005;
05000249/2007005

Dear Mr. Pardee:

On December 31, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 15, 2008, with Mr. D. Wozniak and other members of your staff.

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

Based on these inspections, four self-revealed and one NRC identified findings of very low safety significance (Green) were identified. All of these issues involved violations of NRC requirements. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these violations as Non-Cited Violations consistent with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-001, 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 accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000237/2007005; 05000249/2007005
w/Attachment: Supplemental Information

cc w/encl:
Site Vice President - Dresden Nuclear Power Station
Plant Manager - Dresden Nuclear Power Station
Regulatory Assurance Manager – Dresden Nuclear Power Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
Manager Licensing - Clinton, Dresden, and Quad Cities
Associate General Counsel
Document Control Desk – Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer
Chairman, Illinois Commerce Commission

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

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000237/2007005; 05000249/2007005
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Dresden Nuclear Power Station
Plant Manager - Dresden Nuclear Power Station
Regulatory Assurance Manager – Dresden Nuclear Power Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
Manager Licensing - Clinton, Dresden, and Quad Cities
Associate General Counsel
Document Control Desk – Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer
Chairman, Illinois Commerce Commission

DOCUMENT NAME: G:\Dres\DRES 2007 005.doc
□ Publicly Available □ Non-Publicly Available □ Sensitive □ Non-Sensitive
To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy

OFFICE	RIII	E	RIII							
NAME	M. Ring									
DATE	2/12/08									

OFFICIAL RECORD COPY

Letter to C. Pardee from M. Ring dated February 12, 2008

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
NRC INTEGRATED INSPECTION REPORT 05000237/2007005;
05000249/2007005

DISTRIBUTION:
TEB
RAG1
CXG1
RidsNrrDirsIrib
MAS
KGO
JKH3
CJP3
CAA1
LSL (electronic IR's only)
C. Pederson, DRP (hard copy - IR's only)
DRPIII
DRSIII
PLB1
TXN
ROPreports@nrc.gov (inspection reports, final SDP letters, any letter with an IR number)

TABLE OF CONTENTS

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249
License Nos:	DPR-19; DPR-25
Report No:	05000237/2007005; 05000249/2007005
Licensee:	Exelon Generation Company
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	Morris, IL 60450
Dates:	October 1 through December 31, 2007
Inspectors:	C. Phillips, Senior Resident Inspector M. Sheikh, Resident Inspector D. Meléndez, Resident Inspector J. Jandovitz, Reactor Engineer R. Jickling, Senior Emergency Preparedness Analyst K. Conway, General Engineer B. Cushman, Reactor Engineer W. Slawinski, Senior Health Physics Inspector
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Project

SUMMARY OF FINDINGS

IR 05000237/2007005, 05000249/2007005; 10/01/2007 - 12/31/2007, Dresden Nuclear Power Station, Units 2 and 3; Maintenance Effectiveness, Operability Evaluations, Routine Baseline Radiation Protection Inspection, and Event Follow-up.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a performance deficiency involving a non-cited violation of 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," Section (a) (1), for the failure to take appropriate corrective action to mitigate excessive system unavailability of the Auxiliary Electric Equipment Room (AEER) ventilation system. The AEER heating, ventilation, and air conditioning (HVAC) system is designed to ensure adequate cooling to the AEER which contains several safety-related systems, such as low voltage buses that provide power to mitigating systems. The Unit 2 and Unit 3 AEER ventilation systems have been classified 10 CFR 50.65 (a)(1) since the fourth quarter of 2005 with an established performance goal of no functional failures. Corrective actions to clean the condensing units before the onset of warm weather and cottonwood fuzz season were inappropriately rescheduled to mid-July. As a result, the AEER ventilation system air conditioning compressors tripped on high pressure on July 16 and 17, 2007, due to fouling of the condensing unit fins with cottonwood tree fuzz. The licensee's corrective actions included coding the cleaning of the condensing unit as a summer readiness activity for future work control implementation.

  This finding was more than minor in accordance with IMC 0612, Appendix E, example 7.a due to the licensee's failure to take timely and effective corrective actions when goals were not met. The finding was considered to be of very low safety significance because the poor performance of this system had not resulted in an actual loss of a safety function of safety-related equipment or resulted in an initiating event. The licensee would be able to reasonably perform controlled procedure steps to shutdown the reactor if AEER room temperature exceeded 104°F. The primary cause of this finding was related to the cross-cutting issue of Human Performance, Work Control. Specifically, the licensee did not plan work activities by incorporating environmental conditions which impacted plant structures, systems, and components. (H.3.(a)) (Section 1R12)

Cornerstone: Barrier Integrity

- Green. A performance deficiency involving a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," was self-revealed following 2/3A standby gas treatment (SBGT) train flow controller settings and post maintenance testing which did not ensure that the system would perform satisfactorily inservice. The maintenance and testing on the 2/3A SBGT system from September 10 through 13, 2007, did not challenge controller operation because the reactor building ventilation system was also operating during these activities. As a result, SBGT system oscillations were identified a few days later on September 17, 2007, during system operation. Corrective actions by the licensee include revising test procedure DOS 7500-02 to include required test conditions to test the standby gas treatment system in the expected post accident configuration without reactor building ventilation operating.

  The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, Appendix B, "Issue Screening," issued on September 20, 2007, because it impacted the Barrier Integrity Cornerstone (containment) objective. The failure to perform adequate post maintenance testing on systems, structures or components (SSC) can result in SSC not performing satisfactorily inservice. The issue was of very low safety significance because the 2/3B SBGT train remained operable and available. This finding has a cross-cutting aspect in the area of human performance (resources) because the licensee did not provide accurate procedures to plant personnel. (H.2(c)) (Section 1R15)

- Green. On May 9, 2007, a performance deficiency involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to promptly identify and adequately correct deficiencies with the Unit 3B Refuel Floor Fuel Pool Area Radiation Monitor (ARM) was self-revealed. The licensee's corrective actions for this issue included replacing associated degraded cables and the radiation monitor's detector on May 10, 2007, and discussing with the ARM system manager the importance of applying adequate technical riqor.

  The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on September 20, 2007, because the failure to take corrective actions evaluated and described in a root cause or common cause assessment to prevent an unnecessary challenge to a safety system could result in a more safety significant issue. This deficiency unnecessarily challenged a safety system and could have affected the availability and capability of components and systems that respond to initiating events. The issue was of very low safety significance because there was no actual event in progress. (Section 1R12)

- Green. On November 9, 2007, a performance deficiency involving a non-cited violation of TS 5.4.1 was self-revealed when a nuclear station operator (NSO) was performing Dresden Operating Procedure (DOP) 0500-03, "Reactor Protection System Power Supply Operation," Revision 36. The NSO did not verify that the area radiation monitor's (ARM) power supply voltage was normal and did not reset all trips on the ARM modules prior to removing an installed jumper which bypassed the trips. As a result, the reactor building ventilation system for both units tripped when the NSO removed the jumper. This required entry into TS 3.6.4.1 Limiting Condition of Operation, Action A for reactor building low differential pressure. The operator had been provided with a marked up copy of the procedure, assigned a concurrent verifier, and briefed on jumper placement and removal and on the use of concurrent verification prior to the event. As an immediate corrective action, the individual was temporarily removed from licensed shift duties. The operations department also modified the pre-job brief for this evolution to include the lessons learned and revised procedure DOP 0500-03.

The finding was greater than minor because it impacted the SSCs attribute of the Barrier Integrity Cornerstone objective. The finding was of very low safety significance because it impacted the reactor building differential pressure for a time period of less than one hour. This finding affected the cross-cutting area of Human Performance, "Work Practices," because the NSO failed to utilize human performance error prevention techniques required to safely implement the station procedure. Specifically, the NSO did not practice self-checking and procedure adherence, and failed to use peer checking. (H.4(a)) (Section 4OA3)

Cornerstone: Public Radiation Safety

- Green. A self-revealed finding of very low safety significance and an associated violation of NRC requirements were identified for the failure to continuously sample the Unit 2 and 3 chimney effluent for particulate and iodine radioactivity. Specifically, for an approximate four hour period on July 21, 2007, the primary particulate and iodine effluent sampling system for the chimney was inadvertently rendered inoperable and the licensee failed to establish continuous sampling with auxiliary sampling equipment. Corrective actions taken by the licensee included tailgate training, procedure revisions and the installation of hardware on the effluent monitor panel to reduce the potential for a configuration control problem.

  The issue was more than minor because it was associated with the Facilities/Equipment and Program/Process attributes of the Public Radiation Safety Cornerstone, and affected the cornerstone objective to ensure adequate protection of public health and safety from exposure to radioactivity released into the public domain. The inspectors determined that the issue resulted in a failure to satisfy offsite dose calculation manual (ODCM) sampling requirements for an approximate four hour period and represented a finding of very low safety significance because the licensee was able to estimate the effluent release during the period when sampling was interrupted and to determine that the effluent dose during that short period was within regulatory limits and met the effluent dose design objectives of 10 CFR Part 50, Appendix I. A non-cited violation of Technical Specifications 5.5.1 and 5.5.4 was identified for failure to satisfy ODCM effluent sampling requirements. The inspectors also determined that the finding had a cross-cutting aspect in the human performance area for inadequate work controls to ensure job site conditions, including environmental conditions that may impact human performance, plant components and the human-system interface did not adversely impact plant operations. (H.3.(a)) (Section 2PS1.1)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 2

On October 29, 2007, the unit was taken offline to perform a scheduled refueling outage. The unit returned to full power November 26, 2007.

On December 1, 2007, load was reduced to approximately 67 percent electrical output to perform a control rod pattern adjustment and other activities. The unit returned to full power on the same day.

Unit 3

On October 13, 2007, load was reduced to approximately 96 percent electrical output to maintain switchyard transmission stability to support line maintenance. The unit returned to full power on the same day.

On December 2, 2007, load was reduced to approximately 93 percent electrical output to perform turbine valve testing. The unit returned to full power the same day.

On December 6, 2007, load was reduced to approximately 99 percent electrical output due to degraded extraction steam pressure to the 3C2 and 3B2 feedwater heaters. The unit remained slightly derated for the remainder of the month.

1. REACTOR SAFETY

Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness [R]

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspector assessed the station's readiness for cold weather conditions by an inspection of cold weather preparations for the unit 2 emergency diesel generator, the unit 3 emergency diesel generator, and the ongoing actions taken by the licensee in preparing for winter readiness. Specifically, the inspector was concerned with how the lube oil for the emergency diesel generator sets would be kept in a warm, pre-lubricated, ready to start condition during possible cold temperatures in winter. The inspector reviewed the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS), Dresden's Abnormal Operating procedures, Exelon's Seasonal Readiness procedure and met with the emergency diesel generator system manager. The inspectors review was to determine if there were sufficient barriers in place to ensure continued reliability of the emergency diesel generator sets in cold weather and planned contingencies to maintain the lube oil warm in the event the immersion heaters failed.

During the review of the winter readiness preparations, the inspector reviewed the progress of open work orders coded for winter readiness. Some work orders were rescheduled due to resources being diverted in support of D2R20. All work orders for winter readiness were scheduled to be complete by December 31, 2007. The inspector performed a review of the open work orders to determine that no undue safety risk was presented by the delay of these work orders.

The inspector also performed a review of issue reports related to winter readiness. The inspector walked down the areas of concern and interviewed operators to verify that the issues documented in the issue reports were corrected.

