UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352
January 31, 2013

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

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 – NRC INTEGRATED INSPECTION REPORT 05000254/2012005 AND 05000265/2012005

Dear Mr. Pacilio:

On December 31, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Quad Cities Nuclear Power Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on January 8, 2013, with Mr. T. Hanley, and other members of your staff.

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

One NRC-identified finding and two self-revealed findings of very low safety significance were identified during this inspection. These findings involved violations of NRC requirements. Further, two licensee-identified violations which were determined to be of very low safety significance are listed in this report. The NRC is treating these issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the violations or severity of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Quad Cities Nuclear Power Station.

If you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Quad Cities Nuclear Power Station.

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

Sincerely,

/RA/

Robert Orlikowski, Acting Branch Chief
Branch 1
Division of Reactor Projects

Docket Nos. 50-254; 50-265
License Nos. DPR-29; DPR-30

Enclosure: Inspection Report 05000254/2012005; 05000265/2012005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	05000254/20012005; 05000265/2012005
Licensee:	Exelon Generation Company, LLC
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	Cordova, IL
Dates:	October 1 through December 31, 2012
Inspectors:	J. McGhee, Senior Resident Inspector B. Cushman, Resident Inspector C. Brown, Reactor Engineer J. Draper, Reactor Engineer R. Elliott, Reactor Engineer J. Laughlin, Emergency Preparedness Inspector M. Mitchell, Health Physicist B. Palagi, Senior Operations Engineer D. Passehl, Senior Risk Analyst C. Mathews, Illinois Emergency Management Agency
Approved by:	Robert Orlikowski, Acting Branch Chief Branch 1 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000254/2012005 and 05000265/2012005; 10/01/2012 - 12/31/2012, Quad Cities Nuclear Power Station, Units 1 and 2; Component Design Basis Inspection, Identification and Resolution of Problems, and Event Followup and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. In addition, regional inspectors performed followup inspections for the triennial component design basis inspection. Three Green findings were identified by the inspectors. The findings were considered non-cited violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” for the failure to verify and ensure that operating the emergency diesel generators (EDGs) at the limits of voltage and frequency, allowed by Technical Specification (TS) 3.8.1.2, would not affect the safety-related components. Specifically, the license failed to ensure the EDGs, operating under any combination of allowed voltage and frequency, would not be loaded in excess of the licensed limit and would not cause supplied components to become inoperable. The licensee entered the issue into the corrective action program (CAP) as Issue Report (IR) 01288784, “CDBI – Technical Specification Limits for EDG,” and restricted EDG operation to near the midpoint of the allowed TS range during any potential event until the licensee demonstrates operability over the full TS range.

  The finding was more than minor because it affected the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the design control attribute was adversely affected because the licensee failed to ensure the TS- allowed operating band for EDG frequency and voltage could not affect the operability and reliability of mitigating system components. Based on a Phase 3 internal events SDP evaluation performed by a regional senior reactor analyst, the inspectors determined the finding was of very low safety significance (Green). No cross-cutting aspect was assigned since the analysis was last performed in May of 2007 and is not necessarily reflective of current performance. (Section 1R21.1)

- Green. A self-revealed finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedure, and Drawings,” were identified on October 25, 2012, when the operator performing the Unit 2 EDG surveillance test failed to follow procedural direction when applying load to the machine resulting in the Unit 2 diesel generator being inoperable for approximately seven hours while troubleshooting activities were conducted. The operator did not perform the diesel loading in accordance with the procedure in that real load was applied in a manner that changed reactive load significantly in the opposite polarity from real load and resulted in a “loss of field” trip of the diesel generator output breaker. After troubleshooting, the surveillance was completed to ensure no impact to the voltage regulating circuit and restore operability for prior work activities. This issue was entered into the licensee’s CAP as IR 1431240. Immediate corrective actions included revision of procedures that operated the diesel generator in parallel with another source to include information reminding operators that the Unit 2 EDG responded differently to load adjustments, and care should be used when making adjustments to prevent a “loss of field” trip.

The finding was more than minor because it affected the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The deficiency impacted the Equipment Performance attribute for reliability in that the performance deficiency challenged the voltage regulator protective feature and could have damaged the excitation circuit for the diesel generator. Inspectors performed the Phase 1 screening of the finding using the SDP and determined that the issue was of very low safety significance, or Green. The questions in IMC 0609, Attachment 4, Appendix A, Exhibit 2, Section A were answered “No” by inspectors because the diesel was quickly made available for emergency response following the breaker trip, and the remaining diesel generator and both offsite power sources were operable. Inspectors determined this finding to be cross-cutting in Human Performance-Resources in that the licensee ensures that appropriate training is provided to assure nuclear safety (H.2(b)) because a contributor to this finding was that a post-maintenance change in voltage regulator performance was not systematically communicated to the operating staff through training. (Section 4OA2.4)

- Green. A self-revealed finding of very low safety significance (Green) and an associated NCV of TS 3.5.1.K were identified for two core spray systems inoperable due to degraded flood barriers on August 6, 2012. The failure of the 1B core spray and Unit 2 reactor core isolation cooling/2B core spray floor drain ball valves was caused by wear related degradation that occurred at the valve-to-actuator coupling that allowed the valve to not be fully seated despite the actuator indicating fully closed. Since the surveillance tested the floor drain ball valves in the as-found condition, the condition existed prior to discovery. Therefore, both Unit 1 core spray subsystems were inoperable due to degraded flood barriers. This condition would have required immediate entry into Limiting Condition for Operation 3.0.3 to commence a shutdown within 1 hour. This issue was entered into the licensee’s CAP as IR 1397306. Corrective actions for this issue included repairs to the floor drain ball valves, extent of condition inspection of all reactor building floor drain ball valves and shortening the surveillance interval from 4 years to 2 years.

  The finding was more than minor because it affected the Mitigating Systems Cornerstone objective to ensure the availability of systems to respond to initiating events to prevent undesirable consequences. In this case, the Cornerstone attribute of protection against external factors (internal flood) was impacted. The inspectors performed an SDP Phase 1 screening for the finding using IMC 0609, Attachment 04, “Initial Characterization of Findings,” and IMC 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” and answered the first four questions “No.” Therefore, the finding screened as very low safety significance, or Green. The inspectors identified that this issue had a cross-cutting aspect in the area of Problem Identification and Resolution - Identification (P.1(a)). A contributor to this finding was that the Operations and Engineering Departments were aware that the reach rod operators for the floor drain ball valves were difficult to operate. However, an issue report was never entered into the corrective action program to make the organization aware of this issue, assess for proper operation, trend the valve performance, identify potential failure mechanisms, or document conclusions. (Section 4OA3.2(1))

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1

Unit 1 operated at 100 percent thermal power throughout the evaluated period from October 1 through December 31, 2012, with the exception of planned power reductions for routine surveillances, planned maintenance, main condenser flow reversals, and control rod maneuvers.

Unit 2

Unit 2 operated at 100 percent thermal power throughout the evaluated period from October 1 through November 29, 2012, with the exception of planned power reductions for routine surveillances, planned maintenance, main condenser flow reversals, and control rod maneuvers. At 2:00 p.m. on November 30, 2012, operators reduced power to 84 percent power to perform an emergent repair of an electro-hydraulic control system pressure switch on the #1 turbine control valve. The licensee completed the repair and returned the unit to 100 percent power at 11:30 p.m. that same day. The failure recurred on December 2, 2012, at 03:24 a.m. and operators reduced power to 84 percent at 10:30 a.m. that morning. After the repair, the operators returned power to 100 percent at 3:30 p.m. that same day. Unit 2 operated at 100 percent thermal power through December 31, 2012, with the exception of planned power reductions for main condenser flow reversals.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

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

- reactor building heating steam; and
- contaminated condensate storage tank heat trace.

