July 27, 2007

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
Quad Cities Nuclear Power Station
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000254/2007003; 05000265/2007003

Dear Mr. Crane:

On June 30, 2007, 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 inspection findings which were discussed on July 10, 2007, with Mr. Tulon and other members of your staff.

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

Based on the results of this inspection, the inspectors identified four issues of very low safety significance (Green). Two of these issues involve violations of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into your corrective action program, the NRC is treating these findings and issues as Non-Cited Violations in accordance with Section V1.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulation 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.

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

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000254/2007003; 05000265/2007003
w/Attachment: Supplemental Information

cc w/encl:
Site Vice President - Quad Cities Nuclear Power Station
Plant Manager - Quad Cities Nuclear Power Station
Regulatory Assurance Manager - Quad Cities Nuclear Power Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional Operating Group
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Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
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Chairman, Illinois Commerce Commission
Chief Radiological Emergency Preparedness Section, Dept. Of Homeland Security
D. Tubbs, Manager of Nuclear MidAmerican Energy Company

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Document Control Desk - Licensing
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Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
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Chairman, Illinois Commerce Commission
Chief Radiological Emergency Preparedness Section,
Dept. Of Homeland Security
D. Tubbs, Manager of Nuclear
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Letter to C. Crane from M. Ring dated July 27, 2007

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000254/2007003;
05000265/2007003

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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:	05000254/2007003 and 05000265/2007003
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	Cordova, Illinois
Dates:	April 1, 2007, through June 30, 2007
Inspectors:	K. Stoedter, Senior Resident Inspector M. Kurth, Resident Inspector R. Baker, Resident Inspector - Duane Arnold A. Barker, Project Engineer T. Bilik, Engineering Inspector J. Bozga, Engineering Inspector A. Koonce, Reactor Engineer D. Melendez-Colon, Reactor Engineer W. Slawinski, Senior Health Physicist R. Ganser, Illinois Emergency Management Agency
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000254/2007003, 05000265/2007003; 04/01/2007 - 06/30/2007; Quad Cities Nuclear Power Station, Units 1 & 2; Inservice Inspection; Operability Evaluations; Refueling and Outage Activities; Event Followup.

This report covers a three-month period of inspection by resident and regional inspectors and announced inspections by a regional inservice inspector and a radiation protection specialist. Four Green findings, two of which were Non-Cited Violations (NCVs), were identified. 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 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. On May 7, 2007, the inspectors identified a finding, and a Non-Cited Violation of 10 CFR 50.55a(g)4, for the failure to complete Code qualified weld repairs for Main Steam Safety Relief Valve 1-0203-3A. Specifically, the weld procedures for this repair were not qualified by performing tensile and guided bend tests intended to demonstrate that the weld procedure produced welds with satisfactory strength and ductility for the intended service. Without these tests, the inspectors were concerned that these Non-Code conforming weld repairs affecting the pressure boundary could lead to cracking and failure of the valve body or bellows when the valve was placed in service. Corrective actions for this issue included performing an operability evaluation and entering this issue into the corrective action program.

  This finding was more than minor because it could be reasonably viewed as a precursor to a significant event. In addition, the finding was associated with the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions. Absent NRC intervention, the licensee would have relied on unqualified weld repairs on 1-0203-3A for an indefinite period of service, which may have placed the reactor coolant pressure boundary at increased risk for weld failure resulting in leakage, or an inoperable relief valve. The inspectors determined that this finding was of very low safety significance because it was identified prior to repressurizing the plant following the refueling outage. (Section 1R08.b.2)

- Green. A finding of very low safety significance was self-revealed on February 28, 2007, when operations personnel inserted a manual scram in response to increasing condenser back pressure. The licensee determined that blockage of an offgas system pressure sensing line created a condition which resulted in a system relief valve opening. The open relief valve caused the 2A steam jet air ejector efficiency to drop and increased condenser back pressure. Corrective actions for this issue included removing the blockage from the sensing line and developing a periodic maintenance task to ensure the sensing line remained clean. No violations of NRC requirements were identified due to the offgas system being non-safety related.

This finding was more than minor because it was associated with the equipment performance and procedure adequacy attributes of the initiating events cornerstone. The finding also impacted the cornerstone's objective of limiting the likelihood of events that upset plant stability and challenge safety functions. This finding was of very low safety significance because adequate mitigating systems equipment remained available to respond to a transient with a loss of the power conversion system. The inspectors concluded that this finding was cross-cutting in the area of human performance, resources (H.2(c)), in that the licensee failed to have complete, accurate, and up-to-date procedures regarding pressure sensing line maintenance. (Section 4OA3)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance on May 21, 2007, due to the failure to adequately document and justify the basis for continued operability of the 4 kV breakers in Unit 2 following the identification of a common mode failure mechanism on the 4 kV breakers in Unit 1. In response to this issue, the licensee documented additional information to justify the continued operability of the breakers. The licensee was also developing additional corrective actions to improve the implementation of the operability determination/evaluation process. No violation of NRC requirements was identified because operability determinations were not required by NRC regulations.

  This finding was more than minor because if left uncorrected, continued inadequate justifications could result in incorrectly concluding that safety-related components remained operable rather than inoperable. This finding was of very low safety significance because it was not a design deficiency, did not result in a loss of safety function, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The inspectors concluded that this finding was cross-cutting in the area of human performance, decision making (H.1(b)), in that the licensee did not use conservative assumptions to demonstrate that the proposed action was safe rather than unsafe. (Section 1R15)

- Green. The inspectors identified a finding of very low safety significance, and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, due to the failure to effectively implement QCOS 1600-32, "Drywell/Torus Closeout," in May 2007. Corrective actions for this issue included removing the NRC identified debris from the drywell, informing personnel of the ineffective drywell cleaning, and conducting an assessment to determine more effective methods for cleaning the drywell during future outages.

This finding was more than minor because, if left uncorrected, it would result in the continued accumulation of foreign material in the drywell. The accumulation of materials could result in blocking the emergency core cooling system suction strainers, drywell ventilation equipment, drain lines, or motor vents during normal operation or accident conditions. This finding was of very low safety significance since the debris did not result in an actual loss of safety function for any system and because the debris was removed when it was found. The inspectors concluded that this finding was cross-cutting in the area of problem identification and resolution, corrective action program (P.1(d)), in that the licensee failed to ensure that corrective actions were taken to address a previously identified adverse trend. (Section 1R20)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the corrective action program. This violation and corrective action tracking number is listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at full power. On May 4 operations personnel removed Unit 1 from service to begin Refueling Outage 19. During the outage, the licensee performed maintenance on multiple plant systems, installed a new, digital electrohydraulic control system, and performed inspections of the steam dryer, the electromatic relief valve actuators, and the acoustic side branches. Unit 1 returned to power on May 23. Following two days of power ascension testing, Unit 1 operated at full power levels until June 8 when a feedwater heater transient resulted in operations personnel lowering reactor power to 94 percent for approximately four hours. Unit 1 was returned to full power levels after correcting the cause of the transient. Operations personnel lowered reactor power to 92 percent on June 18 due to an increase in indicated reactor vessel pressure. Reactor power was restored to normal levels once operations personnel confirmed that the indicated pressure increase was due to an instrument deficiency.

Operations personnel maintained Unit 2 at or near full power until April 13 when power was lowered to approximately 30 percent to allow for condenser tube leak repairs and the replacement of the 2A and the 2C reactor feedwater pump seals. Reactor power was lowered to approximately 75 percent on May 24 to allow for an additional replacement of the 2A reactor feedwater pump seals and maintenance on control rod drive accumulator 30-51. Unit 2 returned to normal power levels on May 26. On June 19 reactor power decreased to 95 percent following a control rod unexpectedly drifting into the reactor core. Power levels were restored to normal levels after operations personnel inserted and disarmed the associated control rod hydraulic control unit.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Summer Readiness Review

a. Inspection Scope

The inspectors assessed the licensee’s readiness for warm weather conditions by conducting detailed inspections on the following equipment:

- Unit 1 main power transformer and
- Unit 1 reactor building closed cooling water system.

The inspectors selected the Unit 1 main power transformer as an inspection sample due to recent issues regarding increased temperatures on the low voltage side of the transformer. Additionally, the transformer was replaced during the Unit 1 refueling outage and employed components from various vendors. The reactor building closed cooling water system was chosen for inspection due to reoccurring material condition issues.

The inspectors interviewed system engineers and reviewed the Updated Final Safety Analysis Report, the licensee's seasonal readiness procedures, previously initiated issue reports, cause determinations, and trending packages to assess the resolution of previously identified material condition issues. The inspectors also used this information to evaluate whether unresolved material condition issues could impact the ability of the equipment to perform its function during extreme weather conditions.

This inspection represented the completion of two hot weather samples.

b. Findings

No findings of significance were identified.

.2 Response to High Wind, Severe Thunderstorm, and Tornado Warning Conditions

a. Inspection Scope

On June 1, 2007, the Quad Cities area experienced severe summertime weather including high winds, a severe thunderstorm, and the issuance of a tornado warning. Immediately following the tornado warning issuance, the inspectors entered the control room to observe the operators' response to the adverse weather condition. The inspectors noted that the reactor operators performed frequent panel monitoring to assess any possible impact that the adverse weather could have on the operation of either unit. In addition, the inspectors observed multiple senior reactor operators performing activities such as reviewing mitigating systems status, reviewing the abnormal operating procedures, reviewing the emergency action levels for potential entry conditions, monitoring wind speed and weather radar to determine where the storm was located, and monitoring the weather radio for changes in the tornado warning status.

This inspection represented the completion of one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed a partial walkdown of the following systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors identified any discrepancies that could impact the function of the system and potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control systems components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems via the corrective action program.

- Unit ½ Diesel Generator;
- Safe Shutdown Makeup Pump;
- Unit 1 High Pressure Coolant Injection; and
- 1A Core Spray.

This inspection constituted the completion of four quarterly samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Fire Protection - Tours

a. Inspection Scope

The inspectors conducted a tour of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures; fire detection and suppression equipment was available for use; passive fire barriers were maintained in good material condition; and that compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with the licensee's fire plan.

- Fire Zone 3.0 - Cable Spreading Room;
- Fire Zone 8.2.6.A - Unit 1 D Heater Bay;
- Fire Zone 8.2.6.B - Unit 1 Low Pressure Heater Bay;
- Fire Zone 8.2.8.B - Unit 1 Turbine Building Motor Generator Set 1A;
- Fire Zone 9.3 - Unit ½ Diesel Generator;
- Fire Zone 1.1.1.3 - Unit 1 Reactor Building, Elevation 623'-0", Mezzanine level;
- Fire Zone 1.1.1.4 - Unit 1 Reactor Building, Elevation 647'-6", Third floor;
- Fire Zone 1.1.2.2 - Unit 2 Reactor Building Ground Floor; and
- Fire Zone SBO 120 - Station Blackout Building.

This inspection represented the completion of nine quarterly samples.

b. Findings

On May 3, 2007, the inspectors performed a fire zone inspection in the cable spreading room. During the inspection, the inspectors identified two cardboard boxes which were brought into the area as part of the digital electrohydraulic control system modification. The inspectors also identified an aerosol can, which contained flammable material, located behind a vertical cable tray riser. The licensee initiated Issue Reports 625097 and 636793 to document the inspector-identified deficiencies discussed above. At the conclusion of the inspection, the licensee was in the process of determining how long the aerosol can had been in the room and the specific cables located closest to the can which could have been impacted by a postulated fire. As a result, this issue will remain unresolved pending a review of the licensee's information by a regional fire protection specialist **(URI 05000254/2007003-01; 05000265/2007003-01)**.

1R06 Flood Protection Measures (71111.06)

External Flooding

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) flood analysis to determine the actions to be taken during a flooding event. The inspectors also reviewed the licensee's procedures for external flooding. Following this review, the inspectors compared the procedural actions to the actions specified in the UFSAR to ensure all actions had been incorporated.

This inspection represented the completion of one external flooding sample.

b. Findings

Updated Final Safety Analysis Report Section 3.4.1.1, "External Flood Protection Measures," provided the licensee's external flooding methodology. The methodology was developed based upon the Quad Cities structural design criteria which assumed a flood water level elevation of 590 feet or less. If the flood water elevation exceeded 594.5 feet, the licensee planned to open all outside doors and flood all plant buildings to a level which matched the current river level. Prior to flooding the buildings, the licensee planned to shut down both units, remove the drywell and reactor vessel heads, fill both refueling cavities, remove the cavity gates, rack out all breakers below the 608 foot elevation, and set up portable pumping equipment to maintain water levels in the spent fuel pools/reactor cavities. The UFSAR stated that the portable pump was required to supply 200 gallons per minute to ensure that adequate makeup water was available to supplement the water lost due to evaporative cooling.

On April 23, 2007, the inspectors reviewed QCOA 0010-06, "Flood Emergency Procedure," Revision 10. The inspectors noted that the procedure failed to provide the exact location of the portable pump. Due to the lack of information regarding the pump's location, the inspectors requested that operations personnel locate the pump. Operations personnel were initially unable to locate the pump. However, the pump was found within 24 hours. The licensee initiated Issue Report 621596 to ensure that QCOA 0010-06 was updated to include the pump's location.

On May 3, 2007, the licensee identified that the pump's detachable fuel tank was missing and unable to be located. Eighteen days later the licensee provided an interim fuel tank to be used with the pump. The licensee initiated Issue Report 625112 to document this issue and planned to obtain a permanent fuel tank.