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

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

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

- 2A low pressure coolant injection system restoration; and
- Unit 2 isolation condenser restoration.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstone 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, Administrative TS, outstanding work orders, issue reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted two partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

a. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

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 2 high pressure heater bay, elevation 517' Fire Zone 8.2.5.A;
- Unit 2 low pressure heater bay, elevation 538' Fire Zone 8.2.6.B;
- Unit 3 high pressure coolant injection, elevation 476' Fire Zone 11.1.3;
- Unit 2 east corner room, elevation 476' Fire Zone 11.2.2;
- Unit 2 west corner room, elevation 476' Fire Zone 11.2.1; and
- Unit 3 reactor building ground floor, elevation 517' Fire Zone 1.1.1.2.

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

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

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's testing of the 2 'A' low pressure coolant injection (LPCI) heat exchanger to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing criteria.

This inspection constitutes one sample as defined in Inspection Procedure 71111.07-05.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

a. Inspection Scope

From October 30, 2007, through November 8, 2007, the inspector conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system (RCS) boundary and the risk significant Unit 2 piping system boundaries. The inspector selected the ASME Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspector observed or verified through data review the following three types of nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code.

- Ultrasonic Examination (UT) of Core Spray Safe End to Nozzle Weld 2/1/1403-10/N19A;
- UT Examination of Recirculation System Nozzle 2B Nozzle to Vessel weld N2B-2;
- UT Examination of Recirculation System Nozzle 2B Inner Radius N2B-1;
- Magnetic Particle Examination (MT) of Main Steam (MS) Integral Attachment weld 2/1/300IC-20/M569-4 (IWA);
- MT of Reactor Pressure Vessel (RPV) Integral Attachment weld RPV Shell /M-1175D-1(IWA);
- Visual Examination (VT) of Core Spray (CS) Support 2/1/1403-10/M1150-252; and
- VT of High Pressure Coolant Injection (HPCI) Support 2/1/2305-10/M1151-8.

The inspector reviewed information from the licensee concerning recordable indications that were accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code. The inspector concluded there were no indications exceeding Code acceptance criteria identified from ISI exams conducted since the beginning of the previous refueling outage.

The inspector reviewed two pressure boundary weld repairs to determine if the welding acceptance and pre-service examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed a Class 2 pressure boundary weld repair on the Standby Liquid Control (SBLC) Tank Temperature Switch Well and weld repairs on the Class 2 High Pressure Coolant Injection (HPCI) Inlet Drain Pot Piping.

The inspectors performed a review of ISI related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff, and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the ISI related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to ISI and pressure boundary integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure 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.

This inspection constitutes one sample as defined in Inspection Procedure 71111.08-05.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On December 10, 2007, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

This inspection constitutes one quarterly licensed operator requalification program sample as defined in Inspection Procedure 71111.11-05.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- auxiliary electric equipment room ventilation; and
- area radiation monitors.

The inspectors reviewed events where ineffective equipment maintenance has resulted in 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 SSCs/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

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

These activities constituted two quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

.1 Failure to perform effective corrective action to mitigate excessive train unavailability for Auxiliary Electric Equipment Room (AEER) Heating, Ventilation and Air Conditioning (HVAC)

Introduction: The inspectors identified a performance deficiency involving a non-cited violation of 10 CFR 50.65, “Requirements for monitoring the effectiveness of maintenance at nuclear power plants,” (the Maintenance Rule) Section (a)(1). The licensee failed to perform timely corrective actions to mitigate excessive train unavailability for the AEER ventilation system. This finding was determined to be of very low safety significance, “Green.”

Description: The AEER HVAC system had been classified Maintenance Rule (a)(1) since the fourth quarter of 2005. The licensee attributed the high unavailability to several issues such as: a design problem associated with historical modifications performed to remove the auxiliary computer room (ACR) from the control room envelope, 'B' compressor oil pressure trips, condenser fan motor failures, compressor bearing clearances, failure of the variable speed condenser cooling fan, and fouling of the condensing unit with cottonwood fuzz.

The AEER contains several safety significant and important to safety systems such as: the safety-related essential service bus (ESS), the instrument bus, the reactor protection system (RPS), and the electro hydraulic control system. The AEER normal design operating temperature was 80ºF. The temperature limit for the AEER was 104ºF. The high temperature limit was based on the ESS inverter high ambient operating temperature limit from the vendor manual. A unit shutdown for the affected ESS inverter is initiated at an AEER temperature of 104ºF.

The inspectors reviewed the licensee's June 2006 (a)(1) evaluation which was documented in issue report (IR) 428376, and noted that a monitoring goal for the system was established with "No Functional Failures," that is, no compressor trips due to low oil or low suction pressure.

On June 16 and on June 17, 2007, both AEER HVAC compressors tripped on high pressure which was documented in IR 641152. The high pressure was caused by fouling of the condensing unit fins with cottonwood tree fuzz. The AEER/ACR HVAC system consists of an air handling unit located in the mask area of the turbine building and an air cooled condensing unit located outside. Engineering staff had determined that the location of the condensing unit in relation to large groves of cottonwood trees along the river created the need to clean the coils twice a year. Issue Report 636294 discussed the fact that the unit would trip if warm weather arrived and the cottonwood fuzz release occurred. Therefore, the cleaning was required between mid-April to mid-May before the onset of cottonwood fuzz season and hot weather conditions. However, the cleaning preventive maintenance for the condensing unit was rescheduled to mid-July by the work control staff without addressing the consequences of this delay on system operation. Subsequently, the compressors tripped when air temperature reached 91°F. This event resulted in an entry into Dresden Operating Abnormal Procedure 5701-01, "Ventilation System Failure," and exceeding the (a)(1) monitoring goal.

Analysis: The inspectors determined that the failure to perform appropriate corrective action to mitigate train unavailability for the AEER ventilation system was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on September 20, 2007. The inspectors determined that the finding was more than minor in accordance with IMC 0612, Appendix E, example 7.a due to the licensee failing to take timely corrective actions when 10 CFR 50.65 (a)(1) goals were not met.

The inspectors determined that the finding could be evaluated using IMC 0609, "Significance Determination Process," Appendix A, dated March 23, 2007, because the finding could impact the Initiating Events and Mitigating Systems Cornerstones. For the phase 1 screening, the inspectors answered "No" to the first two questions under the Initiating Events column and answered "No" to all the questions under the Mitigating

Systems column. The inspectors noted that this deficiency affected two cornerstones. However, the inspectors did not perform a phase 2 evaluation because no actual loss of safety function of any system occurred.

Because the licensee had an abnormal operating procedure which included steps to perform a controlled unit shutdown if the AEER HVAC failed and temperatures got too high, the issue was screened to be of very low safety significance, "Green." The primary cause of this finding was related to the cross-cutting issue of Human Performance, "Work Control," because the licensee did not plan work activities by including environmental conditions (i.e. hot weather and cottonwood fuzz) which may impact plant structures, systems, and components. (H.3.(a))

Enforcement: 10 CFR 50.65 (a)(1), requires, in part, that the holders of an operating license shall monitor the performance or condition of structures, systems, and components (SSCs) within the scope of the rule as defined by 10 CFR 50.65 (b), against licensee established goals, in a manner sufficient to provide reasonable assurance that such SSCs, are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety. When the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken.

Contrary to the above, the licensee did not take appropriate corrective actions when the performance of the AEER HVAC systems did not meet the licensee established goal of "No Functional Failures." Specifically, the licensee's failure to take appropriate corrective action caused repeated system functional failures on June 16, 2007, and again on June 17, 2007.

The licensee's corrective actions included coding the cleaning of the condensing unit as a summer readiness activity for future work control implementation. Because this performance deficiency is captured in the licensee's corrective action program as IR 428376, the poor performance of this system has not resulted in an actual loss of a safety function of safety-related equipment or resulted in an initiating event, and the licensee would be able to reasonably perform controlled procedure steps to shutdown the reactor if AEER room temperature exceeded 104°F, the inspectors determined that the licensee's failure to take timely corrective action to prevent system trips and maintain the system's established goal was a non-cited violation of 10 CFR 50.65 (a)(1).
(NCV 05000237/2007005-01; 05000249/2007005-01)

.2 Failure to Take Corrective Actions to Repair Unit 3B Refuel Floor Fuel Pool Area Radiation Monitor in a Timely Manner

Introduction: The inspectors reviewed a self-revealed performance deficiency involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to promptly identify and adequately correct issues with the Unit 3 B Refuel Floor Fuel Pool Area Radiation Monitor. This issue was determined to be of very low safety significance, "Green."

Description: A start of the standby gas treatment system (SBGT) caused by a spurious spike of the Unit 3 B Refuel Floor Fuel Pool Area Radiation Monitor occurred on July 2, 2005. The troubleshooting per Work Order 826511 identified a severe corrosion of the sensor and converter amphenol connector. The corrosion was cleaned at that time. Exelon Engineering performed Common Cause Analysis (CCA) 350308 due to the SBGT start and many other problems with Area Rad Monitors. The CCA identified that the U3 B Refuel Floor Fuel Pool Area Rad Monitor needed its detector, cable, and connector replaced along with checking full cable continuity and leakage current checks. When the system engineer created the issue report (IR) for repair, the IR incorrectly stated that the U3 B Refuel Floor Fuel Pool Area Rad Monitor had acceptable connections and no work was required. Consequently, the work called out in CCA 350308 was not performed.

On May 9, 2007, the Unit 3 reactor building ventilation system isolated and the SBGT system auto started when the Unit 3 B refuel floor fuel pool area radiation monitor spiked high. The licensee determined in IR 627547, assignment 02, "Functional Failure Cause Determination Evaluation," that the SBGT system auto start was due to the failure to perform the maintenance called out in CCA 350308.

Analysis: The inspectors determined that the failure to replace the detector, cable, and connector along with checking full cable continuity and leakage current checks, as called out in CCA 350308, was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on September 20, 2007. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on September 20, 2007, because the failure to take corrective actions evaluated and described in a root cause or common cause assessment to prevent an unnecessary challenge to a safety system could result in a more safety significant issue. This deficiency unnecessarily challenged a safety system and could have affected the availability and capability of components and systems that respond to initiating events.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process," Appendix A, Attachment 1, dated March 23, 2007, and determined that this finding impacted the Barrier Integrity Cornerstone column. The inspectors answered "Yes" to question #1 under the Barrier Integrity column on page A1-11. Therefore, the issue screened out as having very low significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality, such as deficiencies, defective material and equipment, and non-conformances, are promptly identified and corrected.

Contrary to the above, Exelon engineering performed CCA 350308 due to an inadvertent SBGT auto start on July 2, 2005, and many other problems with Area Rad Monitors. The CCA identified that the safety-related Unit 3 B Refuel Floor Fuel Pool Area Rad Monitor needed its detector, cable, and connector replaced along with checking full cable continuity and leakage current checks. When the system engineer created the IR for repair, the IR incorrectly stated that the Unit 3 B Refuel Floor Fuel Pool Area Rad Monitor had acceptable connections and no work was required. Consequently, the work called out in CCA 350308 was not performed between July 2, 2005, and May 9, 2007. This resulted in another inadvertent SBGT auto start on May 9, 2007.

The licensee’s corrective actions for this issue included replacing the cables and detector on May 10, 2007, and discussing with the ARM system manager the importance of applying adequate technical riqor. Because this issue is of very low safety significance and has been entered into the licensee’s corrective action program as IR 627547, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A., of the NRC Enforcement Policy.
(NCV 05000237/2007005-02; 05000249/2007005-02)

.3 <u>Inspector Follow-up Item Regarding Secondary Containment Area Radiation Monitor Range Span</u>

<u>Introduction:</u> The inspectors identified that the radiation monitors in the reactor building do not have the range span to identify when to take required actions identified in the emergency operating procedure and the emergency action level of the site emergency plan.