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

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Condition - High Winds

a. Inspection Scope

Since high winds were forecast in the vicinity of the facility for December 20, 2012, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On December 19, 2012, inspectors performed a walk down of the licensee's emergency alternating current power systems, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, they verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of CAP items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Unit 1/2 'B' standby gas treatment system while the 1/2 'A' standby gas treatment system was inoperable due to planned maintenance, and

- Unit 1/2 emergency diesel generator while the Unit 2 emergency diesel generator was unavailable.

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

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 1.1.2.4, Unit 2 Reactor Building, Elevation 647’-6”, Third Floor;
- Fire Zone 11.1.1.A, B, and C, Unit 1 Turbine Building 547’-0” Elevation, Residual Heat Removal Service Water Pumps;
- Fire Zone 11.1.2.A, B, and C, Unit 2 Turbine Building 547’-0” Elevation, Residual Heat Removal Service Water Pumps; and
- Fire Zone 11.2.3, Unit 1 Reactor Building 554’-0” Elevation, Northwest Corner Room, 1A Core Spray.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee’s fire plan.

The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07T)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

As documented in NRC Inspection Report 05000254/2012004; 05000265/2012004, the inspectors initiated the triennial inspection of heat sink inspection. The inspectors completed the inspection activities associated with the 1B core spray pump room cooler (1-5748-B); however, they had not completed the inspection effort associated with the ultimate heat sink.

During this current inspection period, the inspectors continued their review; however, some elements of the inspection sample have not been completed. Therefore, this inspection remains open.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Annual Operating Test, administered by the licensee from October 9, 2012 through November 14, 2012, required by 10 CFR 55.59(a). The results were compared to the thresholds established in Inspection Manual Chapter (IMC) 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee's licensed operator requalification training program to meet the requirements of 10 CFR 55.59.

This inspection constitutes one biennial licensed operator requalification inspection sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On October 16, 2012, the inspectors observed the licensee administer an annual operating exam per 10 CFR 55.59 to a crew of licensed operators in the plant's simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and activities were 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;
- timely control board manipulations;
- oversight and direction from supervisors; and
- the supervisor's 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. In addition to the operator activities observed, the inspectors evaluated the following aspects of the licensee's annual operating test:

- the licensee's ability to administer the annual requalification operating test;
- the licensee's ability to assess the performance of their licensed operators;
- the adequacy of plant procedures;
- the quality of the operating test scenario guide;
- examination security; and
- simulator performance and fidelity.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program simulator sample with an in-progress operating test as defined in IP 71111.11-05.

b. Findings

No findings were identified.

.3 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On November 17 and 18, 2012, the inspectors observed the operating crew perform power maneuvering to approximately 75 percent thermal power for control rod pattern adjustment and recovery/testing of two control rods on Quad Cities Unit 1. In addition, a maintenance activity was performed to replace a control signal cable for main turbine control valve #3. These were activities that required heightened awareness or were related to increased risk. The inspectors evaluated the following areas:

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

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

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Z5650: Electro-hydraulic Control

The inspectors reviewed degraded equipment and events including valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

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

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

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

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

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Work Week 12-42-04 (high pressure coolant injection 1-2301-30 valve replacement, emergent Unit 1 125 Vdc #1 battery charger oscillations, 345 kV switchyard gas circuit breaker 3-4 outage, 2A core spray system out of service, emergent 1A drywell equipment drain sump control switch failure, and Unit 2 125 Vdc alternate battery service test);
- Work Week 12-43-05 (control room refrigeration condensing unit and air filtration unit out of service, technical support center roofing replacement, Unit 1 reactor core isolation cooling unavailable during maintenance, 1A core spray breaker swap, and 2B/2C residual heat removal service water pump vault watertight door maintenance); and
- Work Week 1-44-06 (Bus 24-1 undervoltage testing, Unit 2 emergency diesel generator and diesel generator cooling water pump outage with unplanned extension due to breaker trip during post-maintenance testing, and Unit 1 emergency diesel generator start failure testing).

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

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- steam leak in high pressure coolant injection room from a capped leak-off line on MO 1-2301-3 valve; and,
- 1-2303-1D inboard main steam isolation valve failed to operate during testing.

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

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

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- Unit 1/2 emergency diesel generator load test following auto start relay replacement;
- flow test for 1/2 emergency diesel generator cooling water pump overhaul;
- battery charger testing following repair of 1A 125 Vdc charger;
- turbine testing following turbine control valve #1 pressure switch repair;
- valve testing following replacement of high pressure coolant injection inlet drain pot drain valve 1-2301-30; and
- control room emergency filtration system test following system outage.

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

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

b. Findings

No findings were identified.

1R21 Component Design Bases Inspection (71111.21)

.1 (Closed) Unresolved Item (URI) 05000254/2011009-05; 05000265/2011009-05: Diesel Generator Technical Specification Frequency and Voltage Variation not Considered in Loading Calculations

a. Inspection Scope

During a 2011 Component Design Basis Inspection (CDBI), the inspectors opened Unresolved Issue (URI) 05000254/2011009-05; 05000265/2011009-05 related to the operability of all structure, systems, and components (SSCs) over the full range of frequency and voltage allowed by TS. At that time, resolution to this issue required reviewing the results of the licensee's evaluation of the effects of the full TS voltage and frequency ranges on all SSCs and verifying the licensed load limit for the emergency diesel generators (EDGs) in order to determine the significance of the finding. In late December 2012, the licensee completed the evaluation; however, the inspectors evaluated the risk based on the worst possible case scenario to determine the significance.

During this inspection, the inspectors communicated the results of the evaluation to the licensee. This review did not represent an inspection sample. Specific documents reviewed are listed in the Attachment of this report.

b. Findings

Introduction: The inspectors identified a finding, with two examples, of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to verify and ensure that operation of the EDGs at the TS 3.8.1.2 limits of voltage and frequency would not affect the safety-related SSCs.

Description: During a 2011 CDBI, the inspectors reviewed the licensee's actions in response to NRC Information Notice 2008-002. In particular, the inspectors noted the licensee staff had evaluated the effects of lower than nominal frequency on pump flows and pressures and determined there were no adverse effects on pump flow and pressures and the upper frequency limit did not cause the EDG loading to exceed the 200 hour per year rating (2973 kW). During the inspection, the inspectors had identified a concern regarding exceeding 110 percent of the continuous EDG rating. After consulting with the Office of Nuclear Reactor Regulations, the inspectors determined the EDGs were not licensed to exceed the UFSAR loading limit of 2860 kW (the 2000 hour/year rating, also equal to 110 percent of the continuous rating). Additionally, the licensee did not have a calculation or design review demonstrating that there were no detrimental effects on any safety-related SSCs over the full range of frequency and voltage allowed by TS. Specifically, the torque developed by a motor is directly proportional to the square of the voltage and inversely proportional to the square of the frequency. The inspectors compared the TS limits to the nominal values for voltage and frequency and determined the torque developed by the motors supplied by the EDGs could vary as much as 14 percent from the nominal torque. The inspectors informed the licensee of their concerns about the operability of the supplied motors being able to meet the design requirements, particularly for pumps and motor-operated valves under the worst torque conditions (minimum voltage and maximum frequency) and EDG loading for the best conditions. The inspectors asked for any licensing document to support exceeding the 2000 hour load limit. The licensee did not have any documentation that allowed exceeding 110 percent of the EDG continuous rating. Further review by the inspectors revealed the EDGs were originally qualified for use in a nuclear plant, in accordance with Regulatory Guide 1.9 and Institute of Electrical and Electronic Engineers 387, to only two ratings; the continuous rating and 110 percent of the continuous rating (a level, that when operated at for 2 hours in a 24 hour period, would not cause the need for more or earlier maintenance). The EDGs were only licensed to two ratings to ensure reliability and availability as a standby power source for nuclear plants. Despite numerous reviews of the calculation performed after receipt of Information Notification 2008-02, the licensee had not recognized that exceeding 110 percent of the continuous rating was exceeding the licensed rating for the EDG.