During a re-review of QCOA 0010-16 on June 1, the inspectors noted that Step D.5.b stated that operations personnel should obtain two 10 foot sections of 4 inch suction hose for use with the portable pump. Since the pump will be located on a landing approximately 8 feet above the floor, and the flood waters will be allowed to flow into the reactor building until the flood waters equalize with Mississippi River level, the inspectors questioned whether the two sections of hose would be adequate to reach from the pump's location to the actual flood water elevation. The licensee initiated Issue Report 638004 to document this issue.

In late April the inspectors questioned operations, maintenance, and engineering personnel to determine whether the licensee periodically tested the portable pump to ensure that the pump could provide the 200 gallons per minute required by the UFSAR. The inspectors also reviewed the vendor manual and found that the pump could not be operated at a pre-determined speed. Instead, the pump speed control was a sliding lever which could be positioned anywhere between the words "slow" and "fast." At the conclusion of the inspection period, the licensee had not found any documentation which proved that the pump could provide adequate flow during a flooding event. However, the licensee was considering testing the pump in the near future. Issue Reports 624645 and 638004 were initiated to document the pump testing and capacity issues. Due to the lack of information, the licensee was unable to clearly demonstrate their ability to implement their external flooding methodology. As a result, the inspectors considered the items associated with implementing the external flooding methodology to be unresolved pending the review of the licensee's actions associated with the issue reports generated during this inspection **(URI 05000254/2007003-02; 05000265/2007003-02)**.

1R08 Inservice Inspection Activities (71111.08)

.1 Piping Systems Inservice Inspection

a. Inspection Scope

From May 7 to May 11, 2007, the inspectors conducted a review of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of Inspection Procedure 71111.08, "Inservice Inspection Activities."

The inspectors conducted an on-site review of the following types of nondestructive examination activities to evaluate compliance with the ASME Code, Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements. Specifically, the inspectors observed the following examinations:

- Ultrasonic examination (UT) of Low Pressure Coolant Injection reducer pipe welds, welds 1012A-1 and 1012A-2 on line 1-1012A-18"-DX; and

- Visual examinations (VT-3) of recirculation pump suction line snubbers (1025-M-102 A&B).

The inspectors reviewed examinations completed during the previous outage with relevant/recordable condition/indications that were accepted for continued service to verify that the licensee's acceptance was in accordance with Section XI of the ASME Code. Specifically, the inspectors reviewed the following records:

- Visual examination records of a main steam line component support 3001B-M-106 (Flued Head Anchor). During the examination, the licensee identified a missing hold down tab and anchor pin (corrected and found to be acceptable for continued service per ASME Code).

- Visual examination records of a main steam line component support 3204A-M-103 (Flued Head Anchor). During the examination, the licensee identified a missing hold down tab and anchor pin (corrected and found to be acceptable for continued service per ASME Code).

The inspectors reviewed a pressure boundary weld for a Code Class 1 system which was completed during the previous refueling outage, to verify that the welding acceptance and preservice examinations (e.g., pressure testing, visual, magnetic particle, and weld procedure qualification tensile tests and bend tests) were performed in accordance with the ASME Code, Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed welds associated with the following work activities:

- Main steam line support 3001B-M-106 support tab weld and anchor pin.

The inspectors performed a review of piping system inservice inspection-related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed these corrective action program documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors evaluated the threshold for identifying issues through interviews with licensee staff and a review of licensee actions to incorporate lessons learned from industry issues related to the inservice inspection program. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

This review represented the completion of one inspection sample.

b. Findings

b.1 Reactor Vessel Weld Examinations

Introduction: The inspectors identified an unresolved item involving Code qualified volumetric examination of the reactor vessel shell welds. Specifically, the licensee used a longer cable length than that used in the UT procedure demonstration, which may have affected the flaw detection capability.

Description: The inspectors noted that the procedure used to perform the complete volumetric examination of the reactor vessel shell welds during refueling outage 18 referenced the use of cable lengths which differed from those demonstrated under the performance demonstrated initiative (PDI).

Specifically, the licensee scheduled UT of 15 reactor pressure vessel (RPV) vertical shell welds during refueling outage 18. The licensee had obtained relief from the NRC to perform UT of 100 percent of the B1.12 RPV welds during the first period of the successive intervals starting with the fourth interval in lieu of Code requirements. The licensee performed the exams using Procedure ISwT-PDI-AUT1, "Automated Inside Surface Ultrasonic Examination of Ferritic Vessel Wall Greater Than 4.0 Inches in Thickness," Revision 0. This procedure was demonstrated by the licensee's vendor as capable of detecting rejectable weld flaws in accordance with the ASME Code Section XI, Appendix VIII, Supplements 4 and 6, in March 1996. During this demonstration, the licensee's vendor used a maximum of 1018 feet of RG-58 cable, two 40-foot sections of RG-174 cable, and a maximum of 13 connectors for examinations of vessel welds less than 7.5 inches thick. The procedure identified the maximum cable lengths and maximum number of connectors as essential procedure variables consistent with requirements of Section XI, Appendix VIII, Article VIII-3130, "Essential Variable Ranges."

On October 5, 2001, the licensee's vendor issued Interim Change Notice 1 to ISwT-PDI-AUT1. This change notice allowed 1350 feet maximum of RG-58 cable, 230 feet maximum of RG-174 cable, and 20 connectors to be used. The vendor performed a technical justification to support the procedure change which measured and applied bandwidth and center frequency shift criteria from Section XI, Appendix VIII, Article 4110, "Pulsers, Receivers and Search Units." The vendor applied criteria from the ASME Code Section XI, Appendix VIII, Article 4110, which applied to pulsers, receivers and search units, to justify the change in cable configuration. The inspectors questioned whether this Article could be applied to cables in that they were not specifically listed. This issue is considered an unresolved item pending clarification of the ASME Code requirements **(URI 05000254/2007003-03)**.

b.2 Unqualified Main Steam Safety Relief Valve Weld Repair

Introduction: The inspectors identified a Green finding of very low safety significance, and a Non-Cited Violation of 10 CFR 50.55a(g)4, for failure to complete Code qualified weld repairs for main steam safety relief valve 1-203-3A. Specifically, the weld procedures for this repair were not qualified by performing tensile and guided bend tests intended to demonstrate that the weld procedure produced welds with satisfactory strength and ductility for the intended service.

Description: On May 7, 2007, the inspectors identified that weld repairs completed on the bellows and pilot valve seat of main steam safety relief valve 1-203-3A did not meet the ASME Section IX Code.

In December 2004 the licensee's vendor completed weld repairs on the 1-203-3A bellows flange-to-base in accordance with Target Rock Corporation Weld Procedure 889C W-6d. The vendor also completed weld repairs on the seat-to-pilot body weld in accordance with Target Rock Corporation Weld Procedure 889C W-1b. These procedures were qualified in accordance with the 1968 Edition of the ASME Code Section IX. The supporting qualification document was a Target Rock Corporation Metallurgical Test Report dated April 30, 1968. However, this report did not contain "reduced section tensile specimens" and "guided bend test specimens" as required by Article Q-10(b) of Section IX of the ASME Code. These tests were intended to demonstrate that the weld procedure produced welds with satisfactory strength and ductility for the intended service. Without these tests, the inspectors were concerned that the weld repairs affecting the pressure boundary (valve body) could lead to cracking, valve failure, or to cracking of the pilot bellows resulting in a nonfunctional relief valve.

The licensee's vendor concluded that the 1968 Edition of ASME Section IX did not address the types of welds needed in the construction of the safety relief valve design because it only provided requirements for groove and fillet welds. Also, the vendor concluded that the 1968 edition of ASME Section IX did not include base material groupings or filler metal groups for base materials and filler metals used in fabrication of this relief valve. Therefore, the vendor applied the term "Special Welds" for all weld designs that were not groove or fillet with Non-Code recognized base/filler materials. The inspectors noted that the design of the welds for the repairs to the bellows and seat of 1-203-3A would be consistent with groove or fillet welds as described in Section IX of the ASME Code and the weld filler materials were also identified in Section IX. The inspectors also noted that the licensee's vendor failed to apply the Code requirements as invoked by Article N-522, "Welding Qualifications and Weld Records," of Section III of the ASME Code 1968 Edition. The article stated that each manufacturer or contractor was responsible for the welding done by his organization and shall establish the procedure and conduct the tests required in N-540 and/or in Section IX of the Code to qualify the welding procedures.

The issue was previously identified by an NRC inspector at Duane Arnold in February 2007. Although the licensee documented the issue in their corrective action program as Issue Report 625801, the issue report was not written until May 5, 2007 (the day after the inspectors notified the licensee that the issue as it pertained to Quad Cities would be discussed during the inservice inspection the following week). The issue report indicated that there were no operability concerns and that the issue was not one of proper valve function or of valve degradation, but of Code compliance. The licensee had elected to defer any further actions until they determined if the issue was applicable at Quad Cities. The inspectors determined that the licensee failed to identify the issue as a non-conformance until the inspectors discussed the issue during the inservice inspection and informed the licensee the welding procedure was not qualified. Following this discussion, the licensee wrote Issue Report 628172 to document that this issue was applicable at Quad Cities. The licensee further determined that a non-conformance existed with regard to design requirements of the welding procedure and that final resolution was pending via the corrective action process and/or an NRC relief request. Engineering personnel were tasked with documenting the acceptability of valve operation through a formal operability determination.

Analysis: The inspectors determined that the failure of the licensee's staff to identify that non-Code weld repairs were completed on main steam relief valve 1-203-3A was more than minor because it could be reasonably viewed as a precursor to a significant event. In addition, the finding was associated with the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions. Absent NRC intervention, the licensee would have relied on unqualified weld repairs on 1-203-3A for an indefinite period of service, which may have placed the reactor coolant pressure boundary at increased risk for weld failure resulting in leakage or an inoperable relief valve.

The inspectors conducted a Phase 1 Significance Determination Process Screening and determined that this finding was of very low safety significance because under worst case degradation the finding would not have resulted in exceeding the Technical Specification limit for identified reactor coolant system leakage. Specifically, the worst case degradation would be a weld repair induced failure of the pilot valve bellows or body, which could propagate under operating pressure induced hoop stress causing a catastrophic failure of the valve. Because the weld repair issue for 3204A-M-103 was identified prior to repressurizing the plant, this scenario did not occur. The inspectors did not identify any current cross cutting aspects associated with this issue.

Enforcement: Title10 CFR 50.55a(g)4 required in part, that throughout the service life of a boiling water reactor facility, components classified as ASME Code Class 1, 2, and 3 must meet requirements of Section XI.

The 1998 Edition, 2000 Addenda, of ASME Code Section XI, Article IWA-4170, required that repairs and installation of replacement items shall be performed in accordance with the Owner's Design Specification and the original Construction Code of the component or system.

The Owners Design Specification, General Electric Specification No. 21A9206, Revision 7, Paragraph 4.5.2.1, "Qualification," required that all welding including fillet, seal, repair and attachment welds be performed in accordance with written welding procedures. Procedure qualification and welder performance qualification shall be in accordance with ASME Boiler and Pressure Vessel Code, Section IX.

The original Construction Code for 1-203-3A, 1968 Edition of Section III, Article N-522, “Welding Qualifications and Weld Records,” required that each manufacturer or contractor was responsible for the welding done by his organization and shall establish the procedure and conduct the tests required in N-540 (required supplemental weld qualification requirements for vessels in addition to those required by Section IX) and/or in Section IX of the Code to qualify the welding procedures.

The 1968 Edition of Section IX, Article Q-10(b), “Types of Tests Required,” stated procedure qualification tests for groove and fillet welds shall be made on groove welds using reduced section tensile specimens and guided bend specimens.

Contrary to the above, in December 2004, repair welds were performed on the pilot seat and bellows of 1-203-3A (reference Purchase Order 00080261) using weld procedures which had not been qualified by tensile and guided bend specimens. Failure to perform Code qualified weld repairs to main steam relief valve 1-203-3A is a violation of 10 CFR 50.55a(g)4. Because of the very low safety significance of this finding and because the issue was entered into your corrective action program as Issue Reports 625801 and 628172, it is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000254/2007003-04)**. Corrective actions for this issue were being developed at the conclusion of the inspection period.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On April 3, 2007, the inspectors observed an operations crew in the simulator during an as-found evaluation.

The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- ability to make timely actions in the safe direction;
- prioritization, interpretation, and verification of alarms;
- procedure use;
- control board manipulations;
- oversight and direction from supervisors; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in the following documents:

- OP-AA-101-111, “Rules and Responsibilities of On-Shift Personnel;”
- OP-AA-103-102, “Watchstanding Practices;”

- OP-AA-103-104, “Reactivity Management Controls;” and
- OP-AA-104-101, “Communications.”

The inspectors verified that the crew completed the critical tasks listed in the observed scenario. If critical tasks were not met, the inspectors verified that crew and operator performance errors were detected and adequately addressed by the licensee’s evaluators. The inspectors verified that the evaluators effectively identified operators requiring remediation and appropriately indicated when removal from shift activities was warranted. Lastly, the inspectors observed the licensee’s critique to verify that weaknesses identified during this observation were noted by the evaluators and discussed with the respective crew.

This inspection constituted the completion of one quarterly sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee’s handling of performance issues and the associated implementation of the Maintenance Rule to evaluate the maintenance effectiveness for the item listed below. This item was selected based on it being designated as risk significant under the Maintenance Rule, being in increased monitoring, or due to an identified issue or problem that potentially impacted system work practices, reliability, or common cause failures.