<u>Description:</u> Both the Emergency Operating Procedure DEOP-300-1, “Secondary Containment Control,” Revision 7, and Emergency Action Level (EAL) EP-AA-1004, “Radiological Emergency Plan Annex for Dresden Station,” Revision 23, require action when secondary containment radiation levels reach a specific level. The areas to be monitored in both cases are the High Pressure Core Injection (HPCI) cubicle, the east and west Low Pressure Core Injection (LPCI) areas, the east and west control rod drive areas, the vessel level instrument rack area, the reactor water clean up area, and the isolation condenser area.

In the case of DEOP (EOP) 300-1, if a primary system is discharging into the reactor building and that discharge cannot be isolated, the required action is that before any area radiation value exceeds 2500 millirem per hour the plant must be scrammed. If two or more area radiation levels exceed 2500 millirem per hour and the primary discharge cannot be isolated, then the reactor must be blown down to the torus.

In the case of EP-AA-1004 if radiation levels exceed 2000 millirem per hour in any area an Alert condition is required to be declared. Only the HPCI and torus area radiation monitors in the reactor building have a scale large enough to monitor the full range of radiation levels from the control room. Other radiation monitors have limited scales. For example, some of the area radiation monitors only have a scale that goes up to 100 millirem per hour.

The licensee identified in IR 361464, “Only 2 of 8 Reactor Building ARMs Can Indicate above Max Safe in the Control Room,” that the Reactor Building ARMs do not have sufficient scale to monitor the emergency operating procedure action levels. The licensee also identified that same issue in IR 37168, dating from April of 2001. In response to IR 37168 the licensee generated Engineering Change Request (ECR) 371883. This ECR stated that the reactor building radiation monitor ranges were acceptable for the following reasons:

- The area radiation monitors design features are to ensure that occupational radiation exposure resulting from radiation sources with the plant meet the As-Low-As-Is-Reasonably-Achievable (ALARA) program objectives. They were not designed for accident conditions.

- If all the area radiation monitors were all pegged high due to a loss of coolant accident (LOCA), a rad tech would have to accompany anyone going into the field due to changing conditions.
- Presently the HPCI and Torus Area radiation monitors are rated at 1 to 10,000 millirem per hour and are located on the same elevation and proximity to the LPCI corner rooms. These monitors would provide Operations with notification of higher radiation levels in these areas.

Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following An Accident," Revision 2, states, it is important that operators be informed if the barriers to the release of radioactive materials are being challenged. Therefore, it is essential that instrument ranges be selected so that the instrument will always be on scale. Regulatory Guide 1.97 also states that the expected range for reactor building radiation monitors is up to 10,000 millirem/hour.

The NRC issued Generic Letter 82-33, "Supplement to NUREG-0737 – Requirements For Emergency Response Capability," part of which intended to determine the licensee's conformance with Regulatory Guide 1.97. The NRC issued a Safety Evaluation Report (SER) to Dresden Station dated September 1, 1988, to discuss the licensee's response to the Generic Letter. The SER accepted the fact that the Reactor Building radiation monitors did not have the range to completely monitor the potential radiation levels that could occur during an accident scenario and that the radiation monitors did not meet the expectations of the Regulatory Guide. The NRC stated, "From a radiological standpoint, personnel would not be permitted into the areas without portable monitoring if the radiation levels reach or exceed the upper limit of the instrumentation provided. Based on the alternative portable monitoring instrumentation used by the licensee with this variable, we find the provided range acceptable."

However, the current requirements to take specific actions in the Emergency Operating Procedures and declare an Alert in the EALs did not exist in 1988. The licensee recently changed the EALs to conform with NEI 99-01, "Methodology for Development of Emergency Action Levels," Revision 4. The basis in NEI 99-01 for which an Alert is declared due to secondary containment radiation levels is a point at which personnel access to equipment would be impaired. The purpose for the actions in the EOPs is to limit the amount of energy from the reactor that is discharged to the secondary containment during an accident. The inspectors considered the need for an individual to monitor radiation levels in an area of the plant in order for the control room to take actions to prevent the discharge of primary fluids into the secondary containment beyond the level that would impair personnel access appeared to be counterintuitive and may be in violation of the NRCs ALARA principles. In addition, the inspectors considered the need for personnel monitoring of the spaces would potentially add unnecessary delays to the actions that are required in the EALs and the EOPs. The inspectors determined that the range of the secondary containment radiation monitors which did not meet or exceed the levels at which EAL and EOP actions are required was an Unresolved Item (**IFI 05000237/2007005-03; 05000249/2007005-03**), pending further inspector review.

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

a. Inspection Scope

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

- Work Order 1015174-04, "Replace standby liquid control check valve 2-1101-43 A;"
- Clearance Order 58321, "Division 2 containment coolant service water supply to control room emergency ventilation out of service work on isolation valve;"
- Issue Report 696655, "Unit 2/3 emergency diesel generator shutdown early during Division I under voltage testing;" and
- Work Order 1065802-01, "Unit 3 Digital Feedwater Backup Card Reboot."

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

These activities constituted four samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- Issue Report 695571, "Entered TS 3.6.4.1 Condition A For Reactor Building Differential Pressure Low;"
- Engineering Change Evaluation 367449, "SBGT[standby gas treatment] A Train Exhibiting Flow Oscillations;"
- Operability Evaluation #07-002, "Procure suitable replacements for all four standby liquid control pump discharge check valves;" and
- Engineering Change Evaluation 368415, "Missing Pipe Clamp on Cable Conduit Support for MSIV [main steam isolation valve] 1D."

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

These activities constituted four samples as defined in Inspection Procedure 71111.15-05

b. <u>Findings</u>

<u>Standby Gas Treatment 'A' Train Exhibiting Flow Oscillations</u>

<u>Introduction</u>: A Green finding involving a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," was self-revealed following 2/3A standby gas treatment (SBGT) train flow controller settings and post maintenance testing which did not ensure the 2/3A SBGT system would perform satisfactorily inservice. The maintenance and testing did not challenge controller operation because the reactor building ventilation system was also operating during these activities. As a result, SBGT system oscillations were discovered a few days later during system operation. This issue was determined to be of very low safety significance, "Green."

<u>Description</u>: On September 10, 2007, the 2/3A standby gas treatment system was declared inoperable to support planned maintenance on multiple components. Among the maintenance activities scheduled was the replacement of flow controller 2/3-7541-28A. This instrument provides input to the 2/3-7510-A flow control valve that regulates 2/3A SBGT flow. Instrument maintenance personnel (IMD) removed and installed the replacement controller without documenting the as-found original controller proportional band and reset values and without documenting the as-left proportional band and reset values for the newly installed controller.

On September 11, 2007, IMD performed tuning and testing of the 2/3A SBGT controller. During the tuning and subsequent testing the Unit 2 and Unit 3 reactor building ventilation (RBV) systems were running. Because of the interaction between the RBV and SBGT this condition did not provide a challenge to the controller.

On September 13, 2007, after all maintenance activities were completed, operations personnel performed a post maintenance test of the system per DOS 7500-02, "SBGT System Surveillance and IST Test," Revision 40, and declared the 2/3A SBGT train operable. However, the surveillance test was performed while the RBV system was in operation. As such, flow controller 2/3-7541-28A was not properly challenged to control SBGT flow. The flow controller maintained a low flow signal to the flow control valve throughout the surveillance test since RBV remained in operation. Therefore, the functionality of the new controller was not adequately verified.

On September 17, 2007, in preparation for a 3A RPS bus swap to the 3B RPS motor generator (MG) set, the 2/3A SBGT system was started per DOP 7500-01, “Standby Gas Treatment System Operation.” After SBGT restarted, the Units 2 and 3 RBV systems were secured per DOP 5750-02, “Reactor Building Ventilation.” When RBV was secured, 2/3A SBGT flow started to oscillate from 4800 to 2500 scfm. The 2/3A SBGT system was declared inoperable due to abnormal flow control, limiting condition for operation (LCO) 3.6.4.3.A, “One SGT subsystem inoperable,” was entered, and online risk changed from GREEN to YELLOW on both Unit 2 and Unit 3. Unit 2 and Unit 3 RBV systems were restarted and the 2/3A SBGT system was secured.

Subsequent investigation found that the controller was tuned six days prior with both the SBGT system and reactor building ventilation system in operation. Technicians and maintenance planners were not aware that both systems share a common suction plenum and reactor building ventilation system operation has a significant effect on the tuning activities of the SBGT flow controller. As a result, system conditions needed to perform adequate controller tuning and post maintenance verification were not specified. Surveillance procedure DOS 7500-02 does not test the SBGT system operation in the same mode as that experienced in a post accident situation. Had SBGT been run in a post accident mode, the oscillations would have been identified before declaring the system operable on September 13, 2007.

Instrument maintenance personnel commenced troubleshooting the 2/3A SBGT oscillations. Following controller tuning, operations personnel restarted Units 2 and 3 RBV systems and secured the 2/3A SBGT system. The controller was tested for stability by starting the 2/3A SBGT system and securing Units 2 and 3 RBV systems. Controller and 2/3A SBGT responses were acceptable with no flow oscillations. The 2/3A SBGT system was declared operable on September 17, 2007, at 4:39 pm and online risk changed on both units from YELLOW to GREEN.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to perform an adequate post maintenance test after replacement of flow controller 2/3-7541-28A was a performance deficiency warranting a significance evaluation. Using IMC 0612, Appendix B, “Issue Screening,” issued on September 20, 2007, the inspectors determined that this finding was more than minor because it impacted the Barrier Integrity Cornerstone objective to provide reasonable assurance that physical design barriers (i.e. containment) protect the public from radio nuclide releases caused by accidents or events. The failure to perform adequate post maintenance testing on systems, structures, and components (SSCs) can result in SSCs not performing satisfactorily inservice. This condition caused the 2/3A SBGT train to be inoperable for an extended period of time. Although an unplanned LCO for the system was entered and online risk changed for both Unit 2 and Unit 3 from GREEN to YELLOW, the 2/3B SBGT train remained operable and available. This finding has a crosscutting aspect in the area of human performance (resources) because the licensee did not provide accurate procedures to plant personnel. (H.2(c))

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, “Significance Determination Process,” Appendix A, Attachment 1, dated March 23, 2007. The inspectors answered “Yes” to the first question under the

Containment Barriers Cornerstone column because the finding only represented a degradation of the radiological barrier function provided by the standby gas treatment system. Therefore, the issue screened as having very low safety significance (Green).

Enforcement: The inspectors determined that the licensee's failure to perform an adequate post maintenance test after replacement of flow controller 2/3-7541-28A was a violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Criterion XI states, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems and components will perform satisfactorily inservice is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents.

The licensee's "Quality Assurance Topical Report," NO-AA-10, Revision 79, Section 11, states, in part, that the Company (i.e. Exelon Generation Company, LLC) establishes and controls a test program to assure that design and performance criteria have been satisfied and assures that testing does not adversely affect the safe operation of the plant. The test program includes, as appropriate, procedures to ensure those SSCs will perform inservice. The test program covers all required tests including the demonstration of satisfactorily performance following plant maintenance and modifications.

Contrary to the above, on September 17, 2007, the licensee failed to perform an adequate post maintenance test after replacement of safety-related flow controller 2/3-7541-28A. This failure resulted in the inoperability of the 2/3A SBGT system due to abnormal flow control and changed online risk from GREEN to YELLOW on both Units 2 and 3. This event was entered into the licensee's corrective action program as IR 672183. Corrective actions by the licensee include revising test procedure DOS 7500-02 to include required test conditions to test the standby gas treatment system in the expected post accident configuration. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000237/2007005-04; 05000249/2007005-04)**

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Work Order 642579-01H, "Clean and inspect 2A low pressure coolant injection heat exchanger;
- Work Order 993758-06, "Repair U2 Standby Liquid Control Tank Thermowell;"
- Work Order 1015174-04, "Replace standby liquid control check valve 2-1101-43A;"
- Work Order 1079142-05, "Emergency diesel generator shutdown early during DIV I under voltage;" and
- Issue Report 695137, "Indications on upper head flange weld found."