In response to the inspectors' questions during the original inspection, the licensee entered the issue into the CAP as Issue Report (IR) 01288784, "CDBI - Technical Specification Limits for EDG," dated November 10, 2011. A review of operating procedures provided reasonable assurance the EDGs would be operated near the midpoint of the allowed TS range during a potential event until the licensee demonstrates operability over the full TS range. An operations standing order was put in place to put additional emphasis on operating the EDG as close to 60hz as possible and to avoid operation near the 110 percent limits. The issue was an unresolved issue pending the results of the licensee's evaluation of the effects of the full TS voltage and frequency ranges on all SSCs and verifying the licensed load limit for the EDGs. The unresolved issue was documented in the CDBI NRC Inspection Report 05000254/2011-009; 05000254/2011-009.

In December 2012 the licensee completed the calculations and provided the results to the inspectors. The calculations confirmed that EDGs would exceed 110 percent of the continuous load limit under the worst loading conditions. Specifically, when the Unit 0 or Unit 2 EDG was aligned to Unit 1 during a loss of offsite power (LOOP), they could exceed the rating by ~ 20 kW. Previously, the inspectors had analyzed the theoretical worst case outcome for the plant assuming that multiple SSCs would be inoperable due to the worst case voltage and frequency effects.

<u>Analysis</u>: The inspectors determined the failure to analyze the combined TS-allowed voltage and frequency variations affects on the EDGs and the supplied SSCs was a performance deficiency. Specifically, the EDG could be overloaded and supplied SSCs could become inoperable if operated under varying conditions. The performance deficiency was determined to be more than minor because it was associated with the Design Control attribute of the Mitigating Systems Cornerstone, and adversely affected the Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee failed to ensure the TS-allowed operating band for EDG frequency and voltage could not affect the operability and reliability of safety-related SSCs.

The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings." Because the finding impacted the Mitigating Systems, Cornerstone, the inspectors screened the finding through IMC 0609 Appendix A, "The Significance Determination Process for Findings At-Power," using Exhibit 2, "Mitigating Systems Screening Questions." The inspectors answered "yes" to the question "Does the finding represent an actual loss of function of at least a single train for > it's Tech Spec Allowed Outage Time?" The risk-significant scenarios involve a LOOP concurrent with a loss of coolant accident (LOCA). During such an event, the EDGs are assumed to operate at minimum TS-allowed voltage and maximum TS-allowed frequency. This in turn could affect some supplied loads such that pump or valve motors may not meet their design requirements under worst torque conditions. The risk of the issue could be bounded assuming failure of two large motor loads such as a residual heat removal pump and a core spray pump. The inspectors contacted a regional senior reactor analyst (SRA) for a detailed risk evaluation.

The SRA performed a Phase 3 internal events SDP evaluation of the finding using SAPHIRE Version 8.0.8.0 and the Quad Cities Standardized Plant Analysis Risk (SPAR) model (Version 8.18). From the SPAR Model, the frequency of a LOCA (large, medium, and small) was 8.53E-4/yr. A LOOP initiating event analysis (with all four classes of LOOPs) was run assuming failure of a Division 1 residual heat removal pump and a core spray pump. The resulting conditional core damage probability was 4.81E-4. Using these values the SRA calculated the core damage frequency to be 4.10E-7/yr.

Based on the Phase 3 analysis, the inspectors determined that the finding was of very low safety significance (Green). This evaluation bounds the results of the licensee's calculation results so the result is still Green. No cross-cutting aspect was assigned since the analysis was last performed in May of 2007 and is not necessarily reflective of current performance.

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control" requires, in part, that measures shall be established to assure applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. It further states design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

Contrary to this requirement, from construction to the present, the licensee failed to demonstrate the adequacy of TS 3.8.1.2 allowed voltage and frequency variations, either by calculation or design review. Specifically, the licensee failed to verify the EDGs loading would not exceed the maximum licensed value and that all supplied SSC could not be made inoperable due to having been operated at the limits of the allowed band. The licensee restricted EDG operation to near the midpoint of the allowed TS range during any potential event until the licensee demonstrates operability over the full TS range. However, because this violation was of very low safety significance and it was entered into the licensee's CAP (IR 01288784, "CDBI – Technical Specification Limits for EDG"), this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000254/2012005-01; 05000265/2012005-01, "Diesel Generator Technical Specification Frequency and Voltage Variation not Considered in Loading Calculations")**.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- QCOS 6600-51, Unit 1 Emergency Diesel Generator Start Failure Logic Test (Routine);
- QCOS 1100-07, SBLC Pump Flow Rate (Routine); and
- QCOS 1600-07, Reactor Coolant Leakage in the Drywell (RCS).

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;

- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted two routine surveillance testing samples, and one reactor coolant system leak detection inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

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

a. Inspection Scope

The NSIR headquarters staff performed an in-office review of the latest revisions of the Emergency Plan and various Emergency Plan Implementing Procedures located under ADAMS Accession Numbers ML12088A343 and ML12192A510 as listed in the Attachment to this report.

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

This inspection constituted one review sample as defined in IP 71114.04-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

The inspection activities supplement those documented in NRC Inspection Report 05000254/2012002; 05000265/2012002 and constitute one complete sample as defined in IP 71124.01-05.

.1 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements to verify conditions.

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed selected occurrences where a worker's electronic personal dosimeter noticeably malfunctioned or alarmed. The inspectors evaluated whether workers responded appropriately to the off-normal condition. The inspectors assessed whether the issue was included in the CAP and dose evaluations were conducted as appropriate.

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors selected several sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact.

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

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

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

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors discussed with the radiation protection manager the controls and procedures for high-risk high radiation areas and very high radiation areas. The inspectors discussed methods employed by the licensee to provide stricter control of very-high radiation area access as specified in 10 CFR 20.1602, “Control of Access to Very-High Radiation Areas,” and Regulatory Guide 8.38, “Control of Access to High and Very-High Radiation Areas of Nuclear Plants.” The inspectors assessed whether any changes to licensee procedures substantially reduce the effectiveness and level of worker protection.

The inspectors discussed the controls in place for special areas that have the potential to become very-high radiation areas during certain plant operations with first-line health physics supervisors (or equivalent positions having backshift health physics oversight authority). The inspectors assessed whether these plant operations require communication before-hand with the health physics group, so as to allow corresponding timely actions to properly post, control, and monitor the radiation hazards including re-access authorization.

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

b. Findings

No findings were identified.

.6 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed with the radiation protection manager any problems with the corrective actions planned or taken.

b. Findings

No findings were identified.

.7 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

b. Findings

No findings were identified.

.8 Problem Identification and Resolution (02.09)

a. Inspection Scope

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

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Emergency Alternating Current Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency Alternating Current Power System performance indicator for Quad Cities Unit 1 and Unit 2 for the period from the fourth quarter 2011 through third quarter 2012. To determine the accuracy of the Performance Indicator (PI) data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009 was used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports and NRC integrated inspection reports for the period of October 2011 through September 2012 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI emergency alternating current power system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - High Pressure Injection Systems performance indicator for Quad Cities Unit 1 and Unit 2 for the period from the fourth quarter 2011 through third quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009 was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC integrated inspection reports for the period of October 2011 through September 2012 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.3 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Heat Removal System performance indicator for Quad Cities Unit 1 and Unit 2 for the period from the fourth quarter 2011 through third quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009 were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC integrated inspection reports for the period of October 2011 through September 2012 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.4 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Residual Heat Removal System performance indicator for Quad Cities Unit 1 and Unit 2 for the period from the fourth quarter 2011 through third quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009 was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC integrated inspection reports for the period of October 2011 through September 2012 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI residual heat removal system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.5 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Cooling Water Systems performance indicator for Quad Cities Unit 1 and Unit 2 for the period from the fourth quarter 2011 through third quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009 were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC integrated inspection reports for the period of October 2011 through September 2012 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.6 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity PI for Quad Cities Nuclear Power Station Units 1 and 2 for the period from the third quarter 2011 through the third quarter 2012. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's reactor coolant system chemistry samples, TS requirements, issue reports, event reports, and NRC integrated inspection reports 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. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.7 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the occupational radiological occurrences PI for the period from the third quarter 2011 through the third quarter 2012. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarms and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very-high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors sampled licensee submittals for the radiological effluent TS/Offsite Dose Calculation Manual radiological effluent occurrences PI for the period from the third quarter 2011 through the third quarter 2012. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009 to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's issue report database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