- Containment Atmospheric Monitoring

The inspectors’ review included an examination of specific issues documented in issue reports, an evaluation of maintenance rule performance criteria and maintenance work practices, an assessment of common cause issues and extent of condition reviews, and trending of key parameters. The inspectors also reviewed the licensee’s maintenance rule scoping, goal setting, performance monitoring, functional failure determinations, and current equipment performance status.

This inspection represented the completion of one sample.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the activities listed below to verify that appropriate risk assessments were performed prior to removing equipment from service for maintenance. 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 verified the appropriate use of the licensee's risk assessment tool and risk categories in accordance with procedures.

- Work Week 15 (April 9 - 15) including a planned downpower for the Unit 2 condenser repair/tube plugging and reactor feed pump seal replacements;
- Work Week 17 (April 23 - 29) including surveillance testing on the Unit 1 reactor core isolation cooling system and planned maintenance on the 1C traveling screen, the 1B reactor feedwater pump, the 1D condensate pump, the 1/2B control room ventilation system, and the 2A stator water heat exchanger;
- Work Week 19 (May 7 - 13) including emergent work on the 1D residual heat removal pump breaker, and planned maintenance on the Unit 1 standby liquid control system, control rod drive system, standby gas treatment system, and switchyard;
- Work Week 20 (May 14 - 20) including planned maintenance on the Unit 1 emergency diesel generator, the Unit 2 reactor core isolation cooling system, the Unit 1 electrical distribution system, and switchyard;
- Work Week 22 (May 28 - June 3) including maintenance and surveillance on the Unit 2 high pressure coolant injection system and the Unit 1 emergency diesel generator; and
- Work Week 25 (June 18 - 24) including maintenance on the 2A and 2B residual heat removal systems and residual heat removal service water systems.

These inspections represented the completion of six samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of the evaluations listed below to ensure that Technical Specification operability or functionality was properly justified and that no unrecognized increase in risk occurred. The inspectors reviewed the Updated Final Safety Analysis Report to verify that the system or component continued to perform its intended function. In addition, the inspectors reviewed compensatory measures to verify that the measures worked as stated and that the measures were adequately controlled. The inspectors also reviewed a sampling of issue reports to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- Issue Reports 493178 and 571343 - Residual Heat Removal Service Water System Orifices Clogged with Debris;
- Issue Report 612628 - Found Red Wire From Cable 13661 Lug Broke;
- Issue Report 630008 - Work at Risk to Install New Fuel Injector;
- Issue Report 633052 - Unit 1 Bypass Valve #2 Fails to Fully Open on Demand;
- Issue Report 631331 - Varflex Wire Sleeves do not meet Specification Requirements; and
- Issue Report 631282 - Extent of Condition for MOC Switch Cam Follower Inspections for Unit 2 4 kV Buses.

This inspection represented the completion of six samples.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance due to the licensee's failure to adequately document and justify the basis for continued operability of the 4 kV breakers in Unit 2 following the identification of a common mode failure mechanism on Unit 1.

Description: On May 7, 2007, the 1D residual heat removal pump breaker tripped as operations personnel attempted to place the pump into service. The licensee conducted an investigation of this event and found that this 4 kV breaker tripped due to the mechanically operated contact switch cam follower (located in the cubicle) coming into contact with the breaker's spring discharge roller. The inspectors observed the licensee's investigation and found that the breaker trip could also be a common mode failure mechanism.

On May 18 the licensee initiated Issue Report 631282 to document the need to conduct an extent of condition review for the 4 kV breakers in Unit 2. This issue report also provided documentation to justify the continued operability of the Unit 2 breakers until an extent of condition review was completed. The inspectors reviewed the licensee's operability documentation and determined that the documentation was inadequate for the following reasons:

- The licensee stated that there was no history of this type of breaker failure on Unit 2 equipment. While this was a true statement, the licensee failed to explain how the lack of history provided assurance of continued operability. The inspectors also noted that this type of breaker failure began occurring on Unit 1 approximately 18 months ago. However, the licensee failed to provide information regarding any changes in the breaker program over the last 18 months nor did they provide justification to explain why this type of failure was not imminent for Unit 2.

- The licensee stated that Unit 2 breaker operation was supported by the fact that the equipment powered by these breakers continued to pass periodic surveillance testing. However, the licensee did not justify why this statement provided a basis for continued operability considering that the 1D residual heat removal pump also passed a periodic surveillance test prior to the breaker failure.

- The licensee concluded that only 2 of the 48 Unit 1 breakers had exhibited this type of breaker failure. The inspectors initially determined that this statement was not applicable because it failed to provide any information regarding Unit 2. The inspectors also informed the licensee that it appeared that they were trying to provide an argument regarding the probability of a Unit 2 breaker failure due to the small number of breaker failures experienced on Unit 1. Current NRC guidance does not allow this type of argument to be made in operability discussions.

- Lastly, the operability basis section of the issue report failed to provide any discussion regarding Unit 2. However, several pieces of information were provided regarding Unit 1.

Analysis: The inspectors determined that the failure to adequately document and justify the continued operability of the Unit 2 4 kV breakers was more than minor because if left uncorrected, continued inadequate justifications could result in incorrectly concluding that safety-related components remained operable rather than inoperable. The inspectors conducted a Phase 1 Significance Determination Process Screening and concluded that this finding was of very low safety significance because it was not a design deficiency, did not result in a loss of safety function, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event **(FIN 05000265/2007003-05)**. The inspectors concluded that this finding was cross-cutting in the area of human performance, decision making (H.1(b)), in that the licensee did not use conservative assumptions to demonstrate that the proposed action was safe rather than unsafe.

Enforcement: Because operability determinations and evaluations were not required by NRC regulations, no violations were identified. Corrective actions for this issue included providing additional information to justify the continued operability of the Unit 2 breakers and developing actions to improve the implementation of the operability determination and evaluation program.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

During the inspection period, the inspectors reviewed the following permanent plant modification:

- Work Order 986547 - Perform Repairs to Unit 1 Standby Liquid Control Tank Supports.

The inspectors reviewed the design adequacy of the modification by verifying one or more of the following:

- Energy requirements were able to be supplied by supporting systems under accident and event conditions;
- Replacement components were compatible with physical interferences;
- Replacement component properties met functional requirements under event and accident conditions;
- Replacement components were environmentally and/or seismically qualified;
- Sequence changes remained bounded by the accident analyses and loading on support systems was acceptable;
- Structures, systems, and components response times were sufficient to serve accident and event functional requirements assumed by the design analyses;
- Control signals were appropriate under accident conditions; and
- Affected operations procedures were revised and training needs were evaluated in accordance with station administrative procedures.

The inspectors verified that post modification testing demonstrated system operability by verifying system integrity, that no unintended system interactions occurred, system performance characteristics met the design basis, and post modification testing results met all acceptance criteria. The inspectors also reviewed issue reports related to permanent plant modifications to ensure that the licensee was entering issues into its corrective action program at an appropriate threshold.

This review represented the completion of one sample.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the licensee’s test procedure to verify that the procedure adequately tested the safety function(s) that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed the test data to verify that test results adequately demonstrated restoration of the affected safety function(s).

- TIC 1775 - Unit 1 Diesel Generator Cooling Water Pump Flow Rate Test following installation of a new cooling water pump;
- QCMMS 6600-03 - Emergency Diesel Generator Periodic Preventive Maintenance Inspection for initial slow roll and overspeed testing following completion of the Unit 1 Emergency Diesel Generator 12-year inspection;
- TIC 1774 - ECCS Room and DGCWP Cubicle Cooler Monthly Surveillance following maintenance on a core spray room cooler plugged line;
- QCOS 5750-02 - Control Room Emergency Filtration System following the replacement of valve 1-5799-384;
- QCOP 1000-10 - Torus Water Transfer to the Main Condenser Via the Condensate Demineralizers; and
- Review of Engineering Change 362979, system leakage tests, and a review of radiography examinations following the removal and replacement of the Unit 1 Standby Liquid Control Tank supports.

This inspection represented the completion of six samples.

b. Findings

On May 7, 2007, the 1D residual heat removal pump breaker, a 4 kV Merlin Gerin AMHG model breaker, tripped open while operations personnel attempted to place the pump in service using QCOP 1000-10, "Torus Water Transfer to the Main Condenser Via the Condensate Demineralizers." The licensee developed and implemented a detailed troubleshooting plan and was able to identify that the breaker cubicle mechanism operated cell switch linkage assembly cam follower rod length was slightly out of tolerance. This caused the attached cam follower to come in contact and apply a load to the breaker's spring discharge roller. Strike marks (minor wear marks) were made on the cam follower due to contact with the breaker's spring discharge roller. The spring discharge roller then applied a pre-load to the breaker's trip paddle which made the breaker very susceptible to tripping during breaker movement.

The licensee's extent of condition review for Unit 1 included an inspection of all 48 4 kV Merlin Gerin AMHG model breaker cubicles before completion of the 2007 refueling outage. In addition, the licensee was in the process of implementing an inspection schedule for Unit 2 and had inspected 10 of the 47 4 kV breaker cubicles that contained the 4 kV Merlin Gerin AMHG model breakers by the conclusion of the inspection period. The inspectors noted that the licensee found strike marks on the 4 kV breaker cubicles' cam followers for the Unit ½ emergency diesel generator feed to Bus 13-1, the 1A core spray pump, the 1B residual heat removal pump, the 1D residual heat removal service water, and the 1C condensate booster pump.

Once identified, the licensee implemented a design change to remove a small portion (approximately 1/4 inch) of the cam follower in the location where strike marks were being found. This was implemented for cam followers in all breaker cubicles that had been inspected and for those that were to be inspected. The removal of the material will allow a larger gap between the cam follower and breaker's spring discharge roller to add margin and prevent the breaker from tripping due to the physical contact between components. The inspectors consider the licensee's corrective actions appropriate to prevent recurrence regarding this failure mode.

At the conclusion of the inspection period, the inspectors had several unanswered questions regarding the causes of and contributors to the 4 kV Merlin Gerin breakers' failure to remain in the closed condition. Based on the unanswered questions, the inspectors determined that this item should be unresolved pending review of the licensee's final apparent cause evaluation report **(URI 05000254/2007003-06; 05000265/2007003-06).**

1R20 Refueling and Outage Activities (71111.20)

.1 Refueling and Outage Activities

a. Inspection Scope

The inspectors evaluated the Unit 1 refueling outage activities which commenced on May 4, 2007. The following specific areas were reviewed as part of the inspectors outage-related inspection activities:

Outage Plan: The inspectors reviewed the Quad Cities Unit 1 Shutdown Safety Risk Assessment for the refueling outage. The inspectors verified that the licensee had considered risk, industry experience, and previous site specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. The inspectors review of this report was compared to the requirements in Procedure OU-QC-104, "Shutdown Safety Management Program Quad Cities Annex." The review verified that contingency measures were identified for high risk significant conditions. The inspectors monitored shutdown safety on a daily basis during the outage.

Shutdown and Cooldown: The inspectors observed portions of the Unit 1 shutdown to enter the outage to verify that activities were performed in accordance with the licensee's procedures. The inspectors verified that the licensee monitored cooldown restrictions and that operations personnel performed the cooldown within the limits specified in the Technical Specifications.

Licensee Control of Outage Activities: The inspectors observed and reviewed several specific activities, evolutions, and plant conditions (listed below) to verify that the licensee maintained defense-in-depth commensurate with the outage shutdown safety plan.

- Decay Heat Removal, Spent Fuel Pool Cooling, and Reactor Recirculation System Instrumentation: The inspectors reviewed decay heat removal procedures and observed decay heat removal system parameters to verify that decay heat was being removed at an appropriate rate. The inspectors also conducted main control room panel walkdowns to ensure that alternate decay heat removal systems were properly configured and that decay heat removal instrumentation was indicating properly. The inspectors reviewed operational logs to verify that procedure and Technical Specification requirements to monitor and record reactor recirculation temperature were met.

- Reactivity Control: The inspectors observed licensee performance during shutdown, outage, refueling, and startup activities to verify that reactivity control was maintained in accordance with licensee procedures and the Technical Specifications. The inspectors conducted a review of outage activities and risk profiles to ensure that activities that could cause reactivity control issues were properly identified.

- Inventory Control and Drywell Closeout: The inspectors observed operator monitoring and control of reactor temperature and level profiles during multiple outage activities. Increased monitoring of these activities was performed during evolutions which had the potential to drain the reactor vessel. The inspectors also conducted a drywell closeout inspection at the conclusion of the outage to ensure that the licensee had removed all unneeded materials from the drywell.

- Electrical Power: The inspectors reviewed the following licensee activities related to electrical power during the refueling outage to verify that they were conducted in accordance with the outage risk plan:

    - Controls over electrical power systems and components to ensure that emergency power was available as specified in the shutdown safety plan;
    - Controls and monitoring of electrical power systems and components in the switchyard; and
    - Operator monitoring of electrical power systems and outages to ensure that Technical Specifications continued to be met.

Refueling Activities: The inspectors reviewed refueling activities to verify that fuel handling operations were performed in accordance with procedures and Technical Specifications. The inspectors also reviewed refueling floor and licensee controls to ensure that foreign material exclusion controls were properly established.

Identification and Resolution of Problems: The inspectors reviewed issue reports on a daily basis to verify that the licensee was identifying problems related to refueling outage activities at an appropriate threshold and entering the problems into their corrective action program. The inspectors reviewed the licensee’s initial assessment of all issue reports to verify that the licensee was appropriately prioritizing the resolution of the identified deficiencies discovered during the outage. The inspectors also reviewed the outage scope add and delete sheets to verify that activities were not being removed inappropriately.