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

These activities constituted five samples as defined in Inspection Procedure 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Refueling Outage Activities (71111.20)

.1 Unit 2 Refueling Outage

a. Inspection Scope

The licensee conducted a refueling outage on Unit 2 from October 29, 2007, through November 19, 2007. During the outage the licensee installed a new steam dryer, installed a new digital electro-hydraulic control unit, replaced the 2B recirculation pump and motor, replaced 20 control rod drive mechanisms, replaced the 2A reactor feed pump casing, replaced the 2C reactor feed pump motor, and replaced transformer 26.

The inspectors routinely reviewed the outage schedule and outage risk assessment to verify the licensee was correctly maintaining required equipment inservice in accordance with the overall outage safety assessment. During the planned outage, the inspectors performed the following activities:

- Attended control room operator and outage management turnover meetings to verify that the current shutdown risk status was well understood and communicated;
- Performed walkdowns of containment to identify any indications of unidentified leakage;
- Ensured that the control room operators adhered to the licensee's TSs;
- Performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;

- Reviewed selected issues that the licensee entered into the corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance;
- Ensured that the licensee appropriately considered risk factors during the development and execution of planned activities;
- Monitored the licensee's troubleshooting efforts for emergent plant equipment issues;
- Performed plant walkdowns to observe ongoing work activities;
- Observed control rod withdrawals and initial transition to criticality;
- Performed a walkdown of the torus prior to closure;
- Performed a walkdown of containment prior to closure to ensure that debris had not been left that could affect the performance of the containment sumps. During the walkdown, the inspectors identified a number of issues which were documented in IR 700927. The inspectors reviewed the licensee's corrective actions and found them acceptable.
- Monitored mode switch changes and observed portions of power ascension.

These activities constituted one sample as defined in Inspection Procedure 71111.20-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- Work Order 920045, "Unit 3 emergency diesel generator 24 Hour endurance testing;"
- Shiftly Daily TS Surveillance Unit 2 (3) Appendix N, Revision 15, "Non-Licensed Operator (NLO) Daily Surveillance Log;"
- Unit 2 2-year in-service testing seat leakage test 1501-25B; and
- DOS 7000-18, "LLRT [local leak rate test] RWCU [reactor water clean up system] Valves 2-1201-1, 1A, 2 & 3," Revision 05 (Isolation Valves).

The inspectors observed in plant activities and reviewed procedures and associated records to determine whether: preconditioning occurred; effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis; plant equipment calibration was correct, accurate, and properly documented; as left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the UFSAR, procedures, and applicable commitments; measuring and test equipment calibration was current; test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied; test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used; test data and results were accurate, complete, within limits, and valid; test equipment was removed after testing; where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable; where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure; where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished; prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test; equipment was returned to a position or status required to support the performance of its safety functions; and all problems identified during the testing were appropriately documented and dispositioned in the corrective action program. Documents reviewed are listed in the Attachment.

This inspection constitutes four samples. Two routine surveillance testing samples, one inservice inspection sample, and one containment isolation valve inspection sample as defined in Inspection Procedure 71111.22-05.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modification(s):

- Work Order 751048-01, “Troubleshoot Apparent Problem With U2 Reactor Water Cleanup Pressure Controller 2-1290-2 and Rest of Loop As Needed.”

The inspectors compared the temporary configuration changes and associated 10 CFR 50.59 screening and evaluation information against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system(s). The inspectors also compared the licensee’s information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee’s decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operations, engineering, and training personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance.

This inspection constitutes one sample as defined in Inspection Procedure 71111.23-05.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

The inspectors performed a screening review of Revisions 21, 22, and 23 of the Dresden Nuclear Power Station Annex to the Standardized Emergency Plan to determine whether changes identified in Revisions 21, 22, and 23 decreased the effectiveness of the licensee's emergency planning for the Dresden Station. This review did not constitute an approval of the changes, and as such, the changes are subject to future NRC inspection to ensure that the emergency plan continues to meet NRC regulations.

This inspection constitutes one sample as defined in Inspection Procedure 71114.04-05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on December 10, 2007, which required emergency plan implementation by a licensee operations crew. This evolution would be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the corrective action program. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment.

This inspection constitutes one drill observation sample as defined in Inspection Procedure 71114.06-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective refueling outage exposure history, current exposure trends for the Unit 2 refueling outage (D2R20) and the early stages of outage activities in order to assess current dose performance and exposure challenges.

The inspectors reviewed the overall D2R20 work and the associated exposure (dose) projections, time/labor estimates and historical dose data focusing on the following work activities which were likely to result in the highest personnel collective exposures or were otherwise radiologically significant activities:

- Drywell Main Steam Safety, Electromatic and Target Rock Valve Maintenance;
- Drywell In-Service-Inspection Activities;
- Drywell “B” Recirculation Pump and Motor Maintenance;
- Reactor In-Vessel-Visual Inspections; and
- Reactor Disassembly/Reassembly.

The inspectors reviewed site specific trends in collective dose based on plant historical exposure for similar work activities and source term data including average contact dose rates with vertical recirculation piping at Electric Power Research Institute (EPRI) defined locations. The inspectors evaluated those processes used for D2R20 to develop dose projections including time/labor estimates, and to track work activity specific exposures.

These activities constituted two inspection samples as defined by Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors obtained the licensee’s list of D2R20 refueling outage work and radiation work permits (RWPs) ranked by estimated exposure and, based on recent refueling outage dose performance issues, reviewed the following radiologically significant D2R20 work activities:

- Reactor Disassembly/Reassembly (RWP 10006807);
- Drywell Main Steam Safety, Electromatic and Target Rock Valve Maintenance Activities (RWP 10006770);

- Drywell In-Service-Inspection Activities (RWP 10006781); and
- Reactor In-Vessel Inspections (RWP 10006809).

For each of the activities listed above, the inspectors reviewed the RWP and the ALARA Plan, including specific task plan time/labor estimates and associated total effective dose equivalent (TEDE) ALARA evaluations (i.e., respirator evaluations), as applicable. The reviews were performed in order to determine if the licensee had established radiological engineering controls and dose mitigation criteria that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA.

The inspectors also reviewed the licensee's work planning and job scheduling to determine whether it included consideration of the benefits of dose rate reduction activities such as water filled components/piping and coordinating/sequencing the installation of shielding.

These activities constituted three inspection samples as defined in Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee's assumptions and basis for its collective refueling outage exposure estimate and for individual outage job estimates and evaluated the methodology and practices for projecting work activity specific exposures. This included evaluating both dose rate and time/labor estimates for adequacy compared to historical station specific or industry data.

The licensee's exposure tracking system was examined to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution were sufficient to support control of outage work exposures. Radiation work permits were reviewed to determine if they covered an excessive number of work activities to ensure they allowed work activity specific exposure trends to be detected and controlled. During the conduct of exposure significant work, the inspectors determined if licensee management and/or the Station ALARA Committee was aware of the exposure status of the work and would intervene if exposure trends increased significantly beyond exposure estimates.

These activities constituted two inspection samples as defined in Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Controls

a. Inspection Scope

The inspectors observed ongoing outage work activities including reactor disassembly, drywell safety relief valve maintenance and drywell in-service inspections to assess the adequacy of the ALARA initiatives and the job specific radiological controls.

The licensee's use of ALARA controls for these work activities was evaluated to determine whether the licensee developed and effectively used engineering controls to achieve dose reductions and to verify that the controls were consistent with the licensee's ALARA reviews.

These activities constituted one inspection sample as defined in Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

.5 Source Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to understand historical trends and current status of plant source term information. The inspectors determined whether the licensee developed contingencies to address the potential radiological impact of moisture carryover or changes in plant chemistry that could affect D2R20 dose.

The inspectors reviewed and discussed plant source term data with radiation protection and chemistry staffs to determine if the licensee had developed an appropriate understanding of the input mechanisms and the methodologies and practices necessary to achieve reductions in source term. The inspectors determined whether the licensee had a source term control strategy in place and if it included initiatives for cobalt (stellite) reduction and an operating chemistry plan, so as to minimize source term external to the core. The inspectors discussed the water chemistry control initiatives implemented by the licensee and its impact on source term reduction compared to industry practices.

The inspectors reviewed the Dresden Nuclear Power Station 2007 - 2011 Exposure (Source Term) Reduction Plan to determine if specific initiatives were identified by the licensee for exposure reduction and to assess the priorities established for implementation of those initiatives. The inspectors reviewed the source term reduction actions taken by the licensee over approximately the 12-month period that preceded the inspection, including initiatives being implemented during the current refueling outage that were anticipated to produce long term exposure reduction benefits.

These activities constituted three inspection samples as defined in Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

.6 Radiation Worker and Radiation Protection Technician Performance

a. Inspection Scope

Radiation worker and radiation protection technician performance was assessed by the inspectors during observed work activities on the refuel floor and in the Unit 2 drywell. The inspectors determined whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope, the tools to be used for the job, and to determine if workers had knowledge of the radiological conditions and adhered to the ALARA requirements for the work activity. Job support and the communications provided by the radiation protection staff were also evaluated by the inspectors.

These activities constituted one inspection sample as defined in Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

.7 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the results of a D2R20 outage readiness ALARA program self-assessment and the associated actions to strengthen identified deficiencies. Additionally, the inspectors reviewed the actions taken by the licensee to address radiological problems encountered during its November 2006 refueling outage as disclosed in a Root Cause Evaluation which the licensee completed in February 2007. The inspectors determined if identified problems were entered into the corrective action program for resolution and if they had been properly characterized, prioritized, and were being addressed.

Corrective action assignment reports (ARs) generated in 2007 through October 2007 that were related to the radiation protection program (including the ALARA program) were reviewed by the inspectors, and licensee staff members were interviewed to assess whether follow-up activities were being conducted in a timely manner commensurate with their importance to safety and risk using the following criteria:

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

These activities constituted three inspection samples as defined in Inspection Procedure 71121.02.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

.1 Gaseous Effluent Sampling and Monitoring

a. Inspection Scope

The inspectors reviewed a gaseous effluent sampling problem that occurred in July 2007, which the licensee evaluated by performing both prompt and human performance investigations. The cause and those factors that contributed to the incident were reviewed by the inspectors to determine whether two other gaseous effluent sampling problems documented in Inspection Report 05000237/2007002; 05000249/2007002 were similar and if an adverse performance trend existed.

These reviews supplement inspection activities previously documented in Inspection Report 05000237/2007002; 05000249/2007002.

b. Findings

Introduction: A self-revealed finding of very low safety significance and an associated Non-Cited Violation of NRC requirements were identified for the failure to continuously sample the Unit 2 and 3 chimney for particulate and iodine effluents as required by the Dresden Station ODCM.

Description: On July 21, 2007 at 1415 hours, the control room received a flow alarm for the Unit 2 and 3 chimney gaseous effluent monitoring system. The Chemistry Department was notified by the operations staff and responded but were unable to determine the cause of the alarm condition, as all parameters and valve lineups on the in-plant monitoring system panel were within specification. A backup chimney effluent sampling system was available and is intended to be placed into service should the primary system be inoperable. However, the backup sampling system was not placed into service, as operations staff continued to trouble-shoot the alarm condition on the primary sampling system. At 1700 hours, chemistry staff was again dispatched to the monitoring system in the plant to determine the position of a local control switch for the chimney sampling system and found that the switch was mis-positioned in the “backup” position. While the “backup” switch position redirects chimney flow to the backup effluent sampling system, actuation of the backup system also requires manual valve lineups and pump initiation. Since the licensee had not performed the lineups and had not initiated the pumps, there was no chimney effluent flow through either the primary or backup sampling systems. At 1800 hours on July 21, 2007, the control switch was returned to the “normal” position and monitoring/sampling of chimney gaseous effluent through the primary sampling system was restored. As a result of the mis-positioned switch, for approximately four hours, the Unit 2 and 3 chimney effluent was not sampled.