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

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of June 1, 2012 through December 1, 2012, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

.4 Selected Issue Followup Inspection: IR 1431240, Unit 2 Emergency Diesel Generator Breaker Tripped During QCOS 6600-42

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting a trip of the Unit 2 EDG output breaker during performance of QCOS 6600-42, "Unit 2 Emergency Diesel Generator Load Test." On October 25, 2012, the procedure was being performed as a post-maintenance test following planned maintenance on the diesel generator and the emergency diesel generator cooling water pump. The licensee promptly initiated a cause investigation/troubleshooting team and entered the issue into the CAP as IR1431240. After performing troubleshooting, the licensee determined that the EDG and voltage regulator responded as expected based on the electrical tuning performed during the voltage regulator replacement in the previous refueling outage under WO 1528286. The cause of the trip was determined to be addition of real load without appropriate adjustment of reactive load resulting in activation of the "loss of field" relay and trip of the diesel generator output breaker. On the next operating shift after the cause of the trip was determined, the operating crew briefed the response of the voltage regulator to the previous manipulations and discussed the expected response of the emergency diesel governor and generator voltage regulator while paralleled to the grid. Subsequently, the load test was performed with no issues.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

Introduction: A finding of very low safety significance (Green) and an NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedure, and Drawings," was self-revealed when the operator performing the Unit 2 emergency diesel generator surveillance test failed to follow procedural direction when applying load to the machine resulting in the Unit 2 diesel generator (DG) being inoperable for approximately 7 hours while troubleshooting activities were conducted.

Description: On October 25, 2012, operators were performing a post-maintenance load test on the Unit 2 EDG when the output breaker tripped on actuation of the generator voltage regulator "loss of field" relay at 09:17 a.m. The licensee shut down the diesel generator and initiated IR 1431240. The operating crew began an event followup investigation while troubleshooting activities reviewed instrumentation and computer records.

Procedural direction for the activity was QCOS 6600-42, “Unit 2 Emergency Diesel Generator Load Test.” Immediately after the diesel output breaker was closed to synchronize the machine with the grid in step H.4.h.(4) of QCOS 6600-42, step H.4.h.(5) directed the operator to “Apply an initial load of at least 200 kilowatt (kW) using DG governor control switch.” The procedure directed application of initial load to prevent a reverse power trip of the output breaker due to minor grid perturbation while the diesel generator is paralleled to the grid. The procedural note preceding the next step (step H.4.i) stated that “The DG should be loaded gradually to reduce thermal stresses and maximize engine life. The loading time is not critical, but should occur over a period of approximately 2 to 4 minutes.” Step H.4.i directed the operator to concurrently load the DG to 2340 kW while maintaining outgoing reactive load (kVARs) at approximately one-half the DG kW.

The licensee determined that when the EDG output breaker was closed, real load was observed to be 500 kW when the operator took the governor control switch to RAISE causing real load to increase. The last kW value observed prior to the trip was 1800 kW and the operator felt that the load was still increasing when the output breaker tripped. With the real load at 1800 kW, the reactive load was observed to be -1200 kVARs (which is the lowest reading on the meter). Field observation determined that the CEH Relay or “loss of field “relay had actuated at the 2252-10 cabinet. The CEH relay was designed to trip the output breaker when a loss of excitation occurred when the machine was operating in a synchronous mode. This trip was designed to protect the generator and the power distribution system from damage due to potential low voltage and high current conditions that could occur when the generator experiences a loss of field while paralleled to another power source. This trip is not active when the EDG is operating in the Isochronous or emergency mode.

Interviews with operators that were involved in tuning and post-maintenance testing of the new voltage regulator installed on April 12, 2012, identified that the new regulator exhibited different operating characteristics than the previous regulator or other two safety-related EDGs. Specifically, the new regulator was significantly stronger (more responsive), and when real load was adjusted on the machine, reactive load decreased. While the operators recognized these differences in operating characteristics, they evaluated the procedural instructions and determined that no change to the operating or surveillance procedures were required. No evidence was identified that indicated operator training requirements were considered at the time and the operator curriculum review committees had not evaluated the change in operating characteristics of the machine for training needs.

With the apparent cause of the breaker trip identified, operators performed the appropriate briefs and started the surveillance again at 3:45 p.m. on the same day. The EDG was synchronized to the bus at 4:28 p.m. and was at rated load at 4:32 p.m. (7 hours, 15 minutes after the initial attempt to raise load).

<u>Analysis</u>: The operator performing the surveillance applied significant real load to the diesel generator immediately after paralleling without verifying the appropriate real load to reactive load ratio was maintained. During this event, the operator had an initial loading of approximately 500 kW and therefore fully met the intent of step H.4.h.(5) of the procedure. Addition of more real load should have been accomplished through execution of step H.4.i of the procedure. The operator’s execution of the procedure caused the trip of the output breaker impacting reliability and was a performance

deficiency. The operator's actions resulted in delay of the post-maintenance test and in the DG being inoperable for an additional 7-1/4 hours while troubleshooting was conducted on the DG. This finding was more than minor because it affected the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to imitating events to prevent undesirable consequences. The deficiency impacted the Equipment Performance attribute for reliability in that the performance deficiency challenged the voltage regulator protective feature and could have damaged the excitation circuit for the DG.

Inspectors performed the Phase 1 screening of the finding using the SDP and determined that the issue was of very low safety significance or Green. The questions in IMC 0609, Attachment 4, Appendix A, Exhibit 2, Section A were answered "No" by inspectors because the diesel was quickly made available for emergency response following the breaker trip, and the remaining DG and both offsite power sources were operable.

Inspectors determined that a contributor to this finding was that the change in voltage regulator performance was not communicated to the operating staff in either training or procedural formats. When questioned, several operators interviewed believed that the steps to close the output breaker and apply real load to the diesel generator comprised a "two handed operation (i.e. the output breaker is closed with one hand and the governor is taken to RAISE with the other). Two-handed operation is not required if the machine speed is appropriately adjusted prior to synchronization so that the synchroscope is moving approximately one revolution per 30 seconds as specified by procedure. Inspectors determined this finding to be cross-cutting in Human Performance-Resources in that the licensee ensures that appropriate training is provided to assure nuclear safety (H.2(b)).

<u>Enforcement</u>: Title 10 CFR 50, Appendix B, Criterion V states in part those activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. NO-AA-10, "QA Topical Report," implemented the regulatory requirement to have and follow written procedures for quality activities in Chapter 5. In definition 2.101 of Appendix D of NO-AA-10 quality related was defined in part as activities which influence quality of safety-related items or work related to those systems, structures, and components as defined in USAR, Table 3.2-1. Updated Safety Analysis Report Table 3.2-1 step 3.2.4 listed standby DGs as one of the electrical components meeting the requirements listed above.

QCOS 6600-42, "Unit 2 Emergency Diesel Generator Load Test,"was a quality procedure governing the specific activity being performed. After the diesel generator was paralleled to the electrical grid using QCOS 6600-42, step H.4.i directed the operator to concurrently load the DG to 2340 kW while maintaining outgoing reactive load (kVARs) at approximately one-half the DG kW.

Contrary to the above, on October 25, 2012, the operator did not perform the diesel loading in accordance with the procedure in that real load was applied in a manner that changed reactive load significantly in the opposite polarity from real load and resulted in a "loss of field" trip of the DG output breaker. Because this violation was of very low safety significance, it was entered into the licensee's CAP as IR 1431240, and immediate actions restored compliance, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement manual **(NCV 05000265/2012005-02, "Failure to Follow Surveillance Procedure").**

The surveillance was completed to ensure no impact to the voltage regulating circuit and restore operability for prior work activities. Immediate corrective actions included revision of procedures that operated the DG in parallel with another source to include information reminding operators that the Unit 2 EDG responded differently to load adjustments and care should be used when making adjustments to prevent a "loss of field" trip.