This inspection represents the completion of one refueling outage sample.

b. Findings

Introduction: An inspector-identified finding of very low safety significance, and a Non-Cited Violation of NRC requirements, was identified for the failure to effectively implement the drywell closeout procedure to ensure that the drywell was free of foreign material at the conclusion of the refueling outage.

Description: On May 22, 2007, the inspectors toured the Unit 1 drywell prior to closure. The inspectors' tour was conducted after the licensee had performed a cleanliness inspection to remove foreign material from the drywell. The inspectors identified a number of foreign objects which included a sling used to support heavy loads, a welding blanket (2 foot by 8 foot), two rubber boots, loose mirrored insulation sheet metal (4 foot by 6 foot) on the floor, discarded cabling, a screw driver, paint chips, plastic and metal tie wraps, and a roll of duct tape. The inspectors also identified that a temperature element (TE1-0261-14B1) for the 3B electromatic relief valve was not mounted in its normal position. The temperature element was used for post-accident monitoring conditions. Once identified, the foreign materials were removed and the temperature element was remounted.

The inspectors reviewed QCOS 1600-32, "Drywell/Torus Closeout," and concluded that the licensee had not effectively implemented the procedure to ensure that the drywell was free of foreign material at the conclusion of the refueling outage. The inspectors were concerned that the foreign material left in the drywell could potentially impact the operation of safety-related equipment following an accident.

Based on the previous inspector-identified finding regarding an adverse trend associated with the failure to remove foreign material in the drywell (refer to NRC Inspection Report 05000254/2005003; 05000265/2005003, Section 4OA2.4), the licensee developed written guidance for workers to follow to ensure that the drywell was free of foreign material prior to the inspectors' closeout tour. The guidance emphasized the need for workers to clean the drywell as specific work activities were completed. Drywell coordinators were to reinforce this behavior through the performance of periodic drywell tours. Lastly, the operations department was to ensure that a final closeout inspection was completed and all foreign material was removed. Based on the inspectors identification of foreign material during the most recent refueling outage, the licensee's previous corrective actions were deemed ineffective.

Analysis: The inspectors determined that the failure to adequately implement the requirements of QCOS 1600-32 was more than minor because, if left uncorrected, the continued accumulation of foreign material in the drywell could lead to a condition in which the material could block the emergency core cooling suction strainers, ventilation, drain lines, or motor vents during normal operation or accident conditions. The inspectors also concluded that this finding should be assessed using the Significance Determination Process since it was associated with the operability, availability, reliability, or function of mitigating systems equipment. The inspectors completed a Phase 1 Screening and determined that this finding was of very low safety significance (Green) because the debris did not result in an actual loss of safety function for any system when the debris was present in the drywell and because the debris was removed when it was found. The inspectors determined that this finding was cross-cutting in the area of problem identification and resolution, corrective action program (P.1(d)), because the licensee failed to ensure that corrective actions were taken to address this adverse trend.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, required that activities affecting quality be prescribed by documented instructions, procedures, and drawings appropriate to the circumstance. In addition, the activities affecting quality shall be accomplished in accordance with these instructions, procedures, and drawings. QCOS 1600-32, "Drywell/Torus Closeout," was the procedure used by the licensee to perform drywell closeout inspections, an activity affecting quality. Step 1.a of Attachment A to QCOS 1600-32, required that debris which could block emergency core cooling system suction strainers, ventilation, spherical junction drain lines, or motor vents during normal operation or accident conditions be removed. Contrary to the above, in May 2007, the licensee failed to adequately implement QCOS 1600-32 such that debris which could potentially impact the above equipment during normal operation or accident conditions was removed. The debris was identified and removed after being found by the NRC inspectors during drywell closeout inspection activities. Because this violation was of very low safety significance, and because the issue was entered into your corrective action program as Issue Report 633194, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2007003-07)**. Corrective actions for this issue included removing the NRC-identified debris from the drywell, informing personnel of the ineffective drywell cleaning and inspections, and further assessment to determine effective methods to remove debris from the drywell during future outages.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed the surveillance tests and/or reviewed test data of the selected risk-significant structures, systems, or components listed below to assess whether the equipment met the requirements of the Technical Specifications, the Updated Final Safety Analysis Report, and American Society of Mechanical Engineers Section XI. The inspectors also determined whether the testing effectively demonstrated that the equipment was operationally ready and capable of performing its intended safety functions.

- TIC 1771 - Unit 1 Emergency Diesel Generator Load Test performed on May 16, 2007;
- QOS 6500-03 - 4 kV Bus 14-1 Undervoltage Functional Test performed on May 16, 2007;
- QCOS 1600-07 - Reactor Coolant Leakage in the Drywell performed on May 15, 2007;
- QCOS 7500-08 - Unit 2 Standby Gas Treatment Initiation and Reactor Building Ventilation Isolation Test performed on April 18, 2007;

- QOS 6500-01- 4 kV Bus 13-1 Undervoltage Functional Test performed on May 17, 2007;
- QCOS 1300-06 - Reactor Core Isolation Cooling Valve Timing and QCOS 1300-22 - Reactor Core Isolation Cooling Condensate Storage Tank Suction Check Valve Closure performed on April 20, 2007;
- QCOS 7500-04 - Unit 1 Standby Gas Treatment Initiation and Reactor Building Ventilation Isolation Test performed April 23, 2007;
- QCOS 1600-32 - Drywell/Torus Closeout Test performed May 22, 2007;
- QCTS 0600-05 - Main Steam Isolation Valve Local Leak Rate Testing performed on May 7, 2007; and
- QCOS 6600-49 - Unit 1 Division I Emergency Core Cooling System Simulated Automatic Actuation and Emergency Diesel Generator Auto-Start Surveillance performed on May 18, 2007.

This inspection represented the completion of two inservice, one leakage, three isolation valve, and four routine surveillance samples.

b. Findings

Refer to Section 1R20 of this report regarding the completion of QCOS 1300-32, "Drywell/Torus Closeout." No other findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the temporary modifications listed below and compared the information to the associated 10 CFR 50.59 screening, the Updated Final Safety Analysis Report, and Technical Specifications. This comparison was performed to verify that the modifications did not affect operability or availability of the affected system. The inspectors walked down each modification to ensure that it was installed in accordance with the modification documents. The inspectors also reviewed post-installation and removal testing to verify that the modification did not adversely impact plant systems or equipment.

- Engineering Change 361720 - Provide Auxiliary Cooling to Panel 902-13A to Limit Drift on B Electrohydraulic Control System Pressure Regulator; and
- Engineering Change 366109 - Install Cooling Fan to Cool Flange on Transformer T-1.

This inspection represented the completion of two samples.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns/Boundary Verifications and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified work being performed within radiation areas, high radiation areas (HRAs) and locked high radiation areas (LHRAs) of the Unit 1 Turbine and Reactor Buildings including the drywell, and reviewed radiation work permit (RWP) packages and radiation surveys for these areas. The inspectors evaluated the radiological controls to determine if these controls, including postings and access control barriers, were adequate. These work activities included but were not limited to:

- Radiography of the Standby Liquid Control Tank;
- Torus Diving;
- Various Activities in the Drywell including Under-Vessel Instrumentation Work;
- Various Turbine Floor Work Activities; and
- In-Vessel Inspections on the Refuel Floor.

The inspectors reviewed the RWPs and work packages which governed the activities in these radiologically significant areas to identify the work control instructions and control barriers that had been specified. For some of these activities, electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications.

The inspectors walked down and surveyed radiologically significant area boundaries in both the Unit 1 and Unit 2 Reactor and Turbine Buildings and the Radwaste Building to determine if the prescribed radiological access controls were in place, licensee postings were complete and accurate, and physical barricades/barriers were adequate. During the walkdowns, the inspectors challenged access control boundaries to determine if HRA and LHRA access was controlled in compliance with Technical Specifications and the requirements of 10 CFR 20.1601, and was consistent with Regulatory Guide 8.38, “Control of Access to High and Very High Radiation Areas in Nuclear Power Plants.”

The inspectors reviewed job planning records and interviewed radiation protection staff to determine if engineering control effectiveness, such as the use of high efficiency particulate air ventilation systems and the use of respiratory protection, were evaluated for worker protection. In particular, several respiratory protection evaluations were reviewed for activities which potentially could generate airborne radioactivity to determine the adequacy of the evaluations and the engineering controls planned. Radiological surveys for work areas having a potential for transuranic isotopes were reviewed to determine if the licensee had assessed that potential and provided appropriate worker protection as applicable. The inspectors reviewed internal dose assessment results for any workers that had intakes during the current Unit 1 outage through May 17, 2007. No worker internal exposures greater than 50 millirem committed effective dose equivalent occurred for the period reviewed by the inspectors.

This inspection represented the completion of four inspection samples.

b. Findings

No findings of significance were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the corrective action program database, along with individual issue reports related to the radiological access and exposure control programs, to determine if identified problems were entered into the corrective action program for resolution. In particular, the inspectors reviewed radiological issues which occurred over an approximate four-month period that preceded the inspection including the review of any HRA radiological incidents (non-performance indicator occurrences identified by the licensee in high and locked high radiation areas) to determine if follow-up activities were conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

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

The inspectors reviewed the licensee’s process for problem identification, characterization, and prioritization and determined if problems were entered into the corrective action program and were being resolved in a timely manner.

This inspection represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

.3 Job-In-Progress Reviews and Review of Work Practices in Radiologically Significant Areas

a. Inspection Scope

The inspectors reviewed selected jobs being performed in HRAs, LHRAs, and potential airborne radioactivity areas to assess those activities that presented the greatest radiological risk to workers. The work included recirculation system pump seal replacement, under-vessel instrumentation work, coatings preparation/painting in the drywell basement, in-service inspection in the drywell, and torus de-sludging. Radiation survey information to support these work activities was reviewed by the inspectors. The radiological job requirements were assessed for adequacy, and field observations were made to determine if as-low-as-reasonably-achievable (ALARA) measures were implemented as necessary to reduce dose. The inspectors also attended the pre-job briefing for one of these activities to assess the adequacy of the information exchanged.

Job performance was observed to determine if radiological conditions in the work areas were adequately communicated to workers through the pre-job briefings and area postings. The inspectors also evaluated the adequacy of the oversight provided by the radiation protection staff including the performance of radiological surveys, air sampling, contamination controls, and the overall oversight provided by the radiation protection technicians (RPTs).

This inspection represented the completion of two inspection samples.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance for conformity with radiation protection work requirements and to determine whether workers were aware of the radiological conditions, the RWP controls and limits in place, and if their performance had accounted for the level of radiological hazards present.

The inspectors also reviewed radiological problem reports, which found the cause of the event was due to radiation worker errors, to determine if there was an observable pattern traceable to a similar cause and to determine if this matched the corrective action approach taken by the licensee to resolve the identified problems.

This inspection represented the completion of two inspection samples.

b. Findings

No findings of significance were identified.

.5 Radiation Protection Technician Proficiency

a. Inspection Scope

During job observations and general plant walkdowns, the inspectors evaluated RPT performance with respect to radiation protection work requirements, conformance with requirements specified in the RWP, and to assess overall proficiency with respect to radiation protection requirements and health physics practices.

The inspectors reviewed selected radiological problem reports generated since January 2007 to determine the extent of any specific problems or trends that may have been caused by deficiencies with radiation protection staff work control and to determine if the corrective actions were adequate.

This inspection represented the completion of two inspection samples.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective refueling outage exposure history, current exposure trends for the Unit 1 refueling outage (Q1R19) and ongoing outage activities in order to assess current dose performance and exposure challenges. This included determining the licensee's current three-year rolling average for collective exposure in order to provide a perspective of significance for any resulting inspection finding assessment.

The inspectors reviewed Q1R19 work and the associated exposure (dose) projections, including time/labor estimates and historical dose data for the following work activities which were likely to result in the highest personnel collective exposures:

- Electromatic/Safety Relief Valve and Target Rock Valve Replacement;
- Reactor Disassembly/Reassembly and Cavity Work;
- Electrohydraulic Control System Modification;
- Control Rod Drive Replacement;
- Inservice Inspection in the Drywell;
- Turbine System Work;

- Under-Vessel Instrumentation; and
- Torus De-sludging.

The inspectors determined site specific trends in collective dose based on plant historical exposure for similar work activities and through a review of source-term measurements (average contact dose rates with reactor coolant piping). The inspectors reviewed procedures associated with maintaining occupational exposures As Low As Reasonably Achievable (ALARA) and evaluated those processes used for Q1R19 to develop dose projections and to track work activity specific exposures.

This inspection represented the completion of four inspection samples.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors obtained the licensee's list of Q1R19 refueling outage work ranked by estimated exposure and reviewed the following work activities that were projected to expend radiation dose of 5 rem or greater or were otherwise potentially radiologically significant activities:

- Control Rod Drives - Remove and Replace (RWP 10007763);
- Torus De-Sludge and Painting - Diving Activities (RWP 10007721);
- Under-Vessel Instrumentation Work (RWP 10007788);
- 1B Recirc Seal - Remove and Replace (RWP 10007836);
- Inservice Inspection - Preparation and Inspection (RWP 10007767);
- Electromatic/Safety and Target Rock Valves - Remove and Replace (RWP 10007762);
- Replace Sump Pumps and Check Valves (RWP 10007883);
- Reactor Disassembly/Reassembly and Cavity Decontamination (RWP 10007727); and
- 1-0220-1 Valve Cutout/Replacement (RWP 10007880).