The licensee's investigations found that the control switch for the chimney monitoring/sampling system was unknowingly bumped by maintenance workers involved in lighting repair, causing the switch to be mis-positioned. The control switch panel is located in dimly lit, small (cramped) room in the radwaste building, which contributed to the work control problem.

Analysis: The failure to "continuously sample" (defined in the ODCM as uninterrupted sampling with the exception of short duration, less than two-hour, interruptions for required surveillance or repair) the Unit 2 and 3 chimney gaseous effluent and immediately re-establish continuous sampling with auxiliary equipment should the primary sampling system be inoperable represents a performance deficiency as defined in NRC IMC 0612, Power Reactor Inspection Reports," Appendix B, "Issue Screening." The inspectors determined that the effluent sampling issue was associated with both the Facilities/Equipment and the Program/Process attributes of the Public Radiation Safety Cornerstone. The inspectors also determined that the issue affected the cornerstone objective to ensure adequate protection of the public from exposure to radioactive materials released into the public domain since gaseous effluents released through the main chimney were not monitored or sampled continuously. Therefore, the issue was more than minor and represented a finding which was evaluated using the Significance Determination Process (SDP).

Since the effluent monitoring/sampling equipment for the Unit 2 and 3 chimney is used to determine (quantify) the gaseous effluents released to the environment and to calculate the associated dose to the public, the inspectors utilized IMC 0609, Appendix D, "Public Radiation Safety SDP," to assess the significance of the finding. The inspectors determined that the finding involved the failure to implement the radiological effluent monitoring program required by the licensee's ODCM. However, the licensee was able to estimate the gaseous effluent release during the four-hour period when samples were not continuously collected from the chimney and determined that the resultant dose impact to the public was minimal. Consequently, the finding was determined to be of very low safety significance (Green).

The problem was caused by a human performance work control issue since the switch that diverts sample flow between the primary and backup chimney sampling/monitoring systems was unknowingly bumped by maintenance staff performing work in the area of the panel. Therefore, the inspectors also determined that the finding had a cross-cutting aspect in the area of human performance, for work controls and work planning that were not adequate to ensure job site conditions, including environmental conditions that may impact human performance, plant structures and components, and the human-system interface did not adversely impact nuclear safety (H.3.a). While similar effluent sampling/monitoring problems occurred in 2005 and in 2006 and were partly attributed to human performance issues as described in Inspection Report 05000237/2007002; 05000249/2007002, the human performance work control interface were not significant factors in those previous occurrences.

Corrective actions taken by the licensee included tailgate training for the maintenance staff, a revision to the chemistry trouble-shooting procedure and the control room annunciator response procedure to immediately verify control switch position for the sampling/monitoring system, and installation of a protective cover over the panel control switch.

Enforcement: Technical Specification 5.5.1 and 5.5.4 require that the licensee establish and implement an Offsite Dose Calculation Manual and a Radioactive Effluent Control Program that includes monitoring, sampling and analysis of effluents in accordance with the methodology and parameters of the ODCM. Section 12.2.2.D and associated Table 12.2-2 of the ODCM (Revision 6) require that with the Unit 2 and 3 chimney particulate and iodine samplers inoperable, that the licensee immediately establish continuous sampling with auxiliary sampling equipment. Contrary to this requirement, during an approximate four hour period on July 21, 2007, the Unit 2 and 3 chimney gaseous effluent iodine and particulate sampling system was inadvertently rendered inoperable and the licensee failed to establish continuous sampling with auxiliary sampling equipment. Since the licensee documented this issue in its corrective action program (Assignment Report (AR) No. 00652478 and associated investigation reports) and because the violation is of very low safety significance, it is being treated as a Non-Cited Violation. **(NCV 05000237/2007005-05; 05000249/2007005-05)**

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the 3rd Quarter 2007 performance indicators for any obvious inconsistencies prior to its public release in accordance with IMC 0608, "Performance Indicator Program."

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

b. Findings

No findings of significance were identified.

.2 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator for Units 2 and 3 for the period from the 3rd quarter 2006 to the 3rd quarter 2007. To determine the accuracy of the performance indicator (PI) data reported during those periods, PI definitions and guidance contained in Revision 5 of the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," 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, issue reports, event reports and NRC Integrated Inspection reports for the period of 2006 and 2007 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. Specific documents reviewed are described in the Appendix to this report.

This inspection constitutes two safety system functional failures samples (one each for Unit 2 and Unit 3) as defined by Inspection Procedure 71151 (MS05).

b. Findings

No findings of significance were identified.

.3 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled licensee submittals for the PI listed below for the periods indicated. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Revision 5 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The following PI was reviewed:

- Reactor Coolant System Specific Activity

The inspectors reviewed Chemistry Department records including results of isotopic analyses completed between November 2006 and September 2007 to determine if the greatest dose equivalent iodine (DEI) values determined during steady state operations for Units 2 and 3 corresponded to the values reported to the NRC. The inspectors also reviewed selected DEI calculations, including the application of dose conversion factors as specified in plant Technical Specifications. Additionally, the inspectors accompanied a chemistry technician and observed the collection and preparation of a reactor coolant system sample to evaluate compliance with the licensee's sampling procedure. Further, sample analyses and calculation methods were discussed with chemistry staff to determine their adequacy.

This inspection constitutes two inspection samples as defined in Inspection Procedure 71151 (BI01).

b. Findings

No findings of significance were identified.

.4 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the Reactor Coolant System Leakage performance indicator for Units 2 and 3 for the period from the 3rd quarter 2006 through the 3rd quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in revision 5 of the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports and NRC Integrated Inspection reports for the period of October 1, 2006, through October 1, 2007 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. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes two reactor coolant system leakage samples as defined in Inspection Procedure 71151 (BI02).

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Semi-annual Trending

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's corrective actions program and associated documents to identify trends that could indicate a more significant safety issue. The inspector's review was focused on Procedure Quality and Electric Breakers, and consisted of a five month period from June 2007 through October 2007. The inspector reviewed multiple issue reports (IRs) generated during the time period, in an attempt to identify potential trends. The screening was accomplished as follows:

The IRs associated with Procedural Quality were sorted by why the IR was generated. The first category of IRs were IRs generated by enhancement of procedures by incorporating operating experience, adding amplifying information, inclusion of warnings, or providing corrections. The second category of IRs were IRs generated because of contradictions, change management issues, references not updated with procedure revisions, or procedures unable to be performed.

The IRs associated with Electrical Breakers were sorted by equipment issues, repetitive occurrences, and discovery. These IRs were then screened for potential common cause issues and considered for potential trends. The inspector was then able to make an assessment by comparing the trends identified by the licensee to those trends identified by the NRC.

These activities constituted one inspection sample for semiannual review for trends as defined in Inspection Procedure 71152.

b. Findings

There were no findings of significance identified. The inspector determined that within the areas reviewed, the licensee staff initiated IRs at an appropriate threshold. The IRs reviewed also identified if any repeat or similar condition had occurred in the past. Many IRs were noted to include the information required for the resolution of the faulted condition.

.2 In-Depth Review

Identification and Corrective Actions Associated with Degraded Unit 2 Component Cooling Service Water (CCSW) piping

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed several IRs regarding degraded CCSW piping. These IRs included, 633086, "NRC Senior Resident Concerns," 665994, "Degraded Unit 2 CCSW Piping," and 667704, "Degraded Division II CCSW Piping." The inspectors discussed the degraded piping with the Generic Letter 89-13 Program and Raw Water Inspection Program engineer. The inspectors reviewed the Generic Letter 89-13 Program and Raw Water Inspection Program implementation documents. After the inspectors reviewed IRs on the CCSW system questions arose about degraded piping on other systems. The inspectors reviewed IR 662805, "Degraded Diesel Generator Cooling Water Piping," IR 639963, "Degraded Service Water Piping," and Engineering Change (EC) 367028, "Code/Operability Minimum Wall Thickness Evaluation for DGSW [diesel generator cooling water] Component 2/3DG12 on 2/3-3930-8" Line."

(2) Issues

The inspectors observed engineering personnel perform ultrasonic inspection of CCSW piping and determined that the method used to find flaws was acceptable. The sample size, however, was questionable as to whether it gave a good indication of system health. The licensee only sampled three to four areas per year which has amounted to only a small percentage of the actual amount of susceptible pipe. In 2007, the licensee observed four areas where wall thinning in CCSW was below design minimum wall but not below operable minimum wall thickness.

The inspectors identified that in EC 367028, which affected Unit 2/3 diesel generator cooling water eight inch piping, the minimum measured wall thickness was .272 inch. The design minimum wall thickness calculated was .270. The licensee calculated the time remaining before the minimum measured wall thickness would degrade below the design minimum wall thickness. The time period calculated was 1.8 years which in EC 367028 was rounded up to two years. Procedure NES-MS-3.1, Revision 3, section 5.4 stated, "Components which have a predicted life less than one operating cycle and do not satisfy the localized thinning area acceptance criteria of [section] 5.3 shall be repaired or replaced unless a more detailed stress analysis (such as finite element analysis) is performed to justify the component structural integrity for continued service. There were issues relating to the licensee's evaluation methodology which are discussed in the Prioritization and Evaluation of Issues section of this inspection report paragraph.

The licensee did not identify that the predicted life was less than one cycle. The EC 367028 stated in the conclusion that "it is projected that the degraded areas will be within the code allowable for the next two years." This was not true per the calculation the licensee used in the EC. No IR was written to put the issue into the corrective action program and no work order was prepared to re-perform the exam or perform repairs. The wall thinning associated with EC 367028 was identified by the licensee on

August 16, 2007. The licensee did not perform a localized thinning area acceptance calculation but instead used the equations in NES-MS-3.2, Revision 5. As stated earlier, Licensee procedure NES-MS-3.2, “Evaluation of Discrepant Piping and Support Systems,” Revision 5, Section 6.5.1, states that ASME Class 3 piping that is below the minimum design wall thickness shall be replaced no later than the next refueling outage. This piping should have been scheduled to have been repaired no later than the Unit 3 refueling outage in the fall of 2008.

When the inspectors brought this issue to the attention of the licensee IR 714843, “Recommendations For DGCW Pipe Actions Not Tracked,” was written. Through the review of IR 714843 the licensee then identified that EC 367028 had not been approved at the time that it was used for evaluation of NDE report 07-165. The licensee re-performed EC 367028 and approved it on December 21, 2007. The newly performed EC 367028 recalculated the remaining life of the piping and determined it to be 22 months. Issue Report 714843 stated that WO 1090658 was written which would repair the degraded condition identified in EC 367028. The inspectors reviewed WO 1090658 and identified that this work order did not in any way address the degraded condition identified in EC 367028. The licensee stated that they planned to re-inspect the piping in 22 months. However, this re-inspection had not been entered into the corrective action program or the work control program.

The performance deficiencies described above demonstrated weaknesses in the identification and evaluation of degraded conditions and the use of the corrective action program. However, because none of the above deficiencies resulted in the failure of piping, the inspectors determined the issues were minor.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed the licensee’s program document ER-AA-5300,”Raw Water Corrosion Program Guide,” Revision 0. The inspectors also interviewed the Raw Water Corrosion Program engineer and other engineering department supervisors.