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

.1 (Closed) Licensee Event Report (LER) 05000-254/2012-004-00: Breech in Secondary Containment

a. Inspection Scope

This event occurred on September 6, 2012, when the Unit 2 high radiation sampling system (HRSS) door in the Unit 2 reactor building interlock opened unexpectedly when the door to the Unit 2 reactor building was opened for normal access. The licensee determined that the door latch was degraded and the door opened due to the impact of positive pressure when the reactor building door opened. With both the reactor building door and the HRSS door open, an air flow path existed from the reactor building to the environment. The worker recognized the open Unit 2 HRSS door, shut the door, and notified the main control room. A review of the alarm history determined that the Unit 2 HRSS door had been open for 8 seconds.

As a corrective action to this issue, the licensee has welded the Units 1 and 2 HRSS doors shut. Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

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

b. Findings

A licensee-identified finding is discussed in Section 4OA7 of this report.

.2 (Closed) Licensee Event Report (LER) 05000-254/2012-003-00: Degraded Flood Protection Barrier

a. Inspection Scope

This event was identified on August 6, 2012, when the licensee discovered that both loops of core spray were inoperable on Unit 1 due to degraded flood barriers. Additional discussion will be included below in the associated NCV of TS. Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

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

b. Findings

(1) Both Unit 1 Core Spray Subsystems Inoperable due to Degraded Flood Barriers

Introduction: A self-revealed finding of very low safety significance (Green) and associated NCV of TS 3.5.1.K were identified for two core spray (CS) subsystems inoperable due to degraded flood barriers on August 6, 2012.

Description: On August 5, 2012, the licensee performed surveillance for the reactor building floor drain ball valves to verify leak tightness. There was one floor drain ball valve associated with each reactor building corner room and one floor drain ball valve associated with the reactor building basement sump. These valves are normally closed to form a watertight boundary between rooms. These valves are credited in the UFSAR as a flood barrier for internal flooding and are required to be functional to support operability of equipment inside the corner rooms.

On August 5, 2012, the licensee identified leakage past the 1B CS room floor drain ball valve during the surveillance test. Technical Specifications 3.5.1, Condition B was entered for one inoperable core spray subsystem. The licensee installed a plug into the floor drain line for the 1B CS corner room and leak tested the plug to restore watertight integrity of the room. The licensee exited Condition B of TS 3.5.1 upon successful completion of the post-maintenance testing for the floor drain plug.

On August 6, 2012, the licensee continued the surveillance for the reactor building floor drain ball valves. On Unit 2, the licensee identified leakage past the floor drain ball valve isolating the corner room shared by Unit 2 reactor core isolation cooling (RCIC) and 2B CS systems. Due to the construction of the reactor building basement, the Unit 1 RCIC/1A CS corner room was not separated from the Unit 2 RCIC/2B CS room by a flood barrier. Therefore, the degraded flood barrier would allow water from the Unit 2 reactor building basement into the Unit 2 RCIC/2B CS room and the water would migrate to the Unit 1 RCIC/1A CS room. This water would not migrate further because the Unit 1 RCIC/1A CS room floor drain ball valve was found to properly isolate during the surveillance. By design, the assumption was all equipment in both rooms would be impacted by an internal flood event in either room. Upon discovery of the leakage, the licensee entered Condition B of TS 3.5.1, ECCS System," for both Unit 1 and Unit 2 due to one CS system inoperable and TS 3.5.3, "RCIC," Condition A for both Unit 1 and Unit 2 due to inoperable RCIC systems. The licensee installed a plug into the drain line for the Unit 2 RCIC/2B CS room, leak tested the plug, and exited TS 3.5.1 Condition B and 3.5.3 Condition A for both Unit 1 and Unit 2 upon successful completion of post-maintenance testing.

Inspectors reviewed the operators' implementation of the TS for both valve failures and concluded that the TS were implemented in accordance with the rules of use and application of the TS. When the operators became aware of the degraded condition, they entered the appropriate conditions and executed the required actions within the time frames specified.

The failure of the 1B CS and Unit 2 RCIC/2B CS floor drain ball valves was caused by wear related degradation that occurred at the valve-to-actuator coupling that allowed the valve to not be fully seated despite the actuator indicating full closed. This design (ball valves and remote actuators) was installed in 2008 and this surveillance was established with a 4-year periodicity and no preventative maintenance or inspection was performed on the coupling in that period. Since the surveillance tested the floor drain ball valves in the as-found condition, the condition existed prior to discovery and existed at the same time for both valves. Therefore, both Unit 1 CS subsystems were inoperable due to degraded flood barriers. With both systems inoperable simultaneously, TS 3.5.1 Condition K required immediate entry into Limiting Condition for Operation (LCO) 3.0.3. This action was not taken because operators were not aware that the equipment was not operable.

Technical Specification 3.5.1 Condition K was designed to require a unit shut down when an emergency core cooling system (ECCS) function is lost and two low pressure CS subsystems is one of the designated criteria. For the condition of these two valves failed, a single internal flooding event into any one corner room or the reactor building basement on either unit would only make one train of CS unavailable due to the physical layout of the units. Therefore, the CS function would have been maintained for any single postulated internal flooding event and all ECCS safety functions would still be satisfied for both units since the redundant train of CS would be unaffected by the single internal flood event and would have remained functional.

Analysis: The inspectors concluded that the failure of the floor drain ball valves to isolate was a performance deficiency and a finding. Inspectors concluded that the issue was within the licensee's ability to control and prevent through implementation of timely and systematic preventative maintenance and surveillance activities. With no periodic inspections of the actuator coupling in place and no operating history to establish a performance basis for the new valves' surveillance interval, the 4-year surveillance frequency established by the licensee allowed the degradation to occur undetected until two corner rooms were simultaneously impacted. The performance deficiency was more than minor because the issue challenged the Mitigating Systems Cornerstone objective to ensure the availability of systems to respond to initiating events to prevent undesirable consequences. In this case, the cornerstone attribute of protection against external factors (internal flood) was adversely impacted.

The inspectors performed an SDP Phase 1 screening for the finding using IMC 0609, Attachment 04, "Initial Characterization of Findings," and IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," and answered the first four questions "No." Therefore, the finding screened as very low safety significance, or Green.

Inspectors determined that a contributor to this finding was that the Operations and Engineering Departments were aware that the reach rod operators for the floor drain ball valves were difficult to operate, but did not enter operating concerns into the CAP. Discussions took place between multiple equipment operators and engineers about the difficulty to operate these ball valves. Operators were informed that these valves had tight tolerances, were self cleaning, and difficult operation of these valves was an expected condition. However, an issue report was never entered into the CAP to make the organization aware of this issue, assess for proper operation, trend the valve performance, identify potential failure mechanisms, or to document conclusions. The inspectors identified that this issue had a cross-cutting aspect in the area of Problem Identification and Resolution - Identification (P.1(a)).

Enforcement: License condition 3.B states in part that the licensee shall operate the facility in accordance with TS.

Technical Specifications 3.5.1, ECCS-Operating was applicable in Modes 1, 2 and 3. Condition K of that LCO was applicable when two low pressure spray subsystems are inoperable for the conditions described in this event (i.e. degraded flood barriers supporting operability).

- The 1B core spray subsystem was inoperable due to failure of the corner room floor drain ball valve to close and provide the leak tight barrier.
- The 1A core spray subsystem was inoperable due to failure of the 2B CS/RCIC room floor drain ball valve to close and provide the leak tight barrier.

Technical Specifications 3.5.1.K required immediate entry into LCO 3.0.3. While in Modes 1, 2 or 3, LCO 3.0.3 requires in part that action to be taken within one hour to place the unit in Mode 3 in 13 hours and Mode 4 within 37 hours.