For each of the activities listed above, the inspectors reviewed the RWP, the ALARA Plan including time/labor estimates and any associated total effective dose equivalent ALARA evaluations (i.e., respirator evaluations), as applicable. The reviews were performed in order to determine if the licensee had established radiological engineering controls and dose mitigation criteria that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into activities that were based on historical precedence, industry norms, and/or special circumstances.

The inspectors compared the exposure results achieved through approximately three-quarters of the scheduled refueling outage including the person-rem expended with the doses projected in the licensee's ALARA planning for the above listed work activities and for other selected outage activities. The initially projected versus actual (final) dose expenditures for the spring of 2006, Unit 2 refueling outage were also reviewed. Reasons for inconsistencies between intended (projected) and actual work activity doses, as well as any significant differences in time/labor expenditures, were examined for both Q1R19 and the last Unit 2 outage to determine if the activities were planned reasonably well and to determine if the licensee was cognizant of work execution or work planning deficiencies.

The inspectors compared the person-hour estimates provided by maintenance planning and contractor craft groups to the radiation protection ALARA staff with the actual work activity time expenditures in order to evaluate the accuracy of these time estimates. The interfaces between radiation protection and maintenance groups were reviewed to identify potential interface problems that may have contributed to flawed time/labor estimates which impacted dose projections. The integration of ALARA requirements into work procedures and RWP documents was evaluated to verify that the licensee's radiological job planning would reduce dose.

Work-In-Progress ALARA Reports were reviewed by the inspectors for those Q1R19 outage jobs that approached or exceeded their respective dose estimates, or that were otherwise generated to document problems, to identify changes in work scope or to document variances in estimated versus actual doses. These reports were reviewed to determine if the licensee could identify problems at an early stage and address them adequately as the work progressed.

This inspection represented the completion of seven inspection samples.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee's assumptions and basis for its collective Unit 1 (Q1R19) refueling outage exposure estimate and for individual outage job estimates, and evaluated the methodology and practices for projecting work activity specific exposures. This included evaluating both dose rate and time/labor estimates for adequacy compared to historical station specific or industry data.

The inspectors reviewed the licensee's process for adjusting outage exposure estimates when unexpected changes in scope, emergent work or other unanticipated problems were encountered which could significantly impact worker exposures. This included determining if adjustments to estimated exposure (intended dose) were based on sound radiation protection and ALARA principles and not adjusted to account for failures to effectively plan or control the work. Outage jobs with dose expenditures significantly greater than projected or those jobs that could potentially exceed the NRC significance determination process collective dose thresholds were evaluated to determine the extent of any work planning or work execution problems.

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

This inspection represented the completion of three inspection samples.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and As Low As Reasonably Achievable Controls

a. Inspection Scope

The inspectors observed several ongoing Unit 1 refueling outage work activities including torus diving, radiography in the reactor building, and various activities in the drywell to assess the adequacy of the ALARA initiatives and the job specific radiological controls.

The licensee's use of ALARA controls for these work activities was evaluated to determine whether:

- The licensee developed and effectively used engineering controls to achieve dose reductions and to verify that the controls were consistent with the licensee's ALARA work packages; and
- Workers were cognizant of work area radiological conditions, proper tools and equipment were available upon work initiation, workers utilized low dose waiting areas, and that radiological oversight of work was adequate.

Additionally, the inspectors reviewed individual worker exposures for selected work groups/crews involved in higher dose jobs to determine if significant exposure variations existed among workers performing similar tasks. Actions taken by the licensee to address any deficiencies with radiation worker practices were reviewed, as applicable.

This inspection represented the completion of three inspection samples.

b. Findings

No findings of significance were identified.

.5 Monitoring of Declared Pregnant Worker and Dose to Embryo/Fetus

a. Inspection Scope

The inspectors reviewed the licensee's monitoring methods and procedures, radiation exposure controls, and the information provided to declared pregnant women to determine if an adequate program had been implemented to limit embryo/fetal dose. The inspectors reviewed the pregnancy declaration forms and the radiation exposure results for those individuals that declared their pregnancy to the licensee between May 2004 and May 2007 to determine whether compliance with the requirements of 10 CFR 20.1208 and 20.2106 was achieved.

This inspection represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker and Radiation Protection Technician Performance

a. Inspection Scope

Radiation worker and RPT performance was assessed by the inspectors through direct observation focusing on outage activities performed in the Unit 1 Reactor Building and in the drywell. The inspectors determined whether workers demonstrated the ALARA philosophy by observing work activities and ensuring that workers were familiar with the work scope, the tools for the job, low dose waiting areas, and radiological conditions associated with the activity. Job support and communications provided by the radiation protection staff both in the field, and remotely through use of the licensee's remote monitoring equipment, were also evaluated for adequacy.

This inspection represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

.7 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the results of an ALARA program self-assessment to evaluate the licensee's ability to identify and correct problems. The inspectors determined if identified problems were entered into the corrective action program for resolution, and that they had been properly characterized, prioritized, and were being addressed.

The inspectors reviewed radiation protection program-related issue reports generated during the initial 13 days of the refueling outage and for the four-month period that preceded the outage. Licensee staff members were interviewed to assess whether follow-up activities were being conducted in a timely manner commensurate with their importance to safety and risk using the following criteria:

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

For potential repetitive deficiencies or possible trends, the inspectors determined if the licensee's self-assessment activities were capable of identifying and addressing these deficiencies, if applicable.

This inspection represented the completion of three inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstone: Mitigating Systems

a. Inspection Scope

Safety System Functional Failures

The inspectors reviewed portions of the operations logs, issue reports, licensee event reports, and performance indicator data to determine the number of safety system functional failures experienced by both units in 2005 and 2006. This information was also reviewed to ensure that the licensee had not failed to report other safety system functional failures which were not recognized as meeting the definitions provided in the industry guidance documents. This data was then compared to the data reported by the licensee to determine if the reported data was correct.

This inspection represented the completion of two samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors screened all items entered into the licensee’s corrective action program. This was accomplished by reviewing the description of each new issue report and attending management review committee meetings as appropriate.

.2 Annual Sample: Review of Unit 1 Standby Liquid Control Tank Repair Activities

a. Inspection Scope

On October 13, 2006, the NRC granted the licensee a Notice of Enforcement Discretion which allowed Quad Cities Unit 1 to remain at power while repairs were made to the standby liquid control tank. The inspectors reviewed the licensee’s 2006 repair efforts and documented the results in Inspection Reports 05000254/2006007 and 05000254/2006017.

During the recent Unit 1 refueling outage, the licensee performed an additional modification to the standby liquid control tank to ensure that a leak in the tank would not recur. Due to the level of NRC involvement during the 2006 tank issue, the inspectors monitored the licensee’s modification preparations and installation.

This inspection represented the completion of one sample.

b. Observations

Based upon the inspectors review, no findings of significance were identified because the tank modification was performed while the system was removed from service. However, the inspectors identified several weaknesses in the licensee’s modification preparation and installation efforts.

Initial Decision to Begin the Tank Modification Prior to Unit 1 Being Shut Down

On May 1, 2007, the inspectors were informed that the licensee planned to begin the standby liquid control tank modification prior to Unit 1 being shut down for the refueling outage. This concerned the inspectors for the following reasons:

- It appeared that the licensee was planning to intentionally enter the Technical Specification Limiting Condition for Operation for operational convenience; and

- If the licensee discovered that the Unit 1 standby liquid control tank was leaking while the reactor was at power, the Technical Specifications would have required the licensee to perform a unit shutdown. The unit shutdown would have resulted in the licensee being unable to implement a planned hot noble metals injection as part of their continued source term reduction efforts.

The inspectors discussed their concerns with licensee management. Following these discussions, the licensee decided to wait and begin the standby liquid control tank modifications after Unit 1 was shut down. The inspectors agreed with this decision.

Review of Engineering Change Associated with Performing the Modification with Unit 1 Online

The inspectors reviewed the licensee's engineering change document which was initiated to justify the continued seismic qualification of the tank if the modification activities began prior to shutting down Unit 1. The inspectors identified several areas where the engineering change failed to provide adequate detail to justify the final conclusions. The inspectors discussed their specific observations with members of the engineering department. While the engineers were in general agreement with the inspectors observations, the engineering change document was not revised due to the licensee's decision to wait and perform the modification after Unit 1 was shut down.

Hot Work Preparations

The inspectors conducted an inspection of the Unit 1 standby liquid control tank area on May 7 to assess the licensee's modification preparations. Based upon this inspection, the inspectors determined that the licensee's initial preparations were inadequate. Specifically, the inspectors noticed that several fire blankets had been secured to the outside of the tank using duct tape. The inspectors also observed that the fire blankets were also secured to each other using duct tape. The inspectors questioned the fire marshal to determine whether it was appropriate to secure the fire blankets in a method which would expose the duct tape to sparks generated from grinding activities. The fire marshal inspected the area and concluded that the fire blankets were not secured correctly. This condition was corrected prior to commencing hot work activities.

Grout Removal Efforts Result in Gouging Tank Wall

On May 9 the inspectors performed an inspection of the Unit 1 standby liquid control tank area and identified that the licensee's grout removal techniques were not adequate. Specifically, personnel had not removed all of the grout material located in the tank supports. This concerned the inspectors because the licensee believed that the original standby liquid control tank leak was caused by wetting of the grout which created a condition which allowed stress corrosion cracking to develop where the grout contacted the tank wall. The inspectors informed the Outage Control Center of the grout removal deficiencies. Following these discussions, the licensee revised their work instructions to ensure that all of the grout would be removed from the tank. However, the licensee's aggressive grout removal efforts resulted in gouging the tank wall and the need for additional welding.

The licensee refilled the tank once the tank repairs were completed. During the filling process, the licensee identified a small leak which initiated from one of the repaired areas. The licensee repaired this area and returned the standby liquid control system to service. At the conclusion of the inspection period, the licensee was conducting two apparent cause investigations associated with the grout removal and the welding activities. The licensee was also considering performing an additional investigation to identify other lessons learned from the 25 issue reports written during the tank modification activity.

.3 Annual Sample: Review of Corrective Actions Associated with Submerged Underground Cables

a. Inspection Scope

In March 2002 the NRC issued Information Notice 2002-12 to notify the industry of issues regarding the failure of safety related cables due to the cables unintentionally being submerged in water. The licensee reviewed the information notice and determined it was not applicable because they had not experienced any cable failures due to submergence. In addition, the licensee had not identified any plant areas which had submergence issues.

As part of the 2003 license renewal efforts, the licensee inspected two cable tunnels located between the service building and the switchyard. The licensee identified several feet of water in specific areas of each tunnel. Following this discovery, the licensee initiated Issue Report 177026 to document the issue and develop corrective actions. The corrective actions included writing a work request to repair the rusted supports and cable trays found in the tunnels, evaluating the condition of the cables and the long term effects of cable submergence, developing a repair plan to redirect the water away from the entrances to the cable tunnels, and creating a preventive maintenance task to inspect the cable tunnels and pump any accumulated water on an annual frequency.

In February 2007 the NRC issued Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients." The requirements of this generic letter were further clarified in a April 13, 2007, letter from the NRC to the Nuclear Energy Institute. Through a review of these letters, the inspectors determined that the issues discovered by the licensee in 2003 were not required to be reported to the NRC for the following reasons:

- The licensee had not experienced any failures of power cables due to submergence; and
- The voltage level for a majority of the cables (103 out of 112) in the tunnels was less than the voltage levels specified in the April 13, 2007, letter.

However, the inspectors chose to review the licensee's 2003 corrective actions to determine whether the corrective actions had addressed and resolved the previously identified cable submergence issue.

This inspection represents the completion of one sample.

b. Observations

The inspectors identified the following weaknesses in the licensee's response to the 2003 cable submergence issue:

Work Request to Repair Rusted Cable Trays and Supports

The inspectors discussed the status of the work request with engineering personnel on February 16, 2007. The inspectors learned that the work was not scheduled to be completed until June 18, 2007. As a result, no work had been done to repair the cable trays or supports. Due to the lack of work, this action was deemed ineffective.

Evaluation of Cable Condition and Long Term Submergence Effects

The inspectors reviewed the corrective action database and found that this corrective action was documented as complete on January 1, 2004. However, during discussions on February 16, 2007, the inspectors determined that this action was not complete. As a result, the inspectors concluded that this action had not been effective in addressing the potential impact of the cable submergence issue.

The inspectors reviewed the corrective action completion notes and found a statement which indicated that the cables in the tunnels were designed to exist in an environment which ranged from 0 to 100 percent submerged. Based upon this information, the licensee concluded that the long term submergence of these cables would not result in any cable degradation. During the 2007 inspection, the inspectors requested that the licensee provide documentation which specified that the cables were rated for full submergence. This documentation was not provided. Instead, the licensee provided information which indicated that cable degradation could occur due to being exposed to water. However, an additional degradation mechanism (such as a flaw in the cable insulation) was needed to create a cable faulting condition. The inspectors also found information which stated a low voltage cable failure due to this type of degradation mechanism was rare.