(2) Issues

The licensee appropriately expanded the scope of inspections per the raw water program as described in ER-AA-5300, “Raw Water Corrosion Program Guide,” Revision 0, section 4.7. However, as stated above, only a small percentage of the amount of susceptible pipe has been examined. Because several areas of wall thinning were identified the sample scope expanded quickly. However, the licensee has not designated any number of samples greater than what was delineated in the program scope which will still leave a large percentage of CCSW piping unsampled.

The inspectors identified an issue with the evaluation of the wall thinning regarding the use of the licensee’s procedures. The licensee evaluated each wall thinning using an EC. Procedure ER-AA-5300 mentioned above stated in section 4.7 that NES-MS-3.1 provided guidelines for establishing acceptance criteria and evaluating pitting /wall thinning in safety and non-safety-related piping. Only one of the five ECs reviewed by the inspectors referenced NES-MS-3.1.

Procedure NES-MS-3.1 described how to calculate the minimum design basis wall thickness for ASME class 2 and 3 piping. There were six methods available to calculate the minimum design wall thickness in NES-MS-3.1. The methods to be used were based on 1) internal pressure; 2) external stresses; 3) stresses caused by exposure to a vacuum; 4) an administrative limit not to go below .1 inch; 5) .2 multiplied by the nominal wall thickness for non-safety-related pipes; and 6) .3 multiplied by the nominal wall thickness for safety-related piping. The largest calculated number from these methods was the design wall thickness per NES-MS-3.1.

The EC's would use the first method in NES-MS-3.1 to calculate the minimum design wall thickness based on internal pipe pressure. However, to calculate the minimum design wall thickness associated with external stresses the licensee used an equation from NES-MS-3.2, "Evaluation of Discrepant Piping and Support Systems," Revision 5. Procedure NES-MS-3.2 was neither referenced for use in any other procedure nor any EC. The licensee did have a Safety Evaluation Report from the NRC dated September 27, 1991, stating that the type of equations used in NES-MS-3.2 were acceptable for use. From this the inspectors concluded that the methods used for calculating minimum design wall thickness may have been technically correct but did not follow the licensee's procedures. Because this performance deficiency did not result in the failure of any safety-related piping the inspectors determined it to be minor.

The next evaluation issue concerned calculations of predicted remaining life. Predicted remaining life is the predicted elapsed time from the current measured minimum wall thickness to when the wall thickness gets below the design minimum wall thickness. The method to calculate predicted remaining life was removed from NES-MS-3.1 in Revision 3 because it was considered redundant to a similar calculation in ER-AA-430-1001, "Guidelines for Flow Accelerated Corrosion Activities," Revision 3. The equation for predicted remaining life in ER-AA-430-1001, section 4.4.7, was the minimum measured wall thickness minus the minimum design allowable wall thickness, divided by the wear rate (WR) times the safety factor (SF) or:

(Tmin measured – Tmin allowable) / (WR x SF)

Procedure ER-AA-430-1001, section 4.4.7, stated that the wear rate should be calculated based on hours online. In all the ECs the inspectors reviewed, the licensee calculated the wear rate based on years since the plant was built, instead of hours the system was inservice, and none of the licensee's calculations included a safety factor.

This became significant in evaluation EC 367265. The predicted time remaining before going below minimum operability wall thickness for component 2CCSW23 calculated by the licensee was 5.5 months. At the time the EC was written the time to the refueling outage was 5.5 months. The inspectors calculated the predicted time remaining using the SF and identified that there was only 5 months remaining before the wall thickness would degrade below the minimum wall thickness for operability. Therefore the licensee's operability evaluation was incorrect. The licensee did repair this pipe during the Unit 2 refueling outage and the pipe did not leak prior to being repaired. Therefore, even though the inspectors considered this corrective action to be untimely there was no actual safety consequence and this performance deficiency was determined to be minor.

The licensee's Standard Quality Assurance Topical Report (NO-AA-10), Revision 79, Chapter 11, "Test Control," states in part, that inspection and test results are documented in a test report or data sheet, and, each test report will document what procedures or instructions were followed in performing the task. The inspectors concluded that ECs were a test report. The inspectors concluded that the ECs prepared to evaluate the degraded wall thinning did not accurately document what procedures or instructions were followed in performing the task. Even though this performance deficiency hampered the inspectors review of the ECs, the pipes have not leaked prior to repair and therefore the performance deficiency was considered minor.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed IRs 663743, 665994, and 667704. All described degraded Unit 2 CCSW piping. The inspectors also interviewed the Raw Water Corrosion Program engineer and other engineering department supervisors.

(2) Issues

The inspectors determined that the corrective actions for some degraded pipe areas were not timely. Licensee procedure NES-MS-3.2, "Evaluation of Discrepant Piping and Support Systems," Revision 5, Section 6.5.1, states that ASME Class 3 piping that is below the minimum design wall thickness shall be replaced no later than the next refueling outage. Wall thinning in Unit 2 CCSW piping identified in IRs 663743, 665994, and 667704 were all below the minimum design wall thicknesses as calculated in ECs 367077, 367184, and 367265, but were not scheduled for repair prior to the end of the Unit 2 refueling outage D2R20 which was scheduled for October 29, to November 20, 2007. When the inspectors identified this to the licensee the repairs were rescheduled to occur during the D2R20 refueling outage. The inspectors determined that the licensee's original corrective actions were in violation of 10 CFR 50, Appendix B, Criterion XVI, because the degraded piping was not scheduled to be repaired prior to the end of the outage. However, this was considered a minor violation because the repairs were rescheduled prior to the end of the refueling outage after the error was pointed out by the inspectors. The degraded pipes were repaired during the Unit 2 refueling outage.

These activities constituted one in-depth review as defined in Inspection Procedure 71152.

d. Findings

There were no findings of significance identified.

4OA3 Event Follow-Up (71153)

Failure To Follow Procedure

a. Inspection Scope

On November 9, 2007, during the swap of the "B" RPS bus to reserve power, a Unit 2 and 3 reactor building ventilation isolation occurred. The licensee determined that the cause of this issue was a human performance error for the failure to perform steps in the proper sequence. All systems were restored in accordance with plant procedures and there was no equipment that was damaged or any personnel that were injured. The licensee entered this issue into their corrective action program as Issue Report 697052.

These activities constituted one sample as defined in Inspection Procedure 71153.

b. Finding

Introduction: A Green finding of very low safety significance involving a non-cited violation of Technical Specification (TS) 5.4.1 was self-revealed when a NSO was performing DOP 0500-03, "Reactor Protection System Power Supply Operation," Revision 36. The NSO did not verify that the ARM power supply voltage was normal and did not reset all trips on the ARM modules prior to removing a jumper that was installed. As a result, the reactor building ventilation system for both units tripped. This required entry into TS 3.6.4.1 Limiting Condition of Operation, Action A for reactor building low differential pressure (d/p).

Description: On November 9, 2007, Operations Department personnel swapped the 2B RPS bus to a reserve power source from the normal power source, using DOP 0500-03, following the completion of the bus undervoltage and emergency core cooling system (ECCS) integrated functional test for the Unit 2/3 emergency diesel generator. The NSO reset a half scram that was expected during this activity and then proceeded with removing a jumper that was installed to allow the transfer. Following the removal of the jumper, the Unit 2 and 3 reactor building ventilation system isolated. The NSO did not verify that the ARM power supply was indicating normal and that the 2B reactor building ventilation and reactor building fuel pool channel 'B' ARMs were reset prior to jumper removal as required by Attachment B of DOP 0500-03. Station procedure DOP 0500-03, Attachment B, "Bypassing and Restoration of Secondary Containment Isolations and SBGT Initiations When De-Energizing RPS Bus B," Revision 36, Removing Jumpers, Step 4, required the use of concurrent verification during the removal of the jumpers. The NSO failed to verify that the system was reset or check the preceding steps had been completed prior to going into the next step, and failed to use concurrent verification while removing the jumpers. The NSO had been provided with a marked up copy of the procedure, assigned a concurrent verifier, and briefed on jumper placement and removal and on the use of concurrent verification prior to the event.

Analysis: The inspectors determined that the failure to implement procedure instructions for performing the swap of the RPS buses to support a planned maintenance activity, that impacted safety-related equipment, was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on September 20, 2007, because it impacted the structures, systems, and components attribute of the Barrier Integrity Cornerstone (containment) objective. This deficiency challenged a safety system and could have affected the availability and capability of components and systems that respond to initiating events.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process," Appendix A, Attachment 1, dated March 23, 2007, and determined that this finding impacted the Barrier Integrity Cornerstone column. The inspectors answered "Yes" to question #1 under the Barrier Integrity column on page A1-9. Therefore, the issue screened out as having very low significance (Green).

The inspectors also concluded that this finding affected the cross-cutting area of Human Performance, “Work Practices,” because the NSO failed to utilize human performance error prevention techniques required to safely implement the station procedure. Specifically, the NSO did not practice self-checking and procedure adherence, and failed to use peer checking (H.4(a)).

Enforcement: Technical Specification 5.4.1 required, 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, dated February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978, paragraph 1.j required administrative procedures for the bypassing of safety functions and jumper control.

Station procedure DOP 0500-03, Attachment B, “Bypassing and Restoration of Secondary Containment Isolations and SBGT Initiations When De-Energizing RPS Bus B,” Revision 36, Removing Jumpers Step 1, stated, “Prior to jumper removal verify ARM power supply 2(3)-1705-7A at 902(3)-10 is indicating normal voltage compared to other power supply.” Step 2 stated, “Reset ALL trips on the 902-(3)-10 ARM Modules,” and Step 3 stated, “Verify the appropriate Reactor Building and Fuel Pool Radiation annunciators on Panel 902(3)-3 are reset.”

Contrary to the above, on November 9, 2007, the NSO did not verify that the ARM power supply 2(3)-1705-7A at 902(3)-10 was indicating normal voltage compared to the other power supply, reset all trips on the 902-(3)-10 ARM Modules, or verify that the annunciators had reset prior to removing jumpers identified in procedure DOP 0500-03, Revision 36.

The NSO had been provided with a marked up copy of the procedure, assigned a concurrent verifier, and briefed on jumper placement and removal and on the use of concurrent verification prior to the start of work. As an immediate corrective action, the individual was temporarily removed from licensed shift duties. The operations department also modified the pre-job brief for this evolution to include the lessons learned, and DOP 0500-03 was revised to incorporate Attachment B into the body of the procedure. Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program as IR 697052, this violation is being treated as non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000237/2007005-06; 05000249/2007005-06)**

4OA5 Other

.1 (Closed) Unresolved Item 05000237/2006010-03; 05000249/2006010-03, Adequacy of Ground/Well Waterborne Monitoring to Satisfy Radiological Effluent Technical Specification Surveillance Requirements

During a baseline radiological environmental monitoring program (REMP) inspection in August 2006, the inspectors identified an unresolved item (URI) regarding compliance with the requirements for groundwater/well water sampling. Environmental monitoring of waterborne pathways is required to supplement the radiological effluent monitoring program and is intended to verify that measurable concentrations of radioactive material in the environment are not greater than expected on the basis of environmental exposure pathway modeling. A URI was opened because the licensee could not provide the basis for its offsite waterborne sampling locations and, therefore, could not demonstrate compliance with the Radiological Effluent Technical Specification (RETS) surveillance requirements specified in Chapter 12.5 of the ODCM. Specifically, Table 12.5-1 of the RETS, “Radiological Environmental Monitoring Program,” required that quarterly ground/well waterborne samples be collected and analyzed “from three sources only if likely to be affected.” Waterborne sources likely to be affected are defined in Table 12.5-1 as those that are “tapped for drinking or irrigation purposes in areas where the hydraulic gradient or recharge properties are suitable for contamination.”