Contrary to the above, in August 2012, the licensee did not recognize that two CS subsystems were inoperable and did not take action within 1 hour to place the unit in Mode 3 within 13 hours as required by LCO 3.0.3 for two inoperable CS subsystems. Since the surveillance tests the ball valves in their as found condition (shut) the degraded condition of the flood barriers were present for both floor drain ball valves prior to the surveillance test on August 5, 2012. Therefore, the 1A CS subsystem and the 1B CS subsystem were simultaneously inoperable at the same time before August 5, 2012, and therefore, the licensee did not operate the facility in accordance with TS. Because this violation was determined to be of very low safety significance, and this issue has been entered into the licensee's CAP as IR 1397306, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000254/2012005-03, "Both Unit 1 Core Spray Subsystems Inoperable")**. Immediate corrective actions were taken to restore watertight integrity using plugs in the drain lines. Corrective actions for this issue have included repairs to the floor drain ball valves, extent of condition inspection of all reactor building floor drain ball valves and shortening the surveillance interval from 4 years to 2 years.

.3 <u>(Closed) Licensee Event Report (LER) 05000265/2012-004-00: Drywell Radiation Monitor Failed Downscale</u>

a. <u>Inspection Scope</u>

On September 21, 2012, the Unit 2, 2B drywell radiation monitor was found downscale by control room operators during routine panel monitoring and documented in the CAP as IR 1416687. The monitor provides input into one division of the primary containment logic designed to limit the release of fission products to the environment. This isolation logic is initiated by two radiation monitors, both of which are required to initiate containment isolation on high drywell radiation. Downscale failure of one monitor resulted in loss of the Group 2 isolation function for drywell high radiation. This function closes isolation valves for a number of systems that penetrate containment such as residual heat removal shutdown cooling supply and discharge to radwaste, drywell vent and purge system, drywell nitrogen and pneumatic supply, and reactor building main vent isolation. All of these valves except one of the drywell vent valves are normally closed. Containment isolations for other functions were not affected by the failure.

The 2B drywell radiation monitor was replaced with a new monitor to restore function. Licensee analysis of the problem determined that dust buildup inside the module caused subcomponents to malfunction resulting in the downscale indication. The licensee had previously not considered the inside of the module to be an accessible area and the preventative maintenance tasks did not disassemble and clean this portion of the monitor. Review of the vendor documentation determined that the vendor maintenance recommendations did not address this vulnerability. With no relevant operating experience and no vendor recommended maintenance actions identified, inspectors determined that the previous maintenance scope was reasonable given the equipment configuration and expected failure modes. The licensee subsequently modified the preventative maintenance task to disassemble and clean these components. The remaining detectors were subsequently scheduled for the improved maintenance.

Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

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

b. Findings

No findings were identified.

4OA5 Other Activities

.1 (Closed) Diesel Generator Technical Specification Frequency and Voltage Variation not Considered in Loading Calculations (URI 5000254/2011009-05; 5000265/2011009-05)

This issue is described in Section 1R21 and was resolved to an NCV of 10 CFR Part 50, Appendix B, Criterion III, Design Control. The URI is closed.

.2 (Closed) NRC Temporary Instruction (TI) 2515/187, Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns

a. Inspection Scope

This inspection was initially discussed in NRC Integrated Inspection Report 05000254/2012-004; 05000265/2012-004. Inspector(s) verified that licensee's walkdown packages incorporated into Engineering Change 391021, "Flood Walkdown Report, Docket Nos. 50-254 and 50-265," contained the applicable elements specified in NEI 12-07 Walkdown Guidance document.

The inspectors accompanied the licensee on their walkdown of below grade exterior walls and penetrations in the reactor building. Specifically inspectors accompanied the licensee on walkdowns in 2A residual heat removal room and Unit 1 high pressure coolant injection room. The inspectors verified that the licensee confirmed required penetration seals were in place and exterior walls showed no obvious signs of degradation due to ground water intrusion.

The inspectors observed the licensee's walkdown simulations of critical mitigation procedures to verify that appropriate techniques and consideration were provided for the simulations.

- Qualified operators were observed in the simulated performance of the QCOA 0010-16 (Flood Emergency Procedure) task to add water to the Torus through the residual heat removal test lines.
- Qualified operators were observed in the simulated performance of the QCOA 0010-16 (Flood Emergency Procedure) task to stage and use the portable pump equipment (including scaffold erections.

The inspectors independently performed walkdown and verified below grade exterior walls and penetrations in the Unit 2 high pressure coolant injection room and the 2B residual heat removal room. In addition, inspectors performed independent walkdowns of QCOA 0010-16 tasks to deenergize station loads and to shut down both reactors. Inspectors verified that the information identified in the independent walkdowns matched the information documented during the licensee's inspections of these spaces and mitigating task simulations.

The inspectors verified that noncompliance with current licensing requirements, and issues identified in accordance with the 10 CFR 50.54(f) letter, Item 2.g of Enclosure 4, were entered into the licensee's corrective action program. In addition, issues identified in response to Item 2.g that could challenge risk significant equipment and the licensee's ability to mitigate the consequences will be subject to additional NRC evaluation.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 8, 2013, the inspectors presented the inspection results to Mr. T. Hanley and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The licensed operator requalification training annual operating test results with the Licensed Operator Requalification Lead Instructor, Mr. G. Thennes, via telephone on December 11, 2012.

- The inspection results for the areas of radiological hazard assessment and exposure controls; and RCS specific activity, occupational exposure control effectiveness, and RETS/ODCM radiological effluent occurrences performance indicator verification with Mr. T. Hanley, Site Vice President, on December 13, 2012.

- The inspectors presented the inspection results for the CDBI unresolved issue to Mr. T. Hanley and others of the licensee staff via telephone on December 19, 2012. The licensee acknowledged the issues presented.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

- A licensee-identified finding of very low safety significance (Green) and associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," were identified on November 23, 2012, when the licensee identified that a temporary alteration to the plant had been in place for longer than allowed by procedure without a 50.59 review. During troubleshooting under WO 1527623 on April 30, 2012, the licensee changed the operating set point for differential pressure controller 1-5741-8557. The setpoint change was part of an activity to improve responsiveness of the reactor building ventilation system to changes in differential pressure. Troubleshooting continued until June 1, 2012, when the active troubleshooting stopped, but the work activity remained active while other work was performed that impacted reactor building ventilation. On November 23, 2012, the licensee identified that the temporary alteration had been in place for more than 90 days with no 50.59 review having been performed as required by Step 4.1.3 of MA-AA-716-004,"Control of Troubleshooting." The finding is more than minor because it adversely affected the design control attribute of the Barrier Integrity Cornerstone objective to provide assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Failure to adhere to process controls for design control during plant modifications or alterations could result in a more significant challenge to plant barriers. The inspectors performed an SDP Phase 1 screening for the finding using IMC 0609, Attachment 04, "Initial Characterization of Findings," and IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," and answered the Reactor Containment questions "No." Therefore, the finding screened as very low safety significance, or Green.

  Title 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings" requires in part that activities affecting quality be accomplished in accordance with written procedures. MA-AA-716-004 governs troubleshooting activities and states in part in Step 4.1.3, "10 CFR 50.59 review is also required if a temporary alteration to the facility is established in direct support of the troubleshooting, and the temporary alteration will be installed for 90 days or greater while at power." Contrary to the above, the temporary alteration was in place for more than 90 days without a 50.59 review being performed. The licensee entered the issue into the corrective action program as IR 1430938 and performed the required 50.59 review. Additional reviews were performed to provide assurance that all other changes were being tracked and reviewed as required by procedure.