The inspectors also reviewed the cable submergence operability determination conducted in 2003. Based upon the results of this review, the inspectors determined that the 2003 operability determination was inadequate because it did not provide information explaining why the cables remained operable. In addition, the licensee had not investigated the specific types and voltage levels of the cables in the tunnel nor had they assessed the potential plant impact if one of the submerged cables failed. Although plant engineering agreed with the inspectors assessment, a prompt operability determination was not performed. A complete evaluation of the cable submergence issue was completed approximately six to eight weeks later. The inspectors reviewed this evaluation and learned that the cable tunnels contained 112 cables. The specific breakdown of the cables was as follows:

- Eighty-four instrumentation and control cables for switchyard components;
- Ten cables for the instrumentation and control of miscellaneous components;

- Eight power cables to miscellaneous and switchyard components; and
- Ten spare cables.

Further evaluation of the 84 switchyard instrumentation and control cables determined that a reactor scram would occur if a fault was present in any of 14 specific cables. In addition, the licensee determined that a loss of offsite power to one unit could result if a fault was to occur in two specific cables.

The inspectors reviewed Revision 3 to the License Renewal Aging Management Report for Electrical Cables. Through this review, the inspectors found that electrical cables could degrade due to exposure to moisture. However, this most often occurred for cable voltages above 4 kV. In addition, the following conditions were also required:

- A cable insulation material void or impurity must be present in the cable;
- An electrical field must be present on continuously energized cables; and
- Continuous moisture must be present.

Based upon this information, the inspectors determined that the likelihood of a cable failure which resulted in a unit scram or a loss of offsite power was extremely low.

<u>Development and Implementation of Preventive Maintenance Task</u>

This task was created as a means of tracking the amount of water in the cable tunnels and trending any identified cable degradation. Initially, this task was performed annually. However, the frequency was changed to quarterly when accumulated water was found in the tunnels during the 2004 inspection. During discussions with plant engineering personnel, the inspectors learned that the tracking and trending activities were to be conducted by reviewing the issue reports generated following completion of the preventive maintenance task.

The inspectors reviewed the preventive maintenance task instructions and determined that instructions regarding issue report initiation were not included. The preventive maintenance task instructions also lacked meaningful acceptance criteria which would have prompted maintenance personnel to write an issue report if a specific amount of water was found in a cable tunnel. As a result, issue reports were not being generated as directed by LS-AA-120, “Issue Identification and Screening Process.” The licensee wrote Issue Report 595145 to document this weakness in the preventive maintenance task instructions. As part of the corrective actions for Issue Report 595145, the licensee reviewed the results of each quarterly task conducted between September 2004 and December 2006. The licensee determined that the tunnels contained water in most cases (actual water level ranged from 3 inches to 6 feet). Maintenance personnel did not specify the amount of water found in the tunnels on two separate occasions. Due to the lack of specific instructions regarding issue report generation, the inspectors concluded that the development of the preventive maintenance task was not effective in creating a tracking and trending tool to assess cable tunnel water accumulation or cable degradation. However, performance of the preventive maintenance task ensured that the cables were not continuously submerged The task instructions were revised to ensure that an issue report was written if water was found in the future.

Redirection of Water Away from Cable Tunnel Openings

In October 2003 engineering personnel conducted an inspection of the opening to each cable tunnel. The engineers determined that the openings were either at or above grade. As a result, the engineers concluded that water was accumulating in the cable tunnels due to ground water in-leakage rather than due to rain. The licensee considered three options for eliminating the ground water in-leakage or reducing the potential that the cables would be submerged due to the leakage. After considering each option, the licensee decided to implement the preventive maintenance task discussed above. At the conclusion of this inspection, the licensee was considering the installation of a sump pump system to ensure that the potential for cable submergence was minimized.

Conclusions

The inspectors concluded that the licensee had not effectively implemented most of the corrective actions developed in 2003. The licensee also took very little action to further understand the potential impact of the submerged cables until prompted by the NRC in 2007. The inspectors reviewed this issue in its entirety and determined that although the licensee's corrective action implementation was poor, and a finding existed, the finding was minor. The classification of this finding as a minor finding was based upon the conclusion that this finding could not be reasonably viewed as a precursor to a significant event due to the extremely low cable failure probability.

.4 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of inspection reports, inspector issues, the licensee's corrective action program, 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 and corrective maintenance issues but also considered the impact that human performance and problem identification and resolution issues had on licensee performance. The inspectors also used the results of their daily issue report review to identify any potential adverse trends. The inspectors' review nominally considered the six-month period of December 2006 through June 2007, although some examples expanded beyond those dates when the scope of the trend warranted.

This inspection represented the completion of one sample.

b. Observations

Adverse Trend in the Review and Documentation of Operability Issues

OP-AA-108-115, "Operability Determinations," Step 2.11, defined an operability determination as a decision made by an on-shift senior reactor operator regarding whether or not an identified or postulated condition has an impact on the operability of a structure, system or component (SSCs). The same section also stated that there must be a reasonable expectation that the SSC will continue to perform its specified safety function in order for the SSC to be considered operable.

Section 2.13 of OP-AA-108-115 stated the following with regards to reasonable expectation:

- Reasonable expectation does not mean absolute assurance that the SSCs are operable. The SSCs may be considered operable where there is evidence that the possibility of failure of an SSC has increased, but not to the point of eroding confidence in the reasonable expectation that the SSC remains operable. The supporting basis for the reasonable expectation of SSC operability should provide a high degree of confidence that the SSCs remain operable.

As discussed in Section 1R15 of this report, the inspectors reviewed six operability determinations during the inspection period. The inspectors determined that four of the six operability determinations were either incorrect, weak with respect to timely documentation of operability issues, or lacked an adequate basis to provide a reasonable expectation that the SSC would continue to perform its safety function. The number of deficiencies was noteworthy as the licensee had taken actions to improve operability determinations and evaluations following the identification of an inadequate operability determination on the Unit 1 standby liquid control tank in late 2006. The specific weaknesses were as follows:

- Evaluation of Submerged Cables in Tunnels Between the Service Building and the Switchyard. (Issue Reports 177026, 595145, and 622100)

  As discussed in Section 4OA2.3 of this report, the inspectors reviewed the licensee's corrective actions following the discovery of water in multiple cable tunnels in 2003. During this review, the inspectors identified that the licensee's 2003 prompt operability determination was incorrect. In addition, the licensee did not take long-term actions to identify the specific cables located in each tunnel and assess the potential impact that a cable failure could have on the operation of the plant. The inspectors informed the licensee of the inadequate operability determination in late February 2007. However, a detailed and complete operability determination was not provided to the operations department for approximately two months. The inspectors also noted that a revised prompt operability determination regarding the submerged cables was not made even though Step 4.1.5 of OP-AA-108-115 clearly stated that prompt operability determinations should be made within 24 hours even though complete information may not be available. Following a review of the complete operability determination, the inspectors agreed that the cables remained operable.

- Inadequate Supporting Basis for Extent of Condition Evaluation for Unit 2 Merlin Gerin 4 kV Breakers. (Issue Reports 631282, 638525, and 639410)

  As discussed in Section 1R15 of this report, the licensee experienced a Unit 1 breaker failure during the refueling outage. The licensee determined that the breaker's failure mechanism had the potential to impact the Unit 2 4 kV breakers.

The inspectors reviewed the Unit 2 operability determination included within the body of Issue Report 638252 and concluded that the determination was inadequate because it failed to provide an adequate basis to support a reasonable expectation that the breakers remained operable.

- Lack of Detail to Support Continued Operability of SSCs Containing Unqualified Varflex Wire Sleeves. (Issue Report 631331)

  IEEE Standard 384-1974 required that the licensee maintain a standard distance between cables, wires, and components or provide an adequate barrier between these types of equipment if the standard distance could not be achieved. In certain cases, the licensee used wire sleeving (qualified per the requirements of Underwriters Laboratory VW-1) as a barrier. On May 18, 2007, corporate personnel initiated the above issue report to document that wire sleeves purchased from Varflex Corporation had not been certified to meet the Underwriters Laboratory requirements. The issue report stated that Varflex had conducted a test which showed that their wire sleeving met the Underwriters Laboratory requirements. However, the specifics of the testing were not discussed in the issue report. In addition, Varflex was legally unable to state that the sleeving met the Underwriters Laboratory requirements because Varflex was not a certified Underwriters Laboratory facility. The inspectors noted that Varflex was a certified Canadian Standards International test facility. However, the issue report failed to provide a comparison regarding how certification as a Canadian Standards International test facility was comparable to being certified as an Underwriters Laboratory facility.

  The inspectors discussed their observations with operations management and learned that the shift manager was provided additional information regarding the similarities between Underwriters Laboratory and Canadian Standards International during his review of the issue report. The shift manager was also provided with specifics regarding the actual testing provided by Varflex. However, this information was not incorporated into the operability determination. Following a review of the supporting information, the inspectors concluded that the equipment containing the unqualified Varflex sleeving remained operable.

- Incorrect Operability Determination for an Inoperable Bypass Valve. (Issue Reports 633052 and 635989)

  On May 23, 2007, operations personnel identified that Unit 1 bypass valve #2 failed to fully open. Technical Specification 3.7.7 required that the main turbine bypass system be operable when reactor power was greater than 25 percent. Upon the discovery of one or more bypass valves becoming inoperable, the Technical Specifications directed that operations personnel apply the minimum critical power ratio penalty specified in the core operating limits report.

  On May 30, 2007, the inspectors reviewed the issue reports, control room log entries, and the Technical Specifications associated with the bypass valve issue. The inspectors noted that the control room operators failed to make a log entry to clearly specify that the #2 bypass valve was inoperable. While reviewing the associated issue reports, the inspectors identified that the shift manager had stated that the bypass valve system remained operable even though the #2 bypass valve failed to fully open. The inspectors discussed this information with operations management. Following these discussions, operations management agreed that the operability determination provided in the issue report was incorrect. The operability determination was subsequently corrected.

This adverse trend was discussed with the licensee on June 11, 2007. The licensee initiated Issue Report 638136 to document the trend. The licensee was developing their corrective actions for this issue at the conclusion of the inspection period.

Inadequate Oversight of Work Activities Results in Failure to Identify Issues

Over the last two inspection periods the inspectors have identified seven human performance issues which were not recognized by personnel performing oversight of the work activities. The specific examples were as follows:

- On January 1 an initial license trainee tripped the operating control room ventilation train when he manipulated equipment during a training simulation activity. The failure of the training evaluator to prevent the trainee from manipulating plant equipment contributed to the control room ventilation trip.

- On January 31 the inspectors identified that operations personnel had not appropriately tested the control room ventilation system to demonstrate compliance with Technical Specification Surveillance Requirement 3.7.4.4. This was notable as the completed surveillance test had been reviewed and determined to be acceptable by multiple licensed senior reactor operators.

- In February 2007 the inspectors determined that the preventive maintenance activity used to assess whether cables in the cable tunnels were continuously submerged was inadequate because licensee personnel failed to initiate issue reports to document the repeated presence of water in the tunnels. The inspectors concluded that better oversight of this activity could have resulted in the generation of issue reports when water was identified in the tunnels. The lack of issue reports between 2004 and 2007 resulted in the licensee's failure to take additional corrective actions.

- In April 2007 the inspectors reviewed the standby gas treatment system logic testing results. During this review, the inspectors noted that the logic testing procedures stated that the tests could create a condition which would normally result in entering the emergency operating procedures. However, the procedure went on to state that the emergency operating procedures did not need to be entered. The inspectors identified that this issue was similar to an NRC issue discussed with the licensee in late 2006. In addition, the direction provided in the standby gas treatment system logic test procedures regarding the emergency operating procedures conflicted with the operations department administrative procedures which directed that the emergency operating procedures be entered whenever an entry condition existed. The licensee corrected the conflict after discussing the issue with the NRC.

- In early May 2007 the inadequate oversight of the Unit 1 standby liquid control tank repair efforts resulted in the failure to identify that starting the repair efforts prior to Unit 1 being shut down jeopardized the noble metals application efforts, that fire blankets were being secured with combustible materials, that duct tape was being placed on the tank and could possibly interact with the tank wall, and that the grout contained within the tank supports was unable to be completely removed.

- On May 5, 2007, operations personnel received an unexpected residual heat removal pressure alarm during testing of the noble metals equipment. After reading the associated issue report, the inspectors believed that the alarm had occurred due to an error by noble metals personnel. However, the inspectors identified that the licensee had not performed any type of human performance investigation for this issue. The inspectors questioned outage control center personnel about the lack of a formal investigation and were told that the outage control center had not been told about the unexpected alarm. Following these discussions, the licensee initiated a human performance investigation of this issue. The licensee subsequently determined that the unexpected alarm occurred due to an error by operations personnel. Specifically, a licensed senior reactor operator gave permission for the noble metals individuals to begin testing their equipment (which injected 1 gallon per minute into the residual heat removal system) without verifying that the residual heat removal system had been placed in service.

- On May 14, 2007, the inspectors performed an observation and identified that operations personnel had incorrectly determined that the flow from a new emergency diesel generator cooling water pump was adequately balanced. The identification of this issue was noteworthy as the operations department had just completed a stand down due to multiple human performance issues. In addition, the licensee had implemented actions which required all operations activities to be observed by a supervisor to ensure that appropriate human performance tools were being implemented. Although an operations supervisor was in attendance during the inspectors observation, the supervisor became overly involved in the actual work activities and failed to identify that the cooling water flow was not balanced. The inspectors discussed the flow balancing error with the operations supervisor while they were in the field and the situation was corrected. However, the associated issue report was not initiated until June 11, 2007.

The licensee was developing corrective actions for this adverse trend at the conclusion of the inspection period.