The licensee had historically sampled from one private and one public drinking well located offsite to the south and west of the Dresden site, respectively. However, the technical basis for limiting the well water sampling program to the two wells historically sampled versus other offsite wells, including additional private wells located south of the Dresden site near the Kankakee River and private wells north of the site near the Illinois River, could not be provided by the licensee. Consequently, compliance with Table 12.5-1 of the RETS could not be demonstrated.

To evaluate this issue, hydrogeologic studies were performed by licensee contractors to better define the groundwater flow and hydraulic gradient characteristics of the Dresden site and surrounding areas and to determine if any offsite wells could be affected by station operations. Those studies concluded that the shallow groundwater in the residential area immediately south of the plant is hydraulically linked to the Dresden Nuclear Power Station hot/cold canal system west of the residential area; therefore, wells in that residential area potentially could be affected by plant operations. Consequently, since three or more “sources” (private wells) in that community could potentially be affected and are used for drinking water and/or for irrigation purposes and since the licensee’s offsite well sampling was limited to only two wells, compliance with Table 12.5-1 of the RETS was not achieved. However, while the ODCM required that three potentially affected wells be sampled, no regulatory or technical basis existed for sampling more than two, as described below.

The licensee’s review disclosed that in January 1998, the ODCM and REMP surveillance requirements were revised to increase the number of offsite well sample locations from two to three. However, the addition of a third well sample location was inconsistent with regulatory guidance nor was it technically warranted and was the result of an oversight and in the licensee’s ODCM change management process. Regulatory guidance in NUREG-1302, “Offsite Dose Calculation Manual Guidance, Standard Radiological Effluent Controls for Boiling Water Reactors,” provides for ground/well waterborne samples from “one” or “two” sources likely to be affected. Additionally, the licensee had historically sampled one of the private wells located in that residential area south of the plant, which continues to provide a representative sample of the well water for that community. Therefore, sampling of offsite wells beyond that historically performed by the licensee was not technically warranted and appeared to exceed regulatory guidance. Although the licensee failed to meet ODCM requirements relative to the number of wells sampled between January 1998 and July 2007 (when the ODCM was revised to coincide with regulatory guidance), the issue constitutes a violation of minor safety significance that is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. This URI is closed.

.2 Inspection of Extended Power Uprate Activities (71004)

a. Inspection Scope

On November 15, 2007, during Unit 2 refueling outage D2R20, the inspectors monitored the licensee's activities associated with the replacement of the Unit 2 steam dryer. The inspectors reviewed issue reports, General Electric design reports, and held discussions with multiple personnel to gain insights into the licensee's resolution of several fit-up issues identified while installing the dryer. The inspectors also reviewed documents describing the modifications to be performed in the dryer as a result of fit-up issues. Once the dryer was installed, the inspectors monitored moisture carry over sample results and verified these sample results were acceptable.

b. Findings

No findings of significance were identified.

.3 (Closed) Licensee Event Report (LER) 50-249/2006-001-01, "Unit 3 Main Steam Safety Valves Exceed Surveillance Setpoint"

Four main steam safety valves (MSSVs) were removed and tested during the Fall 2006 Unit 3 refueling outage as specified by the testing frequency of the inservice testing program. Three failed the +/-1 percent lift setpoint verification as required by TS Surveillance Requirement 3.4.3.1, which required that two valves lift at 1240 psig +/-12.4 psig, two valves lift at 1250 psig +/-12.5 psig, and four valves lift at 1260 +/-12.6 psig. One valve lifted at 1210 psig when its nameplate setpoint listed at 1240 psig, one valve lifted at 1264 psig when its nameplate setpoint listed 1250 psig, and the other valve lifted at 1229 psig when its nameplate setpoint listed 1260 psig. The three valves were within the inservice testing program requirements of lifting within +/-3 percent. The Target Rock safety/relief valve removed from Unit 3 during the refueling outage also exceeded its allowable as-found lift setpoint tolerance. The valve lifted above its lift setpoint by 2.9 percent. The licensee determined the root cause of the valves lifting outside the TS limit was setpoint drift. The failure of the valves to lift within the required TS limit of +/-1 percent is a violation of TS 3.4.3.1.

The safety significance of this event is minimal. The licensee had previously requested a change to the TS for Units 2 and 3 to increase the allowable as-found lift setpoint tolerance for the MSSVs. The plant-specific analyses for a +/-3 percent tolerance was reviewed by the NRC and found to be acceptable. An amendment to revise the MSSV as-found lift setpoint tolerance from +/-1 percent to +/-3 percent was issued on June 21, 2007. All of the valves found out of tolerance were within the +/-3 percent approved lift setpoint.

This TS violation was entered into the licensee's corrective action program as IR 557308, and was determined to be a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This LER is closed.

4OA6 MANAGEMENT MEETINGS

.1 Exit Meeting Summary

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

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- Occupational Radiation Safety Cornerstone ALARA program inspection and follow-up evaluation for an unresolved item dealing with environmental sampling of offsite wells with Messrs. D. Leggett, J. Strmec, H. Bush and others on November 6, 2007.

- Inservice Inspection (IP 71111.08), with Mr. D. Wozniak and other members of licensee management at the conclusion of the inspection on November 08, 2007. The inspectors returned proprietary information reviewed during the inspection and the licensee confirmed that none of the potential report input discussed was considered proprietary.

- Emergency Preparedness inspection with Mr. P. Quealy on December 18, 2007.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

D. Bost, Site Vice President
D. Wozniak, Plant Manager
C. Barajas, Operations Director
H. Bush, Radiation Protection Manager
J. Ellis, Regulatory Assurance Manager
D. Galanis, Design Engineering Manager
D. Glick, Shipping Specialist
G. Graff, Operations Training Manager
J. Griffin, Regulatory Assurance - NRC Coordinator
T. Hanley, Engineering Director
J. Kish, ISI Coordinator
D. Leggett, Nuclear Oversight Manager
J Miller, NDE Level III
M. Overstreet, Lead Radiation Protection Supervisor
C. Podczerwinski, Maintenance Rule Coordinator
P. Quealy, Emergency Preparedness Manager
E. Rowley, Chemistry
R. Rybak, Regulatory Assurance
J. Sipek, Assistant Engineering Director
J. Strmec, Chemistry, Environmental and Radwaste Manager
C. Symonds, Training Director

NRC personnel

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

IEMA personnel

R. Schulz, Illinois Emergency Management Agency

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000237/2007005-01 05000249/2007005-01	NCV	Failure to perform corrective action to mitigate excessive train unavailability for Auxiliary Electric Equipment Room Heating, Ventilation and Air Conditioning (HVAC) (Section 1R12)
05000237/2007005-02 05000249/2007005-02	NCV	Failure to Take Corrective Actions to Repair Unit 3B Refuel Floor Fuel Pool Area Radiation Monitor in a Timely Manner (Section 1R12)

05000237/2007005-03 05000249/2007005-03	URI	Secondary Containment Area Radiation Monitor Range Span (Section 1R12)
05000237/2007005-04 05000249/2007005-04	NCV	Standby Gas Treatment 'A' Train Exhibiting Flow Oscillations (Section 1R15)
05000237/2007005-05 05000249/2007005-05	NCV	Failure to Continuously Sample the Unit 2 and 3 Chimney for Particulate and Iodine Effluents (Section 2PS1)
05000237/2007005-06 05000249/2007005-06	NCV	Unit 2/3 Standby Gas Treatment Auto-started and a Unit 2 and 3 Reactor Building Ventilation Isolation Occurred (Section 4OA3)

Closed

05000237/2007005-01 05000249/2007005-01	NCV	Failure to perform corrective action to mitigate excessive train unavailability for Auxiliary Electric Equipment Room Heating, Ventilation and Air Conditioning (HVAC) (Section 1R12)
05000237/2007005-02 05000249/2007005-02	NCV	Failure to Take Corrective Actions to Repair Unit 3B Refuel Floor Fuel Pool Area Radiation Monitor in a Timely Manner
05000237/2007005-04 05000249/2007005-04	NCV	Standby Gas Treatment 'A' Train Exhibiting Flow Oscillations
05000237/2007005-05 05000249/2007005-05	NCV	Failure to Continuously Sample the Unit 2 and 3 Chimney for Particulate and Iodine Effluents
05000237/2007005-06 05000249/2007005-06	NCV	Unit 2/3 Standby Gas Treatment Auto-started and a Unit 2 and 3 Reactor Building Ventilation Isolation Occurred
05000237/2006010-03 05000249/2006010-03	URI	Adequacy of Ground/Well Waterborne Monitoring to Satisfy Radiological Effluent Technical Specification Surveillance Requirements. (Section 4OA5)
50-249/2006-001-01	LER	Unit 3 Main Steam Safety Valves Exceed Surveillance Setpoint

Discussed

None

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.

1R07 Heat Sink Performance (71111.07)

- EC # 366907, "Perform Evaluation of March 1, 2007, and March 19, 2007, Thermal Performance Test data for the 2A LPCI HX"
- DCP 1008-04, revision 6, "Heat Exchanger Inspection Program"
- DMP 1500-03, revision 26, "Containment Cooling (LPCI) Heat Exchanger Maintenance"
- DTS 1500-05, revision 6, "Containment Cooling Heat Exchanger Thermal Test Data"
- ER-AA-340-1002, revision 3, "Service Water Heat Exchanger and Component Inspection Guide"
- UFSAR Section 6.2.2, "Containment Heat Removal System"
- UFSAR Section 9.2.1, "Containment Cooling Service Water System"
- UFSAR Table 6.2-7, "Containment Cooling Equipment Specifications"
- UFSAR Table 6.2-3a, "Key Parameters for Containment Analysis"
- UFSAR Table 6.2-3b, "Heat Exchanger Heat Transfer Rate"
- UFSAR Figure 6.2-42, "LPCI Heat Exchanger Tube Replacement with AL6XN Versus Plugging"
- Design Analysis No. DRE 98-0117, revision 0, "LPCI Heat Exchanger K Factor"
- IR 693557, "2A LPCI Heat Exchanger As-Found Inspection Results"
- IR 701787, "2A LPCI HX Inlet Isolation Valve 2-1501-4A Leaks By"
- IR 701799, "2A LPCI HX Outlet Isolation MOV 2-1501-3A Leaks By"
- Eddy Current Testing Results for 2A LPCI HX, November, 2007
- Work Order 642579, "D2 RFL PM Clean/Insp/Hydro/Eddy Current 'A' LPCI HX"

1R08 Inservice Inspection (ISI) Activities (IP 71111.08)

- Non-Destructive Examination (NDE)
- Exelon Procedure ER-AA-335-016; VT-3 Visual Examination of Component Supports, Attachments, and Interiors of Reactor Vessels; Revision 4
- GE--UT-209; Procedure for the Automated Ultrasonic Examination of Dissimilar Metal Welds and Nozzle to Safe End Welds; Revision 18
- GE-UT-300; Procedure for Manual Examination of Reactor Vessel Assembly Welds in accordance with PDI; Revision 10
- GE-UT-311; Procedure for Manual Ultrasonic Examination of Nozzle Inner Radius, Bore and Selected Nozzle to Vessel Regions; Revision 15
- GE-MT-100; Procedure for Magnetic Particle Examination Dry Particle, Color Contrast or Wet Particle Fluorescent; Revision 6
- Visual Examination (VT-3) Data Sheet D2R20-021/VT-028; HPCI Support
- 2/1/2305-10/M-1151D-8; dated October 31, 2007
- Visual Examination (VT-3) Data Sheet D2R20-019/VT-027; CS Support
- 2/1/1403-10/M-1150D-252; dated October 31, 2007
- Magnetic Particle Data Sheet D2R20-034/MT-006; Main Steam Integral Attachment; dated November 4, 2007

- Magnetic Particle Data Sheet D2R20-036/MT-005; Reactor Pressure Vessel Integral Attachment; dated November 2, 2007
- Ultrasonic Examination Data Sheet APR-002/APD-002; Core Spray Safe End to Nozzle Weld 2/1/1403-10/N19A-3; dated November 4, 2007
- Ultrasonic Examination Data Sheet D23R20-002; RPV Nozzle Inner Radius, N2B 1; dated November 5, 2007
- Ultrasonic Examination Data Sheet D2R20-006; RPV Nozzle to Shell Weld, N2B-2; dated November 5, 2007.
- Manual RPV Exam Inner Radius Section (IRS) Exam Plan; dated October 25, 2007
- Manual RPV Exam Plan; dated October 25, 2007
- NDE Personnel Certifications: Arrington, D., Catron, E., Knott, B., Fish, K.