- A licensee-identified finding of very low safety significance (Green) and associated NCV of TS 5.4.1.a was identified on May 1, 2012, when the licensee identified that a preventative maintenance (PM) task to adjust/repair/replace door latches was not completed within the specified timeframe. This yearly PM for the Unit 2 HRSS door was last completed in January 2010. The work package documentation was not closed so no subsequent task was scheduled. Failure to properly close the task and reschedule the PM was a finding. When the licensee identified the deficiency, a request was initiated to defer the two missed PMs and re-schedule the next PM for January 2013. While the extension was performed in accordance with the procedure and potential consequences of failure of the door (i.e. maintenance rule functional failure) were included in the evaluation, no evaluation of the material condition of the door or latch was performed before the PM was extended. On September 6, 2012, the worker entering the interlock recognized that the Unit 2 HRSS door opened as he entered the airlock and took action to shut the door and notify the control room. A review of the alarm history determined that the Unit 2 HRSS was open for 8 seconds. The finding was more than minor because it adversely affected the SSC and Barrier Performance attribute of the Barrier Integrity Cornerstone objective to provide assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

  The process for deferring PMs was changed in August 2012. Inspectors verified that the revised process would require an assessment of work history, component performance, and a technical justification when a maintenance rule function failure is identified as a potential consequence because the process would dictate that maintenance rule components have a high consequence failure. Given these changes to the service request program the licensee would have a different classification and prioritization for a similar issue undergoing deferral.

  Technical Specifications 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation). Regulatory Guide 1.33, Appendix A, Section 9, “Procedures for Performing Maintenance,” states in part that maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures, or documented instructions appropriate to the circumstances. Contrary to the above, in January 2010, the licensee failed to implement MA-AA-716-011, “Work Execution and Closeout,” because a work task was left open which prevented the PM task from being rescheduled.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Hanley, Site Vice President
W. Beck, Regulatory Assurance Manager
J. Colgan, Chemistry Supervisor
D. Collins, Radiation Protection Manager
M. DeVault, Training Director
J. Garrity, Maintenance Director
R. Larkin, Manager of Projects
B. Magnuson, Operations Shift Manager
K. O'Shea, Acting Operations Director
K. Ohr, Site Engineering Director
T. Petersen, Regulatory Assurance Lead
P. Simpson, Licensing Manager
T. Wojcik, Online Work Control Manager

Nuclear Regulatory Commission

R. Orlikowski, Acting Chief, Reactor Projects Branch 1

Illinois Emergency Management Agency (IEMA)

R. Zuffa, IEMA

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000254/2012005-01; 05000265/2012005-01	NCV	Diesel Generator Technical Specification Frequency and Voltage Variation Not Considered in Loading Calculations (Section 1R21.1)
05000265/2012005-02	NCV	Failure to Follow Surveillance Procedure (Section 4OA2.4)
05000254/2012005-03	NCV	Both Unit 1 Core Spray Subsystems Inoperable (Section 4OA3.2(1))

Closed

05000254/2012005-01; 05000265/2012005-01	NCV	Diesel Generator Technical Specification Frequency and Voltage Variation Not Considered in Loading Calculations (Section 1R21.1)
05000265/2012005-02	NCV	Failure to Follow Surveillance Procedure (Section 4OA2.4)
05000254/2012005-03	NCV	Both Unit 1 Core Spray Subsystems Inoperable (Section 4OA3.2(1))
05000-254/2012-004-00	LER	Breech in Secondary Containment (Section 4OA3.1)
05000-254/2012-003-00	LER	Degraded Flood Protection Barrier (Section 4OA3.2)
05000-265/2012-004-00	LER	Drywell Radiation Monitor Failed Downscale (Section 4OA3.3)
05000254/2011009-05; 05000265/2011009-05	URI	Diesel Generator Technical Specification Frequency and Voltage Variation not Considered in Loading Calculations (Section 4OA5.1)
2515/187	TI	Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns (Section 4OA5.2)

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.

Section 1R01

- Letter to Bryan Hanson, Senior Vice President of Nuclear Operations Exelon Nuclear from Tim Hanley, Site Vice President Quad Cities Generating Station, Subject: Certification of 2012-2013 Winter Readiness
- QCOP 0010-01; Winterizing Checklist
- QCOA 0010-10; Tornado Watch-Warning, Severe Thunderstorm Warning or Severe Winds;
- WO 1588835; FNE Six Different Refuel Floor Heaters Not Working
- WO 1421582; ES Acceptance of Test Results by Sys. Manager for EC 380421 Replace Heating Coils

Section 1R04

- QCOP 6600-04, Diesel Generator ½ Preparation for Standby Operation, Revision 30
- M-22, Diagram of Service Water piping Diesel Generator Cooling Water, Sheet 3, Revision Z
- IR 1431483, Temporary Rigging Engineering Review Not Requested
- IR 1436245, NRC Identified Rigging Equipment Attached to Unit 1 RHRSW Piping
- WO 1432803, 1/2 DGCWP Cubicle Cooler Replacement
- WO 407312, Review of Trolley Beam in 1B/C RHRSW Vault
- ECR 406793, Rigging Guidance for DGCWP Cubicle Cooler Coil Replacement
- CC-AA-402, Maintenance Specification: Installation of Temporary Rigging, Revision 5
- TS 3.6.4.3, Standby Gas Treatment System.
- M-44, Diagram of Standby Gas Treatment System
- UFSAR 6.5, Fission Product Removal and Control System
- LER-92-013-00, Design Deficiency with the SBGTS Logic
- QCOP 7500-01, SBGTS Standby Operation and Start-up, Revision 19
- M-50, Diagram of Reactor Core Isolation Cooling

Section 1R05

- Pre-fire Plan FZ 11.1.1 A, B, and C; Unit 1 TB 547'-0" Elev. RHR Service Water Pumps
- Pre-fire Plan FZ 11.1.2 A, B, and C; Unit 2 TB 547'-0" Elev. RHR Service Water Pump
- Pre-fire Plan FZ 1.1.2.4; Unit 2 RB 647'-6" Elevation Third Floor
- OP-AA-201-009, Control of Transient Combustible Material, Revision 011
- Pre-fire Plan FZ 11.2.3; Unit 1 RB 554'-0" Elev. NW Corner Room-1A Core Spray

Section 1R11

- Operating examination scenarios for October 16, 2012
- OP-AA-101-111; Roles and responsibilities of On-shift Personnel; Revision 5
- OP-AA-101-111-1001; Operations Standards and Expectations; Revision 12
- OP-AA-101-113; Operator Fundamentals; Revision 7
- LORT Annual Exam Status Report, Quad Cities Station for 2012

Section 1R12

- Enterprise Maintenance Rule Production Database for the following systems:

  - Z5650: Electro-hydraulic Control

Section 1R13

- Work Week Safety Profile (12-42-04)
- Work Week Safety Profile (12-43-05)
- Work Week Safety Profile (01-44-06)

Section 1R15

- IR1427834; MO 1-2301-3 Valve Has Steam Leak From Capped Leak Off Line
- ECR 407163; 1-2301-3 Steam Leak and HPCI Room Temperature
- EC 389853; Impact of Steam Leak on HPCI System Operations
- IR 1445366; 1-0203-1D Inboard MSIV Failed to Operate during QCOS 0250-11
- QCOS 0250-11; MSIV Closure Scram Sensor Channel Non-outage Functional Test for RPS Channel B
- WO 1595343; MSIV Closure Scram Sensor Channel Non-outage Functional Test for RPS Channel B
- IR 882371; 2C MSIV Failed MSIV Scram Senor Channel Functional Test
- WO 1211392; 2C MSIV Failed MSIV Scram Senor Channel Functional Test

Section 1R19

- QCOS 6600-06; Diesel Generator Cooling Water Pump Flow Rate Test; Revision 40
- QCOS 5750-09; ECCS Room and DGCWP Cubicle Cooler Monthly Surveillance; Revision 35
- QCOS 6600-43; Unit 0 Emergency Diesel Generator Load Test; Revision 39
- WO 1570285; (LR) Diesel Generator Load Test (IST)
- WO 1555074; Diesel Generator Cooling Water Pump Group B Flow (IST)
- QCEMS 0210-02; Battery Charger Testing for Safety Related 125 VDC Batteries; Revision 5
- WO 1577567; U1 125 VDC Battery Charger #1 Output Voltage Adjustment
- WO 1573447; 1-2301-30 Has a Pinhole Thru Wall Steam Leak
- WO 1578846; Control Room Emergency Filtration System Test (IST)
- QCOS 5750-02; Control Room Emergency Filtration System Test; Revision 53