.5 Annual Operator Work Around Review

a. Inspection Scope

In accordance with Inspection Procedure 71152, the inspectors performed a comprehensive review of the operator workaround program by inspecting the items on the current operator workaround/challenge list, verifying that sufficient progress was being made to address the documented conditions, and validating that the conditions did not place undue stress on operations personnel during emergency and normal operating conditions. The inspectors also conducted a review of issue reports and current plant issues to determine whether previously identified material condition items had not been considered for inclusion as part of the operator workaround program.

This inspection represented the completion of one sample.

b. Observations

The inspectors reviewed a list of operator workarounds and challenges dated April 2, 2007, to determine the number of items in each category. The inspectors also reviewed the minutes from multiple operator workaround review boards to develop potential insights and to determine if items were being resolved appropriately. The inspectors had the following observations:

- On November 3, 2006, the Workaround Review Board determined that the frequent loss of the plant process computer was an operator challenge. The meeting minutes documented that the process computer had locked up on three separate occasions between September 26 and October 10, 2006. The inspectors noted that the Workaround Review Board had decided to consider including the loss of the plant process computer as an operator workaround if the individual computer outages lasted longer than eight hours. However, a similar criteria was not developed to address a potential increase in the frequency of the plant process computer outages.

- Through a review of the December 5, 2006 meeting minutes, the inspectors determined that the workaround review board had adopted criteria for determining when the response to degraded control rod drive accumulators should be placed on the operator challenge list. Specifically, the board concluded that the receipt of three low nitrogen pressure alarms per week or five high water level alarms per week would result in the board reviewing the accumulator for placement on the operator challenge list. Within the same meeting minutes, the inspectors noted that the workaround review board had reviewed the monthly alarm frequency for Unit 2 hydraulic control unit 10-43 for the period of July through November 2005. The inspectors noted that although this component exceeded the criteria listed above, the review board rejected placing hydraulic control unit 10-43 on the operator challenge list because the average number of alarms was only 2.3 alarms per week.

The inspectors discussed their observations with the individual in charge of the operator workaround program. The individual planned to present the inspectors observations as part of the next quarterly operator work around review board meeting.

4OA3 Event Followup (71153)

(Closed) Licensee Event Report 05000265/07-001: Manual Reactor Scram on Increasing Condenser Back Pressure due to a Decrease in 2A Offgas Train Efficiency.

Introduction: A Green finding was self-revealed when operations personnel inserted a manual scram due to an increasing condenser back pressure. The licensee determined that blockage in an offgas system pressure sensing line created a condition which resulted in the opening of a system relief valve. Once the relief valve opened, the 2A steam jet air ejector efficiency dropped which resulted in an increase in condenser back pressure.

Description: In the mid-1980's, the licensee experienced a fire in the 2A offgas train. Following the fire, the licensee made a conscious decision to leave the 2A offgas train valved out. The 2A offgas train remained in this condition until March 5, 2002. However, the train was not fully recovered until March 29, 2004. Following the licensee's system recovery actions, operations personnel continued to rely on the 2A offgas train as a backup to the 2B train.

On February 27, 2007 at 11 p.m., control room operators commenced a Unit 2 power reduction to allow repairs to be performed on the 2C reactor feedwater pump. The 2A offgas train was in service. Approximately one hour later, a pressure controller malfunction in the auxiliary steam supply to the 2A offgas train caused a reduction in its noncondensible gas removal efficiency. This malfunction impacted the operations of the 2A offgas preheater, the Unit 2 steam dilution, and the 2A steam jet air ejector operation which resulted in an increase in condenser back pressure. Operations personnel inserted a manual scram to address the condenser back pressure issue.

The licensee determined that the condenser back pressure condition was caused by a blockage of the pressure sensing line to pressure controller 2-3041-3A with fine sized corrosion products. The licensee believed that the corrosion products were the result of having the 2A offgas train valved out for an extended period of time. The blockage occurred because the licensee failed to have procedures which ensured that debris was removed from systems prior to returning the system to service after an extended period of time. Specifically, procedures were not available to ensure that maintenance personnel cleaned out the sensing lines to this pressure controller.

Analysis: The inspectors determined that the failure to have a procedure which directed the cleaning of the pressure controller's sensing lines was more than minor because it was associated with the equipment performance and procedure adequacy attributes of the initiating events cornerstone. In addition, the finding impacted the cornerstone's objective of limiting the likelihood of events that upset plant stability and challenge safety functions. The inspectors also determined that this finding was cross-cutting in the area of human performance, resources (H.2(c)), in that the licensee failed to have complete, accurate, and up-to-date procedures regarding pressure sensing line maintenance.

The inspectors conducted a Phase 1 Significance Determination Process Screening and determined that a Phase 2 Evaluation was required because this finding contributed to both the likelihood of a reactor trip and that mitigating systems equipment (the condenser) would not be available. The inspectors used the Risk-Informed Inspection Notebook for Quad Cities Nuclear Power Station, Units 1 and 2, Revision 2, dated September 30, 2005, to complete the Phase 2 Evaluation. The inspectors concluded that the fault exposure time was less than three days. The inspectors also increased the initiating event frequency by one order of magnitude because the finding increased the likelihood of an initiating event. For each Significance Determination Process Worksheet completed, the inspectors assumed that all remaining mitigating systems equipment was available. The inspectors did not allow credit for recovery due to the complexity of restoring condenser vacuum following this event. Using these assumptions, the inspectors evaluated the Transients with Loss of Power Conversion System Worksheet and found one sequence with a value of eight. Based upon the counting rule, the overall increase in safety was determined to be very low (Green) **(FIN 05000265/2007003-08)**.

Enforcement: No violation of NRC requirements was identified due to the offgas system being non-safety related. Corrective actions included cleaning the sensing line and implementing a periodic maintenance task to clean the sensing lines.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. T. Tulon and other members of licensee management on July 10, 2007. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Baseline procedure 71111.08 with technical staff members on May 11, 2007.

- Radiation Protection ALARA and radiological access control inspection with Mr. T. Tulon and other licensee staff on May 18, 2007.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance was identified by the licensee and was a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being disposed as an NCV.

Cornerstone: Occupational Radiation Safety

Technical Specification 5.4.1 requires that written procedures be established and implemented for activities provided in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Procedures specified in Regulatory Guide 1.33 include radiation protection procedures for personnel monitoring, which are provided by licensee procedures RP-AA-210, “Dosimetry Issue, Usage and Control,” Revision 9 and RP-AA-403, “Administration of the Radiation Work Permit Program,” Revision 1. The procedures require that workers wear electronic dosimetry at all times when working in the Radiologically Controlled Area and that workers comply with the requirements of the RWP, respectively. Contrary to these requirements, on May 10, 2007, an individual performed activities using RWP 10007823 in the Unit 1 Condensate Demineralizer Room without wearing an electronic dosimeter as required by the RWP. This incident is documented in the licensee’s corrective action program as Issue Report 628075. This issue represents a finding of very low safety significance because it did not involve ALARA planning or work controls, there was no overexposure or substantial potential for an overexposure given the area radiological conditions and the worker’s knowledge of those conditions, nor was the licensee’s ability to assess worker dose compromised since the worker wore a thermoluminescent dosimeter.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

T. Tulon, Site Vice President
R. Gideon, Plant Manager
B. Adams, Engineering Manager
D. Barker, Work Control Manager
W. Beck, Regulatory Assurance Manager
D. Craddick, Maintenance Manager
D. Moore, Nuclear Oversight Manager
K. Moser, Training Manager
V. Neels, Chemistry/Environ/Radwaste Manager
K. Ohr, Radiation Protection Manager
M. Rice, Exelon Engineering
R. Svaleson, Operations Manager
A. Williams, Radiation Protection Engineering Supervisor

Nuclear Regulatory Commission personnel

M. Ring, Chief, Reactor Projects Branch 1
M. Thorpe-Kavenaugh, NRR Project Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000254/2007003-01; 05000265/2007003-01	URI	Aerosol Can Found in Cable Spreading Room
05000254/2007003-02; 05000265/2007003-02	URI	Implementation of External Flooding Methodology
05000254/2007003-03	URI	Failure to Complete Qualified Reactor Vessel Shell Welds
05000254/2007003-04	NCV	Unqualified Target Rock Valve Repair
05000265/2007003-05	FIN	Inadequate Operability Justification for Unit 2 4 kV Breakers

05000254/2007003-06; 05000265/2007003-06	URI	Review of Unit 1 4 kV Breaker Failures
05000254/2007003-07	NCV	Failure to Adequately Implement Drywell Closeout Procedure
05000265/2007003-08	FIN	Manual Reactor Scram due to Plugged Pressure Sensing Line

Closed

05000265/07-001	LER	Manual Reactor Scram on Increasing Condenser Back Pressure due to Decrease in 2A Offgas Train Efficiency
05000254/2007003-04	NCV	Unqualified Target Rock Valve Repair
05000265/2007003-05	FIN	Inadequate Operability Justification for Unit 2 4 kV Breakers
05000254/2007003-07	NCV	Failure to Adequately Implement Drywell Closeout Procedure
05000265/2007003-08	FIN	Manual Reactor Scram due to Plugged Pressure Sensing Line

Discussed

None

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather
Issue Report 636927; Failure to Protect HPCI and RCIC During Tornado Warning; dated June 4, 2007
WC-AA-107; Seasonal Readiness; Revision 4
QCOP 0010-10; Unit 1(2) Required Hot Weather Routine; Revision 11
Quad Cities Station Component Health Indicator Program CHIP Report; dated November 2006
Issue Report 637255; 1A RBCCW HX TCV Valve Stem in Oscillating; dated June 5, 2007
Issue Report 575261; 1A CW Pump Motor Inspection Needed Before Summer 07; dated January 4, 2007
Issue Report 575265; 1B CW Pump Motor Inspection Needed Before Summer 07; dated January 4, 2007
Issue Report 575267; 1C CW Pump Motor Inspection Needed Before Summer 07; dated January 4, 2007
Issue Report 575269; 2A CW Pump Motor Inspection Needed Before Summer 07; dated January 4, 2007
Issue Report 575271; 2B CW Pump Motor Inspection Needed Before Summer 07; dated January 4, 2007
Issue Report 575272; 2C CW Pump Motor Inspection Needed Before Summer 07; dated January 4, 2007

1R04 Equipment Alignment
QCOP 2900-01; Safe Shutdown Makeup Pump System Preparation for Standby Operation; Revision 23
QOM ½-2900-1; Unit ½ Safe Shutdown Makeup Pump System Checklist; Revision 4
QCOP 6600-04; Diesel Generator ½ Preparation for Standby Operation; Revision 26
QOM ½-6600-01; Unit ½ Diesel Generator Valve Checklist; Revision 15
QCOP 1400-01; Core Spray System Preparation for Standby Operation; Revision 18
Issue Report 511960; Disassemble/Inspect 1-1402-71 Check Valve During Q1R19; dated July 21, 2006
Issue Report 475188, PSU Q2R18 Spray Cool Flow Value Needed for RPV Control EOP; dated April 5, 2006
QOM 1-1400-09; Unit 1 A Core Spray Valve Checklist; Revision 4
QOM 1-1400-08; Core Spray System Fuse and Breaker Checklist; Revision 3
QOM 1-2300-01; Unit 1 High Pressure Coolant Injection Valve Checklist; Revision 9

1R05 Fire Protection
OP-MW-201-004; Fire Prevention for Hot Work; Revision 1
OP-AA-201-009; Control of Transient Combustible Material; Revision 5

Quad Cities Pre-fire Plan
Quad Cities Fire Hazards Analysis Report
Quad Cities Fire Marshal Outage Training Information Package
Issue Report 626964; Exposed Duct Tape Securing Fire Blanket; dated May 7, 2007
Issue Report 625097; Transient Combustible Material in Transient Exclusion Zone - Cable Spreading Room; dated May 3, 2007

<u>1R08</u> <u>Inservice Inspection Activities</u>
WPS D1.1-SM; Welding Procedure Specification Record; Revision 0
Purchase Order 00080261; Valve Safety relief; dated March 26, 2005
Work Order 795495; PSU MSL Support Missing Hold Down Tab and Anchor Pin; dated April 4, 2005
GE-ADM-1062; Procedure for Determining and Documenting Examination Requirements for Risk-Informed Inservice Inspections; Revision 0
GE-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds; Revision 5
GE-UT-704; Procedure for the Examination of Reactor Pressure Vessel Welds with GERIS 2000 OD in Accordance with Appendix VIII; Revision 7
GE-MT-100; Procedure for Magnetic Particle Examination (Dry Particle, Color Contrast or Wet Particle, Fluorescent); Revision 7
ER-AA-335-002; Liquid Penetrant Examination; Revision 4
Issue Report 625801; OPEX Applicability Review for Quad SRV's; dated May 5, 2007
Issue Report 628357; Q1R19-NRC Inspector Requested Re-Exam of an Unacceptable Exam; dated May 11, 2007
Issue Report 5096717; Duane Arnold Reactor Vessel NDE Information; dated February 26, 2007
Issue Report 371631; Perform UT on 2B Cond Booster Pump Discharge Elbow; dated August 8, 2005
Issue Report 430026; U1 SBLC Valve Threaded Connections Need Cleaned and Inspected; dated December 2, 2005.
Issue Report 452587; Boric Acid Residue on Components; dated February 10, 2006
Issue Report 475742; PSU Q2R18 Unable to Perform Preservice UT Inspection; dated April 6, 2006
QDC-25247; PowerLabs Field and Lab Evaluation of a Leak in the 1B Standby Liquid Control Tank at Quad Cities Station; dated November 13, 2006