CORRECTIVE ACTION DOCUMENTS
- AR00596717; Dresden Reactor Vessel NDE Information; dated February 26, 2007
- AR00628420; Target Rock OPEX from IR 625801; dated May 9, 2007
- AR00658858; Inconsistent BWRVIP Recommendations to Review DM Weld UT; dated August 9, 2007
- AR00624474; Review DN Weld UT per BWRVIP 2007-051 Recommendation 1; dated May 2, 2007
- AR00654273; U2 HPCI Inlet Drain Pot Piping Leak; dated July 26, 2007
- AR00654708; HPCI Drain Line Piping UT Less Than Minimum Wall; dated July 27, 2007
- Examination Summary Sheet 2R18-053; Review of 2003 Data for Recirculation Nozzle 2/1/0201K-12/N2C-3; dated October 31, 2007
- Examination Summary Sheet 2R18-056; Review of 2003 Data for Recirculation Nozzle 2/1/0201C-12/N2F-3; dated October 31, 2007
- Examination Summary Sheet 2R18-050; Review of 2003 Data for Recirculation Nozzle 2/1/0202B-28/N1B-3; dated October 31, 2007

CORRECTIVE ACTION DOCUMENTS BASED ON INSPECTOR ISSUES
- AR00692858; No Tracking of Recommendation Made in EC/Eval; dated October 30, 2007
- AR00695483; NRC Observations During the Examination of the N2B Nozzle; November 6, 2007.
- AR00696299; Review Enhancement Opportunities to GE Procedure GE-UT-311; November 8, 2007

DOCUMENTS RELATED TO ISI FLAW EVALUATION
- AR695137; Indications on Upper Head Flange Weld Found; dated November 6, 2007
- Owner's Activity Report Submittal, Fourth 10-Year Interval 2005 Refueling Outage Activities, Letter from D. Bost to NRC; dated February 20, 2006

DOCUMENTS RELATED TO WELDED REPAIRS
- Work Order 00993758; Small Leak Evident at Connection of Flow Indicator to SBLC; dated January 19, 2007
- Welding Procedure; WPS 8-8-GTSM; Revision 1; dated August 20, 2003
- ASME Weld Data Record for WO 993758-04; dated January 19, 2007
- Liquid Penetrant Data Sheet 07-020; Weld Number TS-2-1155 Weld No.1; dated January 19, 2007
- Liquid Penetrant Data Sheet 07-019; Weld Number TS-2-1155 Weld No. 2; dated January 9, 2007
- ASME Section XI Repair/Replacement Plan; 00993758-04 R/RP 2-07-001; dated January 19, 2007

- Work Order 01049528; U2 HPCI Inlet Drain Pot Piping Leak; dated July 27, 2007
- Welding Procedure WPS 8-8-GTSM-PWHT; Revision 0; dated December 19, 2002
- ASME Weld Data Record for WO 01049528-01; dated July 27, 2007

1R11 Licensed Operator Requalification Program (71111.11)

- Scenario ILTS058, Revision 5, dated February 2007

1R15 Operability Evaluations (71111.15)

- EC Eval 367449, “Standby Gas Treatment (SBGT) ‘A’ Train Exhibiting Flow Oscillations”
- IR 672183, “2/3A SBGT Flow Swinging Excessively”
- IR 672572, “SBGT FICS Need to Be Tuned Following Overhaul of Valve/Act”
- IR 711893, “SBGT EC Eval 367449 Found Inaccurate After NRC Questions”
- Technical Specification 3.6, “Containment Systems”
- Technical Specification 5.5.7, “Ventilation Filter Testing Program (VFTP)”
- Regulatory Guide 1.52, “Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants,” Revision 3.
- Dresden UFSAR Section 6.5, “Fission Product Removal and Control Systems”
- Work Order 1056215, “D2/3 1M TS SBGT Charcoal Absorber Moisture Removal”
- DOP 7500-01, “Standby Gas Treatment System Operation”, Revision 26
- DOS 7500-02, “SBGT System Surveillance and IST Test”, Revision 41

1R23 Temporary Plant Modifications (71111.23)

- CC-MW-112-1001, “Temporary Configuration Change,” Revision 8

1EP4 Emergency Action Level and Emergency Plan Changes

- Dresden Nuclear Power Station Annex of the Exelon Standardized Emergency Plan; Revisions 20, 21, 22 and 23

1EP6 Drill Evaluation (71114.06)

- Scenario ILTS058, Revision 5, dated February 2007

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

- RWP 10008000 and Associated ALARA Plan; D2R20 Drywell Safety, Electromatic and Target Rock Valve Maintenance; Revision 0
- RWP 10008013 and Associated ALARA Plan; D2R20 Drywell “B” Recirc Pump and Motor Maintenance; Revision 1
- RWP 10008011 and Associated ALARA Plan; D2R20 Drywell In-Service-Inspection; Revision 0
- RWP 10008038 and Associated ALARA Plan; D2R20 Reactor Disassembly, Reassembly and Related Activities; Revision 0
- RWP 10008040 and Associated ALARA Plan; D2R20 Refuel Floor Reactor In-Vessel Inspections; Revision 0
- Radiation Protection Cross Functional Self-Assessment Report; ALARA Planning for Outage Readiness & Preparation; dated October 5, 2007

- D2R20 Daily Dose Reports for October for October 31 - November 6, 2007
- Dresden Nuclear Power Station 2007 - 2011 Exposure Reduction Plan; Revision 1
- Root Cause Investigation Report and Associated Corrective Action Information; D3R19 Outage Dose Exceeded Goal; Report Dated February 16, 2007 with Corrective Action Status thru November 1, 2007
- AR 00676602; Shoe Contamination from Particle In Sole of Shoe; dated September 26, 2007
- AR 00676705; LHRA Door to Drumming Room Has to be Locked with Key; dated September 27, 2007
- AR 00591362; Operations Enters High Radiation Area for Weekly Round; dated February 14, 2007

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

- AR 00652478; Unit 2 and 3 Chimney Gas Monitor Flow Hi/Lo; dated July 21, 2007, and Associated Prompt and Human Performance Investigation Reports dated July 22, 2007
- AR 00639628; Release of Turbine Building Air; dated June 12, 2007
- AR 00687732; HRSS Filter Unit Appears to be Full of Water; dated October 22, 2007
- AR 00668190; Small Water Intrusion Identified in Cribhouse; dated September 5, 2007
- Offsite Dose Calculation Manual for Dresden Station; Revision 6

4OA1 Performance Indicator Verification (71151)

- NEI 99-02, "Regulatory Assessment Performance Indicator Guideline"
- USNRC Public Website
- DCP 3207-01; Gamma Isotopic Analysis; Revision 24
- CY-AA-110-200; Sampling; Revision 5
- Gamma Isotopic Reports and Dose Equivalent Iodine Calculation Data for Selected Periods between November 2006 - September 2007
- Resident Office Daily Reactor Coolant System Leakage Spreadsheet

LERs
- 237/2006-005, "Units 2 and 3 Control Room Emergency Ventilation Air Conditioning System Inoperable Due to Leaking Fittings"
- 249/2006-001,"Unit 3 Main Steam Safety Valves Exceed Surveillance Setpoint"
- 237/2006-004, "Unit 2 Reactor Scram Due To Main Steam Isolation Valve Closure"
- 237/2006-003, "Unit 2 Reactor Steam Dome Pressure-Low Permissive Switch Determined to Have Been Historically Inoperable"
- 237/2006-002, "Unit 2 High Pressure Coolant Injection System Declared Inoperable"
- 237/2006-001, "Unit 2 Isolation Condenser Declared Inoperable Due To Inadequate Backfilling of Instrumentation Sensing Lines"
- 237/2007-003, "Unit 2 High Pressure Coolant Injection System Declared Inoperable"
- 237/2007-002, "Unit 2 Reactor Scram Due To Loss of Feedwater"
- 249/2007-001, "Unit 3 High Pressure Coolant Injection System Declared Inoperable"
- 237/2007-001, "Unit 2 Standby Liquid Control System Tank Inoperable Due To A Small Linear Crack"

4OA5 Other

- Hydrogeologic Investigation Report for Dresden Generating Station, Prepared by Conestoga-Rovers and Associates; dated September 2006
- AR 00532766; Potential ODCM Violation; dated August 17, 2007

- Groundwater Tritium Investigation Report - Dresden Generating Station, Prepared by The Retec Group, Inc; dated December 7, 2005
- Hydrogeology and Groundwater Investigation at the Dresden Nuclear Power Station near Morris, Illinois, Prepared by Sundance Environmental and Energy Specialists, Ltd; dated June 30, 2005
- Dresden Station Site Groundwater Study, Harza Engineering Company; dated July 1991
- Dresden Groundwater Study, Harza Consulting Engineers and Scientists; dated January 1995
- IR 697712, "D2R20 New Dryer Fails to Seat in RPV"
- IR 699448, "D2R20 IVVI – Separator Guide Rod Tack Weld Indication"
- EC 356822, Revision 001, "Steam Dryer Replacement – U2"

LIST OF ACRONYMS USED

ACR	Auxiliary Computer Room
AEER	Auxiliary Electric Equipment Room
ALARA	As-Low-As-Is-Reasonably-Achievable
ARM	Area Radiation Monitor
ASME	American Society of Mechanical Engineers
CCA	Common Cause Analysis
CCSW	Containment Cooling Service Water
CFR	Code of Federal Regulations
D2R20	Dresden Unit Refueling Outage 20
d/p	Differential Pressure
DEI	Dose Equivalent Iodine
DEOP	Dresden Emergency Operating Procedure
DOP	Dresden Operating Procedure
DRP	Division of Reactor Projects
EAL	Emergency Action Level
EC	Engineering Change
ECCS	Emergency Core Cooling System
ECR	Engineering Change Request
EOP	Emergency Operating Procedure
ESS	Essential Service Bus
GE	General Electric
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation and Air-Conditioning
IMC	Inspection Manual Chapter
IMD	Instrument Maintenance Personnel
IR	Issue Report
ISI	Inservice Inspection
IST	Inservice Test
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHRA	Locked High Radiation Area
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
MG	Motor-Generator
MSIV	Main Steam Isolation Valve
MSSV	Main Steam Safety Valves
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
NSO	Nuclear Station Operator
ODCM	Offsite Dose Calculation Manual
PI	Performance Indicator
PM	Post Maintenance
psig	Pounds Per Square Inch Gauge
RBV	Reactor Building Ventilation
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RETS	Radiological Effluent Technical Specification

RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SBGT	Standby Gas Treatment
SBLC	Standby Liquid Control
SDP	Significance Determination Process
SER	Safety Evaluation Report
SSC	Systems, Structures, and Components
TEDE	Total Effective Dose Equivalent
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order