Section 1R21

- IR 0591442; Effect of EDG Freq on Loading and Pump Flows
- IR 1288784; CDBI – Technical Specification Limits For EDG
- IR1463907; Tech Spec Limits for EDG Freq and Voltage

Section 1R22

- WO 01424042; Emergency Diesel Generator Start Failure Logic Test
- QCOS 6600-51; Unit 1 Emergency Diesel Generator Start Failure Logic Test, Revision 8
- AR 01431688; Procedure QCOS 6600-51 Needs to Be Updated
- WC-AA-101; Online Work Control Process, Revision 19
- QCOS 1100-07; SBLC Pump Flow Rate
- QCOS 1600-07; Reactor Coolant Leakage in the Drywell (RCS)

Section 1EP4

- EP-AA-112; Emergency Response Organization (ERO) Emergency Response Facility (ERF) Activation and Operation; Revision 16
- EP-AA-112-200; TSC Activation and Operation; Revision 8
- EP-AA-112-400; Emergency Operations Facility Activation and Operation; Revision 11
- EP-AA-1000; Standardized Radiological Emergency Plan; Revision 21

Section 2RS1

- AR 1334882; INPO mid-cycle Observation: Radiation Worker Practices; March 1, 2012
- AR 1343955; 2012-06 Level 1 Personnel Contamination Event; March 21, 2012
- AR 1344982; 2012-08 Level 3 Personnel Contamination Event; March 23, 2012
- AR 1345279; 2012-09 Level 1 Personnel Contamination Event; March 24, 2012
- AR 1345282; 2012-10 Level 1 Personnel Contamination Event; March 24, 2012
- AR 1345927; 2012-13 Level 1 Personnel Contamination Event; March 26, 2012
- AR 1346881; 2012-15 Level 1 Personnel Contamination Event; March 28, 2012
- AR 1348245; 2012-21 Level 1 Personnel Contamination Event; March 30, 2012
- AR 1348493; Quad Radiation Protection: Electronic Dosimeter Dose Rate Alarms; April 25, 2012
- AR 1348502; 2012-22 Level 1 Personnel Contamination Event; March 31, 2012
- AR 1348747; 2012-24 Level 1 Personnel Contamination Event; April 1, 2012
- AR 1348772; Nuclear Oversight Identified Poor Worker Practice in Contaminated Area; April 1, 2012
- AR 1349220; Nuclear Oversight Identified Poor Worker Practice in Contaminated Area; April 2, 2012
- AR 1352703; Nuclear Oversight Identified Poor Contamination Control Practices; April 11, 2012
- AR 1398782; Nuclear Oversight Identified Poor Worker Practice on Refuel Floor; August 9, 2012
- AR 1409283; Personnel Receiving Neutron and Beta Dose; September 5, 2012
- AR 1450713; Nuclear Oversight Identified: No Follow-up When Contaminated Material Identified; December 11, 2012
- OU-AA-390; Spent Fuel Pool Material Log; Revision 0
- WO 1542236; Leak Testing of Sealed Radioactive Byproduct; November 1, 2012

Section 4OA1

- NEI 99-02; Regulatory Assessment Performance Indicator Guideline, Revision 6
- Enterprise Maintenance Rule Production Database for the following systems:
- Z2300; High Pressure Coolant Injection System
- Z1000; Residual Heat Removal System
- Z6600; Diesel Generator System
- Z1300; Reactor Core Isolation Cooling System
- Z9700; 345 kV Switchyard
- System Engineer Notebook and Accountability Logs for the following systems: Residual Heat Removal, RHR Service Water, Reactor Core Isolation Cooling, HPCI, and Emergency Diesel Generators
- CY-QC-110-608; Reactor Sample Routine; Revision 6
- CY-QC-120- 503; Reactor Water Iodine Analysis; Revision 2
- CY-QC-120-720; Plant Effluent Dose Calculations; Revision 4

- LS-AA -2090; Monthly Data elements for NRC Reactor Coolant system Specific Activity; Revision 4
- LS-AA-2140; Monthly Data Elements for NRC Occupational Exposure Control Effectiveness; Revision 5
- LS-AA-2150; Monthly Data Elements for RETS/ODCM Radiological Effluent Occurrences; Revision 5

Section 4OA2

- IR 1431240; U2 EDG Breaker Tripped During QCOS 6600-42
- QCOS 6600-42; Unit 2 Emergency Diesel Generator Load Test; Revision 40
- QCOS 6600-42; Unit 2 Emergency Diesel Generator Load Test; Revision 41
- QCOP 6600-02; Emergency Diesel Generator 1(2) Start-up; Revision 31
- QCOP 6600-02; Emergency Diesel Generator 1(2) Start-up; Revision 32
- EC 388636; Replace R2 in U2 EDG Voltage Regulator
- WO 1528286; QCOS 6600-48, ECCS and EDG Auto Start Test Aborted
- IR 1364779; NOS ID: U2 EDDG Troubleshooting VR Needs Post Job Critique

Section 4OA3

- IR 1409820; Two Interlock Doors Open At the Same Time
- IR 1362046; Non-Critical (8) Non-Safety Related PMS Found Not Credited; 5/1/2012
- IR 1418909; U-2 Interlock Door to the Outside Needs Adjusted; 9/26/2012
- IR 1432897; Secondary Containment Testing Requirements for Interlocks; 10/29/2012
- QCOS 1600-34; Monthly Secondary Containment Integrity Surveillance; Revision 15
- Service Request 77697 for IR 1362046; HRSS Door PM Extension
- MA-AA-716-011; Work Execution and Close Out; Revision 17
- Apparent Cause Report for IR 1409820; A Secondary Containment Breach When Unit 2 Reactor Building 595' Interlock and HRSS Doors Open at the Same Time; 9/6/2012
- LER 254/2012-004-00; Breach in Secondary Containment
- LER 254/2012-003-00; Degraded Flood Protection Barrier
- Apparent Cause Report for IR 1406071, 1397306, 1397691; 1(2)-4899-121 Floor Drain Ball Valves Fail Leak test Due to Travel Stop Misalignment
- IR 1406071; Reportability Review for RB Floor Drain Sump Valve Leakage; 8/28/2012
- IR 1397306; 1-4899-121 Failed QCOS 0020-04; 8/5/2012
- IR 1397691; 2B CS Room Floor Drain Ball Valve Failed QCOS 0020-04; 8/6/2012
- IR 1416687; 2-2419B 2B Drywell Rad Monitor Found Reading Downscale
- LER 265/2012-004-00; Drywell Radiation Monitor Failed Downscale
- Sorrento Electronics; E-115-876 (Revision 3), High Range Gamma Radiation Monitoring System Operation & Maintenance Manual

Section 4OA5

- AMEC Environment & Infrastructure, Inc., Flooding Walkdown Report for the Quad Cities Nuclear Power Station (Unit 1 & Unit 2)
- EC 391021; Flood Walkdown Report, Docket Nos. 50-254 & 50-265

Section 4OA7

- IR 1430938; Temp Alteration Under Troubleshooting Exceeded 90 Day Rule
- IR 1436175; Event Under IR 1430938 Determined to be a Crew Clock Reset
- MA-AA-716-004; Conduct of Troubleshooting; Revision 11

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
CAP	Corrective Action Program
CDBI	Component Design Bases Inspection
CFR	Code of Federal Regulations
CS	Core Spray
DG	Diesel Generator
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
HRSS	High Radiation Sampling System
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
kW	Kilowatt
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LER	Licensee Event Report
MSPI	Mitigating System Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PARS	Publicly Available Records System
PI	Performance Indicator
PM	Preventative Maintenance
PMT	Post-Maintenance Testing
RCIC	Reactor Core Isolation Cooling
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
Vdc	Volts Direct Current
WO	Work Order

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Sincerely,

/RA/

Robert Orlikowski, Acting Branch Chief
Branch 1
Division of Reactor Projects

Docket Nos. 50-254; 50-265
License Nos. DPR-29; DPR-30

Enclosure: Inspection Report 05000254/2012005; 05000265/2012005
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