<u>1R12</u> <u>Maintenance Effectiveness</u>
Maintenance Rule Performance Evaluation Report for Function 2400-01; dated March 2007
(a)(1) Action Plan for Maintenance Rule Function Z2400-01; dated March 8, 2007
Maintenance Rule Expert Panel Meeting Minutes; dated December 14, 2006
Issue Report 324316; Valve 1-2499-2A Did Not Open Upon Initiation of Cam in Drywell Position; dated April 13, 2005
Issue Report 327433; Valve Failed Closed; dated April 22, 2005
Issue Report 329770; 1A CAM Oxygen Monitor Inoperable; dated April 28, 2005
Issue Report 373154; 2A CAM Hydrogen Monitor Declared Inoperable; dated September 13, 2005

Issue Report 390013; 2B Hydrogen/Oxygen Analyzer Failed Oxygen Surveillance; dated October 25, 2005
Issue Report 495457; 2B CAM is Reading Lower Than Reasonably Expected; dated May 31, 2006
Issue Report 506674; Oxygen Analyzer is Inoperable When Drywell is Selected; dated July 5, 2006
Issue Report 518106; 2B Drywell Oxygen Analyzer Reading Lower Than Reasonably Expected; dated August 9, 2006
Issue Report 532773; 2A CAM Would Not Pass Channel Check; dated September 18, 2006
Issue Report 540130; 1A CAM Hydrogen Monitor is Reading High; dated October 5, 2006
Issue Report 552286; 1A CAM Indicates Containment Hydrogen is Greater Than 4 Percent; dated November 2, 2006
Issue Report 563415; 1A CAM Hydrogen Monitor is Inoperable; dated November 30, 2006
Issue Report 563418; 1B CAM Hydrogen Monitor is Inoperable; dated November 30, 2006
Issue Report 616486; Replace 1B Hydrogen Cell; dated April 12, 2007

<u>1R13</u> <u>Risk Assessments and Emergent Work</u>
Work Week Safety Profiles
Operations Department Daily Orders
Shutdown Safety Risk Assessments

<u>1R15</u> <u>Operability Evaluations</u>
QCOS 5600-05; Turbine Generator Monthly Testing; Revision 9
QCTS 0340-07; Turbine Bypass Valve Opening Time Measurement; Revision 6 and Revision 8
Underwriters Laboratories 1441; UL Standard for Safety for Coated Electrical Sleeving; Fourth Edition
Letter from Linda Dankel, Varflex Corporation to Eric Ballou, Exelon Corporation; dated May 18, 2007
Letter from Robert Smalley, Varflex Corporation to Michael Hayse, Exelon Corporation; dated May 15, 2007
Quad Cities Unit 1 Cycle 20 Core Operating Limits Report; Revision 0

<u>1R19</u> <u>Post Maintenance Testing</u>
TDBD-DQ-1; Quad Cities Units 1 and 2 Structural Design Criteria; dated April 13, 2000
Engineering Change 362979; Seismic Evaluation of Standby Liquid Control System Tank Anchor Chair Removal, Grout Removal, and Anchor Chair Replacement; Revision 1
Issue Report 626108; 1D RHR Pump Tripped During Manual Start; dated May 7, 2007
QCOP 1000-10; Torus Water Transfer to the Main Condenser Via the Condensate Demineralizers; Revision 13
Issue Report 631282; EOC MOC Cam Follower Inspections for Unit 2 4KV Buses; dated May 18, 2007
Issue Report 631363; PSU Q1R19 Breaker Tripped at Start Attempt; dated May 19, 2007
Issue Report 631015; Strike Marks on MOC Switch Cam Follower at Bus 13-1, Cubicle1; dated May 18, 2007

<u>1R20</u> <u>Refueling and Outage Activities</u>
QCOP 1000-24; Draining Reactor Cavity and Vessel to the Torus; Revision 14
QCGP 3-1; Reactor Power Operations; Revision 52

QCGP 2-1; Normal Unit Shutdown; Revision 56
Calculation QDC-1900-N-1580; Alternate Decay Heat Removal System Qualification; Revision 0
Issue Report 633194; Q1R19 OLL DW Closeout; dated May 24, 2007
Issue Report 339884; Final Drywell Closeout Deficiencies During Q1M18; dated May 31, 2005
Issue Report 632154; PSU Q1R19 TE 1-0261-14B1 Not Connected to 1-203-3B ERV; dated May 22, 2007
Issue Report 325572; Q1R18 OLL Drywell Closeout Q1R18; dated April 17, 2005
QCOS 1600-32; Drywell/Torus Closeout; Revision 11

1R22 Surveillance Testing
Issue Report 620733; Blown Fuse During QCOS 7500-04; dated April 23, 2007

1R23 Temporary Modifications
Issue Report 612585; WTO 2006-8324 for Service Building Lighting Aborted; dated April 3, 2007
Operational Technical Decision Making Document 06-020; Should Secondary Pressure Amplifier Circuit Boards be replaced online; dated October 3, 2006
Issue Report 502367; A and B Pressure Regulator in Control Lights Both Lit; dated June 22, 2006
Issue Report 510495; Unit 2 EHC Pressure Regulator Drifted Less Than 1 Pound Since Last Reading; dated July 18, 2006
Issue Report 528071; Unit 2 Reactor Pressure Increased about 2 Pounds During QCOS 5600-05; dated September 7, 2006
Issue Report 575252; Unit 1 EHC Pressure Regulator Bias Drifting; dated December 28, 2006
Issue Report 575730; Unexpected Increase in Reactor Pressure; dated January 5, 2007
Issue Report 596697; Unit 1 EHC Backup Pressure Regulator Drifting; dated February 20, 2007
Issue Report 606743; Unit 2 Reactor Pressure Vessel Pressure Increase During Turbine Testing; dated April 26, 2007
Issue Report 607261; Recommend Revision to OTDM 06-020 for Unit 2 EHC Pressure Regulator; dated March 21, 2007
Issue Report 609011; Unit 2 EHC Backup Pressure Regulator Change; dated March 21, 2007
Issue Report 616458; Engineering Change 361720 has Unclear Seismic Statements; dated April 12, 2007
Adverse Condition Monitoring Plan for Unit 2 EHC Pressure Regulator; dated March 30, 2007
CC-AA-112; Temporary Configuration Changes; Revision 11
Issue Report 634196; Hot Area Discovered on East Side of Transformer; dated May 26, 2007
Issue Report 635343; Not All Required Data Available on U-1 MPT Severon; dated May 31, 2007
Issue Report 637444; Main PWR XFMR #1 Calisto Monitor Upward Trending of Reading; dated June 6, 2007

2OS1 Access Control to Radiologically Significant Areas
Radiation Work Permit 10007741; Radiography Outside Drywell; Revision 0
Radiation Work Permit 10007721; Torus Desludge and Painting - Diving Activities; Revision 0
Radiation Work Permit 10007729; Reactor Vessel In-Vessel/Dryer Inspections; Revision 0
Issue Report 626850; Individual Working in the Regen Room Received Rate Alarm; dated May 8, 2007

Issue Report 626962; Worker Received ED Dose Rate Alarm; dated May 8, 2007
Issue Report 588161; ED Accumulated Dose Alarm; dated February 5, 2007

<u>2OS2</u> <u>ALARA Planning and Controls</u>
RP-AA-270; Prenatal Radiation Exposure; Revision 3
RP-AA-401; Operational ALARA Planning and Controls; Revision 7
Radiation Work Permit 10007721; Unit 1 Torus Desludge and Painting - Diving Activities; Revision 0 and associated ALARA Plan; dated March 21, 2007
Radiation Work Permit 10007763; Control Rod Drives - Remove/Replace; Revision 0 and associated ALARA Plan and TEDE ALARA Evaluation; dated April 25, and May 3, 2007
Radiation Work Permit 10007788; Under Vessel Instrumentation Work; Revision 0 and associated ALARA Plan and TEDE ALARA Evaluation; dated April 25 and May 3, 2007
Radiation Work Permit 10007836; 1-B Recirc Seal - Remove/Replace and Test, Revision 0, and associated ALARA Plan and TEDE ALARA Evaluation; dated November 13 and 14, 2006
Radiation Work Permit 10007767; In-Service-Inspection Preparation and Inspection, Revision 0, and associated ALARA Plan; dated April 27, 2007
Radiation Work Permit 10007762; Electromatic, Safety Relief and Target Rock Valves - Remove and Replace, Revision 0, and associated ALARA Plan; dated April 18, 2007
Radiation Work Permit 10007883; Replace Sump Pumps and Check Valves, Revision 0, and associated ALARA Plan and TEDE ALARA Evaluation; dated March 19, 2007, and January 30, 2007
Radiation Work Permit 10007727; Reactor Disassembly, Reassembly and Cavity Decontamination, Revision 0, and associated ALARA Plan and TEDE ALARA Evaluations; dated March 19, 2007
Radiation Work Permit 10007880; 1-0220-1 Valve Cutout and Replace, Revision 0, and associated ALARA Plan and TEDE ALARA Evaluation; dated March 20, 2007 and February 26, 2007
Q1R19 Daily Outage Doses for all Radiation Work Permits; May 8 - 17, 2007
Individual Radiation Worker Doses for Radiation Work Permit 10007767 (In-service Inspection Preparation and Inspection); Radiation Work Permit 10007784 (Drywell Insulation Activities); and Radiation Work Permit 10007771 (Drywell Scaffold Support); dated May 7 - 10, 2007
ALARA Post Job Review for Radiation Work Permit 10006006; Q2R18 Reactor Disassembly, Reassembly and Associated Work; dated April 16, 2006
Work-In-Progress Reviews for Radiation Work Permit 10007833; Turbine System Work; dated May 8 - 10, 2007
Work-In-Progress Review for Radiation Work Permit 10007865; Unit 1 Digital Electro-Hydraulic Control Modification; dated May 11, 2007
Work-In-Progress Review for Radiation Work Permit 10007769; Unit 1 Drywell FAC Pipe Replacement; dated May 13, 2007
Work-In-Progress Review for Radiation Work Permit 10008171; Unit 1 Drywell Repair of X13A Penetration; dated May 13, 2007
Work-In-Progress Review for Radiation Work Permit 10007813; Unit 1 Feedwater Heaters; dated May 16, 2007
Work-In-Progress Review for Radiation Work Permit 10007729; Reactor Vessel In-Vessel Visual Inspections/Dryer Inspections; dated May 14, 2007
Radiation Protection Self Assessment Report; ALARA Planning and Controls; dated April 9, 2007
Issue Report 628415; Facial Contamination, Refuel Floor; dated May 10, 2007

Issue Report 627083; Nozzle Flushing Issues; dated May 9, 2007
Issue Report 626430; ED Alarm in Unit 1 Drywell; dated May 7, 2007

4OA2 Problem Identification and Resolution
OP-AA-102-103, "Operator Work-Around Program," Revision 1
Control Room Distractions; dated February 28, 2007
Operator Work-Around/Challenge Update; dated April 2, 2007
Operator Work-Around Board Minutes of September 6, 2006
Operator Work-Around Board Minutes of November 3, 2006
Operator Work-Around Board Minutes of December 5, 2006
Operator Work-Around Board Minutes of January 3, 2007
Operator Work-Around Board Minutes of January 19, 2007
Operator Work-Around Board Minutes of March 28, 2007
Issue Report 630513; Rejectable Indication on Unit 1 Standby Liquid Control Tank Repair Area; dated May 17, 2007
Issue Report 627342; Damage to Standby Liquid Control Tank During Grout Removal; dated May 9, 2007
Issue Report 177026; Manholes 3 and 4 Have Water in the Cable Tunnel; dated February 18, 2003
Issue Report 595145; Weaknesses in Manhole Inspection Preventive Maintenance; dated February 23, 2007
Issue Report 604500; Manholes Discovered with Ground Water Inside; dated March 15, 2007
Issue Report 622100; Re-Evaluation of Issue Report 177026 Cable Assessment; dated April 26, 2007
Issue Report 638156; Three to Four Feet of Water in South Number Three Manhole; dated June 7, 2007
Issue Report 638136; Operability Documentation Enhancements; dated June 7, 2007
Duane Arnold Energy Center NRC Inspection Report 2004003
Brunswick Steam Electric Plant NRC Inspection Report 2000004
Dresden and Quad Cities License Renewal Application, Section B.1.33; Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
Dresden and Quad Cities License Renewal Application, Section 3.6; Aging Management of Electrical and Instrumentation and Controls
Dresden and Quad Cities License Renewal Application, Section 2.1; Scoping and Screening Methodology

4OA3 Event Follow-up
Root Cause Report 597002-06; Unit 2 Manual Reactor Scram on Increasing Condenser Back Pressure due to Blockage of the Pressure Sensing Line by Fine Size Internal Corrosion Products; dated April 18, 2007

4OA7 Licensee Identified Violations
Issue Report 628075; Radiation Work Permit Violation; dated May 10, 2007
RP-AA-210; Dosimetry Issue, Usage and Control; Revision 9
Radiation Work Permit 10007823; Unit Condensate Demineralizer Modification; Revision 0
RP-AA-403; Administration of the Radiation Work Permit Program; Revision 1

LIST OF ACRONYMS USED

ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
HRA	High Radiation Area
LHRA	Locked High Radiation Area
MT	Magnetic Particle Examination
PDI	Performance Demonstrated Initiative
RPT	Radiation Protection Technician
RWP	Radiation Work Permit
SSC	Structure, System or Component
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Examination
VT	Visual Examination